Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 1

PREPARED DIRECT TESTIMONY

OF

WILLIAM REED

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

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I. CALIFORNIA'S ENERGY ACTION PLAN

The California Energy Action Plan estimates that for the next several years, California's peak energy demand is expected to grow by 1500 MW annually – equivalent to building approximately three new large generation facilities *every year*. While SDG&E vigorously supports the construction of new energy infrastructure, a primary directive of the state's Energy Action Plan is that demand-side reductions should be maximized before new generation is considered. To this end, developing programs that encourage customers to reduce demand and shift electricity usage away from peak periods is a priority.

Proceeding R.02-06-001, the Commission's Advanced Metering, Demand Response and Dynamic Rates rulemaking, established an ambitious goal of 5% peak load reduction through demand response programs. Currently, however, SDG&E's demand-response compatible metering infrastructure is deployed to only our very largest customers, representing less than 17% of bundled system load. SDG&E believes that deployment of a state-of-the art, cost effective metering Advanced Metering Infrastructure (AMI) to all of our customers enables us to meet, and possibly exceed, the state's demand reduction goals. However, as detailed in the testimony of witness Edward Fong, a critical factor in making this vision a reality is the Commission's approval of a rate structure that provides appropriate price signals to customers. Without implementing dynamic rates, which may require changes to AB1X, the maximum demand response benefits of installing AMI technology will not be achieved, and therefore AMI deployment may not be justified.

The following chapters provide a detailed account of SDG&E's preferred deployment strategy for an AMI system and of the ratepayer benefits accruing from this system. In addition to the demand response benefits outlined in the chapter of Dr. Steve George, SDG&E's AMI deployment will increase system reliability, reduce environmental impacts, yield operational cost savings and provide customers greater control over their energy bills.

II. SDG&E'S AMI PROPOSAL

As described in Witnesses Edward Fong and Patrick Charles' testimony, and as supported by the many other SDG&E witnesses submitting testimony in this AMI application, SDG&E urges the Commission to adopt SDG&E's proposed AMI program, and specifically to proceed expeditiously with authorizing recovery of pre-deployment costs. SDG&E regards AMI as a "transforming" technology. Specifically, deployment of AMI (along with implementation of corresponding rate structures) will begin to transform how customers perceive and use electricity. In addition, this initiative will impact the manner in which utilities balance supply resources with demand response tools, design and plan transmission and distribution capacity, and provide customer services. This transformation will play a critical role in ensuring that California's energy future is one that minimizes environmental impacts while providing reliable electric service.

For the reasons stated in the following chapters, SDG&E believes that the Commission will find that the costs and benefits of the AMI initiative warrant full system implementation on a rapid schedule. Full deployment provides substantial benefits as reflected in the significant Net Present Value that is presented by Edward Fong in Chapter 2. In addition to these quantified benefits, full deployment will clearly improve operating and installation efficiency and would likely lead to further operating savings in the future. Further, it is far preferable from a customer service perspective to be able to offer all customers access to the same rates.

SDG&E's proposed implementation plan includes a strategy of seeking the highest expected benefits first, and reviewing the results of the program at various stages to ensure that the projected benefits are being achieved. Witness Edward Fong proposes several "off ramps" that can be executed by the Commission to readily modify its AMI deployment strategy if the cost and benefits are substantially different than those included in this application. In particular, SDG&E believes that the Commission needs to adopt appropriate rate designs to achieve the desired demand response benefits. Because of the considerable investment SDG&E must incur to initiate AMI deployment, the Commission's commitment to a reasonable, long-term cost recovery plan must be included in the Commission's authorization of AMI deployment.

This concludes my prepared direct testimony.

QUALIFICATIONS

OF

WILLIAM REED

I am Senior Vice President of Regulatory Affairs for San Diego Gas & Electric Company (SDG&E). I have held this position since April, 2002. I am the officer responsible for regulatory policy for SDG&E. Prior to my current position, I have worked for SDG&E or its parent company for approximately 28 years. My earlier positions have been in the areas of law, bulk power control, energy procurement, regulatory and governmental affairs, and strategic planning. I have testified before the California Public Utilities Commission on numerous occasions.

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CHAPTER 2

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EDWARD FONG

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PREPARED DIRECT TESTIMONY

OF

EDWARD FONG

I. INTRODUCTION

The purpose of this testimony is to provide a summary of: 1) San Diego Gas & Electric Company's (SDG&E) management philosophy and business vision regarding Advanced Metering Infrastructure (AMI), dynamic pricing[1] and demand response, and the overarching policy issues that the Commission must consider with the implementation of AMI and dynamic rates; 2) SDG&E's recommended preferred optimum deployment scenario; and 3) other regulatory and financial factors impacting SDG&E's AMI business case.

SDG&E continues to be a strong proponent of, and leader in, integrating AMI, dynamic rates and demand response. SDG&E's AMI business case preliminary analysis,[2] supplemental analysis,[3] and this application demonstrate (over the analysis horizon through 2021), that, under a preferred default dynamic pricing scenario, AMI and dynamic rates provide sufficient estimated operational and demand response benefits to justify a full or partial scale AMI deployment.

A. Costs Benefits Analysis

SDG&E's updated AMI cost and benefit analysis is contained in Chapter 6 of this application. As specifically indicated, operational benefits from AMI alone do not justify full or partial deployment of AMI. The combination of demand response benefits (i.e. capacity and

[1] Dynamic pricing, dynamic rates, demand response rates, time differential rates and other similar phases are used interchangeably throughout all aspects of this application.
[2] SDG&E's October 22, 2004 filing on the "Preliminary Analysis Regarding Advanced Metering Infrastructure Business Case".
[3] SDG&E's January 12, 2005 snpplemental filing updating the October 22, 2004 filing, "Advanced Metering Infrastructure (AMI) Business Case Snpplemental Filing".

energy) and operational benefits are required to justify AMI deployment. The costs and benefits calculations are discounted to present value terms. The net present value of the costs and benefits represent net "societal benefits." The costs represent all AMI design, deployment, installation and going forward operating and maintenance costs. The benefits include operational benefits and demand response benefits.

Importantly, the functional requirements for AMI drive a significant portion of the AMI costs. If demand response and dynamic rate structures were not included in the functional requirements, the AMI technical requirements would have been reduced or simplified (e.g., exclusion of the requirements for the solid state interval meter, two-way communications, additional meter data management systems, etc.). Lower estimated AMI operational costs, both for installation and on-going, would result from the reduced requirements.

Table EF 2-1

Present Value of AMI Societal Costs and Benefits
($ millions)

	Present Value (2005-2021)				
	1	2	3	4	5
	Cost	Operational Benefits	Demand Response Benefits	Net PV	PV Environ Benefits
Full Deployment	$ 612	$ 392	$ 268	**$ 48**	$2 - 6
Partial Deployment	$ 340	$ 242	$ 207	**$ 109**	$1 - 4

B. AMI and Dynamic Rates Must Be Concurrently Implemented to Realize the Full Benefits of Demand Response

Demand response benefits are calculated assuming implementation of dynamic rates as a default rate structure.[4] Witness Dr. George's prepared direct testimony in Chapter 13 assumes

[4] SDG&E's demand response impact assumes implementation of a default dynamic rate with a one month lag after AMI implementation. The default dynamic rate structure is assumed to be a Critical Peak Pricing rate similar to that implemented for the Statewide Pricing Pilot. Details of the demand response impact analysis are provided in Chapter 13, Dr. George's testimony.

concurrent implementation of a default dynamic rate structure and a relative critical peak pricing level to obtain the demand response benefits shown in Tables 2, 3 and 4 of Chapter 13. If dynamic rates are not, or cannot, be implemented to the degree that induces the demand response shown in witness Dr. George's testimony, then the total benefits may not be sufficient to justify AMI deployment.

C. Demand Response Benefits

AMI facilitates the use of price signals during extreme peak conditions. The Statewide Pricing Pilot (SPP) conducted in 2003-04 demonstrated that with the experimental critical peak pricing (CPP) structure, residential customers reduced demand during CPP periods by an average of 14.4%. Customers in warmer climate zones reduced by an even greater percentage, with the Inland climate[5] zones (climate zones 3 and 4) showing reductions of 16.3% and 17.4% on CPP days. Details regarding the demand response impacts incorporated in the preferred full deployment and partial deployment scenarios are contained in Witness Dr. George's testimony.

The demand response benefits include avoided generation capacity requirements for the extreme peak hours. As set forth in the July 21, 2004 Assigned Commissioner Ruling (Appendix B), avoided generation costs (or capacity benefits) are calculated assuming $85 kW/yr. The present values of avoided capacity or generation benefits are $251 million and $194 million for the preferred full and partial deployment scenarios, respectively. Avoiding energy during the peak demand hours provides significant avoided generation capacity benefits. When net energy reductions are also added to demand response benefits, the present value of total demand response benefits is $268 million for full deployment and $207 million for partial deployment.[6]

[5] Working Group 3 Report, "Impact Evaluation of the California Statewide Pricing Pilot, Final Report," Charles River Associates.

[6] See Chapter 13, Dr. George's testimony, Table 2, showing 50% percentile of present value of demand response benefits from the Monte Carlo simulation.

D. Enabling Technologies, Customer Choice and Longer Term Demand Response

More importantly, the SPP demonstrated that customers are price sensitive and therefore will change their behavior to adjust to price signals. AMI will provide customers with time of day and related energy usage information, and the impacts on their bills. Customers will gain a much greater understanding and awareness of the costs and pricing of electricity, thereby leading to more intelligent and informed customer energy usage choices.

The availability of "enabling technologies" will provide customers with greater control and options over energy use via automated appliance controls, information display devices and other emerging technologies. Nevertheless, SDG&E assumed a very conservative estimate for smart thermostat penetration. SDG&E demand response results assume a 2% penetration of smart thermostat (approximately 24,000 customers).[7] Moreover, the long-term demand response may be even greater as affordable consumer energy control technologies become much more prevalent and customers can exercise even greater choice in terms of appliance and equipment usage.

E. Reliability Benefits Are Difficult to Estimate and Quantify

Although difficult to quantify, increased system reliability will result from implementation of demand response rate structures. The probability of rotating outages (i.e. outages due to demand exceeding supplies) is reduced if price signals can be provided in advance to customers so that demand reductions result in the proper sequence of the "stacking" order for resources as defined the State's Energy Action Plan. Rotating outages due to supply shortages are essentially a short-term phenomenon reflecting conditions, where the price for electricity is extremely high – a vertical supply curve where no additional electric energy resources are available. With proper signals, customers reduce demand during the higher price

[7] See Chapter 10, Mr. Fong's testimony.

periods, thereby decreasing the likelihood of the need for outages. In other words, demand response is a fundamental tool to avoid rolling blackouts during extreme peak periods.

The reliability value of avoiding a rotating outage is often referred to as "the value of service" to customers. Preliminary "value of service" calculations using methodology similar to that presented in SDG&E's October 22, 2004 AMI Preliminary Business Case filing, yields an estimated present value of benefits from reliability of only $11 million in the full deployment case and $8 million in the partial deployment case. SDG&E has not included these benefits in this application's cost benefit analysis.

F. Environmental Benefits are Real, But Difficult to Quantify

SDG&E estimated preliminary environmental benefits, but has provided very low estimates for this application. Because of their very nature, environmental benefits are extremely difficult to quantify. With the assumed CPP rate structure, the net reduction in annual electricity usage is small. However, the reduction of electricity use during the CPP hours is significant. Some shifting of load to non-CPP hours during CPP days does occur, but attempting to quantify the specific marginal avoided resource during CPP and non-CPP hours and their corresponding emissions impact is difficult. SDG&E has estimated a present value $2-6 million in environmental benefits for the full deployment scenario and $1-4 million for the partial deployment scenario.[8] SDG&E does not include these environmental benefits in the net present value analysis, but states the above range of environmental benefits as a potential addition to societal benefits in of support AMI and dynamic pricing.

[8] Assuming avoided CO2 emissions are valued at $8-25 per ton. Energy and Environmental Economics, Inc., "A Forecast of Cost Effectiveness, Avoided Costs and Externality Adders", January 8, 2004.

G. Market Price Mitigation Benefits Are Difficult to Quantify

In addition to reducing the probability of rotating outages and reducing emissions, dynamic rates that induce demand response during high demand periods mitigate even higher wholesale market prices as the wholesale and retail electric markets become more closely aligned in terms of supply and demand conditions. This market price mitigation benefit has not been quantified in SDG&E's application but clearly represents an increase in market efficiency and a more efficient allocation of resources.

H. AMI Technological Uncertainty Is Included in the Costs and Benefits Analysis

Implementing the right AMI technology presents an interesting dilemma prevalent in any technology choice for a 21st century consumer or organization. Specifically, with rapid changes and innovation in technologies, most technologies face "market" obsolescence within a short period of time. Examples of technologies exposed to this obsolescence range from personal computers, to cellular phones, to computer games. SDG&E has been and continues to be a proponent and champion for establishing AMI technology open architecture standards. SDG&E is an active participant, supports, and is a member of the Advisory Board of the Open AMI Task Force. More importantly, SDG&E believes that a single, end-to-end turnkey AMI solution increases the risk of market and technology obsolescence. SDG&E has pursued and continues to design an AMI system in a multi-layered architecture environment, with multiple vendors providing different AMI components for the different architectural layers. Witness Mr. Paul Pruschki provides further technical discussion on the AMI meter and communications components. Witness Mr. Rick Carusa discusses the supporting AMI application software components.

II. SDG&E'S MANAGEMENT PHILOSOPHY AND AMI BUSINESS VISION

Witness Mr. William Reed succinctly affirms SDG&E's executive management support for wide scale AMI deployment, citing AMI benefits accruing from utility operations and customer demand response. This section of my testimony provides additional background and actions taken by SDG&E that reflect Mr. Reed's statement of SDG&E's AMI vision.

As stated in SDG&E's October 22, 2004 "Preliminary Analysis Regarding Advanced Metering Infrastructure Business Case," SDG&E has long been a strong advocate for implementation of advanced metering technologies and movement of customers to demand response rates. Not only will demand response benefits emerge from the implementation of AMI and dynamic rates, but customers will have energy usage information to make informed decisions regarding their individual demand and load profiles. Specifically, customers will have the ability to determine their incremental or marginal energy usage depending on a time differentiated energy price signal. Because retail electric prices will be time differentiated, many customers will likely choose more efficient appliances, automated energy management systems, and load control devices.

Under current flat or tiered rate structures, residential customers are essentially insulated from wholesale electric market prices that vary with market and system conditions. This disconnect from the wholesale market distorts the demand and supply conditions by further exacerbating higher demand during peak hours, thereby leading to a possible gap between demand and supply. In response, SDG&E was the first utility in California to request that the Commission authorize the implementation of "Real-time Energy Meters" and dynamic rates in 2000 in application A.00-07-055. In D.01-05-032, the Commission ultimately approved the settlement of the joint parties authorizing SDG&E to implement advanced meters for approximately 5,000 commercial and industrial (C&I) customers with a demand of 100 kW or

greater. SDG&E is in the process of implementing an advanced metering system with these C&I customers that should be expandable to a wider scale residential and small commercial AMI solution. Furthermore, SDG&E not only supported including state funding of $35 million in AB29X to pay for advanced meters for large C&I customers, but SDG&E also collaborated with the California Energy Commission (CEC) to make additional funds available for the installation of such meters for municipalities.

SDG&E was the first California electric utility to propose and implement time-differentiated rates for a large segment of its C&I customers. Since the late 1980's, all SDG&E C&I customers with a demand of 20 kW or greater have been on a form of a time-of-use rate.[9] In 2003, SDG&E was also the first utility in the United States to have proposed an hourly pricing option (HPO) for large C&I customers.

SDG&E has supported a wider deployment of "smart" thermostat controls in residential homes with central air conditioning. SDG&E believes that customers should have a choice to have their air conditioner controls automatically adjusted to respond to pricing or other events, and, in most circumstances, retain the ability to override the automatic adjustment.[10]

SDG&E continues to champion and advocate for implementation of an opened information technology architecture for AMI. SDG&E firmly believes that if data, hardware, middleware and software interfaces can be standardized across various AMI components, then the adverse impacts of technological or market obsolescence with any single component will be minimized.

[9] Most of SDG&E's C&I 20 kW customers are on a three period AL-TOU rate.
[10] SDG&E proposed to continue the residential smart thermostat program beyond 2004 with modifications. In D.05-01-056, the Commission approved SDG&E's proposed extension and modifications.

III. OVERARCHING POLICY CONSIDERATIONS

A. Voluntary Demand Response Programs Alone are Insufficient

A necessary condition for AMI to achieve sufficient and significant demand response benefits is the simultaneous deployment of dynamic rates. Without default dynamic rates, customers would have little or no incentive to reduce demand during critical peak periods. Voluntary demand response programs alone are insufficient to achieve the 5% demand response targets established in this proceeding and restated in the Energy Action Plan. Voluntary programs will always have some element of "free ridership." In particular, customers with flatter than the class average or system load profiles will benefit from enrolling in a voluntary dynamic rate program, while providing little, or no, demand reductions during the peak periods to achieve such benefits. However, even with dynamic rates, SDG&E believes a portfolio of voluntary demand response and reliability programs should continue to be available for customers as alternatives or complements to the dynamic rates.

B. AB1X Is A Constraint that Prohibits Proper Price Signals from Reaching Customers for Demand Response

Unfortunately, the ability to combine an AMI deployment with the implementation of supporting dynamic rate tariff structures is currently constrained by AB1X. The Commission's application of AB1X is incompatible with implementation of a dynamic rate structure. SDG&E urges the Commission to commence a proceeding and determine dynamic rate structures to be implemented that are consistent with the demand response levels described in this application. AB1X places restrictions on rate design, including absolute rate levels, for residential customer energy usage up to 130% of their baseline allowances. In D.04-02-057 (in R.01-05-047), the "Baseline Phase 2" decision, the Commission adopted an even more restrictive interpretation of AB1X that required SDG&E to freeze total residential customer rates for usage up to 130% of baseline allowances. As a result of this interpretation, SDG&E has been ordered to offset certain

previous non-commodity rate increases by lowering the commodity rates for usage up to 130% of baseline allowances. The costs of providing AB1X rate protection are currently financed through commodity rate surcharges applied to the non-exempt usage of bundled customers, or are resulting in commodity cost undercollections. Even if the pre-D.04-02-057 interpretation of AB1X were only to apply to SDG&E's energy commodity rates, implementation of dynamic rates would be, at best, a convoluted overlay of the current tiered rate structure based on total monthly usage.

If the Commission's interpretation of AB1X were to remain in effect for the full term of the bonds that the State of California previously issued to pay the costs of the 2000-2001 energy crisis, until 2022, SDG&E would be prevented from passing on even normal inflationary increases in rates for approximately 70% of residential usage. Without the ability to pass along an appropriate price signal for over 70% of SDG&E's current residential usage, the maximum demand response benefits of installing AMI technology cannot be realized. Thus, the Commission's interpretation on whether AB1X precludes the utilities from assigning residential customers to a default dynamic rate tariff will prove critical to the success of AMI deployment. The July 21, 2004 Assigned Commissioner's Ruling (ACR) acknowledges this constraint:

> *The Attachment identifies several different tariff structures to analyze but we wish to emphasize that in the near term (given legislative constraints on rate design modifications for some customer classes), we see the most potential benefits deriving from the operational cases.* (ACR, at p. 3)

Until such restrictions are removed or modified, the full demand reduction impacts and benefits of AMI and dynamic pricing cannot be realized. In the event that AB1X or other Commission decisions or legislative action prohibit SDG&E from sending accurate demand response price signals for residential usage of up to 130% of baseline allowances, a portion of the AMI demand response benefits from residential customers identified in witness Dr. Steve

George's testimony would not be achievable. As described below, SDG&E recommends that the AMI business case be reevaluated if default dynamic rates are not instituted.

C. Various Dynamic Rate Options and Demand Response Programs Must Be Available

SDG&E believes that the Commission must determine the appropriate dynamic rate structure to induce demand response that reflects the levels presented in this application. Various dynamic rate options should be made available to customers. The analysis of potential demand response impacts was completed for this filing using illustrative dynamic rate structures specified by the Commission. A comprehensive set of dynamic rate structures must be in place, since the primary objective of AMI deployment is to enable time-differentiated rates, and indeed, the key cost justification of AMI is the demand response impact that result from such price signals. The Commission must commence a proceeding to address dynamic pricing and establish various rate options that can be made available to customers in order to achieve the equivalent demand response impacts set forth in this Application. SDG&E is not advocating one dynamic rate structure over others in this application. Nevertheless, dynamic rates are necessary to induce demand response benefits that are stated in above Table EF2-1.

D. CARE and Medical Baseline Customers Should Retain Their Current Level of Protection

Time-differentiated rates do not prevent SDG&E from providing CARE and Medical Baseline discounts. Relative price ratios are the most important element of inducing demand response between high-priced and low-priced hours during critical peak days. SDG&E currently accommodates the CARE program discount in its SPP tariff offerings, and could similarly incorporate these discounts into future default dynamic pricing tariffs and programs.

Specific rate design changes to protect CARE and Medical Baseline customers should be determined in a separate proceeding to address customer segment specific dynamic rate structures that would need to be implemented to achieve demand response goals. Regardless of the specific dynamic rates adopted for residential and small commercial customers, SDG&E believes that in terms of annual bill impacts, the class of CARE and Medical Baseline customers should not be disadvantaged.

E. Communication and Education Efforts in Support of AMI

To ensure that SDG&E's proposed AMI initiative is successful, SDG&E is planning a robust customer communication and education effort. Although, through the Statewide Pricing Pilot, SDG&E has gained considerable experience with supporting and assisting customers in a dynamic pricing and AMI environment, SDG&E will need to provide for AMI deployment, on an order of magnitude greater, significant customer support, communications and education. AMI deployment will significantly impact customers, including everything from the scheduling of meter change outs to education and information on rate and demand response program options. SDG&E's goal is to provide sufficient customer education and information for intelligent decision making and choices regarding energy use. Please refer to the prepared testimony of SDG&E witness Ms. Wagner, Chapter 12, for a discussion of SDG&E's communication and education plan

F. Evolution of and Improvements in AMI Technology Should Be Encouraged

AMI technology, including advanced solid state interval meters for residential customers, network communications, and meter data management systems, are evolving and changing. Industry open architecture standards are evolving as several organizations, including the Commission and the CEC, have pro-actively encouraged AMI industry participants to establish a "reference design" for hardware, middleware and interfaces. Even de facto industry standards

have yet to evolve because AMI technologies are already moving away from first and second generation automated meter reading (AMR) end-to-end systems, to multi-layered, multi-vendor offerings. Many of the second generation, fixed wireless network solutions are moving away from proprietary networks to the use of public and private wireless and wired wide area networks (WAN) for transporting meter data from network concentrators or data collectors, back to utility servers.

SDG&E is a long-time proponent of establishing open architecture standards with AMI industry vendors. In 2001, SDG&E was the first US utility to require ANSI standard C12.19 data table structures for solid state meters in its Request for Proposal for meter purchases. Moreover, SDG&E was one of the first utilities to provide specifications for an AMI system that could communicate on multiple wide area networks (wired or wireless). SDG&E has been, and continues to be, a leader in shaping the forward looking requirements for AMI systems and to breaking away from the end-to-end, single vendor AMI proprietary systems model.

SDG&E believes that paying a slight premium for technologies with multi-layered components, or "modular" technologies, that are "best of breed," provides a forward looking, flexible and adaptable AMI. In other words, since foresight about future technological innovation and changes is less than perfect, SDG&E believes that as a component (e.g., meter, local area network communications, wide area network communications, software, etc.) ultimately becomes obsolete, SDG&E can minimize the cost of moving to newer and better technology by minimizing the number of components that may be impacted from such changes. SDG&E believes that replacing the parts of an AMI will, in the long-run, be much less costly than replacing the whole AMI.

IV. SDG&E'S OPTIMUM DEPLOYMENT PLAN

A. Plan for Full Deployment

SDG&E's optimum AMI plan assumes a full-deployment scenario with a carefully targeted phased implementation. SDG&E proposes that, if key assumptions driving the estimated costs and benefits contained in SDG&E's business case analysis do not materialize, AMI deployment off-ramps be utilized to protect AMI investments. As stated above, several of the benefits, including reliability (value of service), environmental, increase market efficiency, and customer control over energy are difficult, if not impossible, to quantify. To determine if the subsequent AMI expansion is justified after the Inland climate zone is completed, SDG&E plans to monitor and evaluate changing financial conditions, variance to business case assumptions and estimates, and the cost of deployment operations at various AMI deployment stages. Witness Mr. Patrick Charles, Chapter 3, provides details on SDG&E's proposed deployment plan and schedule.

B. Target Inland Climate Zone & C&I First

SDG&E is proceeding with the assumption of a full deployment AMI scenario. However, SDG&E will begin deployment of AMI and associated demand response rates in the Inland climate zone first. In other words, SDG&E's will start with the preferred partial deployment scenario, which targets the Inland climate zone customers and all C&I customers, and provides a significant positive net present value (NPV).

C. Reevaluation Off-ramps or Gate Decision for Continuing Full Deployment

SDG&E proposes that the initial deployment be completed for the Inland Climate Zone and all C&I customers over 20 kW. If, during the initial deployment phase in the Inland climate zone, economic or dynamic rate assumptions appear to materially impact SDG&E's business case assumptions, then SDG&E proposes that deployment to the Coastal climate zone residential

and small commercial customers be delayed until conditions change to warrant the expanded deployment. It must be noted that SDG&E costs incurred to date should remain recoverable

Specifically, SDG&E proposes that the following conditions be monitored during the Inland climate zone deployment phase:

1) **Dynamic rates are not adopted by the Commission for all customers that will achieve the equivalent demand response impacts set forth in this Application.** Full deployment to Coastal climate zone residential and small commercial customers (remaining 60% of SDG&E's customer base) should be deferred until such rates are in place.
2) **Customer opt-out rates from default dynamic rates after the first year (2007) of deployment appear to exceed 40%.** The business case assumes an approximate 20% opt-out rate. A 40% or greater opt-rate will trigger the off-ramp. Deployment to Coastal residential and small commercial climate zone customers will be deferred until changes in the rate design are implemented to reduce the opt-out rate.
3) **Deployment or installation price points for residential customers (meters, communications hardware, installation labor costs) exceed estimated price points contained in the business case by 20%.** Deployment would be suspended for the Coastal climate residential and small commercial customers until price points are sufficiently low to justify the continuation of full deployment.
4) **Software development cost for AMI meter data management systems appear to be exceeding business case estimates by 50%.** Deployment will be deferred for Coastal climate zone residential and small commercial customers until expanded deployment is justified.

5) **Recovery of existing meters.** SDG&E intends to recover the remaining book value of the installed costs for the existing meters consistent with current ratemaking treatment adopted by the Commission, using the normal straight-line remaining-life depreciation practice. SDG&E will recover the installed cost of the existing meters over the average remaining life prior to implementation of AMI technology. If SDG&E does not receive recovery of the existing meters over their remaining life, then SDG&E reserves the option to suspend AMI deployment.

SDG&E proposes to monitor and report on the above conditions on an annual basis, beginning with year-end 2007 results reported in February 2008. Given the deployment schedule presented by Witness Mr. Charles, SDG&E will not complete AMI deployment to the Inland climate zone customers until mid-2008.

V. OTHER FINANCIAL, REGULATORY AND LEGISLATIVE CONSIDERATIONS

A. Specific Rate Design Is Not in the Scope of this Filing

This proceeding, R. 02-06-001, and the July 21, 2004 ACR setting forth the requirements for this AMI application, did not intend for the utilities to propose ***specific*** dynamic rates that may be implemented at some future date. Rather, the present effort is focused on developing an AMI Business Case, putting forth SDG&E's proposal for AMI deployment, and identifying and estimating the costs and benefits associated with such a deployment of AMI. SDG&E anticipates that once the Commission determines the manner of AMI deployment, the Commission will then undertake the process of developing more specific customer class dynamic rate proposals. Thus, specific default dynamic rate design is not in the scope of this filing. The

scenarios analyzed in the AMI Business Case are as prescribed by the ACR,[11] and are illustrative in nature. They are not presented to be indicative of SDG&E's future rates and pricing proposals, but instead are used for business case demand response modeling purposes. In most cases, the dynamic rates used for the business case analysis approximate the rates used in the SPP.

B. Synchronization With Other Commission and CEC Proceedings

SDG&E understands that several other proceedings have and will incorporate assumptions or forecast for demand response. This application contains forecasts that are specific to dynamic rate structures and critical peak pricing levels that are consistent with the SPP assumptions and results. The specific value of avoided generation costs, environmental benefits, and reliability benefits are based on the values set forth in Appendix B of the July 21, 2004 ACR.

SDG&E cautions that because of the timing of other regulatory proceedings, and the assumptions and forecast used in those proceedings, SDG&E has not be able to perfectly synchronize the demand response forecast across such proceedings.

Issues associated with the development of various demand response programs and costs, the integration of these programs into broader resource plans, as well as consideration of various pricing proposals (including the establishment of default Critical Peak Pricing programs and tariffs), are being considered in a number of interrelated proceedings, including the following:

R. 02-06-001.[12] This proceeding has considered a number of dynamic pricing concepts, demand response goals and targets, and has generated a number of proposals designed to

[11] See ACR, Attachment A, page 10.
[12] Order Instituting Rulemaking on Policies and Practices for Advanced Metering, Demand Response, and Dynamic Pricing.

achieve various pricing and demand response goals. The following proceedings include demand response impacts in their analysis.

Application 05-01-016 et.al.[13] These consolidated Critical Peak Pricing applications, as directed by the assigned Commissioner and ALJ Ruling, proposed default CPP programs and tariffs for implementation by June 1, 2005.

R. 04-04-003.[14] This proceeding is considering policy and program coordination and integration in electric utility resource planning. The role of demand response is an integral consideration in this effort.

R. 01-08-028.[15] This proceeding is addressing energy efficiency policies and administration. In addition, the Commission's recently issued D. 05-01-056, which adopted various utility demand response programs for 2005, directed the utilities to file proposed demand response programs and budgets for 2006 – 2008 on June 1, 2005, the same date on which 2006 – 2008 energy efficiency applications are due to be filed. The integration of demand response and energy efficiency programs is, clearly, an important issue.

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[13] Application of Pacific Gas and Electric Company for Authority to Implement Default CPP Rate Options for Large Customer (A.05-01-016)/Application of San Diego Gas & Electric Company (U902-E) for Adoption of a 2005 Default Critical Peak Pricing Structure for Commercial and Industrial Customers with Peak Demands Exceeding 300 kW (A.05-01-017)/Southern California Edison Company's (U338-E) Application for Approval of Rate Design Proposals for Large Customers (A.05-01-018).

[14] Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.

[15] Order Instituting Rulemaking to Examine the Commissioner's Future Energy Efficiency Policies, Administration and Programs.

The above discussion of various related proceedings is not meant to be an all-inclusive list, but rather is intended to highlight the various forums in which issues related to demand response, energy efficiency, and dynamic pricing are being addressed. These issues are common to these, and other proceedings, and will ultimately require careful consideration and synchronization, as goals, targets, and program designs are established.

C. Terminal Year in Planning Horizon (2021)

As established by the July 21, 2004 ACR, SDG&E's AMI planning and analysis horizon is 2005-2021. Financial analysis methods require that the terminal year, 2021, capture benefits and costs that extend beyond this planning horizon. Conceptually, remaining assets will eventually be replaced and benefits will continue to accrue beyond 2021. SDG&E has abstracted assumptions based on speculation of specific replacement timing and costs for AMI meters and communications equipment. AMI meters and communications equipment are assumed to have a 15 year book life, and are modeled as such in the revenue requirements calculations. However, SDG&E's cost and benefit analysis (total societal benefits), incorporates simplifying assumptions to value the remaining book life of assets extending beyond 2021, as a lump-sum asset in 2021. Therefore, Chapter 6 of my cost and benefits testimony contains this calculation for terminal asset values.

VI. CONCLUSION

SDG&E regards AMI as a "transforming" technology. Specifically, deployment of AMI will begin to transform customers' perception and use of electricity. In addition, utilities will be transformed as demand response will be an additional tool used for balancing supply and demand, designing and planning transmission and distribution capacity projects, and provision of customer services. This AMI transformation will impact almost all utility operations. The customer transformation is less predictable, but may lead to structural changes in demand curves

that may lead to even larger long-run price elasticities, as energy management technology choices become widely available.

This concludes my testimony on AMI policy and SDG&E's management philosophy regarding AMI.

QUALIFICATIONS

OF

EDWARD FONG

Mr. Edward Fong is currently the Director of Measurement and Advanced Metering Infrastructure (AMI) for San Diego Gas & Electric (SDG&E). He is responsible for directing, managing and planning the electric measurement activities and advanced metering technology implementation for SDG&E. Prior to assuming his current position in October 2004, Mr. Fong was Director of Measurement & Meter Reading from 2002-2004, Director of Customer Services Solutions from 2000-2001, and Director of Revenue Cycle Services for from 1998-2000. Mr. Fong has directed and managed measurement, meter reading, billing, call center, branch office, credit and collections, direct access services and other customer services operations at SDG&E.

Ed is currently SDG&E's lead director for the California Public Utilities Commission (CPUC) rulemaking proceeding on Advanced Metering, Dynamic Pricing and Demand Response, R.02-06-001.

Prior to joining SDG&E in 1998, Ed held various director level management positions with the Southern California Gas Company in Human Resources, Organizational Development, Customer Contact, Customer Services Operations Staff, Information Technology, and Planning.

Ed has testified before the CPUC on numerous occasions covering a variety of topics ranging from cost of service, measurement and meter reading to billing systems implementation.

Ed is a graduate of University of California, San Diego with undergraduate and graduate degrees in Economics.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 3

PREPARED DIRECT TESTIMONY

OF

PATRICK K. CHARLES

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 3

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MARCH 30, 2005

CHAPTER 3
PREPARED DIRECT TESTIMONY
OF
PATRICK K. CHARLES

I. INTRODUCTION

The purpose of my testimony is to describe SDG&E's Advanced Metering Infrastructure (AMI) pre-deployment plan as well as the overall full and partial deployment plans and sequence. Additionally, I include a discussion of SDG&E's pre-deployment costs and benefits (for years 2005 and 2006) with the exception of information technology (IT) related costs and benefits which will be covered by witness Rick Carusa in Chapter 4.

II. DISCUSSION

A. SDG&E's AMI Pre-Deployment Plan

SDG&E is requesting expedited approval and authorization for costs that will be incurred in the 2005-06 period for pre-deployment AMI planning and design activities necessary to enable an AMI production roll-out in early (first quarter) 2007. As I discuss in more detail in following sections, if the Commission is unwilling to authorize the aforementioned 2005-06 funding for AMI pre-deployment costs (as well as the IT related pre-deployment costs that witness Carusa details), then SDG&E will not be in a position to begin the AMI production roll-out until 18 months following Commission authorization of AMI pre-deployment expenditures at the earliest. As witness Carusa describes in Chapter 4, developing the IT systems will require at least 18 months, even for such items as purchased vendor software products (that will all require customization / interface development). Additionally, in Chapter 5, witness Van Lierop proposes a cost recovery mechanism for AMI pre-deployment costs.

B. Activities Associated with SDG&E's Pre-Deployment Plan

Specific activities included in the AMI pre-deployment phase include the following:

1) Information technology (IT) systems planning, requirements, design, programming and testing. Witness Rick Carusa will detail these predeployment costs in Chapter 4.
2) Single phase interval solid state meter design, development and testing.
3) Gas module design, development and testing.
4) Communications network testing and development for large scale deployment.
5) Customer education and communications material development and customer contact planning prior to the early Q1 2007 start date of the production roll-out.
6) Overall AMI project and management support, financial management and control and pre-deployment customer contact and field problem resolution.
7) Limited facilities procurement, billing, customer contact center, human resources, claims and meter reading activities.

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Table PC 3-1

SDG&E Pre-Deployment Costs as a precursor to Full Deployment

Direct Pre-Deployment Costs (2005 - 2006) Incurred in Preparation for FULL Deployment ($s in Thousands, not loaded, not escalated) Totals (not Present Value)			
Full Deployment - Costs			
		Pilot / Testing	
		2005	2006
Capital	Communication System	12	2,284
	Facilities	0	637
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	0	3,231
	Information Technology	12,520	14,894
	T&D	0	0
	Totals	12,532	21,025
O&M	AMI Project Management	408	1,631
	Billing	0	158
	Customer Contact Center	0	31
	Claims	0	2
	Communication System	76	388
	Load Control Technology	0	223
	Facilities	0	137
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	7	1,244
	HR	197	117
	Information Technology	20	1,074
	Load Research	0	0
	Mass Markets / Major Markets	24	1,122
	Meter Reading	0	68
	T&D	0	0
	Totals	732	6,194

Loaded & Escalated Pre-Deployment Costs (2005 - 2006) Incurred in Preparation for FULL Deployment ($s in Thousands, loaded and escalated) Totals (not Present Value)			
Full Deployment - Costs			
		Pilot / Testing	
		2005	2006
Capital	Communication System	13	2,569
	Facilities	0	696
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	0	3,637
	Information Technology	14,741	18,127
	T&D	0	0
	Totals	14,754	25,029
O&M	AMI Project Management	667	2,735
	Billing	0	274
	Customer Contact Center	0	53
	Claims	0	2
	Communication System	103	462
	Load Control Technology	0	367
	Facilities	0	145
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	7	1,836
	HR	334	203
	Information Technology	34	1,470
	Load Research	0	0
	Mass Markets / Major Markets	25	1,674
	Meter Reading	0	105
	T&D	0	0
	Totals	1,170	9,326

Table PC 3-2

SDG&E Pre-Deployment Costs as a precursor to Partial Deployment

Direct Pre-Deployment Costs (2005 - 2006) Incurred in Preparation for PARTIAL Deployment ($s in Thousands, not loaded, not escalated) Totals (not Present Value)			
Partial Deployment - Costs			
		Pilot / Testing	
		2005	2006
Capital	Communication System	12	813
	Facilities	0	630
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	0	3,059
	Information Technology	10,804	12,373
	T&D	0	0
	Totals	10,816	16,874
O&M	AMI Project Management	408	1,631
	Billing	0	158
	Customer Contact Center	0	31
	Claims	0	2
	Communication System	78	222
	Load Control Technology	0	146
	Facilities	0	192
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	7	962
	HR	197	117
	Information Technology	20	986
	Load Research	0	0
	Mass Markets / Major Markets	24	992
	Meter Reading	0	48
	T&D	0	0
	Totals	732	5,467

Loaded & Escalated Pre-Deployment Costs (2005 - 2006) Incurred in Preparation for PARTIAL Deployment ($s in Thousands, loaded and escalated) Totals (not Present Value)			
Partial Deployment - Costs			
		Pilot / Testing	
		2005	2006
Capital	Communication System	13	960
	Facilities	0	689
	Gas & Electric Meters / Gas Modules & Installation (Gas & Electric)	0	3,436
	Information Technology	12,790	15,008
	T&D	0	0
	Totals	12,804	20,092
O&M	AMI Project Management	667	2,735
	Billing	0	274
	Customer Contact Center	0	53
	Claims	0	2
	Communication System	103	286
	Load Control Technology	0	233
	Facilities	0	203
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	7	1,390
	HR	334	203
	Information Technology	34	1,309
	Load Research	0	0
	Mass Markets / Major Markets	25	1,470
	Meter Reading	0	73
	T&D	0	0
	Totals	1,170	8,232

SDG&E requests expedited approval and authorization of the above expenditures in order to proceed in timely manner with an AMI production roll out beginning in early Q1 2007. As shown in Tables PC 3-1 and PC 3-2 above, SDG&E's pre-deployment plan and associated costs are largely the same for both the full and partial production roll out. The activities and related costs are largely the same under either scenario with differences related to scaling issues associated with the applicable follow-on deployment scenario. SDG&E has proposed that the Commission proceed with a separate procedural schedule for reviewing the authorization and approval of the utilities' overall AMI deployment proposals. Nevertheless, SDG&E cannot prudently proceed without funding for these significant pre-deployment activities.

Accordingly, SDG&E urges the Commission to act expeditiously in reviewing and approving this limited portion of the proposal so as to not slow the momentum of AMI deployment and, therefore, delay the operational and demand response benefits that will accrue from AMI and the associated dynamic rate implementation.

III. AMI PREDEPLOYMENT COSTS – FURTHER INFORMATION

A. Single phase interval solid state meter design, development and testing.

A majority of the customers in our service territory are residential customers. These customers require a lower cost AMI metering alternative than the available commercial and industrial customers' AMI meter. SDG&E has developed a residential AMI electric meter specification that represents the critical AMI functionality required at the residential level. SDG&E will need to contract with both a meter vendor and an AMI communications supplier to develop a metering product that meets SDG&E's specifications. It will take time to develop and test prototype products against ANSI and FCC standards. SDG&E will need to install these new metering devices in the field and complete evaluation and reliability studies prior to implementing AMI on a system wide basis. In addition, SDG&E prefers to have multiple meter vendors in order to reduce potential delays of product shipments that may extend the installation schedule. As discussed in more detail below, SDG&E plans to conduct a 10,000 AMI electric meter beta test evaluation in 2006.

B. Gas module design, development and testing.

SDG&E expects to deploy 10,000 AMI compatible gas meter communications modules in 2006 for the purpose of performing a beta test of the gas modules. The AMI compatible gas meter communications modules are battery-powered devices that allow wireless radio communication with a relay, an electric meter, or a gateway. SDG&E expects that a small

percentage of gas meters will require replacement to facilitate an AMI gas communications module.

The 2005 and 2006 costs are associated with the purchase of the AMI gas modules, a percentage of replacement gas meters, labor costs to install the 10,000 gas modules (and a percentage of gas meters), and training and oversight necessary for quality assurance and safety during these beta phase installations.

C. Communications network testing and development for large scale deployment.

SDG&E captured a portion of the pre-deployment costs related to the communications network in the Commercial AMI (also known as RTEM) deployment that will occur between 2005 and 2006. SDG&E intends to continue that pace of deployment into the AMI deployment. As trials for residential gas and electric meter and module installations are conducted, SDG&E will continue to deploy the communications network to accommodate the 10,000 meter beta test. This testing is necessary in order to ensure that the communications network functions with residential meters in a large scale deployment.

Therefore, there will be very few 2005 incremental costs related to the communication network for AMI. SDG&E anticipates that it will begin accruing incremental costs in the second quarter of 2006 associated with the AMI communications network design.

D. Customer education and communications material development and customer contact planning prior to the early Q1 2007 start date of the production roll-out.

It is important that customers understand the new meter installation and the associated dynamic rate options that will be possible under AMI. SDG&E will be proactive with customers, educating and informing them at community outreach events and local city events. For non-residential customers, brochures and other tools will be developed that will be disseminated at trade shows, vendor mixers, corporate and chamber of commerce presentations

as well as through targeted direct mailings to specific industries. All communication material produced will also be made available to service technicians for distribution.

E. Overall AMI project management support, financial management and control and pre-deployment customer contact and field problem resolution.

In 2005 and 2006, SDG&E requires resources to manage the overall AMI project and to develop and maintain the proper financial management and controls necessary for a project of this magnitude. SDG&E must develop customer policies, field procedures and practices in advanced of 2007 field deployment. Additionally, pre-deployment customer contact and field problem resolution personnel will also be required. These costs are primarily related to the additional work force associated with these efforts.

F. Limited facilities procurement, billing, customer contact center, human resources, claims and meter reading activities.

IV. AMI PRE-DEPLOYMENT BENEFITS

Due to the very limited number of AMI meters that will be installed during the 2005 – 2006 timeframe, very little benefits accrue during this period. Witness Fong shows 2005 and 2006 benefit numbers in Chapter 6. Once the beta phase is completed in 2006, SDG&E estimates that the meter reading and billing functions will accrue some minor benefits in 2006. SDG&E does not expect to accrue significant benefits until the production roll-out in early 2007.

V. AMI DEPLOYMENT WILL BUILD UPON THE REAL TIME ENERGY METERING (RTEM) AB29X METERING DEPLOYMENTS

SDG&E worked closely with the California Energy Commission (CEC) and the Governor's office to develop a statewide real-time energy metering proposal that was incorporated in the passage of emergency legislation (AB 29X) in response to the California energy crisis in 2001. One of the key provisions of AB 29X was state funding to install real-time energy meters for all large commercial and industrial customers whose peak demand exceeds 200kW (SDG&E was granted a threshold of 300kW).

SDG&E completed its deployment of AB29X meters with communications in the late third quarter of 2004. In this phase of work, SDG&E used 'land lines' (hardwired telephone connections) or cell phone devices to transfer data from each individual meter to the utility on a daily (or more frequent) basis. This approach was utilized because SDG&E's distributed AMI communication network technology is still in development, and will likely not be fielded until the late third quarter of 2005 as part of the Commercial AMI (aka RTEM) deployment (customers 100 kW or greater).

The RTEM deployment will result in the installation of a communication network of gateways and relays throughout SDG&E's inland and coastal climate zones representing roughly 15% - 20% of that needed for a full AMI deployment. This early Commercial AMI deployment does, however, represent a significant step forward and will provide SDG&E with greater hands-on experience using AMI technology.

VI. SDG&E'S AMI DEPLOYMENT PLAN PROPOSAL

A. Background

Witness Edward Fong has provided the policy background outlining SDG&E's proposed AMI deployment approach and as required by the CPUC's November 24, 2004 Assigned Commissioner and Administrative Law Judge's Ruling (11/24 ACR). As required the ACR, SDG&E is presenting two geographic AMI deployment scenarios: a partial deployment scenario and a full deployment scenario. Both scenarios are preceded by a beta test phase.

B. Beta Test Phase

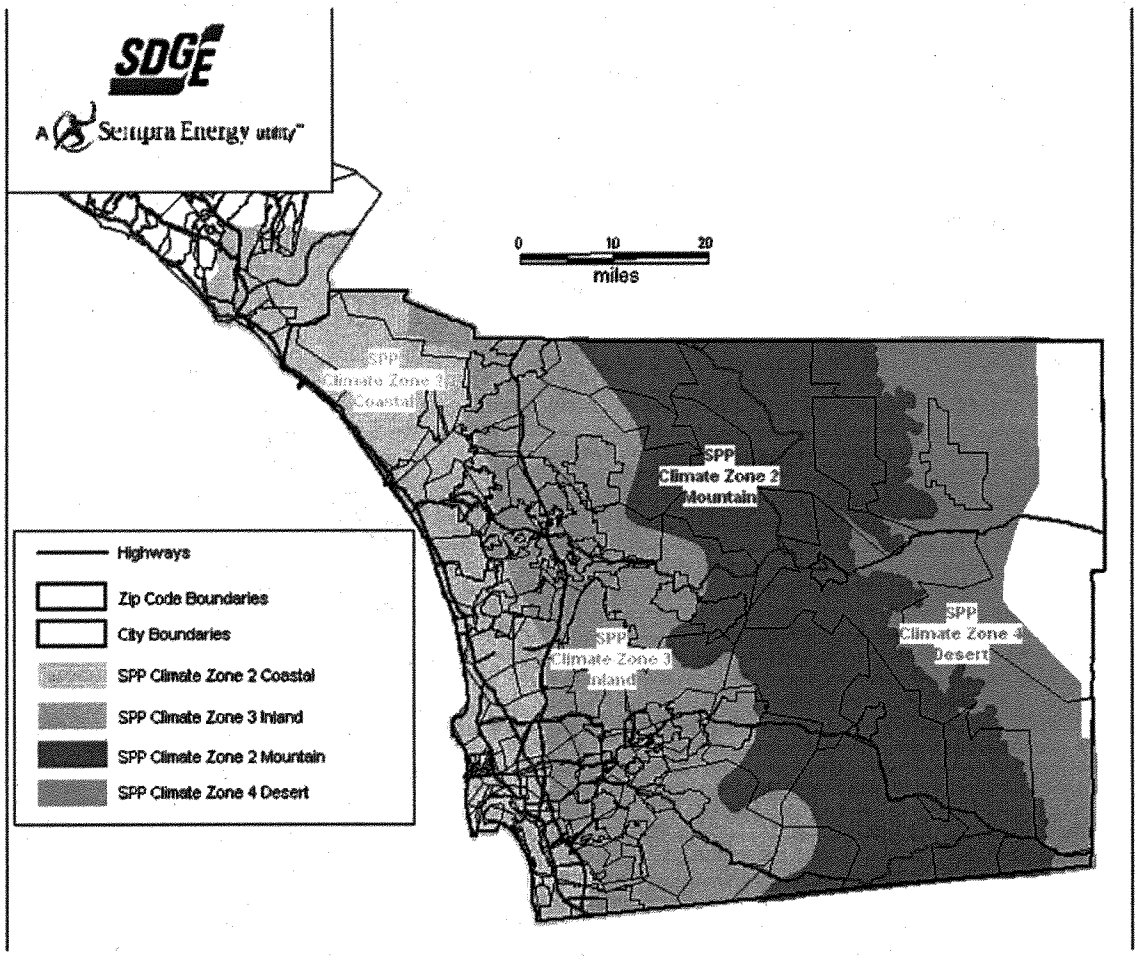
As discussed in the October 22nd and January 12th preliminary analysis filings, each of SDG&E's AMI deployment scenarios includes an initial test, or "beta" phase, beginning in the first quarter of 2006. The beta phase of each deployment scenario consists of installing 10,000 AMI enabled electric meters (roughly 8,000 single-phase electric meters and 2,000 poly-phase

electric meters) during an approximate six-month period and the associated gas AMI installations (approximately 10,000 gas AMI installations would occur - - ideally a mix of changing out some older gas meters, and performing the simple gas index retrofits). Completion of the beta phase will provide SDG&E the opportunity to review its installation process, test installation support systems, and permit incorporation of any necessary changes to technology or process improvements in preparation for the launch of the "production" installation phase (either preferred partial or preferred full scale) beginning in January 2007.

C. SDG&E's Partial Deployment Scenario

SDG&E's partial AMI deployment scenario targets all customers in SDG&E's Inland Climate Zone and all commercial and industrial customers throughout SDG&E's service territory whose peak load exceeds 20 kW. SDG&E's inland climate zone is generally comprised of the Interstate 15 corridor in the northern section of San Diego County, and the area east of Interstate 805 in the central and southern portions of the county. Specifically, SDG&E's climate zones are shown in the following map (Figure 3.1).

Figure 3-1
Climate Zones in SDG&E Service Territory



SDG&E's inland climate zone is warmer on average than the coastal zone and contains a significant portion of SDG&E's overall customer base. SDG&E's partial deployment focuses on the inland zone because of the warmer climate in this geographical area and the higher penetration and use of air conditioning during peak demand conditions as evidenced by the inland climate zone customers' higher average monthly use than coastal customers.

Specifically, SDG&E's customer base is shown in Table 3-3.

Table PC 3-3

SDG&E's Average Customer Base By Climate Zone (Bundled and DA in 2003)			
Customer Class	**Coastal and Mountain CZs**	**Inland and Desert CZs**	**Total**
Residential	664,778	481,590	**1,146,368**
Small C&I <20 kW	71,201	46,350	**117,551**
Medium C&I 20kW – 300 kW	10,972	6,064	**17,036**
Large C&I > 300 kW	1,044	792	**1,836**
Total	**747,995**	**534,796**	**1,282,791**

Table 3-4 illustrates the differences in demand response impact between the partial (all customers in the inland zone and all commercial customers throughout the service territory 20kW and larger) and the full deployment scenarios.[1]

Table PC 3-4

SDG&E Demand Response Impact Summary - MWs		
Default / Optional Tariff Structure	**Deployment Scenario**	**2010 Demand Response Impact**
Preferred	Partial	271
Preferred	Full	360

[1] See prepared direct testimony of witness George, Chapter 13 for additional demand response details.

Table 3-3 shows that roughly 39% of SDG&E's customers will be covered by the preferred partial scenario ((481,590 + 17,036 + 1836) / 1,282, 791 = 39%). Table 3-4 demonstrates that customers covered by the preferred partial scenario will provide roughly 75% of the full-deployment scenario's demand response under our preferred rate assumption (271 / 360 = 75%). Dr. George will provide much greater detail regarding the preferred rate scenario and demand response assumptions in his testimony contained in Chapter 13.

D. SDG&E's Preferred Full Deployment Scenario Leverages an Initial Deployment to Inland Climate Zone Customers

SDG&E's preferred full AMI deployment scenario starts with deployment to Inland climate zone customers and all commercial customers with 20 kW or greater in demand. Because the partial scenario includes SDG&E's commercial customers with demands of 20 kW or greater on the AMI platform, the AMI communications gateways established for these commercial customers could be extended to the remaining residential customers in the Coastal climate zone and elsewhere when appropriate.

By end of 2008, SDG&E's partial deployment plan calls for installing approximately 600,000 electric meters and approximately 400,000 gas meters over a three-year period (one year beta phase followed by a two year production roll out period). In the partial deployment scenario, SDG&E will have gained considerable experience in large scale installation of advanced meters and will have refined the information tracking systems, optimized the installation process, established the meter data collection processes, and worked with customers and communities to maximize the efficiency of the deployment process and the resource requirements.

SDG&E's Full-Deployment AMI Scenario

Because the partial scenario includes SDG&E's commercial customers 20 kW or greater, the AMI communications network (gateways and relays) established for these commercial customers could be extended for the remaining customers in the coastal climate zone. In SDG&E's full deployment scenario, however, anticipates a more aggressive pace of installations from the outset in order to complete the production roll-out over a three year period (2007-2009).

As stated, SDG&E's full deployment scenario initially focuses deployment efforts on the inland climate zone followed by the coastal climate zone and finally moves to the more sparsely populated desert and mountain zones. As shown above, the inland zone represents a large portion of SDG&E's customer base with a high penetration of central air conditioning and correspondingly higher electric usage. For these reasons, SDG&E's full deployment begins with the inland zone and branches out upon its completion.

Figure 3-2 provides an overview of the timelines associated with SDG&E's partial and full deployment scenarios.

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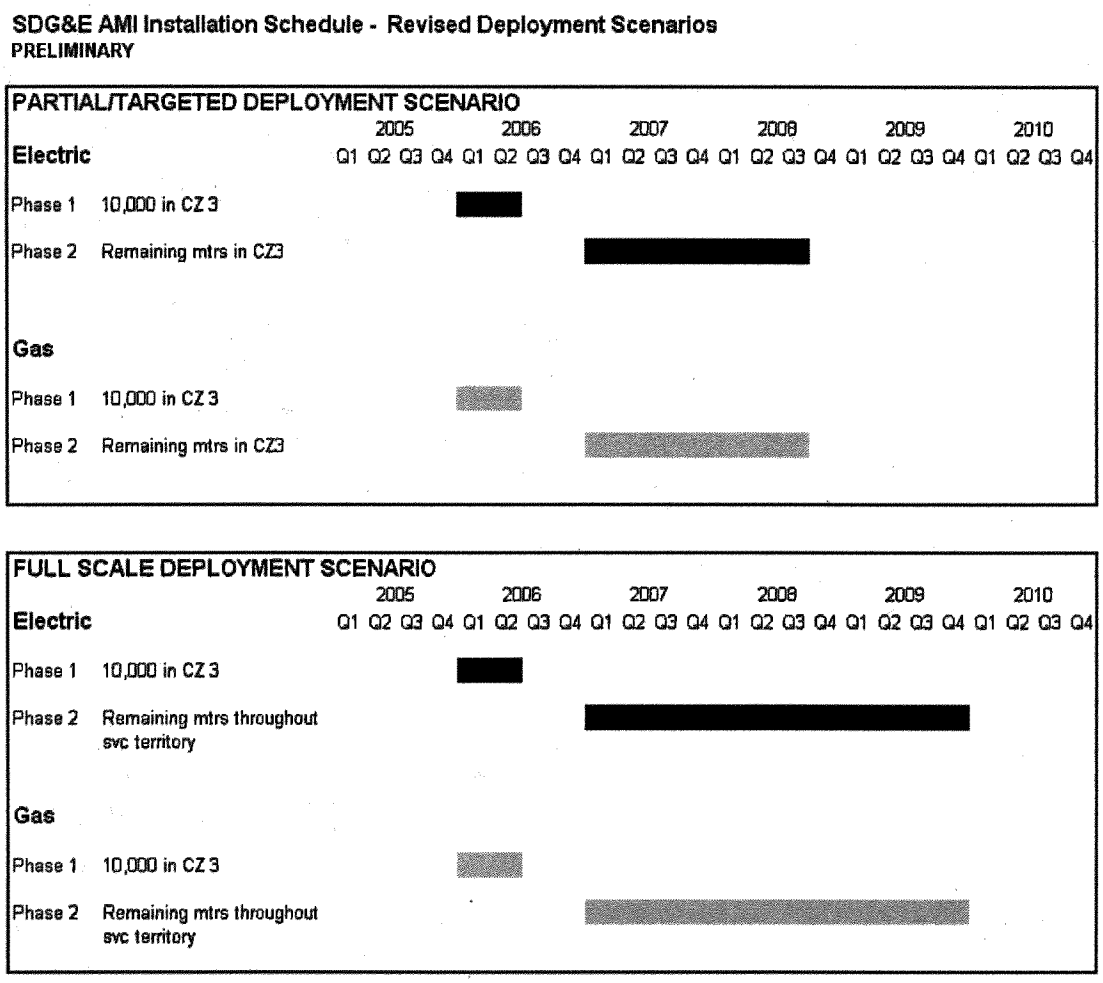
Figure 3-2



Remote, Sparsely-Populated Regions

Customers in remote areas of SDG&E's service territory will receive the same AMI compatible meters as other customers, however, their meter data will most likely be retrieved via drive-by collection.

Premises potentially falling into this category will be evaluated on a case-by-case basis to determine the cost effectiveness of extending AMI network coverage, and in cases where it is determined that it is not cost effective (typically an installation whose cost exceeds the average cost by more than 100%), SDG&E will use a drive by data gathering approach to gather meter

data (time-of-use data, not interval data). SDG&E anticipates that the AMI communications network will reach at least 95% of our customer base and the remaining 5% of customers will be covered by an alternate system. See witness Paul Pruschki's testimony in Chapter 8 for further details regarding SDG&E's network coverage assumptions.

This concludes my prepared direct testimony.

QUALIFICATIONS

OF

PATRICK K. CHARLES

My name is Patrick K. Charles and I am employed by San Diego Gas & Electric Company (SDG&E). My business address is 8326 Century Park Court, CP62C, San Diego, CA 92123.

My present position is Planning and Analysis Manager in the Electric Measurement and AMI Department of SDG&E. I have been employed by SDG&E since 1999. Previous positions relevant to my testimony include Customer Services Support Manager within the Federal Accounts Department at SDG&E from 2001 – 2003 and Project Management Manger within the Meter Reading Department from 2003 – 2004.

I received a Bachelor's Degree in Business Administration (Marketing) from the University of Colorado at Boulder in 1989, and an MBA with an emphasis in finance from the University of Missouri at Kansas City in 1999. I have not previously testified before the California Public Utilities Commission.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 4

PREPARED DIRECT TESTIMONY

OF

RICHARD CARUSA

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 4

PREPARED DIRECT TESTIMONY

OF

RICHARD CARUSA

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

CHAPTER 4
PREPARED DIRECT TESTIMONY
OF
RICHARD CARUSA

I. INTRODUCTION

The purpose of my testimony is to: (1) describe the predeployment costs and benefits associated with Information Technology (IT) systems for both the full and partial deployment scenarios of Advanced Metering Infrastructure (AMI); and (2) describe the *ongoing* costs and benefits associated with IT systems for both full and partial deployment scenarios of AMI. The specific cost/benefit categories that I discuss are in Tables RC4-1 through RC4-5.

Table RC 4-1

Table RC 4-1 Information Technology ($ thosands)							
Full Deployment	Direct **Costs** (not loaded, not escalated)						
		2005	**2006**	**2007**	**2008**	**2009**	**2010 - 2021**
	Capital	12,520	14,894	6,693	1,224	598	15,062
	O&M	20	1,074	2,787	3,803	3,855	39,901
	Direct **Benefits** (not loaded, not escalated)						
		2005	**2006**	**2007**	**2008**	**2009**	**2010 - 2021**
	Capital	0	750	831	0	0	0
	O&M	0	0	0	0	0	0
Partial Deployment	Direct **Costs** (not loaded, not escalated)						
		2005	**2006**	**2007**	**2008**		**2009-2021**
	Capital	10,804	12,373	5,278	1,075		12,658
	O&M	20	966	2,418	3,154		35,808
	Direct **Benefits** (not loaded, not escalated)						
		2005	**2006**	**2007**	**2008**		**2009-2021**
	Capital	0	750	831	0		0
	O&M	0	0	0	0		0

II. DISCUSSION

IT cost estimates are based on an eighteen-month schedule to implement the majority of the systems projects. Because of this aggressive schedule, much of the IT project work will require outsourcing to contractors and software vendors, resulting in a relatively high percentage of contract labor usage. SDG&E estimates a 50-75% contractor to internal labor mix on most projects. To further expedite the AMI development process, SDG&E will most likely evaluate and select available vendor software packages over custom-built solutions. In developing the

estimates and forecasts in this testimony, SDG&E assumed three rounds of IT computer server replacements for the period through 2021. A 20% reduction in cost versus the initial purchase was also assumed for the server replacements. Although it is difficult to predict specific innovations in technology, history (such as Moore's Law),[1] demonstrates that technology becomes cheaper over time.

A. Capital Costs

Due to widespread residential AMI deployment, capital "Startup and Design Costs" focus on labor costs related to identifying and designing incremental or additional AMI network requirements. Capital "Installation" costs are the most significant portion of the AMI systems costs. These costs include development and implementation of several new systems to support AMI business requirements, as well as modifications to existing systems. Capital "Ongoing" costs include server replacements as well as support of AMI infrastructure deployment activities, including exception processing and other work to ensure accuracy of customer records. For further scope of anticipated projects, see Section II D.

Systems will be developed and deployed in a two-phased approach. The initial phase will support the "Beta Phase" meter pre-deployment activities and will include enhancements to systems to support new or modified business processes required to support AMI deployment and operations. The second phase of implementation will support more widespread AMI deployment (both full or partial deployment scenario). This second phase of AMI deployment will include enhancements to existing systems and new systems required to support new rates and high volumes of interval data transfer, access and storage. Furthermore, this phase also includes any system enhancements identified through beta phase pre-deployment "lessons learned." Overall

[1] Moore's Law is based on Intel co-founder Gordon Moore's predictions that computing processing power doubles every 18-24 months.

project management and system integration costs will be incurred during the capital "installation" phase.

B. O&M / A&G Costs Related to AMI Systems Support and Interval Data Processing

Ongoing O&M costs represent expected new incremental O&M workforce resources to support new applications, databases, and other AMI-related systems assets. These incremental costs include on-going software licensing and incremental charges to support hardware and software maintenance. In addition, several of the AMI systems and database projects will directly support the higher volume of interval data transactions that will be processed daily. SDG&E's operations currently processes approximately 8,000 interval meters. SDG&E is expected to process 1.4 million interval meters in the full deployment scenario and some 600,000 interval meters with partial deployment. Clearly, introduction of the new meters will require additional resources to complete the daily interval data collection, processing, validation and exception handling.

C. Partial versus Full Deployment Costs

The percentage of system costs incurred in the various deployment scenarios (i.e. partial versus full) was determined on a system-by-system basis. With the exception of storage and CPU costs, the overwhelming majority of costs for AMI related systems are not dependent on the number or volume of AMI meters deployed. Most system costs are related to business process changes associated with deploying and maintaining a large scale AMI and the customer service impacts associated with such an effort and would apply in either the full or partial deployment scenario.

D. Software Application Projects

The following are specific IT software applications that require development to support AMI:

1. Meter Information Tracking

AMI requires management of many new data elements, including but not limited to: meter firmware versioning, network path (parenting), and accounting information to help manage communication costs. Also, the deployment and maintenance of the metering infrastructure requires new IT support services for order scheduling, telecommunications accounting, issue tracking, interfaces to contractor systems, and project reporting. SDG&E proposes to augment the meter management functions available in current systems with this new system. To leverage customer service work order efficiencies and customer service operational support, SDG&E assumes this new system will be fully integrated with existing SDG&E order and dispatch systems.

2. Meter Data Management

SDG&E's current MV-90 system processes approximately 8,000 interval meters every month. In addition to calling meters and retrieving their data, this system validates the data and allows editing and estimation for missing or erroneous intervals. A full deployment of AMI will require a system to validate and process the in excess of 18 billion intervals per year. At most, SDG&E's current system is capable of processing 32,000 interval meters. A new system is required to handle the volume of meter data anticipated for either the partial or the full deployment scenarios. SDG&E anticipates that the bulk of the cost for this system will derive from the hardware and communications infrastructure required to store and process this volume of data.

3. AMI Network Vendor

SDG&E anticipates installing, customizing, and interfacing to an AMI network software solution. This application provides communication to the meters through the appropriate AMI devices. This system will also likely contain the diagnostic functions to remotely determine

meter hardware and communication failures. Additionally, this system may provide outage restoration data and information and may be integrated with other outage management applications to support restoration efforts.

SDG&E is currently working with an AMI vendor to develop the Commercial AMI (formerly named RTEM) project which includes only our largest commercial meters (100 kW or greater). To develop the application to SDG&E's specification to support a larger deployment of advanced meters for residential and small commercial customers, further work with the vendor is required.

4. Meter Data Presentment

This customer information application displays load shapes based upon a customer's electricity consumption from the previous day. A web accessible and browser-based application would be provided to all customers free of charge, but SDG&E would require customer enrollment for access and security privileges. SDG&E estimates that, at most, 15% of residential customers will be interested in this service; however, no more than 2% of our customers would use the application concurrently. These assumptions are consistent with Statewide Pricing Pilot (SPP) survey results. SDG&E plans to store thirteen months of interval data for active participants.

Meter Data Presentment functionality is currently available to SDG&E customers participating with AB 29X metering and/or demand response programs, including the Statewide Pricing Pilot. Given the anticipated volume of customers using this vendor-hosted application, SDG&E will evaluate whether to renegotiate the current contract, choose another vendor, or develop an alternative application. SDG&E has issued an RFI to nine vendors and has received six responses. SDG&E intends to issue an RFP as a next step.

5. AMI Data Warehouse

Managing AMI requires tracking and managing new equipment types, new attributes for existing equipment, and new work order types and elements. This new reporting warehouse will provide meter history information, gateway and relay inventory, interval data, and other data elements. In addition, reports generated from the warehouse will provide key performance information for deployment activities.

SDG&E anticipates the need to integrate information from several different systems, new and legacy, into a single data repository. Data sets and reports will be generated from this repository using various warehousing tools and/or cube technology. These tools will support customer service, metering, project management, and load research activities without impacting production systems.

6. AMI Deployment

During tbe first three years of the deployment, SDG&E will be building, customizing, and integrating systems to support AMI. However, because several critical path dependencies are involved in systems development, some of the systems will not be available on "day one" of meter deployment. Lasting three years, SDG&E anticipates the need for additional resources and work force during the systems application development and start up period. These resources would be responsible for building and supporting the "bridging applications" and ad-hoc reporting envisioned during the first two years of the deployment period (e.g., beta test phase and first year of mass deployment). To assure that the terms, conditions and schedule are met, these resources will also be responsible for handling data exchange issues with external vendors (such as the contract meter installers).

7. Existing Infrastructure Upgrades

Due to the extensive volume of data associated with wide scale AMI deployment, SDG&E needs to conduct a comprehensive analysis of existing technical infrastructure to identify capacity issues and bottlenecks. Specific infrastructure projects may be required to expand storage capacity, backup and recovery technology, security, networking, or other areas with limited capacity or throughput. These upgrades will likely include a new region of the mainframe computers for systems development and testing.

8. Meter Shop Enhancements

SDG&E anticipates the need to make enhancements to its Meter Shop to facilitate and expand meter-testing activities associated with the new AMI meter technologies.

9. Customer Information System (CIS)/Service Order AMI Enhancements

SDG&E's core systems, such as CIS, are responsible for most billing and customer service functions. Although SDG&E's existing core systems will be augmented with new systems supporting AMI, the existing CIS and Billing systems will need to include identification of new equipment types, attributes, work order types and associated customer contacts. SDG&E anticipates the need for new self-service tools to assist customers to enroll or opt out of the new rate and load control programs. These new customer tools will be available through the SDG&E Customer Portal as well as SDG&E's interactive voice response system.

10. Billing System

To minimize the impact of day-to-day AMI billing and customer service operations, interval data will continue to be aggregated outside of SDG&E's billing system. SDG&E currently aggregates and processes interval data into billing determinants outside of the billing system, and then, on a daily basis, passes those determinants on to produce customer bills. Interval Data Systems (IDS) is a custom-developed, in-house system that processes interval data

into billing determinants. With the extensive volume of data required by the AMI and Demand Response scenarios, modification or replacement of SDG&E's existing IDS is required. RFIs have been issued to fourteen vendors; eight have responded.

11. Systems Integrator

Due to the significant number and complexity of parallel systems projects required to support AMI, SDG&E recognizes the inherent risk in meeting the current AMI deployment schedule. Although SDG&E has extensive experience in managing projects in-house, utilization of an external Systems Integrator resource would add experience, labor resources, tools, and methodologies that could greatly mitigate many of the AMI IT systems development project's risks. The outsourcing of some aspects of the project management provides SDG&E with specific AMI systems integration experience, and the Systems Integrator will be, among other things, tasked with completing an analysis of the most cost effective mix of internal and outsourced software development resources. SDG&E sent an RFI for AMI Systems Integration to nineteen vendors, and has since received eleven responses.

12. Handheld Devices

SDG&E anticipates that the installation and retrofit of the meters supporting AMI will be outsourced. However, SDG&E personnel are assigned the role of troubleshooting broken meters and gathering meter data manually when communications fail. SDG&E personnel will require portable handheld devices to support the related field work. New handheld devices and supporting software may need to be developed.

13. Load Control Software

SDG&E has included the cost of load control device software to, among other things, signal various load control devices, track customer enrollment and participation in the program,

and generate incentive payments. SDG&E will work with load control technology vendors willing to integrate their products with the chosen AMI telecommunications solutions.

14. Notables System Not Included in AMI Systems

SDG&E does not envision contacting individual customers to notify them of critical peak pricing events. The estimates assume that customers will be notified via mass media communications and electronic alerts (e.g., website and email). Contacting individual customers for critical peak events has significant cost as well as technological implications. Even with a robust automated notification system, contacting a large subset of customers the day before a pricing event may not be technically possible given the sheer number of customers being contacted over a standard telecommunications infrastructure. Even if it were possible, the recurring monthly cost of maintaining the telecommunications trunk capacity and infrastructure would be significant.

SDG&E does not envision the requirement for meter route optimization stringing software, a business function that is handled manually today. SDG&E does not believe that activities like extensive engineering surveys and significant software customization could be completed in time to benefit the AMI project.

This concludes my prepared direct testimony

Tables RC 4-2 through RC 4-5

Table RC 4-2

Information Technology

FULL Deployment Scenario - Cost Summary ($ thousands)

Cost Category Summary

Yearly Total **Direct** Costs

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs																	
IT Applications	12,520	14,894	6,693	1,224	598	2,013	3,061	0	0	0	1,994	2,919	142	0	0	1,988	2,945
Total Capital Costs	12,520	14,894	6,693	1,224	598	2,013	3,061	0	0	0	1,994	2,919	142	0	0	1,988	2,945
O & M / A & G Costs																	
IT Applications	20	1,074	2,787	3,803	3,855	4,180	4,025	4,011	4,018	4,018	2,808	2,808	2,801	2,808	2,808	2,808	2,808
Total O&M / A&G Costs	20	1,074	2,787	3,803	3,855	4,180	4,025	4,011	4,018	4,018	2,808	2,808	2,801	2,808	2,808	2,808	2,808

Cost Category Summary

Yearly Total **Fully Loaded** Costs

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs																	
IT Applications	14,354	17,187	7,715	1,651	620	2,092	3,175	0	0	0	2,072	3,027	147	0	0	2,062	3,058
Total Capital Costs	14,354	17,187	7,715	1,651	620	2,092	3,175	0	0	0	2,072	3,027	147	0	0	2,062	3,058
O & M / A & G Costs																	
IT Applications	33	1,397	3,702	5,163	5,381	5,919	5,670	5,655	5,663	5,663	3,667	3,667	3,660	3,667	3,667	3,667	3,667
Total O&M / A&G Costs	33	1,397	3,702	5,163	5,381	5,919	5,670	5,655	5,663	5,663	3,667	3,667	3,660	3,667	3,667	3,667	3,667

Table RC 4-3

Information Technology

FULL Deployment Scenario - Benefit Summary ($ thousands)

Benefit Category Summary

Yearly Total **Direct** Benefits

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits																	
IT Applications	0	750	831	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Benefits	0	750	831	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Benefits																	
IT Applications																	
Total O&M / A&G Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Benefit Category Summary

Yearly Total **Fully Loaded** Benefits

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits																	
IT Applications	0	837	913	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Benefits	0	837	913	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Benefits																	
IT Applications																	
Total O&M / A&G Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Benefit Element Detail

Yearly Total **Direct** Benefits

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits																	
IT for Meter Reading																	
MB-15	0	750	831	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Benefits	0	750	831	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Benefits																	
IT for Meter Reading																	
MB-15																	
Total O&M / A&G Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Benefit Element Detail

Yearly Total **Fully Loaded** Benefits

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits																	
IT for Meter Reading																	
MB-15	0	837	913	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Benefits	0	837	913	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Benefits																	
IT for Meter Reading																	
MB-15																	
Total O&M / A&G Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table RC 4-4

Information Technology

PARTIAL Deployment Scenario - Cost Summary ($ thousands)

Cost Category Summary

Yearly Total **Direct** Costs

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs																	
IT Applications	10,804	12,373	5,278	1,075	449	1,816	2,295	0	0	0	1,797	2,189	106	0	0	1,791	2,215
Total Capital Costs	10,804	12,373	5,278	1,075	449	1,816	2,295	0	0	0	1,797	2,189	106	0	0	1,791	2,215
O & M / A & G Costs																	
IT Applications	20	966	2,418	3,154	3,113	3,240	3,085	3,074	3,079	3,079	2,449	2,449	2,444	2,449	2,449	2,449	2,449
Total O&M / A&G Costs	20	966	2,418	3,154	3,113	3,240	3,085	3,074	3,079	3,079	2,449	2,449	2,444	2,449	2,449	2,449	2,449

Cost Category Summary

Yearly Total **Fully Loaded** Costs

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs																	
IT Applications	12,454	14,229	6,157	1,496	466	1,887	2,380	0	0	0	1,868	2,270	110	0	0	1,857	2,301
Total Capital Costs	12,454	14,229	6,157	1,496	466	1,887	2,380	0	0	0	1,868	2,270	110	0	0	1,857	2,301
O & M / A & G Costs																	
IT Applications	33	1,244	3,223	4,272	4,304	4,515	4,265	4,254	4,259	4,259	3,220	3,220	3,215	3,220	3,220	3,220	3,220
Total O&M / A&G Costs	33	1,244	3,223	4,272	4,304	4,515	4,265	4,254	4,259	4,259	3,220	3,220	3,215	3,220	3,220	3,220	3,220

Table RC 4-5

Information Technology

PARTIAL Deployment Scenario - Benefit Summary ($ thousands)

Benefit Category Summary

Yearly Total **Direct** Benefits

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits																	
IT Applications	0	750	831	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Benefits	0	750	831	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Benefits																	
IT Applications																	
Total O&M / A&G Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Benefit Category Summary

Yearly Total **Fully Loaded** Benefits

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits																	
IT Applications	0	837	913	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Benefits	0	837	913	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Benefits																	
IT Applications																	
Total O&M / A&G Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Benefit Element Detail

Yearly Total **Direct** Benefits

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits																	
IT for Meter Reading																	
MB-15	0	750	831	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Benefits	0	750	831	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Benefits																	
IT for Meter Reading																	
MB-15																	
Total O&M / A&G Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Benefit Element Detail

Yearly Total **Fully Loaded** Benefits

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits																	
IT for Meter Reading																	
MB-15	0	837	913	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Benefits	0	837	913	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Benefits																	
IT for Meter Reading																	
MB-15																	
Total O&M / A&G Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

QUALIFICATIONS

OF

RICHARD CARUSA

My name is Richard Carusa and I am employed by San Diego Gas & Electric Company (SDG&E). My business address is 9965 Carroll Canyon Rd, San Diego, CA. 92131.

My present position is Manager in the Information Technology Customer Care Department of SDG&E. I have been employed by SDG&E since 1982. Previous positions relevant to my testimony include Principle Consultant at Sierra Systems Consulting Group, 1999 – 2001.

I received a B.A. in Business Administration (Information Systems) from San Diego State University.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 5

PREPARED DIRECT TESTIMONY

OF

JOHANNES VAN LIEROP

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 5

PREPARED DIRECT TESTIMONY

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JOHANNES VAN LIEROP

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MARCH 30, 2005

CHAPTER 5
PREPARED DIRECT TESTIMONY
OF
JOHANNES VAN LIEROP

I. INTRODUCTION

The purpose of my testimony is to present SDG&E's proposal for recovery of Advanced Metering Infrastructure (AMI) costs for the interim period 2005 - 2007. This chapter describes in detail the proposed mechanisms to support SDG&E's cost recovery for AMI pre-deployment costs that will be incurred in 2005-2006, as well as the first year of AMI deployment in 2007. On or before March 30, 2005, I intend to file Supplemental Testimony. In that Supplemental Testimony, I will identify the forecasted revenue requirements to be recovered by the mechanism proposed in this testimony, and that reflect the costs presented by other SDG&E witnesses in this application.

II. INTERIM COST RECOVERY PROPOSAL

This section presents SDG&E's regulatory accounting, cost allocation, and rate design proposals for recovery of AMI implementation and incremental operating costs through 2007. As described in Section A, *below*, SDG&E requests authorization to establish new regulatory accounts to record capital-related revenue requirements (i.e., depreciation, return and taxes) and O&M expenses associated with AMI pre-deployment in year 2005 and 2006. These accounts would also be utilized to record 2007 AMI costs and benefits and AMI-related revenues. Section A describes the balancing account entries and ratemaking details related to these accounts. SDG&E will address AMI cost recovery for the post-2007 period in its Test Year 2008 Cost of Service (COS) filing. In that filing SDG&E may propose to continue the incremental balancing account treatment described below or propose a different ratemaking framework for AMI costs.

A. Regulatory Accounting Proposal

1. Scope of the Regulatory Accounts

Other witnesses describe the impact that AMI is expected to have on generation, transmission, and distribution costs. For generation, AMI will enable certain rate designs that provide our customers with incentives to move load away from peak periods, resulting in benefits consisting of deferred investments of generation capacity and avoided energy commodity costs. These anticipated benefits are included in the Cost/Benefit analysis described in the testimony of witnesses Dr. Stephen George and Edward Fong. For generation costs, SDG&E currently has a ratemaking mechanism that provides for annual forecasts and true-up of generation costs through the Energy Resource Recovery Account (ERRA) for fuel and purchased power costs, and through the Non-Fuel Generation Balancing Account (NGBA) for other generation costs. This existing generation ratemaking mechanism will flow any generation-related AMI benefits through to customers, which avoids the need to include such benefits in the new AMI recovery mechanism.

For transmission SDG&E has a Federal Energy Regulatory Commission authorized ratemaking mechanism that provides for annual true-ups and rate adjustments through applicable transmission balancing accounts. Therefore, for transmission also there is no need to include such benefits in the new AMI recovery mechanism.

At least until SDG&E's next distribution cost-of-service true-up goes into effect, which is anticipated to occur in 2008, distribution costs have no mechanism that would record incremental costs and benefits from AMI. Therefore, the AMI balancing account mechanism should include incremental distribution costs and

benefits for both gas and electric, but not generation and electric transmission benefits.

2. Recording 2005 Expenditures

For 2005 SDG&E proposes to record pre-deployment capital-related and O&M expenses in new balancing accounts, to be named the Advanced Metering Infrastructure Balancing Accounts (AMIBA). Since costs will be recovered from SDG&E gas and electric customers, two balancing accounts need to be created to separately record the gas and electric expenditures. Because SDG&E does not propose any AMI-related rate changes for 2005, no AMI-related revenues will exist in 2005. Also, SDG&E does not expect any avoided or deferred cost savings in 2005. In my Supplemental Testimony I will identify the forecasted 2005 revenue requirements and will describe in further detail the calculation of the revenue requirements that will be recorded into the AMI accounts.

3. Recording 2006-2007 Costs, Benefits and Rate Revenues

Upon approval of AMI predeployment plan, the Commission should direct SDG&E to file an advice letter to request recovery of the forecasted AMI revenue requirement for 2006, along with the projected year-end balance in the AMIBA for 2005. Beginning January, 2006, SDG&E would record actual capital-related and O&M costs, estimated distribution benefits, and rate revenues in both the AMIBA-Electric and the AMIBA-Gas for annual true-up and recovery.

Likewise, for year 2007 SDG&E would file an advice letter in which the projected year-end 2006 balance in the AMIBA would be combined with the forecasted 2007 AMI revenue requirement to produce the total dollar amount to be recovered in gas and electric distribution rates.

4. Formula Mechanism for Recording Incremental AMI Benefits

While incremental capital and O&M costs are readily observable, it is not generally true that benefits in the form of avoided or deferred distribution costs can be directly observed and recorded in the AMIBA. To avoid future time-consuming review and litigation, SDG&E proposes a formula-based approach to estimate the incremental capital and O&M operational benefits that result from deployment of AMI meters. These benefits would be recorded to the AMIBA and used to offset the capital-related and O&M costs to ensure recovery of the appropriate revenue requirements. As I will describe in my Supplemental Testimony, operational benefits are included in the forecasted revenue requirement calculation, and therefore should be accounted for in the cost recovery mechanism.

In order to derive a formula approach, SDG&E conducted a detailed review of the forecasted incremental capital and O&M benefits for years 2005, 2006 and 2007, and determined which of these items are included implicitly or explicitly in the recently adopted COS revenue requirement for test year 2004 and beyond. Any cost item that is currently included in rates, such as meter reading, customer service field, capital spending on replacement meters, etc., is included in the formula used to estimate benefits to offset AMI costs.

Once the appropriate benefits for inclusion in the formula were identified, SDG&E reviewed the projected number of meters upon which achievement of the operational benefits was based. SDG&E then calculated an average dollar amount of benefits that would be reasonable to expect from deployment of 10,000 meters. SDG&E proposes to base the formula on dollars per 10,000 meters, rather than some smaller number because many benefits (such as meter reading) are not achieved until

a substantial number of meters are deployed. For example, a meter reading route cannot be eliminated with the deployment of only a few hundred meters. SDG&E selected the 10,000 meter number since this will allow benefits from completing the proposed Beta Phase in 2006 to be used to offset AMI costs.

Until SDG&E gains experience with wide-scale deployment of AMI, the true costs and benefits of deployment will be uncertain. SDG&E believes that use of a formula approach for recording AMI operational benefits is the most reasonable and equitable approach for the initial years 2006-2007, and that this methodology can be re-evaluated once large-scale deployment has taken place in 2007 to determine whether to update the formula or use an entirely different approach for recording AMI benefits for years 2008 and beyond.

5. Details of Benefit Formula

SDG&E plans to present the detailed benefit formula calculation along with revenue requirements in my Supplemental Testimony. However, Sections a and b, *below*, provide a description of the benefits to be included in the formula in years 2006 and 2007, respectively. Due to the larger range of cost savings achieved in the first year of AMI deployment versus the Beta Phase, SDG&E plans to compute the benefit formula separately for 2006 and 2007.

a) 2006 Benefit Formula – Beta Phase

Benefits resulting from the Beta Phase meter deployment and proposed to be included in the benefit formula are from the Billing and Meter Reading areas. These benefits are described in the testimony of Mr. James Teeter, and include O&M benefits associated with the 10,000 AMI meter deployment avoided meter

reading and avoided rebills. In addition, an avoided capital-related benefit for replacing meter reading handheld devices is included in the formula calculation.

b) 2007 Benefit Formula – AMI Deployment

Benefits resulting from the first year of AMI meter deployment and proposed to be included in the benefit formula are from the Billing, Meter Reading, Customer Service Field, Customer Contact Center, Customer Services Staff, Electric Metering, Electric Distribution, and Electric Load Research areas. These benefits are described by other SDG&E witnesses supporting these areas and include both O&M and capital benefits resulting from the first full year of AMI meter deployment.

O&M benefits include: avoided meter reading costs, avoided customer service field orders, avoided rebills, avoided non-capitalized portion of labor costs for gas meter changeouts as well as electric growth and load research meter installations, and reduced call volumes in the Customer Contact Center.

Capital benefits include: avoided replacement of meter reading handheld devices, avoided gas and electric meters as a result of customers receiving new AMI meters, avoided capital costs to install gas and electric meters, and avoided costs of electric distribution transformers due to the estimated demand response resulting from AMI deployment.

B. Cost Allocation

SDG&E proposes to allocate the revenue requirements associated with AMI implementation and incremental operating costs to its gas and electric customers based on the number of customers in each class weighted by the cost of their AMI meter. Costs to purchase, install and maintain AMI metering technology, as well as supporting O&M and customer

services costs, are customer related costs and should therefore be allocated based on a measure of the number of customers in each class. The AMI meter costs contained in this application are based on the best estimates currently available, but these estimates are likely to change. Thus, if significant cost differences arise once AMI meter deployment begins, SDG&E proposes to update the allocation factors in its annual year-end advice letter.

As described in the testimony of SDG&E witness Mr. Paul Pruschki, for the electric utility, three types of AMI meters will be installed. Each meter type has a unique cost, and therefore SDG&E projected how many meters of each type would be installed for each customer class. The number of customers receiving each meter type, multiplied by the unit cost of the meter, yielded the allocation factor used to assign costs. Table 1, below, presents the allocation factor that would be used to allocate costs to SDG&E electric customer classes.

Table 1
AMI Revenue Requirement Allocation - Electric

Ln.	Customer Class	Proposed AMI Cost Allocation
1	Residential	73.82%
2	Small Commercial	20.81%
3	Medium and Large C&I	4.79%
4	Agricultural	0.58%
5	Street Lighting	0.00%
6	Total system	100.00%

For the gas utility, the majority of customers will receive an identical AMI gas module. However, as described in the testimony of SDG&E witness Mr. Ted Reguly, about 28% of customers will require a full meter replacement. SDG&E determined the number of residential and commercial customers receiving each AMI meter installation type, along with the associated unit cost. The unit cost multiplied by the number of customers receiving each AMI installation

type by class yielded the allocation factor used to assign costs. SDG&E has not allocated AMI gas revenue requirements to customers with existing AMR gas meters, since those meters will not be replaced or retrofitted with AMI. The vast majority of SDG&E's noncore customers have AMR meters, which is reflected in the allocation percentages. Table 2, below illustrates the allocation factor used to allocate costs to SDG&E gas customer classes.

Table 2
AMI Revenue Requirement Allocation - Gas

Ln.	Customer Class	Proposed AMI Cost Allocation
1	Residential	93.176%
2	GN-3	6.814%
4	NGV	0.007%
5	Subtotal core	99.998%
6	GTNC	0.002%
7	Electric Generation	0.000%
8	Power Plants	0.000%
9	Subtotal noncore	0.002%
10	Total system	100.000%

C. Rate Design Proposal

SDG&E proposes to recover the revenue requirements associated with AMI implementation from its gas and electric customers through the electric distribution rate component and gas transportation rates. Costs for AMI meters, meter installation costs, and corresponding technology and customer services are all distribution-related, and therefore should be recovered in the distribution rate component for electric, and transportation rates for gas. SDG&E proposes to recover the allocated revenue requirement for each customer class based on existing electric and gas rate design methods previously adopted in the most recent Rate Design Window (RDW) and Biennial Cost Allocation (BCAP) proceedings.

D. Cost Recovery and Uncertainty

As described in the testimony of Edward Fong the forecasted benefits and costs of AMI are subject to an amount of uncertainty that is much greater than the uncertainty that surrounds more typical utility investments. For that reason Mr. Fong discusses and proposes a number of "off-ramps" designed to protect utility customers from uneconomic investments in case actual outcomes or conditions about costs, benefits or dynamic rates differ materially (unfavorably) from assumptions made in this proceedings. In case one or more off-ramps is triggered or in case where this or a future Commission changes its view about deployment of AMI it is possible that parts of the AMI project will be abandoned and would not meet the traditional "used-and-useful" standard for rate recovery. SDG&E shareholders should not be at risk for having all or part of their investment stranded because such an outcome would not be due to any imprudent action of SDG&E. To provide reasonable certainty that SDG&E will recover its costs of AMI pre-deployment and subsequent deployment the Commission should adopt a policy that the utility should be allowed to recover all AMI-related costs as long as the expenditures were pursuant to and consistent with specific AMI spending authority and guidance provided by this Commission.

This concludes my prepared direct testimony.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 6

PREPARED DIRECT TESTIMONY

OF

EDWARD FONG

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

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I. INTRODUCTION

The purpose of my testimony is to describe SDG&E's discounted cash flow process for evaluating the incremental costs and benefits of the full and partial rollout scenarios for the Advanced Metering Infrastructure (AMI). This chapter provides a description of the logic behind the discounted cash flow process used to organize, consolidate and report the present values of the various incremental capital and operational costs and benefits, shown in Chapter 2, Table EF 2-1.

II. DISCUSSION

A. Discounted Cash Flow Process

Discounted cash flow analysis quantifies the cash flow implications of alternative capital investment scenarios and their corresponding operational costs and benefits. In its simplest form, called the "societal perspective," discounted cash flow ignores the tax effects of cost deductions and capital depreciation. That is, the annual projections of nominal capital and operational costs and benefits are present-valued using a pre-tax discount factor. The resulting annual present values are then cumulated across the years to yield a present value for each element of cost and benefit.

B. Input Values for Cost Elements

The AMI incremental cost inputs are aggregated into three broad functional categories: i) start up and design; ii) installation; and iii) operations and maintenance. These functional categories are comprised of numerous cost elements, each associated with a particular type of

operational or capital expense. The cost inputs are evaluated over a 17-year planning horizon (2005-2021), and are expressed in terms of their annual difference from a "business-as-usual" base case. The incremental cost elements, both operational and capital, are input as constant 2004 dollars.

C. Input Values for Benefit Elements

The AMI incremental benefit inputs are aggregated into three broad categories: i) systems operation benefits; ii) customer service benefits; and iii) management & other benefits. These categories are comprised of numerous benefit elements, each associated with a particular type of operational or capital cost savings. The benefit inputs are evaluated over a 17-year planning horizon (2005-2021), and are expressed in terms of their annual difference from a "business-as-usual" base case. The incremental benefit elements, both operational and capital, are input as constant 2004 dollars.

D. Overhead Loaders for Costs and Benefits

Composite overhead loading factors are applied to each direct cost and benefit input, according to its accounting classification as union or non-union labor, contract labor, purchased materials and services, and capital. Each composite factor consists of one or more incremental loaders, which are described in Chapter 15 of witness Mr. Kyle's prepared direct testimony.

Table EF 6-1
Overhead Leaders

	Factor 1= 46.95%	Factor 2 = 3.71%	Factor 3 = 0.52%	Factor 4 = 50.14%	Factor 5 = 64.95%	Factor 6 = 68.14%
Payroll Taxes = 10.42%	x			x	x	x
Vacation & Sick time = 16.65%	x			x	x	x
Pension & Benefits = 14.43%	x			x	x	x
Workers' Comp = 3.01%	x			x	x	x
Liability Insurance = 2.44%	x			x	x	x
Non-union ICP = 18.00%					x	x
Purchased Services & Materials = 0.52%		x	x			
Administrative & General = 3.19%		x		x		x

The factors are applied in the following fashion:

Factor 1 – O&M union labor

Factor 2 – capital contract labor and all non-labor

Factor 3 – O&M contract labor and all non-labor

Factor 4 – capital union labor

Factor 5 – O&M non-union labor

Factor 6 – capital non-union labor

E. Escalation of Costs and Benefits

The loaded 2004-dollar values of costs and benefits are escalated for inflation by factors appropriate to either capital or O&M. The capital escalation factors are taken from Global Insight UCON25Y (2004:1), while the O&M escalation factors are taken from Global Insight TREND25YEAR0204 and UCON25Y (2004:1).

Table EF 6-2 shows the undiscounted loaded with appropriate overheads (Table EF 6-1) and escalated AMI incremental costs and operational benefits for the full and partial deployment scenarios.

Table EF 6-2
Undiscounted Costs & Operational Benefits
Full Deployment

	Development & Installation 2005-2009	On-going 2010-2021	Total 2005-2021
Costs			
Capital	$ 438	$ 278	$ 716
O&M + Other	$ 99	$ 274	$ 374
Operational Benefits			
Capital	$ 17	$ 205	$ 223
O&M + Other	$ 67	$ 617	$ 684

Partial Deployment

	Development & Installation 2005-2008	On-going 2009-2021	Total 2005-2021
Costs			
Capital	$ 194	$ 200	$ 394
O&M + Other	$ 52	$ 172	$ 224
Operational Benefits			
Capital	$ 9	$ 162	$ 171
O&M + Other	$ 26	$ 348	$ 374

F. Net Present Value of Discounted Net Cash Flows

The escalated annual streams of costs and benefits are discounted by SDG&E's 8.18% authorized, pre-tax weighted cost of capital, and cumulated to yield the present value of each discounted cash flow.

Table EF 6-3
Discounted Costs and Operational Benefits

Full Deployment
($ millions)
Present Value

	Costs	Operational Benefits
Capital	$ 395	$ 81
O&M + Other	$ 217	$ 311

Partial Deployment
($ millions)
Present Value

	Costs	Operational Benefits
Capital	$ 197	$ 69
O&M + Other	$ 143	$ 173

G. Depreciation of Electromechanical Meter Stock

SDG&E's base case[1] analysis assumes that the installed cost of electromechanical meters that are replaced by AMI compatible meters will remain in rate base until the undepreciated book value is fully recovered over the remaining book life. Changes in this assumption will impact the total incremental costs included in the business case.

III. SUMMARY OF NET PRESENT VALUES FOR OPERATIONAL COSTS AND BENEFITS

Table EF-6-4 shows the present value of operational costs and benefits identified in above Table EF 6-2 (identical to Table EF 2-1), along with the present value of demand response benefits (Chapter 13, witness Dr. George) for a computation of net present value (from a "societal perspective"). Column 1 is the present value of costs. Column 2 is the present value of operational benefits. Column 3 is the present value of demand response benefits. Column 4 represents the net present value of AMI costs and benefits. Column 5 includes the present value of environmental benefits. As discussed in my Policy testimony, Chapter 2, SDG&E is not including these benefits in the net present value calculation.

[1] SDG&E's January 12, 2005 Supplemental Preliminary AMI Analysis filing.

Table EF 6-4
Present Value of AMI Societal Costs and Benefits
($ millions)

	Present Value (2005-2021)				
	1	2	3	4	5
	Cost	Operational Benefits	Demand Response Benefits	Net PV	PV Environ Benefits
Full Deployment	$ 612	$ 392	$ 268	**$ 48**	$2 - 6
Partial Deployment	$ 340	$ 242	$ 207	**$ 109**	$1 - 4

(1) Present value of cash flow of costs, including capital expenditures and going forward O&M
(2) Present value of operational benefits include O&M cost savings & avoidance, capital avoidance & deferral
(3) Demand response benefits are computed from Charles Rivers Associate SPP Econometric model. Assumes $85 per kW year avoided generation capacity value and energy values from SDG&E forecast
(4) Environmental savings not included in final analysis. E3 Study estimate of $8-25 cost per ton of CO2

Appendices A and B, filed today under separate confidential seal, show the present value and loaded/escalated costs, respectively, of each of the individual cost and benefit elements described throughout the Application and testimony. Tables EF 6-5, EF 6-6 show the detail for the PV results.

This concludes my prepared direct testimony on the cost and benefits methodology.

Table EF 6-5 through EF 6-6

Table EF 6-5

($ thousands) Totals (not PV) - Fully loaded and escalated (inflation applied)

Full Deployment - Costs

		Pilot / Testing		Production Rollout			Ongoing / Maintenance														
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2005-2009	2010-2021	Total
Capital	Communication System	13	2,569	5,854	7,135	7,398	209	223	230	237	244	251	258	265	476	500	732	756	22,969	4,383	27,352
	Facilities	0	696	1,000	1,025	1,053	0	0	0	0	0	0	0	0	0	0	0	0	3,775	0	3,775
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	0	3,637	120,434	119,931	123,489	6,186	7,193	8,263	8,623	9,000	9,375	9,756	10,161	10,623	12,016	13,480	15,975	367,492	120,651	488,142
	Information Technology	14,741	18,127	8,333	1,828	705	2,447	3,818	0	0	0	2,780	4,164	208	0	0	3,161	4,824	43,734	21,401	65,135
	T&D	0	0	0	0	0	0	1,621	0	1,715	0	9,324	0	36,089	15,030	38,858	26,950	2,127	0	131,715	131,715
	Totals	14,754	25,029	135,621	129,919	132,645	8,843	12,856	8,493	10,575	9,244	21,730	14,177	46,724	26,129	51,374	44,323	23,682	437,969	278,150	716,119
O&M	AMI Project Management	667	2,735	2,801	2,871	2,949	756	0	0	0	0	0	0	0	0	0	0	0	12,022	756	12,779
	Billing	0	274	1,346	1,272	1,481	705	730	759	791	825	861	895	934	973	1,015	1,059	1,107	4,374	10,654	15,028
	Customer Contact Center	0	53	499	510	457	26	27	28	29	30	32	33	35	36	38	39	41	1,519	393	1,912
	Claims	0	2	47	48	49	0	0	0	0	0	0	0	0	0	0	0	0	145	0	145
	Communication System	103	462	1,297	2,225	3,236	3,513	3,595	3,679	3,776	3,876	3,984	4,078	4,188	4,296	4,418	4,539	4,672	7,323	48,614	55,936
	Load Control Technology	0	367	1,925	2,886	2,110	2,091	1,166	1,210	1,259	1,311	1,366	1,418	1,477	1,537	1,602	1,668	1,741	7,288	17,847	25,135
	Facilities	0	145	339	325	382	0	0	0	0	0	0	0	0	0	0	0	0	1,192	0	1,192
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	7	1,836	7,785	8,229	8,527	2,097	2,175	2,261	2,353	2,452	3,063	14,752	15,917	19,781	8,401	9,186	5,820	26,385	88,257	114,642
	HR	334	203	280	213	0	0	0	0	0	0	0	0	0	0	0	0	0	1,030	0	1,030
	Information Technology	34	1,470	3,991	5,704	6,106	6,891	6,785	6,958	7,183	7,405	4,949	5,087	5,235	5,402	5,575	5,748	5,938	17,305	73,156	90,461
	Load Research	0	0	135	277	285	438	450	463	477	492	508	522	538	554	572	590	609	697	6,211	6,908
	Mass Markets / Major Markets	25	1,674	4,916	5,373	5,746	1,687	1,227	1,262	1,303	1,344	1,389	1,429	1,475	1,520	1,571	1,621	1,676	17,733	17,502	35,235
	Meter Reading	0	105	643	711	873	707	739	773	807	846	883	924	965	1,009	1,059	1,108	1,161	2,331	10,982	13,313
	Totals	1,170	9,326	26,003	30,645	32,200	18,910	16,894	17,392	17,979	18,582	17,033	29,139	30,763	35,110	24,250	25,557	22,765	99,343	274,374	373,718

Partial Deployment - Costs

		Pilot / Testing		Production Rollout		Ongoing / Maintenance															
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2005-2008	2009-2021	Total
Capital	Communication System	13	960	3,496	4,044	123	127	131	135	148	152	157	162	167	256	274	375	389	8,513	2,597	11,110
	Facilities	0	689	992	1,017	0	0	0	0	0	0	0	0	0	0	0	0	0	2,698	0	2,698
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	0	3,436	70,643	72,587	2,399	2,930	3,486	3,649	3,814	3,986	4,159	4,333	4,521	4,749	5,479	6,285	7,105	146,666	56,894	203,560
	Information Technology	12,790	15,008	6,650	1,656	529	2,208	2,863	0	0	0	2,506	3,122	155	0	0	2,847	3,630	36,105	17,860	53,965
	T&D	0	0	0	0	0	0	1,621	0	0	0	9,324	28,528	36,645	3,261	40,513	3,227	0	0	123,120	123,120
	Totals	12,804	20,092	81,783	79,304	3,051	5,265	8,101	3,784	3,961	4,138	16,145	36,145	41,488	8,267	46,267	12,735	11,124	193,983	200,472	394,454
O&M	AMI Project Management	667	2,735	2,801	2,871	737	0	0	0	0	0	0	0	0	0	0	0	0	9,074	737	9,811
	Billing	0	274	918	770	375	388	402	418	435	453	472	490	510	531	554	577	602	1,962	6,206	8,168
	Customer Contact Center	0	53	324	354	90	94	98	102	106	111	116	121	127	133	139	145	152	731	1,534	2,265
	Claims	0	2	30	31	0	0	0	0	0	0	0	0	0	0	0	0	0	62	0	62
	Communication System	103	286	701	1,379	1,435	1,471	1,510	1,551	1,599	1,648	1,700	1,747	1,800	1,854	1,914	1,974	2,040	2,469	22,241	24,710
	Load Control Technology	0	233	1,212	2,303	1,577	711	739	768	801	836	872	906	945	985	1,029	1,072	1,121	3,747	12,363	16,111
	Facilities	0	203	516	381	0	0	0	0	0	0	0	0	0	0	0	0	0	1,100	0	1,100
	Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	7	1,390	6,014	5,806	1,057	1,105	1,146	1,190	1,238	1,288	1,795	9,313	10,101	3,991	3,935	2,945	2,869	13,217	41,973	55,190
	HR	334	203	208	213	0	0	0	0	0	0	0	0	0	0	0	0	0	958	0	958
	Information Technology	34	1,309	3,474	4,720	4,884	5,256	5,105	5,234	5,403	5,570	4,346	4,468	4,599	4,744	4,896	5,048	5,215	9,537	64,767	74,304
	Load Research	0	0	68	139	142	219	225	231	239	246	254	261	269	277	286	295	305	206	3,248	3,454
	Mass Markets / Major Markets	25	1,470	3,192	3,272	1,381	860	885	910	939	968	1,000	1,029	1,061	1,094	1,130	1,165	1,205	7,959	13,625	21,584
	Meter Reading	0	73	319	365	297	311	324	338	353	373	389	406	425	446	466	488	512	757	5,127	5,884
	Totals	1,170	8,232	19,775	22,603	11,976	10,413	10,434	10,742	11,112	11,492	10,944	18,740	19,837	14,055	14,347	13,709	14,020	51,780	171,821	223,601

Table EF 6-6

($ Thousands) Totals (not PV) - Fully loaded and escalated (inflation applied)

Full Deployment - Benefits

		Pilot / Testing		Production Rollout			Ongoing / Maintenance														
		2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2005-2009	2010-2021	Total
Capital	Avoided Load Research Programs / Projects	0	0	241	503	835	791	816	909	860	888	985	930	958	1,064	1,007	1,041	1,158	1,579	11,408	12,987
	Customer Service Field	0	0	0	18	37	56	60	62	65	536	71	76	78	81	87	89	95	55	1,353	1,408
	Demand Response	0	0	196	402	619	637	655	674	693	712	731	749	768	789	811	835	859	1,217	8,912	10,129
	Avoided / Deferred G&E Meters & Labor and other E&G Mtr Savings	0	0	1,589	1,546	1,787	1,354	1,408	1,469	1,500	1,575	1,615	1,677	1,742	1,812	1,887	1,967	2,050	4,922	20,056	24,978
	IT for Meter Reading	0	883	986	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,869	0	1,869
	Meter Reading	0	36	37	0	0	0	0	0	0	1,846	1,894	0	0	0	0	0	0	72	3,740	3,812
	Mtr-Elec-Residual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	17,767	0	17,767	17,767
	Mtr-Gas-Residual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12,833	0	12,833	12,833
	T&D	0	0	31	3,017	4,631	7,999	1,982	8,617	18	31,852	13,935	21,730	29,290	10,002	1,806	2,089	23	7,679	129,343	137,022
	Totals	0	918	3,081	5,486	7,908	10,837	4,921	11,730	3,136	37,408	19,231	25,161	32,836	13,749	5,598	6,020	34,786	17,393	205,412	222,806
O&M	Avoided Load Research Programs / Projects	0	0	71	149	228	234	240	247	255	263	271	279	287	296	305	315	325	448	3,317	3,765
	Billing	0	21	1,016	2,060	3,162	3,290	3,431	3,577	3,741	3,912	4,095	4,270	4,466	4,666	4,885	5,108	5,353	6,259	50,795	57,054
	Customer Contact Center	0	0	9	17	27	28	29	30	32	33	35	36	38	39	41	43	45	53	429	482
	Customer Service Field	0	0	24	997	2,020	3,094	3,239	3,394	3,571	3,754	3,952	4,145	4,357	4,580	4,820	5,068	5,341	3,041	49,313	52,354
	Claims	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
	Demand Response	0	0	5,428	11,127	17,140	17,586	18,078	18,584	19,160	19,754	20,386	20,957	21,607	22,255	22,967	23,679	24,461	33,695	249,476	283,171
	Avoided / Deferred G&E Meters & Labor and other E&G Mtr Savings	0	0	101	119	172	126	130	134	130	137	139	143	147	152	157	162	167	392	1,723	2,114
	Meter Reading	0	36	2,718	7,688	13,164	16,575	17,283	18,021	18,845	19,708	20,630	21,512	22,498	23,506	24,608	25,736	26,969	23,606	255,892	279,498
	T&D	0	0	0	0	0	411	423	434	448	462	477	490	505	520	537	554	572	0	5,833	5,833
	Totals	0	58	9,367	22,157	35,911	41,344	42,852	44,422	46,182	48,023	49,985	51,832	53,905	56,014	58,320	60,665	63,234	67,493	616,778	684,271

Partial Deployment - Benefits

		Pilot / Testing		Production Rollout		Ongoing / Maintenance															
		2,005	2,006	2,007	2,008	2,009	2,010	2,011	2,012	2,013	2,014	2,015	2,016	2,017	2,018	2,019	2,020	2,021	2005-2008	2009-2021	Total
Capital	Avoided Load Research Programs / Projects	0	0	121	252	417	396	408	454	430	444	493	465	479	532	504	520	579	372	6,121	6,493
	Customer Service Field	0	0	0	11	24	25	26	27	28	237	32	33	34	36	37	40	43	11	621	633
	Demand Response	0	0	196	402	413	425	437	449	462	475	487	499	512	526	541	556	573	598	6,354	6,952
	Avoided / Deferred G&E Meters & Labor and other E&G Mtr Savings	0	0	1,500	1,511	1,624	1,485	1,534	693	717	753	775	806	838	916	954	995	1,039	3,012	13,128	16,140
	IT for Meter Reading	0	883	986	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,869	0	1,869
	Meter Reading	0	36	37	0	0	0	0	0	0	138	141	0	0	0	0	0	0	72	279	352
	Mtr-Elec-Residual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,480	0	3,480	3,480
	Mtr-Gas-Residual	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5,424	0	5,424	5,424
	T&D	0	0	31	2,918	4,068	6,898	1,982	6,949	18	31,852	13,935	19,875	29,290	10,002	1,806	22	23	2,949	126,720	129,670
	Totals	0	918	2,871	5,095	6,546	9,228	4,387	8,572	1,655	33,898	15,863	21,678	31,153	12,012	3,842	2,134	11,160	8,884	162,128	171,012
O&M	Avoided Load Research Programs / Projects	0	0	36	74	114	117	120	124	127	131	136	139	144	148	153	157	163	110	1,772	1,883
	Billing	0	21	647	1,303	1,360	1,417	1,480	1,546	1,619	1,696	1,778	1,857	1,945	2,036	2,134	2,236	2,347	1,972	23,453	25,424
	Customer Contact Center	0	0	6	11	12	12	13	13	14	14	15	16	17	17	18	19	20	17	200	217
	Customer Service Field	0	0	24	645	1,299	1,359	1,425	1,496	1,572	1,652	1,739	1,824	1,918	2,014	2,121	2,232	2,353	669	23,003	23,672
	Claims	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
	Demand Response	0	0	5,428	11,127	11,427	11,725	12,053	12,390	12,774	13,170	13,592	13,972	14,406	14,838	15,313	15,787	16,308	16,555	177,756	194,311
	Avoided / Deferred G&E Meters & Labor and other E&G Mtr Savings	0	0	42	53	74	58	60	61	62	65	66	68	70	80	82	85	88	95	921	1,016
	Meter Reading	0	36	1,781	4,985	6,872	7,162	7,478	7,808	8,177	8,563	8,976	9,373	9,815	10,269	10,765	11,272	11,829	6,803	118,360	125,162
	T&D	0	0	0	0	0	177	182	187	194	200	207	213	220	227	234	242	250	0	2,533	2,533
	Totals	0	58	7,964	18,199	21,158	22,026	22,811	23,626	24,540	25,493	26,509	27,462	28,535	29,629	30,821	32,031	33,358	26,221	347,998	374,219

QUALIFICATIONS

OF

EDWARD FONG

Mr. Edward Fong is currently the Director of Measurement and Advanced Metering Infrastructure (AMI) for San Diego Gas & Electric (SDG&E). He is responsible for directing, managing and planning the electric measurement activities and advanced metering technology implementation for SDG&E. Prior to assuming his current position in October 2004, Mr. Fong was Director of Measurement & Meter Reading from 2002-2004, Director of Customer Services Solutions from 2000-2001, and Director of Revenue Cycle Services for from 1998-2000. Mr. Fong has directed and managed measurement, meter reading, billing, call center, branch office, credit and collections, direct access services and other customer services operations at SDG&E.

Ed is currently SDG&E's lead director for the California Public Utilities Commission (CPUC) rulemaking proceeding on Advanced Metering, Dynamic Pricing and Demand Response, R.02-06-001.

Prior to joining SDG&E in 1998, Ed held various director level management positions with the Southern California Gas Company in Human Resources, Organizational Development, Customer Contact, Customer Services Operations Staff, Information Technology, and Planning.

Ed has testified before the CPUC on numerous occasions covering a variety of topics ranging from cost of service, measurement and meter reading to billing systems implementation.

Ed is a graduate of University of California, San Diego with undergraduate and graduate degrees in Economics.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 7

PREPARED DIRECT TESTIMONY

OF

PATRICK K. CHARLES

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 7

PREPARED DIRECT TESTIMONY

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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

CHAPTER 7
PREPARED DIRECT TESTIMONY
OF
PATRICK K. CHARLES

I. INTRODUCTION

The purpose of my testimony is to describe the costs and benefits associated with overall AMI project management, Human Resources and Load Research areas that SDG&E anticipates from deploying either a full or partial Advanced Metering Infrastructure (AMI) system. The costs and benefits associated with these areas fall within the Installation Cost category and include the full time equivalents (FTEs) required for AMI Project Management activities and the Human Resources (HR) area, as well as employee relocation costs within the HR area, and the Customer Service Benefits category (specifically, benefit element CB-10 associated with avoided Load Research projects).

II. DISCUSSION

A. Introduction

The costs and benefits covered in this chapter are summarized in Table PC 7-1.

Table PC 7-1
Cost-Benefit Summary Table

Table PC 7-1 Human Resources, Project Mgmt, Load Research ($ thousands)					
Full Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010-2021**
	Capital	0	0	0	0
	O&M	1,864	1,900	1,783	3,144
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010-2021**
	Capital	215	439	708	8,058
	O&M	66	134	200	2,398
Partial Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**		**2009-2021**
	Capital	0	0		0
	O&M	1,786	1,824		1,852
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**		**2009-2021**
	Capital	108	219		4,383
	O&M	33	67		1,299

B. Discussion

1. AMI Project Management

AMI project management costs are associated with FTE labor and non labor expenses required to manage SDG&E's AMI effort. As detailed in chapters 8 and 9 by witnesses Mr. Pruschki and Mr. Reguly, the material and labor costs associated with the installation of an AMI network are significant (for a full deployment, costs will be approximately $140M annually (fully loaded) during the production roll-out period). Due to the scale of this project, it is necessary and prudent to have work force and management dedicated to project management support and financial management and controls. Additionally, within the general category of AMI project management, labor is dedicated to measurement systems and equipment development support, customer problem resolution, statistical analysis and overall management of the AMI project.

Tables PC 7-2 and PC 7-4 show the direct and fully loaded costs associated with AMI project management (including project management support, financial management and controls, measurement systems and equipment development and liaison, customer problem resolution, statistical analysis and overall leadership of the AMI project) for both the full and partial deployment scenarios.

2. Human Resources

HR costs are driven by company wide incremental labor additions necessary due to the AMI project. In both the partial and full deployment case, SDG&E will need significant numbers of new employees, most notably during the production roll-out period, and this, in turn, impacts costs in the HR area. HR costs include the addition of one mid level recruiting resource as well as costs associated with the relocation of a very small fraction of the overall labor resources added for the AMI project.

Tables PC 7-2 and PC 7-4 show the direct and fully loaded costs associated with HR (including both the incremental HR labor and the relocation expenses mentioned) for both the full and partial deployment scenarios.

3. Load Research

SDG&E's load research function shows significant benefits associated with either the partial or the full deployment scenario due to avoided load research meter requirements. These benefits are somewhat offset by an expected increase in labor associated with additional analysis due to the vastly increased amount and availability of interval data due to AMI.

SDG&E assumes load research benefits (avoided special metering projects) will begin in 2007, but during the roll-out years the benefits are scaled to the expected portion of the roll-out to be completed in those years.

a) Avoided Metering Projects

Avoided metering projects / load research benefits are categorized into six groups:

(1) Load Research / Tariff Sample

The largest of the load research areas listed, the assumptions around this sample include over 1000 meters that SDG&E would need to field every third year beginning in 2009. These meters would not require communications, but none the less have a significantly higher cost than standard, electromechanical meters. Avoided labor installation costs are included in these benefits.

(2) Dynamic Load Profile (DLP) Sample

The DLP sample size assumption is about half that of the load research / tariff sample size, but does require communicating meters. This sample

also requires fielding every third year, with the first avoided sample being in 2007 (benefits in 2007 are about one third of those expected during later iterations due to the scaling issue mentioned above).

(3) Title 20 Requirement Samples

The Title 20 requirement sample is slightly more than half the size of the DLP sample (about one fourth that of the load research / tariff sample) and does not require communications. This sample requires fielding every third year with the first avoided sample being in 2007 (again, benefits in 2007 are about one third of those expected during later iterations due to the scaling issue mentioned above).

(4) Special Projects Measurement and Evaluation (M&E)

This sample is assumed to be slightly smaller than the DLP sample size (making it about one third the size of the load research / tariff sample). These samples are required for such things as the AB970 Smart Thermostat evaluation and other similar programs for which understanding customer consumption behavior at an interval level is necessary. SDG&E assumes slightly less than half of these meters require communications. This sample also requires fielding every third year with the first avoided sample being in 2008 (benefits in 2008 are about two thirds of those expected during later iterations due to the scaling issue mentioned above).

(5) Future M&E

This sample is also assumed to be slightly smaller than the DLP sample size (making it slightly larger than one third the size of the load research /

tariff sample). These samples are required for anticipated future projects for which understanding customer consumption behavior at an interval level is necessary. Slightly less than half of these meters are assumed to require communications. This sample also requires fielding every third year with the first avoided sample being in 2008 (benefits in 2008 are about two thirds of those expected during later iterations due to the scaling issue mentioned above).

(6) Avoided Communications Costs

As mentioned above, many of the meters required for the above samples are communicating meters. In the absence of AMI, an expensive communications approach is necessary, such as a landline to each meter or a digital cellular device for each meter. With AMI, these communications costs would be avoided.

b) Additional Load Research Labor

Because AMI will result in a vastly increased amount of interval data available to SDG&E, the Load Research function will require additional resources to analyze this data. The full deployment case assumes roughly twice the labor requirement of the partial.

Tables PC 7-2 through PC 7-5 show the direct and fully loaded costs associated with load research (including both the avoided load research project benefits within the CB-10 benefit element and the incremental labor mentioned for additional analysis) for both the full and partial deployment scenarios.

This concludes my prepared direct testimony.

Tables PC 7-2 through PC 7-5

Table PC 7-2

Human Resources, Project Mgmt, Load Research

FULL Deployment Scenario - Cost Summary ($ thousands)

Cost Category Summary

Yearly Total **Direct** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
AMI Project Mgmt															
Human Resources															
Load Research															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
AMI Project Mgmt	1,631	1,631	1,631	408	0	0	0	0	0	0	0	0	0	0	0
Human Resources	157	117	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Research	76	152	152	228	228	228	228	228	228	228	228	228	228	228	228
Total O&M / A&G Costs	1,864	1,900	1,783	636	228	228	228	228	228	228	228	228	228	228	228

Cost Category Summary

Yearly Total **Fully Loaded** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
AMI Project Mgmt															
Human Resources															
Load Research															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
AMI Project Mgmt	2,598	2,598	2,598	650	0	0	0	0	0	0	0	0	0	0	0
Human Resources	260	193	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Research	125	251	251	376	376	376	376	376	376	376	376	376	376	376	376
Total O&M / A&G Costs	2,983	3,042	2,849	1,026	376	376	376	376	376	376	376	376	376	376	376

Table PC 7-3

Human Resources, Project Mgmt, Load Research

FULL Deployment Scenario - Benefit Summary ($ thousands)

Benefit Category Summary

Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
AMI Project Mgmt															
Human Resources															
Load Research	215	439	708	652	655	708	652	655	708	652	655	708	652	655	708
Total Capital Benefits	215	439	708	652	655	708	652	655	708	652	655	708	652	655	708
O & M / A & G Benefits															
AMI Project Mgmt															
Human Resources															
Load Research	66	134	200	200	200	200	200	200	200	200	200	200	200	200	200
Total O&M / A&G Benefits	66	134	200	200	200	200	200	200	200	200	200	200	200	200	200

Benefit Category Summary

Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
AMI Project Mgmt															
Human Resources															
Load Research	223	455	734	676	679	734	676	679	734	676	679	734	676	679	734
Total Capital Benefits	223	455	734	676	679	734	676	679	734	676	679	734	676	679	734
O & M / A & G Benefits															
AMI Project Mgmt															
Human Resources															
Load Research	66	135	201	201	201	201	201	201	201	201	201	201	201	201	201
Total O&M / A&G Benefits	66	135	201	201	201	201	201	201	201	201	201	201	201	201	201

Benefit Element Detail

Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Avoided Load Research Activity															
CB-10	215	439	708	652	655	708	652	655	708	652	655	708	652	655	708
Total Capital Benefits	215	439	708	652	655	708	652	655	708	652	655	708	652	655	708
O & M / A & G Benefits															
Avoided Load Research Activity															
CB-10	66	134	200	200	200	200	200	200	200	200	200	200	200	200	200
Total O&M / A&G Benefits	66	134	200	200	200	200	200	200	200	200	200	200	200	200	200

Benefit Element Detail

Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Avoided Load Research Activity															
CB-10	223	455	734	676	679	734	676	679	734	676	679	734	676	679	734
Total Capital Benefits	223	455	734	676	679	734	676	679	734	676	679	734	676	679	734
O & M / A & G Benefits															
Avoided Load Research Activity															
CB-10	66	135	201	201	201	201	201	201	201	201	201	201	201	201	201
Total O&M / A&G Benefits	66	135	201	201	201	201	201	201	201	201	201	201	201	201	201

Table PC 7-4

Human Resources, Project Mgmt, Load Research

PARTIAL Deployment Scenario - Cost Summary ($ thousands)

Cost Category Summary

Yearly Total **Direct** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
AMI Project Mgmt															
Human Resources															
Load Research															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
AMI Project Mgmt	1,631	1,631	408	0	0	0	0	0	0	0	0	0	0	0	0
Human Resources	117	117	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Research	38	76	76	114	114	114	114	114	114	114	114	114	114	114	114
Total O&M / A&G Costs	1,786	1,824	484	114	114	114	114	114	114	114	114	114	114	114	114

Cost Category Summary

Yearly Total **Fully Loaded** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
AMI Project Mgmt															
Human Resources															
Load Research															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
AMI Project Mgmt	2,598	2,598	650	0	0	0	0	0	0	0	0	0	0	0	0
Human Resources	193	193	0	0	0	0	0	0	0	0	0	0	0	0	0
Load Research	63	125	125	188	188	188	188	188	188	188	188	188	188	188	188
Total O&M / A&G Costs	2,854	2,917	775	188	188	188	188	188	188	188	188	188	188	188	188

Table PC 7-5

Human Resources, Project Mgmt, Load Research

PARTIAL Deployment Scenario - Benefit Summary ($ thousands)

Benefit Category Summary

Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
AMI Project Mgmt															
Human Resources															
Load Research	108	219	354	326	327	354	326	327	354	326	327	354	326	327	354
Total Capital Benefits	108	219	354	326	327	354	326	327	354	326	327	354	326	327	354
O & M / A & G Benefits															
AMI Project Mgmt															
Human Resources															
Load Research	33	67	100	100	100	100	100	100	100	100	100	100	100	100	100
Total O&M / A&G Benefits	33	67	100	100	100	100	100	100	100	100	100	100	100	100	100

Benefit Category Summary

Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
AMI Project Mgmt															
Human Resources															
Load Research	112	227	367	338	339	367	338	339	367	338	339	367	338	339	367
Total Capital Benefits	112	227	367	338	339	367	338	339	367	338	339	367	338	339	367
O & M / A & G Benefits															
AMI Project Mgmt															
Human Resources															
Load Research	33	67	100	100	100	100	100	100	100	100	100	100	100	100	100
Total O&M / A&G Benefits	33	67	100	100	100	100	100	100	100	100	100	100	100	100	100

Benefit Element Detail

Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Avoided Load Research Activity															
CB-10	108	219	354	326	327	354	326	327	354	326	327	354	326	327	354
Total Capital Benefits	108	219	354	326	327	354	326	327	354	326	327	354	326	327	354
O & M / A & G Benefits															
Avoided Load Research Activity															
CB-10	33	67	100	100	100	100	100	100	100	100	100	100	100	100	100
Total O&M / A&G Benefits	33	67	100	100	100	100	100	100	100	100	100	100	100	100	100

Benefit Element Detail

Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Avoided Load Research Activity															
CB-10	112	227	367	338	339	367	338	339	367	338	339	367	338	339	367
Total Capital Benefits	112	227	367	338	339	367	338	339	367	338	339	367	338	339	367
O & M / A & G Benefits															
Avoided Load Research Activity															
CB-10	33	67	100	100	100	100	100	100	100	100	100	100	100	100	100
Total O&M / A&G Benefits	33	67	100	100	100	100	100	100	100	100	100	100	100	100	100

QUALIFICATIONS

OF

PATRICK K. CHARLES

My name is Patrick K. Charles and I am employed by San Diego Gas & Electric Company (SDG&E). My business address is 8326 Century Park Court, CP62C, San Diego, CA 92123.

My present position is Planning and Analysis Manager in the Electric Measurement and AMI Department of SDG&E. I have been employed by SDG&E since 1999. Previous positions relevant to my testimony include Customer Services Support Manager within the Federal Accounts Department at SDG&E from 2001 – 2003 and Project Management Manger within the Meter Reading Department from 2003 – 2004.

I received a Bachelor's Degree in Business Administration (Marketing) from the University of Colorado at Boulder in 1989, and an MBA with an emphasis in finance from the University of Missouri at Kansas City in 1999. I have not previously testified before the California Public Utilities Commission.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 8

PREPARED DIRECT TESTIMONY

OF

PAUL PRUSCHKI

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 8

PREPARED DIRECT TESTIMONY

OF

PAUL PRUSCHKI

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

CHAPTER 8

PREPARED DIRECT TESTIMONY

OF

PAUL PRUSCHKI

I. INTRODUCTION

The purpose of my testimony is to describe the estimated costs and benefits associated with the communication system and electric meters that would be deployed with the Advanced Metering Infrastructure (AMI) in both a full and partial deployment scenarios. The specific cost categories that I discuss are the Communication System and Electric Meters cost elements identified in Tables PP 8-1 through Tables PP 8-5. The specific benefit categories that I discuss are the Systems Operations Benefits also in the above mentioned tables associated with avoided meter-related customer site visits contained within SB-7, avoided electric meter purchasing costs by reusing electromechanical meters (in the partial deployment scenario only) contained within MB-3, and electric meter purchase avoidance due to growth meter displacement contained within MB-3.

Table PP 8-1
Electric Meters, Data Communications

Table PP 8-1					
Electric Meters, Data Communications ($ thousands)					
Full Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010-2021**
	Capital	72,463	70,452	70,599	67,508
	O&M	1,876	2,935	3,717	56,150
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010-2021**
	Capital	881	894	907	22,866
	O&M	0	3	3	46
Partial Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**		**2009-2021**
	Capital	40,552	40,986		32,350
	O&M	1,139	1,672		26,074
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**		**2009-2021**
	Capital	1,119	1,126		10,474
	O&M	0	3		49

II. DISCUSSION

A. Introduction

The purpose of this chapter is to describe the functional requirements of the communication system and electric meters that would enable the benefits described in various chapters herein, including operational and demand response benefits.

1. Background

Witness Charles' testimony discusses SDG&E's AMI deployment scenarios including a beta phase of 10,000 electric meters and 10,000 gas meters in 2006, followed by a launch of a production phase of either a preferred partial or preferred full deployment for the mass installation of gas and electric meters.

2. Communication Network Description

SDG&E's AMI communications network cost estimates are based on a wireless system between meters, relays and collection devices (gateways), which communicate with the utility's back office system. The wireless network in the vicinity of the gateways operates in the 900 MHz Federal Communications Commission Industrial Scientific and Medical (ISM) unlicensed band, with each of the electric meters capable of acting as a relay (along with other dedicated relays) with a power output in the one watt range. SDG&E anticipates that backhaul from each gateway to the back office system will be via a public digital cellular network.

AMI system costs and benefits are dependent on the assumptions regarding AMI system functional requirements. SDG&E addresses this issue by detailing the most capable system architecture.

SDG&E's "most capable" AMI infrastructure assumes:

- the system would be capable of measuring, storing and handling 15 minute interval data for all C&I customers and hourly data for all residential customers.
- the system would be capable of gathering reads from every electric meter, every day.
- the system would have the capability to gather consumption reads for gas and water meters on a daily basis (all meters "polled" daily; read data gathered monthly), although costs associated with water functionality are not included.
- the communications network would be fully bi-directional (two-way communications) between the utility back office system and the endpoint device (meter).

These above assumptions of the most capable system architecture would enable various dynamic rate structures such as those described in the functional requirements document issued in a Joint Assigned Commissioner and Administrative Law Judge Ruling Providing Guidance for the Advanced Metering Infrastructure Business Case Analysis in R.02-06-001, February 19, 2004. A less capable architecture would result in less flexibility and, therefore, constrain the possible dynamic rate structure and demand response benefits.

3. Electric Meter Description

The largest AMI cost component is the purchase of AMI-compatible electric meters with embedded communication modules. The electric meters are categorized by their relative difference in costs and complexity. These categories are: single-phase meters for residential applications; network meters for multi-family applications; and poly-phase meters for commercial and industrial applications. These categories are used

to calculate initial meter costs, meter maintenance costs, and incremental costs of meters required because of customer growth.

The electric meters that are being deployed are expected to be ANSI C12.19 compliant and provide a wireless communications interface to read and extract gas and water meter data.

B. Start-Up and Design Costs

The start-up costs have been captured during the Commercial AMI (aka RTEM) deployment. Commercial AMI deployment was authorized and funded in a previous Commission decision. Therefore, only the incremental staff required for the full or partial residential and commercial/industrial (<100 kW) deployment is captured in the design costs. The design costs are comprised of the following:

- Performing and reviewing site surveys to determine placement of network equipment.
- Mapping of network equipment on company facilities (asset facility mapping).
- Network planning and engineering - coverage studies, technology selection, field testing & engineering.

C. Installation Costs

All installation costs are based on incremental costs over and above the Commercial AMI deployment.

1. Communication System

The following costs were estimated:

- Administration of contracts/supervision of installer workforce.
- Installation and testing equipment costs (tools, equipment and vehicles).
- Installation contract labor.
- Costs of pole replacement (addition) - to "fit" concentrators.

- Installation costs of cross arms (e.g., streetlight arms for pole top installations) and other mounting.
- Cost of network communications equipment and hardware.
- Training of work force for installation of WAN/LAN equipment.

The communications and supporting systems cost estimates were based on an AMI wireless node consisting of one gateway surrounded by four relay devices. For design estimating purposes, a single node is assumed to cover a circular region one mile in diameter and a maximum of 500 electric meters, 500 gas meters and 500 water meters.

The network will primarily be installed on existing streetlights. Five percent of the installations will be on existing utility poles where mast arms and secondary power will need to be installed. One percent of the installations will require new poles to be installed in areas where a suitable streetlight or utility pole does not exist.

Estimated costs for installation include anticipated contractor labor costs as well as a small number of SDG&E resources for management and quality assurance. SDG&E assumes that the contractor will provide the appropriate tools for the contracted workforce. SDG&E also assumes the vendor contracted to perform gateway/relay installations will have their own technology tools, such as routing devices, and a communications-testing tool as well as be able to provide a systems interface for SDG&E systems on a daily basis. SDG&E has not included costs for these tools. SDG&E has accounted for the cost of interfacing SDG&E systems with the contractor systems in Witness Mr. Carusa's estimated systems development costs (see Chapter 4).

2. Electric Meter Costs

New Meters:

SDG&E used a Request for Proposal (RFP) process to obtain costs. Many meter vendors do not currently have products available to address the residential and lower cost Network meter applications. A final pricing structure was difficult to obtain without actually committing to deliveries and a time schedule. Because of the relative uncertainty of a meter vendors ability to deliver, two vendors were selected from the RFP responses to provide the single-phase residential and network meter product costs, which make up a majority of the meters. Because the quantities are much lower, and a working product is currently available, costs associated with poly-phase meter purchases were selected from only one vendor's RFP response.

SDG&E assumed that meter purchases will be split between a primary meter supplier and secondary meter supplier to ensure reliability of delivery and provide a second source of supply should the primary solution fail to deliver expected results. This split would provide the meter products based upon the most economical and practical split for the partial and full deployment scenarios, yielding the largest percentage of business to the primary supplier and a larger portion of the business to an alternate vendor for the full deployment scenario. This, however, has a negative impact on costs, increasing the average price for metering devices in the full deployment scenario for the Single-phase and Network meters above the average pricing used for partial deployment.

SDG&E excluded from the quantity of poly-phase meters the expected number of Commercial AMI meters that will be installed prior to the partial and full roll-out time schedules.

Replacement Meters due to Failure:

Solid State meters are not expected to have the same life as their electromechanical counterparts being used today. However, the failure rate of solid state metering devices is expected to be higher on the order of 1% per year for all meters installed in the field. Failures due to infant mortality (first year of service) are covered under the manufacturer's warranty. The analysis assumes that any failure occurring during the first three years would be covered under the manufacturer's warranty. The costs for acquiring metering products to replace failures occurring in years 4-15 are included in the analysis

D. Operation and Maintenance Costs (O&M)

O&M costs are based on incremental costs over and above the Commercial AMI deployment.

1. Communication System Costs

SDG&E estimated the following costs:

- Incremental costs to existing O&M due to more complex metering and the communications infrastructure (labor, tools, equip, vehicles).
- Attachment costs for gateways and relays (e.g., rent or lease charges by cities or other 3rd parties not owned by utility).
- Dispatching and O&M of field LAN/WAN and infrastructure equipment.
- Backhaul cost of public network connections (WAN Common Carrier costs - Verizon, SBC, etc.).
- Electric power consumed by LAN/WAN equipment and/or meter modules.
- Risk contingencies (e.g., technology obsolescence/reliability).

Attachment Costs:

SDG&E assumed that attachment costs will be paid on a monthly basis for city owned streetlights. SDG&E's estimates were based on fees currently charged other communication providers that use city owned streetlights.

Power Consumption:

Electric power consumed was based on data supplied by the vendor on typical usage for gateways and relays, and on what we charge for non-metered streetlights (6.4 cents/kWh).

Backhaul:

Backhaul from gateways to the utility's back office system is anticipated to be via a public digital cellular network. This will also require frame relay circuits between the digital cellular carrier and SDG&E.

2. Electric Meter Costs

Meter Engineering Labor:

Due to the large volume of meters that will be handled during the partial and full deployments, additional SDG&E meter engineering resources will be required. These employees will support field personnel and staff. These meter engineers will conduct meter failure analysis, evaluate and test firmware upgrades, coordinate programming changes and follow up with the vendors to ensure product support for the life of the meters.

Battery Replacement Costs:

The poly-phase and network meters will likely have backup batteries within the meter to maintain time when power outages occur. These batteries are expected to have a 10 year life. Costs for the replacement batteries were derived from the current costs for

backup batteries and were replaced in the 11th year after installation. Costs were included for all installed poly-phase and network meters (growth and deployment).

Power Consumption:

Any AMI solution installed under the meter cover will result in increased un-metered power consumption and thus additional load on the electric utility grid. SDG&E completed an analysis of measurements from devices currently under test and noted a continuous non-transmitting power consumption increase of 1.25 watts. When combined with the cost of energy and number of metering devices deployed, a total cost for additional energy consumption is calculated.

3. Risk Contingencies

Due to the fact that these types of AMI products are not yet available on the market to meet all of the technology and functional requirements in California, SDG&E included funding for risk contingencies in case other communications solutions were chosen for deployment. These costs reflect 5% of the total hardware costs that are anticipated to be spent on the technology being used to deploy a communications system and replace existing electric meters in the partial and full deployment scenarios. Communications system hardware and electric meters for new customer growth are included through 2021.

E. Systems Operations Benefits

1. Customer Site Visits

The AMI system will be able to provide information from customer locations that are currently obtained through physical SDG&E work force site visits. Meter shop personnel currently respond to customer requests to obtain this information. Savings are expected to result when this information can be obtained remotely through an AMI

system, thus saving the labor to obtain the information on-site. These benefits are captured specifically in the benefit element SB-7.

2. Re-Using Electromechanical Meters

In the partial deployment scenario only, metering equipment that is removed from one service point could be cleaned, tested and recalibrated if necessary and placed back into inventory for future use where maintenance on electromechanical meters continues in the remaining portion of our service territory. The savings depicted here are calculated based upon the cost of the meter types that would no longer require to be purchased, less the cost for cleaning, testing and placing product into inventory. These savings were calculated over 5 years after the start of the AMI deployment. These benefits are captured specifically in benefit element MB-3.

3. Growth Meter Displacement

AMI meters will be installed for all future customer growth. Therefore, SDG&E will avoid the meter cost of capital expenditures allocated to purchase electromechanical meters for new customer growth. Costs savings for 15 years of growth expansion are included based upon the type of meter expected to be installed for the various customer classes (Residential, Multi-family and Commercial). These benefits are captured specifically in benefit element MB-3.

This concludes my prepared direct testimony

Tables PP 8-2 through PP 8-5

Table PP 8-2

Electric Meters, Data Communications ($ thousands)

FULL Deployment Scenario - Cost Summary

Cost Category Summary

Yearly Total **Direct** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Communication Systems	5,018	5,923	5,982	173	179	179	180	180	181	181	181	317	324	461	462
Electric Meters	67,445	64,529	64,617	3,608	4,252	4,898	4,971	5,045	5,121	5,197	5,275	5,373	6,055	6,729	7,987
Total Capital Costs	72,463	70,452	70,599	3,780	4,431	5,077	5,151	5,226	5,301	5,378	5,457	5,690	6,379	7,189	8,449
O & M / A & G Costs															
Communication Systems	1,076	1,806	2,568	2,733	2,719	2,706	2,692	2,680	2,667	2,655	2,643	2,632	2,621	2,611	2,601
Electric Meters	800	1,129	1,149	1,188	1,203	1,218	1,233	1,249	1,265	1,280	1,458	3,743	3,869	4,571	1,912
Total O&M / A&G Costs	1,876	2,935	3,717	3,921	3,922	3,923	3,926	3,928	3,932	3,936	4,102	6,375	6,490	7,182	4,513

Cost Category Summary

Yearly Total **Fully Loaded** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Communication Systems	5,420	6,445	6,507	179	185	186	186	187	187	188	188	329	336	478	479
Electric Meters	69,947	66,923	67,014	3,742	4,410	5,080	5,156	5,233	5,311	5,390	5,471	5,572	6,280	6,978	8,283
Total Capital Costs	75,367	73,369	73,521	3,920	4,596	5,266	5,342	5,419	5,498	5,578	5,659	5,901	6,615	7,456	8,762
O & M / A & G Costs															
Communication Systems	1,203	2,014	2,852	3,017	3,004	2,990	2,977	2,964	2,952	2,939	2,928	2,916	2,906	2,895	2,885
Electric Meters	907	1,238	1,258	1,297	1,312	1,327	1,343	1,358	1,374	1,390	1,569	3,865	3,992	4,698	2,025
Total O&M / A&G Costs	2,110	3,251	4,110	4,315	4,316	4,317	4,320	4,322	4,326	4,330	4,496	6,781	6,898	7,593	4,910

Table PP 8-3

Electric Meters, Communications ($ thousands)

FULL Deployment Scenario - Benefit Summary

Benefit Category Summary

Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Electric Meters Deferred / Avoided	881	894	907	921	935	949	963	977	992	1,007	1,022	1,037	1,052	1,068	1,084
Electric Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10,860
Total Capital Benefits	881	894	907	921	935	949	963	977	992	1,007	1,022	1,037	1,052	1,068	11,944
O & M / A & G Benefits															
Electric Meters Deferred / Avoided	0	3	3	4	4	4	4	4	4	4	4	4	4	4	4
Electric Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	0	3	3	4	4	4	4	4	4	4	4	4	4	4	4

Benefit Category Summary

Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Electric Meters Deferred / Avoided	914	927	941	955	969	984	998	1,013	1,028	1,044	1,059	1,075	1,091	1,108	1,124
Electric Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11,263
Total Capital Benefits	914	927	941	955	969	984	998	1,013	1,028	1,044	1,059	1,075	1,091	1,108	12,388
O & M / A & G Benefits															
Electric Meters Deferred / Avoided	0	5	5	5	5	5	5	6	6	6	6	6	6	6	6
Electric Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	0	5	5	5	5	5	5	6	6	6	6	6	6	6	6

Benefit Element Detail

Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Electric Meters Deferred / Avoided															
MB-3	881	894	907	921	935	949	963	977	992	1,007	1,022	1,037	1,052	1,068	1,084
SB-7															
Electric Meter Residual Value															
MB-3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10,860
Total Capital Benefits	881	894	907	921	935	949	963	977	992	1,007	1,022	1,037	1,052	1,068	11,944
O & M / A & G Benefits															
Electric Meters Deferred / Avoided															
MB-3															
SB-7	0	3	3	4	4	4	4	4	4	4	4	4	4	4	4
Electric Meter Residual Value															
MB-3.5															
Total O&M / A&G Benefits	0	3	3	4	4	4	4	4	4	4	4	4	4	4	4

Benefit Element Detail

Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Electric Meters Deferred / Avoided															
MB-3	914	927	941	955	969	984	998	1,013	1,028	1,044	1,059	1,075	1,091	1,108	1,124
SB-7															
Electric Meter Residual Value															
MB-3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11,263
Total Capital Benefits	914	927	941	955	969	984	998	1,013	1,028	1,044	1,059	1,075	1,091	1,108	12,388
O & M / A & G Benefits															
Electric Meters Deferred / Avoided															
MB-3															
SB-7	0	5	5	5	5	5	5	6	6	6	6	6	6	6	6
Electric Meter Residual Value															
MB-3.5															
Total O&M / A&G Benefits	0	5	5	5	5	5	5	6	6	6	6	6	6	6	6

Table PP 8-4

Electric Meters, Communications ($ thousands)

PARTIAL Deployment Scenario - Cost Summary

Cost Category Summary

Yearly Total **Direct** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Communication Systems	3,018	3,418	104	105	105	106	112	112	113	113	114	171	178	236	238
Electric Meters	37,534	37,568	1,372	1,742	2,112	2,148	2,185	2,222	2,259	2,298	2,337	2,395	2,770	3,164	3,541
0															
Total Capital Costs	40,552	40,986	1,476	1,846	2,217	2,253	2,296	2,334	2,372	2,411	2,451	2,565	2,948	3,400	3,779
O & M / A & G Costs															
Communication Systems	575	1,098	1,114	1,113	1,111	1,110	1,110	1,109	1,109	1,108	1,108	1,108	1,108	1,108	1,109
Electric Meters	565	574	584	600	608	615	622	630	637	645	750	1,889	1,949	1,172	948
0															
Total O&M / A&G Costs	1,139	1,672	1,698	1,713	1,719	1,725	1,732	1,739	1,746	1,753	1,858	2,996	3,057	2,281	2,057

Cost Category Summary

Yearly Total **Fully Loaded** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Communication Systems	3,237	3,653	108	108	109	109	116	117	117	118	118	177	184	245	247
Electric Meters	38,927	38,962	1,423	1,806	2,190	2,228	2,266	2,304	2,343	2,383	2,424	2,484	2,873	3,282	3,672
0															
Total Capital Costs	42,164	42,614	1,531	1,915	2,299	2,337	2,382	2,421	2,460	2,501	2,542	2,661	3,057	3,526	3,919
O & M / A & G Costs															
Communication Systems	650	1,248	1,265	1,263	1,262	1,261	1,260	1,260	1,259	1,259	1,259	1,258	1,259	1,259	1,259
Electric Meters	671	680	690	707	714	721	729	736	744	752	857	2,002	2,062	1,282	1,056
0															
Total O&M / A&G Costs	1,321	1,928	1,955	1,970	1,976	1,982	1,989	1,996	2,003	2,010	2,115	3,260	3,321	2,541	2,316

Table PP 8-5
Electric Meters, Data Communications ($ thousands)
PARTIAL Deployment Scenario - Benefit Summary

Benefit Category Summary
Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Electric Meters Deferred / Avoided	1,119	1,126	1,134	1,141	1,148	457	464	472	480	488	496	504	513	521	530
Electric Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,127
0															
Total Capital Benefits	1,119	1,126	1,134	1,141	1,148	457	464	472	480	488	496	504	513	521	2,657
O & M / A & G Benefits															
Electric Meters Deferred / Avoided	0	3	3	4	4	4	4	4	4	4	4	4	4	4	4
Electric Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0															
Total O&M / A&G Benefits	0	3	3	4	4	4	4	4	4	4	4	4	4	4	4

Benefit Category Summary
Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Electric Meters Deferred / Avoided	1,161	1,168	1,176	1,183	1,191	474	481	489	498	506	514	523	532	540	549
Electric Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,206
0															
Total Capital Benefits	1,161	1,168	1,176	1,183	1,191	474	481	489	498	506	514	523	532	540	2,756
O & M / A & G Benefits															
Electric Meters Deferred / Avoided	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Electric Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0															
Total O&M / A&G Benefits	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3

Benefit Element Detail
Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Electric Meters Deferred / Avoided															
MB-3	1,119	1,126	1,134	1,141	1,148	457	464	472	480	488	496	504	513	521	530
SB-7															
Electric Meter Residual Value															
MB-3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,127
Total Capital Benefits	1,119	1,126	1,134	1,141	1,148	457	464	472	480	488	496	504	513	521	2,657
O & M / A & G Benefits															
Electric Meters Deferred / Avoided															
MB-3															
SB-7	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Electric Meter Residual Value															
MB-3.5															
Total O&M / A&G Benefits	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2

Benefit Element Detail
Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Electric Meters Deferred / Avoided															
MB-3	1,161	1,168	1,176	1,183	1,191	474	481	489	498	506	514	523	532	540	549
SB-7															
Electric Meter Residual Value															
MB-3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,206
Total Capital Benefits	1,161	1,168	1,176	1,183	1,191	474	481	489	498	506	514	523	532	540	2,756
O & M / A & G Benefits															
Electric Meters Deferred / Avoided															
MB-3															
SB-7	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Electric Meter Residual Value															
MB-3.5															
Total O&M / A&G Benefits	0	3	3	3	3	3	3	3	3	3	3	3	3	3	3

QUALIFICATIONS

OF

PAUL PRUSCHKI

My name is Paul Pruschki and I am employed by San Diego Gas & Electric Company (SDG&E). My business address is 8326 Century Park Court, CP62C, San Diego, CA 92123.

My present position is Measurement Data Communications Manager in the Electric Measurement & Advanced Metering Infrastructure Department of SDG&E. I have been employed by SDG&E since 2003. Previous positions relevant to my testimony include Technical Project Manager (2000-2003), RF Manager (1997-1999) and RF Engineer (1992-1997).

I received a B.S. in Electrical Engineering from Rensselaer Polytechnic Institute. I have not previously testified before the California Public Utilities Commission.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 9

PREPARED DIRECT TESTIMONY

OF

TED REGULY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 9

PREPARED DIRECT TESTIMONY

OF

TED REGULY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

CHAPTER 9
PREPARED DIRECT TESTIMONY
OF
TED REGULY

I. INTRODUCTION

The purpose of my testimony is to describe the incremental operational costs and benefits related to gas and electric meter installations gas modules, gas meters and claims that would be realized with the deployment of Advanced Metering Infrastructure (AMI) in either the full or partial deployment scenario. The benefit categories that I will discuss are the Customer Services Field Service Savings within SB-02; avoided costs of future gas meter changes, in MB-04 and MB-13; savings related to remote meter reprogramming in SB-05; and a reduction in potential claims, a contributing factor of benefit element SB-01.

Table TR 9-1

Table TR 9-1
Gas Meters, Gas Modules, Gas and Electric Meter Installation, Facilities, Claims, Customer Service Field
($ thousands)

Full Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010 - 2021**
	Capital	37,688	37,542	37,726	19,571
	O&M	5,113	5,024	5,099	33,323
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010 - 2021**
	Capital	538	468	639	10,937
	O&M	109	744	1,412	26,503
Partial Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**	**2009-2021**	
	Capital	24,216	24,337	9,489	
	O&M	4,407	3,966	15,354	
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**	**2009-2021**	
	Capital	220	200	5,067	
	O&M	55	462	12,588	

II. DISCUSSION

A. Meter System and Installation Costs

Patrick Charles' testimony (Chapter 3) discusses SDG&E's AMI deployment scenarios including a beta phase of 10,000 electric meters and 10,000 gas meters in 2006, followed by the launch of a production phase of either a preferred partial or preferred full deployment for the mass deployment of gas and electric meter installations. The costs in my testimony address partial and full deployment years 2007 – 2021. The direct costs addressed in my testimony are summarized in Table TR 9-1.

1. Gas Meter, Gas Modules, and Electric Meter Installation

SDG&E expects AMI gas and electric meter installations to be performed by a contracted workforce with internal project management, contractor employee training, testing and quality assurance oversight, and contract administration. SDG&E will establish a certification and quality assurance process for the contract workforce assigned to work on SDG&E gas and electric meter equipment. The contract labor force will be trained to comply with SDG&E's gas and electric standards.

2. Electric Meter Installation Costs

AMI electric installation costs include labor for installing single-phase and poly-phase electric meters. A 10% revisit rate is assumed for unsuccessful initial installation based upon preliminary discussions with other utilities and contractors who have performed mass deployment installations to address access and energy diversion issues, meter failures, and meter communication malfunctions. Also

included are costs associated with a corresponding follow-up installation test to verify installation and equipment parameters for customers with instrument (transformer) rated metering equipment. Additionally, included within the installation costs are electric residential panel repairs and conversions from obsolete hard-wired (A-Base) meter installations to standard socket based meter installations.

Electric installation costs also include sample meter testing of 400 meters for each shipment lot of 10,000 meters. Labor is included for installation and quality assurance training, and certification of the installation contractor work force, as well as training of SDG&E employees who will operate, troubleshoot and maintain the new AMI meters and modules.

3. Gas Meter and Module Installation Costs

SDG&E estimates that approximately 72% of the existing installed gas meters will be retrofitted with an AMI communications module, and will not require a replacement meter. The AMI installation cost associated with this group of gas meters involves the retrofit of the communication module onto existing gas meters.

SDG&E estimates that 28% of existing installed gas meters, due to their design, cannot be retrofited with an AMI communications module and will require replacement to support the AMI communications module. The costs associated with removing and replacing these meters and attaching the communication module have been included. SDG&E expects gas meter communications module installation and gas meter replacements to be performed by a contract workforce,

overseen by SDG&E contract administrators and quality assurance staff. A 10% revisit rate is assumed for unsuccessful initial installation attempts typically caused by customer access issues and damage, based upon preliminary discussions with contract vendors and utilities that have completed mass deployment efforts of this magnitude.

Labor is included for the training, quality assurance and certification processes required for the installation contractor work force, as well as training SDG&E employees who will operate, troubleshoot and maintain the new AMI meters and modules.

4. Gas Meter and Module Purchases

The largest gas-related cost component is the purchase of AMI-compatible gas meter communication modules that would be installed on approximately 72% of SDG&E's existing gas meters and installed with replacement gas meters in approximately 28% of existing premises. The gas module is powered by a battery that communicates wirelessly with the AMI communication network, as referenced by witness Mr. Paul Pruschki's testimony in Chapter 8 regarding the AMI communication network.

After the initial deployment period, a small number of gas modules will be procured annually, consistent with forecasted customer growth. SDG&E anticipates that these gas modules will be integrated into new gas meters from meter manufacturers after the initial AMI deployment period.

5. Logistics, Warehousing and Facilities During Mass Deployment

SDG&E envisions that there will be a centralized hub where receipt and issuance of electric and gas meters will be performed. Costs include receiving and issuing meters, warehousing space, and shuttling to satellite locations. Satellite warehouse facilities will be established and closed during the deployment phase as the installation process progresses throughout SDG&E's service territory. The satellite locations include the necessary infrastructure to support the contracted force labor.

6. Potential Claims During Deployment

With mass deployment and installation of gas and electric meters and modules, as well as panel repairs, comes the risk of potential customer claims related to damages. Although SDG&E expects to complete gas and electric meter installations with a contract workforce, potential AMI-related claims costs were estimated using historical experience for relates types of tasks completed by internal workforce during the years 2002 – 2004.

B. Operations and Maintenance Costs

1. Risk Contingency and Technology Obsolescence

Witnesses Edward Fong (Chapter 2) and Paul Pruschki (Chapter 8) have discussed issues related to technological obsolescence in their testimony. Costs related to technological obsolescence of AMI communications modules retrofit on gas meters are included. Consistent with AMI network and electric costs as referenced by witness Mr. Paul Pruschki, these costs reflect an additional 5% of the

gas AMI communications module purchases as an element of risk associated new technology not yet available on the market to meet all of the technology and functional requirements in California. The 5% risk contingency has been included in the gas module purchase costs for deployment and new customer growth through 2021.

2. Increased Electric O&M

Costs include incremental maintenance for marginally higher failure rates than currently experienced with an electromechanical metering system, as referenced by witness Mr. Paul Pruschki. It is expected that only poly-phase electric meters will be equipped with a battery. The life expectancy of the battery is 10 years. It is assumed that the battery replacement will be performed by contract labor.

3. AMI Gas Module Battery Replacement

Incremental gas operations and maintenance costs include the labor, materials and vehicle costs related to battery maintenance and module failures. Although the estimated battery life contained within the gas AMI-enabled meter is 10 years, the costs have been estimated assuming a mass change-out of all batteries every 9 years. Before the change-out period SDG&E will determine to replace or repair the old module based on economics and technology improvements. For this reason the module is assumed to have a 9 year useful life. SDG&E assumes that contract labor will be used for the mass change-out to remove and replace the old module with a refurbished module equipped with a new battery. Labor and material

costs for performing corrective maintenance of premature module failures are included. SDG&E field employees are assumed to respond to these failures.

C. Systems Operations Benefits

1. Customer Services Field Personnel

Benefits related to a reduction of field orders to perform re-reads and reads associated with turn-on's/turn-off's, include reduced labor, vehicle, and equipment costs.

2. Avoided/Deferred Gas Meters

Benefits include savings related to the accelerated replacement of approximately 28% of gas meters as a result of the AMI meter deployment. Savings include materials and labor associated with this group of gas meters, and represent costs that would have otherwise been incurred to replace this group of gas meters later in the business case period in the absence of AMI.

3. Poly Phase Electric Meter Reprogramming

Poly phase meters can be reprogrammed remotely via the AMI network. On-site reprogramming of AMI poly phase meters are no longer necessary.

4. Savings Related to the Reduction of Claims

Savings related to avoided claims as a result of the labor reductions in Meter Reading, as referred to by witness James Teeter (Chapter 11), as well as Customer Services Field personnel.

D. Next Steps Include RFI Results and RFP Initiation

SDG&E has issued a Request for Information (RFI) on March 4, 2005 to seven known meter deployment contractors. Expected replies for requested information is April 11, 2005. SDG&E issued this document for the purpose of gathering information on meter deployment contractor experience, equipment and systems capabilities, employee recruitment, and training and certification capabilities. The information gathered will then be used to validate SDG&E's deployment assumptions, finalize a comprehensive Request for Proposal (RFP) and select a short list of contractors to compete for the AMI meter deployment project.

If the results of the RFI/RFP process indicate a substantial change from SDG&E's estimated meter deployment costs, SDG&E will file an updated estimate for the AMI meter deployment costs and reevaluate the AMI deployment plan. (See witness Edward Fong's (Chapter 2) testimony discussion of AMI project off-ramps).

This concludes my prepared direct testimony.

Tables TR 9-2 through TR 9-5

Table TR 9-2

Gas Meters, Gas Modules, Gas and Electric Meter Installation, Facilities, Claims, Customer Service Field

FULL Deployment Scenario - Cost Summary

Cost Category Summary

Yearly Total **Direct** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Facilities	893	893	893	0	0	0	0	0	0	0	0	0	0	0	0
Gas Meters, Gas Modules, Installation (Gas & Electric)	36,795	36,649	36,833	1,491	1,515	1,540	1,564	1,590	1,616	1,642	1,668	1,695	1,722	1,750	1,778
Claims															
Total Capital Costs	37,688	37,542	37,726	1,491	1,515	1,540	1,564	1,590	1,616	1,642	1,668	1,695	1,722	1,750	1,778
O & M / A & G Costs															
Facilities	313	293	335	0	0	0	0	0	0	0	0	0	0	0	0
Gas Meters, Gas Modules, Installation (Gas & Electric)	4,757	4,688	4,721	361	362	366	368	371	723	9,026	9,242	9,243	1,160	909	1,188
Claims	43	43	43	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Costs	5,113	5,024	5,099	361	362	366	368	371	723	9,026	9,242	9,243	1,160	909	1,188

Cost Category Summary

Yearly Total **Fully Loaded** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Facilities	926	926	926	0	0	0	0	0	0	0	0	0	0	0	0
Gas Meters, Gas Modules, Installation (Gas & Electric)	41,562	41,411	41,602	1,546	1,571	1,597	1,622	1,649	1,676	1,703	1,730	1,758	1,786	1,815	1,844
Claims															
Total Capital Costs	42,488	42,337	42,528	1,546	1,571	1,597	1,622	1,649	1,676	1,703	1,730	1,758	1,786	1,815	1,844
O & M / A & G Costs															
Facilities	315	295	337	0	0	0	0	0	0	0	0	0	0	0	0
Gas Meters, Gas Modules, Installation (Gas & Electric)	6,315	6,211	6,257	504	505	510	513	517	895	9,242	9,559	9,561	1,533	1,162	1,569
Claims	43	43	43	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Costs	6,673	6,548	6,637	504	505	510	513	517	895	9,242	9,559	9,561	1,533	1,162	1,569

Table TR 9-3

Gas Meters, Gas Modules, Gas and Electric Meter Installation, Facilities, Claims, Customer Service Field

FULL Deployment Scenario - Benefit Summary

Benefit Category Summary

Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Service Field	0	16	31	46	48	48	49	395	51	53	53	54	56	56	58
Gas & Electric Meters / Gas Modules & Installation (Gas & Electric)	538	452	608	195	194	196	174	184	169	169	169	169	169	169	169
Gas Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7,844
Claims															
Total Capital Benefits	538	468	639	241	242	244	223	579	220	222	222	223	225	225	8,071
O & M / A & G Benefits															
Customer Service Field	16	649	1,280	1,911	1,945	1,983	2,023	2,063	2,104	2,147	2,189	2,234	2,278	2,323	2,371
Gas & Electric Meters / Gas Modules & Installation (Gas & Electric)	93	95	132	82	82	82	76	78	76	76	76	76	76	76	76
Gas Meter Residual Value															
Claims	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	109	744	1,412	1,993	2,027	2,065	2,099	2,141	2,180	2,223	2,265	2,310	2,354	2,399	2,447

Benefit Category Summary

Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Service Field	0	17	32	48	50	50	51	410	53	55	55	56	58	58	60
Gas & Electric Meters / Gas Modules & Installation (Gas & Electric)	558	469	631	202	201	203	180	191	175	175	175	175	175	175	175
Gas Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8,135
Claims															
Total Capital Benefits	558	485	663	250	251	253	231	600	228	230	230	231	233	233	8,371
O & M / A & G Benefits															
Customer Service Field	23	902	1,780	2,657	2,706	2,759	2,815	2,870	2,928	2,987	3,046	3,108	3,170	3,233	3,298
Gas & Electric Meters / Gas Modules & Installation (Gas & Electric)	93	103	146	103	103	103	97	99	97	97	97	97	97	97	97
Gas Meter Residual Value															
Claims	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	93	103	146	103	103	103	97	99	97	97	97	97	97	97	97

Benefit Element Detail

Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Service Field															
SB-2	0	16	31	46	48	48	49	395	51	53	53	54	56	56	58
Gas & Electric Meters / Gas Modules & Installation (Gas & Electric)															
MB-4	445	371	505	156	155	157	141	149	136	136	136	136	136	136	136
MB-13	93	81	103	39	39	39	33	35	33	33	33	33	33	33	33
Gas Meter Residual Value															
MB-13.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7,844
Claims															
SB-1															
Total Capital Benefits	538	468	639	241	242	244	223	579	220	222	222	223	225	225	8,071
O & M / A & G Benefits															
Customer Service Field															
SB-2	16	649	1,280	1,911	1,945	1,983	2,023	2,063	2,104	2,147	2,189	2,234	2,278	2,323	2,371
Gas & Electric Meters / Gas Modules & Installation (Gas & Electric)															
MB-13	93	81	103	39	39	39	33	35	33	33	33	33	33	33	33
SB-5	0	14	29	43	43	43	43	43	43	43	43	43	43	43	43
Gas Meter Residual Value															
MB-13.5															
Claims															
SB-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	109	744	1,412	1,993	2,027	2,065	2,099	2,141	2,180	2,223	2,265	2,310	2,354	2,399	2,447

Benefit Element Detail

Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Service Field															
SB-2	0	17	32	48	50	50	51	410	53	55	55	56	58	58	60
Gas & Electric Meters / Gas Modules & Installation (Gas & Electric)															
MB-4	462	385	524	162	161	163	146	155	141	141	141	141	141	141	141
MB-13	96	84	107	40	40	40	34	36	34	34	34	34	34	34	34
Gas Meter Residual Value															
MB-13.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8,135
Claims															
SB-1															
Total Capital Benefits	558	485	663	250	251	253	231	600	228	230	230	231	233	233	8,371
O & M / A & G Benefits															
Customer Service Field															
SB-2	23	902	1,780	2,657	2,706	2,759	2,815	2,870	2,928	2,987	3,046	3,108	3,170	3,233	3,298
Gas & Electric Meters / Gas Modules & Installation (Gas & Electric)															
MB-13	93	81	104	39	39	39	33	35	33	33	33	33	33	33	33
SB-5	0	21	43	64	64	64	64	64	64	64	64	64	64	64	64
Gas Meter Residual Value															
MB-13.5															
Claims															
SB-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	116	1,005	1,926	2,761	2,810	2,862	2,912	2,970	3,025	3,085	3,143	3,205	3,267	3,330	3,396

Table TR 9-4

Gas Meters, Gas Modules, Gas and Electric Meter Installation, Facilities, Claims, Customer Service Field

PARTIAL Deployment Scenario - Cost Summary

Cost Category Summary

Yearly Total **Direct** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Facilities	886	886	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Meters, Gas Modules, Installation (Gas & Electric)	23,330	23,451	662	673	683	695	706	717	729	740	752	765	776	789	802
Claims															
Total Capital Costs	24,216	24,337	662	673	683	695	706	717	729	740	752	765	776	789	802
O & M / A & G Costs															
Facilities	476	343	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Meters, Gas Modules, Installation (Gas & Electric)	3,904	3,595	172	173	174	176	177	178	502	5,848	6,013	532	410	460	541
Claims	28	28	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Costs	4,407	3,966	172	173	174	176	177	178	502	5,848	6,013	532	410	460	541

Cost Category Summary

Yearly Total **Fully Loaded** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Facilities	919	919	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Meters, Gas Modules, Installation (Gas & Electric)	26,481	26,607	687	698	708	721	732	744	756	767	780	793	805	818	832
Claims															
Total Capital Costs	27,400	27,525	687	698	708	721	732	744	756	767	780	793	805	818	832
O & M / A & G Costs															
Facilities	478	345	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Meters, Gas Modules, Installation (Gas & Electric)	4,908	4,575	241	242	244	246	247	249	586	5,961	6,204	707	526	597	716
Claims	28	28	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Costs	5,415	4,947	241	242	244	246	247	249	586	5,961	6,204	707	526	597	716

Table TR 9-5

Gas Meters, Gas Modules, Gas and Electric Meter Installation, Facilities, Claims, Customer Service Field

PARTIAL Deployment Scenario - Benefit Summary

Benefit Category Summary

Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Service Field	0	10	20	21	21	21	21	175	23	23	23	24	24	25	26
Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	220	190	244	83	82	83	79	83	77	77	77	105	105	105	105
Gas Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,315
Claims															
Total Capital Benefits	220	200	264	104	103	104	100	258	100	100	100	129	129	130	3,446
O & M / A & G Benefits															
Customer Service Field	16	420	823	839	856	874	891	908	926	945	964	983	1,003	1,024	1,045
Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	39	42	56	37	37	37	36	37	36	36	36	41	41	41	41
Gas Meter Residual Value															
Claims	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	55	462	879	876	893	911	927	945	962	981	1,000	1,024	1,044	1,065	1,086

Benefit Category Summary

Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Service Field	0	10	21	22	22	22	22	181	24	24	24	25	25	26	27
Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	228	197	253	86	85	86	82	86	80	80	80	109	109	109	109
Gas Meter Residual Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,438
Claims															
Total Capital Benefits	228	207	274	108	107	108	104	268	104	104	104	134	134	135	3,574
O & M / A & G Benefits															
Customer Service Field	23	584	1,144	1,167	1,191	1,216	1,239	1,263	1,288	1,314	1,341	1,367	1,395	1,424	1,453
Gas & Electric Meters / Gas Modules & installation (Gas & Electric)	39	46	63	47	47	47	46	47	46	46	46	51	51	51	51
Gas Meter Residual Value															
Claims	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	62	629	1,207	1,214	1,238	1,263	1,285	1,310	1,335	1,361	1,387	1,418	1,446	1,475	1,504

Benefit Element Detail

Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Service Field															
SB-2	0	10	20	21	21	21	21	175	23	23	23	24	24	25	26
Gas & Electric Meters / Gas Modules & installation (Gas & Electric)															
MB-4	181	155	202	67	66	67	64	67	62	62	62	85	85	85	85
MB-13	39	35	42	16	16	16	15	16	15	15	15	20	20	20	20
Gas Meter Residual Value															
MB-13.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,315
Claims															
SB-1															
Total Capital Benefits	220	200	264	104	103	104	100	258	100	100	100	129	129	130	3,446
O & M / A & G Benefits															
Customer Service Field															
SB-2	16	420	823	839	856	874	891	908	926	945	964	983	1,003	1,024	1,045
Gas & Electric Meters / Gas Modules & installation (Gas & Electric)															
MB-13	39	35	42	16	16	16	15	16	15	15	15	20	20	20	20
SB-5	0	7	14	21	21	21	21	21	21	21	21	21	21	21	21
Gas Meter Residual Value															
MB-13.5															
Claims															
SB-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	55	462	879	876	893	911	927	945	962	981	1,000	1,024	1,044	1,065	1,086

Benefit Element Detail

Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Service Field															
SB-2	0	10	21	22	22	22	22	181	24	24	24	25	25	26	27
Gas & Electric Meters / Gas Modules & installation (Gas & Electric)															
MB-4	188	161	209	69	68	69	66	69	64	64	64	88	88	88	88
MB-13	40	36	44	17	17	17	16	17	16	16	16	21	21	21	21
Gas Meter Residual Value															
MB-13.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,438
Claims															
SB-1															
Total Capital Benefits	228	207	274	108	107	108	104	268	104	104	104	134	134	135	3,574
O & M / A & G Benefits															
Customer Service Field															
SB-2	23	584	1,144	1,167	1,191	1,216	1,239	1,263	1,288	1,314	1,341	1,367	1,395	1,424	1,453
Gas & Electric Meters / Gas Modules & installation (Gas & Electric)															
MB-13	39	35	42	16	16	16	15	16	15	15	15	20	20	20	20
SB-5	0	10	21	31	31	31	31	31	31	31	31	31	31	31	31
Gas Meter Residual Value															
MB-13.5															
Claims															
SB-1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total O&M / A&G Benefits	62	629	1,207	1,214	1,238	1,263	1,285	1,310	1,335	1,361	1,387	1,418	1,446	1,475	1,504

QUALIFICATIONS

OF

TED MICHAEL REGULY

My name is Ted Michael Reguly and I am employed by San Diego Gas & Electric Company (SDG&E). My business address is 8326 Century Park Court, San Diego, CA 92123.

My present position is Director of Customer Service Field South Inland Region in the Customer Services Department of SDG&E. I have been employed by SDG&E since 1981. I have held various positions of increasing responsibility in Electric Generation, Electric and Gas Distribution, Supply Management, and Gas and Electric Customer Service supervision. I am a registered California Mechanical Engineer. I assumed my current position in 2004.

I received a B.S. in Mechanical Engineering from California State University, Long Beach, and an MBA from San Diego State University.

I have not previously testified before the California Public Utilities Commission.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 10

PREPARED DIRECT TESTIMONY

OF

EDWARD FONG

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 10

PREPARED DIRECT TESTIMONY

OF

EDWARD FONG

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

CHAPTER 10
PREPARED DIRECT TESTIMONY
OF
EDWARD FONG

I. INTRODUCTION

The purpose of this chapter is to describe the incremental AMI operational costs and benefits for the Customer Contact Center (CCC), Demand Response Programs and Demand Response Enabling Technologies. Section II presents the incremental operational costs and benefits for the Customer Contact Center. Section III presents the incremental costs and benefits related to the reduction of demand response program offerings funded through non-cost of service rates.[1] Section IV presents SDG&E's proposal for funding demand response enabling technologies as part of the AMI implementation.

AMI costs for these activities are identified in Tables EF 10-1 through EF 10-5.

Table EF 10-1

Table EF 10-1 Customer Contact Center, Demand Response Programs & Enabling Technology ($ thousands)					
Full Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010-2021**
	Capital	0	0	0	0
	O&M	1,935	2,756	1,971	11,686
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010-2021**
	Capital	175	350	525	6,300
	O&M	4,490	8,980	13,468	161,636
Partial Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**		**2009-2021**
	Capital	0	0		0
	O&M	1,227	2,195		8,881
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**		**2009-2021**
	Capital	175	350		4,550
	O&M	4,488	8,976		116,699

[1] Almost all incremental costs related to SDG&E's current demand response programs for C&I and residential customers are recorded in the Advanced Metering and Demand Response Memorandum Account (AMDRMA) and recovered via the Rewards and Penalties Balancing Account.

II. CUSTOMER CONTACT CENTER INCREMENTAL OPERATIONAL COSTS AND BENEFITS

This section describes incremental costs and benefits associated with CCC activities.

A. Installation Costs

Incremental CCC cost related to the installation of AMI electric meters, gas modules and gas meter replacements are based on additional training requirements for SDG&E CCC personnel on the AMI installation process and the proper procedures to handle customer calls related to installation. Incremental costs for the CCC also include the additional customer calls and incremental average handle time related to such calls.

SDG&E expects 1 hour of additional training for customer contact personnel related to AMI deployment and installation of AMI electric meters. SDG&E estimates that 10% of the customers in year one (2007) will contact the CCC with miscellaneous questions or concerns regarding the AMI electric meter installation. In addition, SDG&E estimates that 3% of the customers will contact the CCC with miscellaneous questions or concerns regarding the AMI gas meters. SDG&E assumes that these phone calls will average 2 minutes. SDG&E expects the percentage of customer calls to decrease to 5% in subsequent years throughout the installation process.

B. Operation and Maintenance Costs

The incremental cost associated with continuing operation and maintenance of AMI included the additional required training for CCC personnel on the billing, default dynamic rate and optional rate structures. In addition, incremental costs are included for additional talk time

associated with customers moving from a residence which may require a change in rate (during the deployment period or in the partial deployment scenario), additional billing calls regarding the new rate structure, and additional calls related to customers electing an optional rate.

SDG&E expects an incremental 4 hours of training for existing and future CCC personnel. SDG&E anticipates receiving a call from 10% of our customers related to the new dynamic rate. SDG&E expects these calls will average 250 seconds in length. A customer moving from a residence with an AMI meter to one without will experience a rate change. SDG&E will notify these customers of this change during the customer call to transfer service. SDG&E estimates the incremental average handle time for these calls to be 30 seconds. SDG&E assumes that that approximately 20% of residential customers will select an optional rate. The expected average handle time for these calls is 250 seconds.

C. Reliability Event Costs

SDG&E estimates that a small portion of customers will call in regards to their inability to override the smart thermostat setting as a result of a reliability signal or event.

D. Installation Benefits

SDG&E does not expect any benefits through the meter installation process.

E. Operation and Maintenance Benefits

CCC operation and maintenance benefits result from reduced calls due to the reduction of meter reading errors. Currently, customers contact SDG&E about meter reading errors. Two types of customer contact transactions can occur. The customer can call about a possible meter error requiring dispatch of customer services field personnel to confirm the error (0.18%/electric meters and 0.14%/gas meters), or a customer provides SDG&E with the correct read and the billing department corrects the error (0.27%/gas and electric meters).

III. DEMAND RESPONSE PROGRAMS ARE REDUCED

The purpose of this section is to describe the potential benefits from reducing expenditures currently authorized for demand response programs (i.e., including management, administration, measurement and evaluation, customer recruitment, and other costs) as a result of the deployment of AMI and default dynamic rates. The specific benefit category is identified in Tables EF 10-4 and EF 10-5, Benefit Category MB-2, Reduced Miscellaneous Support Expenses (including office equipment and supplies).

A. Background on Demand Response Programs

As set forth in the Tables EF 10-4 and EF 10-5, SDG&E estimates a reduction in the future costs of its existing Demand Response Programs as a result of either a partial or full deployment of AMI. As noted in my policy testimony, SDG&E believes that the full extent of the demand response benefits from AMI can only be realized through the simultaneous introduction of a dynamic pricing structure. Table EF 10-4 and Table EF 10-5 present SDG&E's estimation of the potential reduction in Demand Response Programs costs beginning in 2007 with the anticipated deployment of AMI, with incremental increases in cost reductions over the years of AMI deployment. SDG&E has retained a level of demand response program funding consistent with current and expected funding levels.

B. SDG&E's Demand Response Program Authorization and Funding

At present, the vast majority of SDG&E's Demand Response Program Authorization and associated funding is determined on an annual, or other short term basis, by the Commission. Commission Decision (D.) 05-01-056, issued on January 27, 2005, approved SDG&E's current portfolio of programs, and an associated budget of approximately $18 million. These costs are not reflected in SDG&E's Cost of Service authorized rates; these costs are recorded in the

SDG&E's Advanced Metering and Demand Response Memorandum Account (AMDRMA) and recovered via the Rewards and Penalties Balancing Account.

In issuing D.05-01-056, the Commission approved programs and budgets for only one year, 2005, and directed SDG&E to file an application on June 1, 2005, proposing programs and budgets for the period 2006 – 2008.[2] With this pattern of authorized programs and funding spanning from annually to only a few years at a time, it is difficult at this time to anticipate just which Demand Response Programs and related costs will be in place during the period of initial AMI deployment and beyond. Nonetheless, SDG&E has made a conservative assumption that with the deployment of AMI, and the associated introduction of a default dynamic pricing structure, a certain portion of its existing voluntary Demand Response Programs will be eliminated, or at least scaled back in some fashion, thus resulting in the estimated cost reductions set forth in Tables EF 10-4 and EF 10-5 attached.

C. Demand Response Program Reductions

Assuming that default dynamic rates are in place for all customers by 2010 and that SDG&E has approximately $18 million of annual funding for demand response and interruptible programs in 2010, SDG&E expects a reduction of $11-12 million annually in these refundable programs. SDG&E anticipates that in the future, some of the existing Day-Ahead (pricing) voluntary programs will be not be needed as a result of AMI deployment. Most of these cost reductions will come from program operations, such as customer communications and recruitment, measurement and evaluation and other program management costs. Over time, these cost reductions will increase as AMI reaches (full) deployment and more customers are placed on dynamic rates.

[2] See D.05-01-056, Ordering Paragraph 3.

SDG&E believes that the cost reduction estimates are conservative because it is expected that Day-Of (reliability) programs will continue beyond AMI deployment. These programs will actually complement dynamic pricing and offer customers additional incentives (financial or otherwise) to reduce load during peak periods with shorter term notification.

IV. DEMAND RESPONSE ENABLING TECHNOLOGIES

The purpose of this section is to describe SDG&E's preferred demand response enabling technology, smart thermostats. Smart thermostats will be offered to customers with central air conditioning and whose summer monthly energy usage is greater than 1,000 kWh. Customers with central air conditioning who fall below 1,000 kWh average summer monthly energy usage will also be able eligible for the smart thermostat program if the initial offering to the 1,000 kWh or greater customers has not exhausted the authorized funding. These costs for enabling technologies are identified in Tables EF 10-2 and EF 10-3.

A. Start-Up and Design Costs

SDG&E plans to target large residential electric users with central air conditioning for installation of smart thermostats. SDG&E will provide customers who are willing to have their air conditioning thermostat settings automatically increased during high price periods with a smart thermostat and installation with no charge. Customers enrolled in such a program will have the option to override the automatic set point, but may face a surcharge for each override event. Customers will not be able to override the automatic thermostat setting during a "reliability" event.

B. Installation Costs

SDG&E will purchase and install the smart thermostat for an eligible customer who enrolls in SDG&E's program. Installation and equipment costs are estimated based on 24,000 smart thermostats.

C. Operation and Maintenance Costs (O&M)

Incremental operational costs are based on continuing program management and administration costs. These include replacement equipment costs and continuing tracking of customer performance, change of residents and follow-up recruitment, etc.

D. Demand Response and Reliability Benefits

Charles River Associates (CRA) estimates that the incremental demand response benefit from the smart thermostat program (24,000 customers) is approximately 15 MW by 2010 when full deployment is completed. (See Witness Dr. George's testimony, Chapter 13.) Specifically, this demand response reduction from the smart thermostat technology is in addition or incremental to the default dynamic price demand response impacts. The direct reliability benefits are estimated at approximately 3 MW from the non-override feature during reliability events.

This concludes my testimony on customer contact center, demand response program management and enabling technologies operating costs and benefits.

Tables EF 10-2 through EF 10-5

Table EF 10-2

Customer Contact Center, Demand Response Programs & Enabling Technology ($ thousands)

FULL Deployment Sceanrio - Cost Summary

Cost Category Summary

Yearly Total **Direct** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Customer Contact Center															
Demand Response Programs															
Enabling Technology															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Customer Contact Center	281	280	244	13	14	14	14	14	14	14	15	15	15	15	15
Demand Response Programs	1,653	2,475	1,726	1,663	845	855	864	874	884	893	904	914	924	935	946
Enabling Technology	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total O&M / A&G Costs	1,935	2,756	1,971	1,676	860	869	879	889	899	909	919	930	940	951	962

Cost Category Summary

Yearly Total **Fully Loaded** Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Customer Contact Center															
Demand Response Programs															
Enabling Technology															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Customer Contact Center	463	461	403	22	22	23	23	23	24	24	24	24	25	25	25
Demand Response Programs	1,786	2,612	1,859	1,796	974	983	993	1,002	1,012	1,022	1,033	1,043	1,053	1,064	1,075
Enabling Technology	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total O&M / A&G Costs	2,250	3,075	2,263	1,819	997	1,007	1,017	1,027	1,037	1,047	1,058	1,069	1,079	1,090	1,102

Table EF 10-3

Customer Contact Center, Demand Response Programs & Enabling Technology ($ thousands)

FULL Deployment Sceanrio - Benefit Summary

Benefit Category Summary

Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Contact Center															
Demand Response Programs	175	350	525	525	525	525	525	525	525	525	525	525	525	525	525
Enabling Technology															
Total Capital Benefits	175	350	525	525	525	525	525	525	525	525	525	525	525	525	525
O & M / A & G Benefits															
Customer Contact Center	5	10	14	14	15	15	15	15	16	16	16	16	16	17	17
Demand Response Programs	4,485	8,970	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454
Enabling Technology															
Total O&M / A&G Benefits	4,490	8,980	13,468	13,468	13,469	13,469	13,469	13,469	13,470	13,470	13,470	13,470	13,470	13,471	13,471

Benefit Category Summary

Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Contact Center															
Demand Response Programs	181	363	544	544	544	544	544	544	544	544	544	544	544	544	544
Enabling Technology															
Total Capital Benefits	181	363	544	544	544	544	544	544	544	544	544	544	544	544	544
O & M / A & G Benefits															
Customer Contact Center	8	16	23	24	24	24	25	25	26	26	26	27	27	28	28
Demand Response Programs	5,035	10,071	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105
Enabling Technology															
Total O&M / A&G Benefits	5,043	10,086	15,129	15,129	15,129	15,130	15,130	15,130	15,131	15,131	15,132	15,132	15,132	15,133	15,133

Benefit Element Detail

Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Contact Center															
SB-4															
Demand Response Programs															
MB-2	175	350	525	525	525	525	525	525	525	525	525	525	525	525	525
Total Capital Benefits	175	350	525	525	525	525	525	525	525	525	525	525	525	525	525
O & M / A & G Benefits															
Customer Contact Center															
SB-4	5	10	14	14	15	15	15	15	16	16	16	16	16	17	17
Demand Response Programs															
MB-2	4,485	8,970	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454	13,454
Total O&M / A&G Benefits	4,490	8,980	13,468	13,468	13,469	13,469	13,469	13,469	13,470	13,470	13,470	13,470	13,470	13,471	13,471

Benefit Element Detail

Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Contact Center															
SB-4															
Demand Response Programs															
MB-2	181	363	544	544	544	544	544	544	544	544	544	544	544	544	544
Total Capital Benefits	181	363	544	544	544	544	544	544	544	544	544	544	544	544	544
O & M / A & G Benefits															
Customer Contact Center															
SB-4	8	16	23	24	24	24	25	25	26	26	26	27	27	28	28
Demand Response Programs															
MB-2	5,035	10,071	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105	15,105
Total O&M / A&G Benefits	5,043	10,086	15,129	15,129	15,129	15,130	15,130	15,130	15,131	15,131	15,132	15,132	15,132	15,133	15,133

Table EF 10-4

Customer Contact Center, Demand Response Programs & Enabling Technology ($ thousands)

PARTIAL Deployment Sceanrio - Cost Summary

Cost Category Summary

Yearly Total Direct Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Customer Contact Center															
Demand Response Programs															
Enabling Technology															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Customer Contact Center	182	194	48	49	49	50	51	52	52	53	54	55	55	56	57
Demand Response Programs	1,044	2,000	1,309	534	540	547	555	562	569	576	583	591	599	607	615
Enabling Technology	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total O&M / A&G Costs	1,227	2,195	1,358	583	591	599	607	614	622	630	638	646	655	664	673

Cost Category Summary

Yearly Total Fully Loaded Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Customer Contact Center															
Demand Response Programs															
Enabling Technology															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Customer Contact Center	300	320	79	80	82	83	84	85	86	87	89	90	91	93	94
Demand Response Programs	1,124	2,084	1,390	611	617	625	632	639	646	653	661	668	677	684	692
Enabling Technology	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Total O&M / A&G Costs	1,425	2,406	1,471	692	700	708	717	725	734	742	750	759	769	778	787

Table EF 10-5

Customer Contact Center, Demand Response Programs & Enabling Technology ($ thousands)

PARTIAL Deployment Sceanrio - Benefit Summary

Benefit Category Summary

Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Contact Center															
Demand Response Programs	175	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Enabling Technology															
Total Capital Benefits	175	350	350	350	350	350	350	350	350	350	350	350	350	350	350
O & M / A & G Benefits															
Customer Contact Center	3	6	6	6	6	6	7	7	7	7	7	7	7	7	8
Demand Response Programs	4,485	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970
Enabling Technology															
Total O&M / A&G Benefits	4,488	8,976	8,976	8,976	8,976	8,976	8,977	8,977	8,977	8,977	8,977	8,977	8,977	8,977	8,978

Benefit Category Summary

Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Contact Center															
Demand Response Programs	181	363	363	363	363	363	363	363	363	363	363	363	363	363	363
Enabling Technology															
Total Capital Benefits	181	363	363	363	363	363	363	363	363	363	363	363	363	363	363
O & M / A & G Benefits															
Customer Contact Center	5	10	10	10	11	11	11	11	11	11	12	12	12	12	12
Demand Response Programs	5,035	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071
Enabling Technology															
Total O&M / A&G Benefits	5,041	10,081	10,081	10,081	10,081	10,081	10,082	10,082	10,082	10,082	10,082	10,083	10,083	10,083	10,083

Benefit Element Detail

Yearly Total **Direct** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Contact Center															
SB-4															
Demand Response Programs															
MB-2	175	350	350	350	350	350	350	350	350	350	350	350	350	350	350
Total Capital Benefits	175	350	350	350	350	350	350	350	350	350	350	350	350	350	350
O & M / A & G Benefits															
Customer Contact Center															
SB-4	3	6	6	6	6	6	7	7	7	7	7	7	7	7	8
Demand Response Programs															
MB-2	4,485	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970	8,970
Total O&M / A&G Benefits	4,488	8,976	8,976	8,976	8,976	8,976	8,977	8,977	8,977	8,977	8,977	8,977	8,977	8,977	8,978

Benefit Element Detail

Yearly Total **Fully Loaded** Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Customer Contact Center															
SB-4															
Demand Response Programs															
MB-2	181	363	544	544	544	544	544	544	544	544	544	544	544	544	544
Total Capital Benefits	181	363	544	544	544	544	544	544	544	544	544	544	544	544	544
O & M / A & G Benefits															
Customer Contact Center															
SB-4	5	10	10	10	11	11	11	11	11	11	12	12	12	12	12
Demand Response Programs															
MB-2	5,035	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071	10,071
Total O&M / A&G Benefits	5,041	10,081	10,081	10,081	10,081	10,081	10,082	10,082	10,082	10,082	10,082	10,083	10,083	10,083	10,083

QUALIFICATIONS

OF

EDWARD FONG

Mr. Edward Fong is currently the Director of Measurement and Advanced Metering Infrastructure (AMI) for San Diego Gas & Electric (SDG&E). He is responsible for directing, managing and planning the electric measurement activities and advanced metering technology implementation for SDG&E. Prior to assuming his current position in October 2004, Mr. Fong was Director of Measurement & Meter Reading from 2002-2004, Director of Customer Services Solutions from 2000-2001, and Director of Revenue Cycle Services for from 1998-2000. Mr. Fong has directed and managed measurement, meter reading, billing, call center, branch office, credit and collections, direct access services and other customer services operations at SDG&E.

Ed is currently SDG&E's lead director for the California Public Utilities Commission (CPUC) rulemaking proceeding on Advanced Metering, Dynamic Pricing and Demand Response, R.02-06-001.

Prior to joining SDG&E in 1998, Ed held various director level management positions with the Southern California Gas Company in Human Resources, Organizational Development, Customer Contact, Customer Services Operations Staff, Information Technology, and Planning.

Ed has testified before the CPUC on numerous occasions covering a variety of topics ranging from cost of service, measurement and meter reading to billing systems implementation.

Ed is a graduate of University of California, San Diego with undergraduate and graduate degrees in Economics.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 11

PREPARED DIRECT TESTIMONY

OF

JAMES S. TEETER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 11

PREPARED DIRECT TESTIMONY

OF

JAMES S. TEETER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30 2005

CHAPTER 11
PREPARED DIRECT TESTIMONY
OF
JAMES S. TEETER

I. INTRODUCTION

The purpose of my testimony is to describe the costs and benefits that would be realized by Billing, Meter Revenue Protection, Meter Reading and Safety with the deployment of Advanced Metering Infrastructure (AMI) in both a full and partial deployment scenarios. The specific cost categories that I discuss are the Billing and Meter Revenue Protection, Meter Reading and Safety installation costs and ongoing O&M costs listed in Tables JT 11-2 and JT 11-4, and the specific benefit categories that I discuss are the Billing and Meter Reading Operational benefits listed in Tables JT 11-3 and JT 11-5.

Table JT 11-1

Table JT 11-1 Billing, Meter Reading, Safety, Meter Revenue Protection ($ thousands)					
Full Deployment	Direct Costs (not loaded, not escalated)				
		2007	2008	2009	2010 - 2021
	Capital	0	0	0	0
	O&M	1,171	1,166	1,366	10,919
	Direct Benefits (not loaded, not escalated)				
		2007	2008	2009	2010 - 2021
	Capital	33	0	0	2,722
	O&M	2,683	6,696	10,893	166,784
Partial Deployment	Direct Costs (not loaded, not escalated)				
		2007	2008	2009-2021	
	Capital	0	0	0	
	O&M	726	669	5,711	
	Direct Benefits (not loaded, not escalated)				
		2007	2008	2009-2021	
	Capital	33	0	203	
	O&M	1,741	4,313	77,441	

II. DISCUSSION

A. Billing and Meter Revenue Protection Impacts

Installation of AMI and dynamic pricing rates will affect customer billing operations. Meter reading errors will be eliminated and estimated billing errors due to access issues will by eliminated. SDG&E expects that energy theft will be reduced due to the installation of more sophisticated metering technology will produce additional revenue that should eventually lower rates as the unaccounted for energy cost is reduced for all customers.

Although meter reading errors will be virtually eliminated, new issues will occur due to meter communications. Further, more complex electric rates will require more time and effort in exception bill processing and corrections. Implementation costs will increase billing costs in the short-term, but then level off after a transition period and further expected automation. Costs and benefits for Billing and Meter Revenue Protection from 2007-2021 are summarized in Tables JT 11-2 through Tables JT 11-5.

1. Installation Costs

Customer Billing Operations (Billing) will experience minor installation costs when AMI devices are installed.

(a) Costs to Process Meter Changes

Billing expects an increase in exception bill processing related to the increase of AMI meter changes in the field. Billing expects to manually process exceptions on 7% of the meter installations. Accordingly, Billing will require additional resources over the meter installation phase to process the exceptions on the high volume of meter installations. These resources will not be needed

following deployment. These changes in cost are reflected in Tables JT 11-2 and JT 11-4.

(b) Training Costs

Based on prior experience with implementing new information systems, significant incremental training costs will be required for all billing employees. Approximately one-half of current Billing employees have prior experience with interval data meters and are expected to require 40 additional hours of training. Those without that interval meter billing experience will require an additional 80 hours of training.

2. Operations and Maintenance (O&M)

Billing will be more complex. Witness Fong discusses the concurrent implementation of AMI with dynamic rates to induce demand response (see Chapter 2). Billing residential accounts with dynamic rates may involve dealing with 720 data elements (hourly intervals) for residential meters instead of one (monthly consumption read).

(a) Higher Level Requirements For Billing Staff

More complex billing requires more analytical skills and knowledge. Much of the exception bill processing will shift from clerical workers to analysts. In order to attract and retain employees with higher skill sets, SDG&E assumes that salaries will increase by approximately 10%.

(b) More Time Will Be Required to Process Interval Data Billing

With potentially 720 data points to analyze each month, the time required to handle billing exceptions, make billing adjustments or correct errors

will increase, thereby increasing labor costs. This projection is based on experience from processing bills for the Statewide Pricing Pilot (SPP) and our current interval data accounts that require 20-50% longer to handle compared to simpler single-entry meter readings.

3. Benefits

Unaccounted-for Energy (UFE) will be reduced due to meter replacements and less energy theft. Bills will be more accurate and delivered in a more timely manner to customers.

(a) Energy Theft Will Be Reduced.

Industry research indicates that, in general, electric utilities experience approximately 1-2% of their revenue is lost due to electric energy theft. The most common method of energy theft is turning the meter upside-down, allowing the meter to run backwards. Advanced meters will record usage digitally and tamper alarms will alert the utility to such tampering. Accordingly, this method of energy theft will no longer be undetected.

Meter readers currently detect approximately 42% of SDG&E's electric meter diversion. Without the benefit of monthly site visits from meter readers, other methods of energy theft could go undetected as customers develop more sophisticated methods of stealing energy. SDG&E estimates that this type of theft will increase by 50%.

During the concentrated effort to replace all electric meters, SDG&E assumes it will discover a much higher rate of energy theft which will require investigation. The revenue protection benefits of reduced theft will be offset by

modest increases in Meter Revenue Protection labor costs during the meter installation phase.

(b) Billing Adjustments Due to Meter Reading Errors Will Be Eliminated.

AMI will eliminate approximately 4,000 electric rebills and 2,800 gas rebills each month due to meter reading errors.

(c) Cash Flow Will Be Improved By Eliminating Late Meter Readings.

Historically a fraction of meter readings have not been available on the scheduled billing date as a result of workload peaks and unavoidable operational issues. For business case analysis we have assumed a 15% occurrence. AMI will eliminate late bills due to late readings because the elements that cause delayed readings will be removed from the information transferal process. When the bill is delayed one or more days, the due date is delayed one day and customers tend to pay their bills one day later. AMI will improve cash flow.

B. Meter Reading and Safety Impacts

SDG&E collects gas and electric meter readings by visual reads using a workforce of approximately 190 meter readers. Meter routes are downloaded into a handheld collection device (computer) daily. All meter readings are entered into the data collection device and readings are uploaded to the mainframe computer at the close of each business day. When AMI installation is completed, SDG&E anticipates 95% network coverage with the remaining 5% collected via an alternate system.

Concerning safety, SDG&E meter readers have a high number of safety incidents due to their challenging work environment. Safety performance measures are Motor Vehicle Incidents (MVI), OSHA injuries (OSHAs), and Lost Work Days (LWDs)

resulting from an OSHA-related incident. Under AMI, SDG&E will experience a significant cost reduction in these safety areas, including the cost per case and administration to support, develop and promote safety training and reduction in claims.

1. Installation Costs

As AMI is installed, Meter Reading will plan the needs of the workforce while still providing quality meter readings and meeting business demands. The cost savings under AMI will come from attrition in the workforce, reduction in vehicles, fuel, equipment, supplies, and management support. Regular workforce positions will transition into either new positions that will be used to support the AMI business plan, or will transition into other areas of the company. SDG&E's call-in or part-time meter readers will be used as needed to fill behind the regular employees as they move into other areas of the company. As AMI installations reduce the need for manual readings, the need for call-ins will reduce in proportion to installations.

(a) Route Balancing Cost Will Increase During the Transition Period.

As new meters are installed, route sizes will rapidly become out of balance, and additional work force will be required to conduct route realignments to maximize manual meter reading efficiency. Additional resources will be required to keep routes balanced during the installation period. After that time, additional labor resources will no longer be required.

(b) Additional Safety Costs Will Be Incurred During the Installation Years.

I discuss the benefit of reduced safety incidents in paragraph II. B3(c) below. However, the safety costs for additional meter installers will exceed the

savings of fewer meter readers during the first three years. Once meters have been installed, no additional safety costs will be incurred.

2. Operation and Maintenance Costs (O&M)

SDG&E expects no additional O&M costs after the transition period. However, SDG&E will incur costs to read the 5% of meters not covered by the AMI network.

3. Benefits

(a) Meter Reading Costs Will Drop to Near Zero.

Since walk by meter reading will no longer be required for the meters in SDG&E's service territory, costs will be substantially reduced for meter reading labor, meter access resolution, office support, handheld devices, vehicles, uniforms and equipment. Cost savings in each of these categories have been computed from 2004 budget costs and translated to a cost per meter basis.

(b) Meter Access Related Issues Will Be Eliminated

Since all meters will have electronic modules, monthly visits to 95% of customer homes will no longer be required.

(c) Safety Benefits

Safety benefits were computed on a cost per incident basis. Since SDG&E's safety record has been improving, cost reductions were estimated by projecting continuing decrease in safety incidents.

(d) Avoided Capital Expenses Associated With Handheld Devices

Meter reading handheld devices are replaced approximately every 5-7 years. SDG&E shows an avoided capital cost in 2005-2006 and 2014-2015 associated with handheld devices for the full deployment scenario.

This concludes my prepared direct testimony.

Tables JT 11-2 through JT 11-5

Table JT 11-2
Billing, Meter Reading, Safety, Meter Revenue Protection
FULL Deployment Scenario - Cost Summary ($ thousands)

Cost Category Summary
Yearly Total Direct Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Billing															
Meter Reading															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Billing	757	698	791	367	370	374	378	382	387	391	396	400	405	410	414
Meter Reading	414	468	574	478	486	494	501	509	515	524	531	539	548	556	564
Total O&M / A&G Costs	1,171	1,166	1,366	845	856	868	879	891	902	915	927	939	953	966	978

Cost Category Summary
Yearly Total Fully Loaded Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Billing															
Meter Reading															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Billing	1,249	1,151	1,305	605	610	617	624	631	638	645	653	660	668	676	683
Meter Reading	596	643	769	608	618	628	637	647	655	666	675	685	697	706	717
Total O&M / A&G Costs	1,845	1,795	2,074	1,213	1,228	1,245	1,260	1,278	1,293	1,311	1,327	1,345	1,364	1,382	1,400

Table JT 11-3
Billing, Meter Reading, Safety, Meter Revenue Protection
FULL Deployment Scenario - Benefit Summary ($ thousands)

Benefit Category Summary
Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Billing															
Meter Reading	33	0	0	0	0	0	0	1,361	1,361	0	0	0	0	0	0
Total Capital Benefits	33	0	0	0	0	0	0	1,361	1,361	0	0	0	0	0	0
O & M / A & G Benefits															
Billing	907	1,795	2,683	2,721	2,760	2,799	2,839	2,880	2,921	2,963	3,005	3,049	3,092	3,137	3,182
Meter Reading	1,776	4,901	8,210	10,124	10,267	10,412	10,560	10,710	10,862	11,016	11,173	11,333	11,495	11,659	11,826
Total O&M / A&G Benefits	2,683	6,696	10,893	12,845	13,027	13,211	13,399	13,590	13,783	13,979	14,179	14,381	14,587	14,796	15,008

Benefit Category Summary
Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Billing															
Meter Reading	34	0	0	0	0	0	0	1,411	1,411	0	0	0	0	0	0
Total Capital Benefits	34	0	0	0	0	0	0	1,411	1,411	0	0	0	0	0	0
O & M / A & G Benefits															
Billing	942	1,864	2,786	2,826	2,867	2,908	2,949	2,992	3,034	3,078	3,122	3,167	3,212	3,259	3,306
Meter Reading	2,521	6,959	11,601	14,237	14,441	14,647	14,857	15,069	15,286	15,505	15,728	15,954	16,184	16,417	16,654
Total O&M / A&G Benefits	2,521	6,959	11,601	14,237	14,441	14,647	14,857	15,069	15,286	15,505	15,728	15,954	16,184	16,417	16,654

Benefit Element Detail
Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Billing															
MB-1	33	0	0	0	0	0	0	1,361	1,361	0	0	0	0	0	0
Total Capital Benefits	33	0	0	0	0	0	0	1,361	1,361	0	0	0	0	0	0
O & M / A & G Benefits															
Billing															
CB-4	55	108	161	164	166	169	171	174	176	179	182	184	187	190	193
SB-3	829	1,641	2,453	2,488	2,523	2,559	2,595	2,632	2,670	2,708	2,747	2,786	2,826	2,866	2,907
SB-7	23	46	69	70	71	72	73	74	75	76	77	78	79	80	81
Meter Reading															
CB-1	52	142	233	277	281	285	289	294	298	303	307	312	316	321	326
MB-1	256	707	1,299	1,732	1,753	1,774	1,795	1,816	1,838	1,861	1,883	1,906	1,930	1,953	1,977
MB-12	0	0	43	232	232	232	233	233	233	233	233	233	233	233	234
MB-2	45	124	203	241	244	248	252	255	259	263	267	271	275	279	284
SB-1	1,423	3,928	6,433	7,642	7,757	7,873	7,992	8,112	8,233	8,357	8,483	8,611	8,740	8,872	9,005
Total O&M / A&G Benefits	2,683	6,696	10,893	12,845	13,027	13,211	13,399	13,590	13,783	13,979	14,179	14,381	14,587	14,796	15,008

Benefit Element Detail
Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Billing															
MB-1	34	0	0	0	0	0	0	1,411	1,411	0	0	0	0	0	0
Total Capital Benefits	34	0	0	0	0	0	0	1,411	1,411	0	0	0	0	0	0
O & M / A & G Benefits															
Billing															
CB-4	85	169	252	255	259	263	267	271	275	279	284	288	292	297	301
SB-3	834	1,650	2,466	2,501	2,536	2,572	2,609	2,646	2,684	2,722	2,761	2,801	2,841	2,881	2,922
SB-7	23	46	69	70	71	72	73	74	75	76	77	78	80	81	82
Meter Reading															
CB-1	85	235	384	456	463	470	477	484	492	499	507	514	522	530	538
MB-1	258	711	1,306	1,741	1,762	1,783	1,804	1,826	1,848	1,870	1,893	1,916	1,940	1,963	1,988
MB-12	0	0	63	341	341	342	342	342	342	342	342	343	343	343	343
MB-2	45	124	204	242	245	249	253	257	261	264	268	272	277	281	285
SB-1	2,134	5,889	9,644	11,457	11,629	11,803	11,981	12,161	12,343	12,529	12,717	12,909	13,103	13,300	13,501
Total O&M / A&G Benefits	3,464	8,823	14,387	17,063	17,307	17,555	17,806	18,061	18,320	18,583	18,850	19,121	19,396	19,676	19,960

Table JT 11-4
Billing, Meter Reading, Safety, Meter Revenue Protection
PARTIAL Deployment Scenario - Cost Summary ($ thousands)

Cost Category Summary
Yearly Total Direct Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Billing															
Meter Reading															
0															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Billing	516	422	200	202	204	206	208	210	212	214	216	219	221	223	225
Meter Reading	210	247	206	210	213	216	219	224	227	230	234	238	241	245	249
0															
Total O&M / A&G Costs	726	669	406	412	417	422	427	434	439	444	450	457	462	468	474

Cost Category Summary
Yearly Total Fully Loaded Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Billing															
Meter Reading															
0															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Billing	852	697	331	333	336	339	343	346	350	353	357	360	364	368	372
Meter Reading	296	330	262	267	271	274	278	285	288	292	297	303	306	311	316
0															
Total O&M / A&G Costs	1,147	1,027	592	600	607	614	621	631	638	645	654	663	670	679	688

Table JT 11-5
Billing, Meter Reading, Safety, Meter Revenue Protection
PARTIAL Deployment Scenario - Benefit Summary ($ thousands)

Benefit Category Summary
Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Billing															
Meter Reading	33	0	0	0	0	0	0	102	102	0	0	0	0	0	0
0															
Total Capital Benefits	33	0	0	0	0	0	0	102	102	0	0	0	0	0	0
O & M / A & G Benefits															
Billing	577	1,135	1,153	1,171	1,190	1,209	1,228	1,248	1,268	1,288	1,309	1,329	1,351	1,372	1,394
Meter Reading	1,164	3,177	4,261	4,327	4,396	4,465	4,535	4,606	4,679	4,752	4,827	4,903	4,981	5,058	5,139
0															
Total O&M / A&G Benefits	1,741	4,313	5,414	5,499	5,586	5,674	5,763	5,854	5,947	6,040	6,136	6,233	6,332	6,431	6,534

Benefit Category Summary
Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Billing															
Meter Reading	34	0	0	0	0	0	0	105	105	0	0	0	0	0	0
0															
Total Capital Benefits	34	0	0	0	0	0	0	105	105	0	0	0	0	0	0
O & M / A & G Benefits															
Billing	600	1,180	1,198	1,218	1,237	1,257	1,277	1,297	1,318	1,339	1,360	1,382	1,404	1,426	1,449
Meter Reading	1,653	4,512	6,057	6,152	6,248	6,346	6,446	6,548	6,651	6,755	6,862	6,970	7,080	7,190	7,305
0															
Total O&M / A&G Benefits	2,253	5,692	7,255	7,369	7,485	7,603	7,723	7,845	7,968	8,094	8,222	8,352	8,484	8,617	8,754

Benefit Element Detail
Yearly Total Direct Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Billing															
MB-1	33	0	0	0	0	0	0	102	102	0	0	0	0	0	0
Total Capital Benefits	33	0	0	0	0	0	0	102	102	0	0	0	0	0	0
O & M / A & G Benefits															
Billing															
CB-4	36	70	71	72	73	74	76	77	78	79	80	82	83	84	86
SB-3	527	1,036	1,053	1,069	1,087	1,104	1,121	1,139	1,157	1,176	1,195	1,214	1,233	1,253	1,273
SB-7	15	29	29	30	30	31	31	32	32	33	33	34	35	35	36
Meter Reading															
CB-1	34	92	119	121	123	125	127	129	131	133	135	138	140	142	144
MB-1	168	456	593	603	612	622	632	642	653	663	674	685	696	706	718
MB-12	0	18	151	152	153	154	155	156	157	158	159	160	161	162	163
MB-2	29	80	104	105	107	109	111	112	114	116	118	120	122	124	126
SB-1	933	2,532	3,294	3,346	3,400	3,455	3,510	3,566	3,624	3,682	3,741	3,801	3,863	3,925	3,988
Total O&M / A&G Benefits	1,741	4,313	5,414	5,499	5,586	5,674	5,763	5,854	5,947	6,040	6,136	6,233	6,332	6,431	6,534

Benefit Element Detail
Yearly Total Fully Loaded Benefits

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Benefits															
Billing															
MB-1	34	0	0	0	0	0	0	105	105	0	0	0	0	0	0
Total Capital Benefits	34	0	0	0	0	0	0	105	105	0	0	0	0	0	0
O & M / A & G Benefits															
Billing															
CB-4	56	109	111	112	114	116	118	120	122	124	126	128	130	132	134
SB-3	530	1,042	1,058	1,075	1,092	1,110	1,127	1,145	1,163	1,182	1,201	1,220	1,239	1,259	1,279
SB-7	15	29	30	30	31	31	32	32	33	33	34	34	35	35	36
Meter Reading															
CB-1	56	151	197	200	203	206	210	213	216	220	223	227	231	234	238
MB-1	169	458	596	606	615	625	635	646	656	666	677	688	699	709	722
MB-12	0	26	222	223	225	226	228	230	231	233	234	236	237	239	240
MB-2	30	80	104	106	108	109	111	113	115	117	118	120	122	124	126
SB-1	1,398	3,796	4,938	5,017	5,097	5,179	5,262	5,347	5,433	5,520	5,609	5,699	5,791	5,884	5,979
Total O&M / A&G Benefits	2,253	5,692	7,255	7,369	7,485	7,603	7,723	7,845	7,968	8,094	8,222	8,352	8,484	8,617	8,754

QUALIFICATIONS

OF

JAMES S. TEETER

My name is James S. Teeter and I am employed by San Diego Gas & Electric Company (SDG&E). My business address is 8306 Century Park Court, Suite 42i, San Diego, CA 92123-1530.

My present position is Billing Manager in the Customer Billing Operations Department of SDG&E. I have been employed by SDG&E since 1972. Previous positions relevant to my testimony include Manager-Measurement and Billing (1998-2002) and Manager-Billing Services (1989-1998).

I received a B. S. in Accounting from San Diego State University. I have not previously testified before the California Public Utilities Commission.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 12

PREPARED DIRECT TESTIMONY

OF

PATRICIA WAGNER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 12

PREPARED DIRECT TESTIMONY

OF

PATRICIA WAGNER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

CHAPTER 12
PREPARED DIRECT TESTIMONY
OF
PATRICIA WAGNER

I. INTRODUCTION

The purpose of my testimony is to describe the costs associated with San Diego Gas & Electric Company's (SDG&E's) customer communications, education and feedback for full or partial AMI program. The roll-out of any new program typically requires a communications effort of some magnitude in order to inform and educate customers and other stakeholders, as well as to promote understanding (particularly of new alternatives and options), and gain acceptance. With AMI and dynamic pricing SDG&E will be transforming the way customers will think of and manage their electric consumption and bills. Qualitative market research indicates that in order to enhance the success and value of this effort, a significant education and awareness campaign will be necessary.

SDG&E intends to leverage a broad mix of communication mediums and tools to educate and inform stakeholders about the purpose and benefits of AMI and the complementary roles of dynamic pricing, demand response programs, and energy efficiency programs. These efforts will be geared toward building long-term awareness and acceptance of the value of dynamic pricing as well as awareness of the tools and information that will be available to customers to assist them in the efficient use and management of energy.

Table PW 12-1

Table PW 12-1 Mass Markets ($ thousands)					
Full Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010-2021**
	Capital	0	0	0	0
	O&M	4,076	4,376	4,576	8,820
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**	**2009**	**2010-2021**
	Capital	0	0	0	0
	O&M	0	0	0	0
Partial Deployment	Direct **Costs** (not loaded, not escalated)				
		2007	**2008**		**2009-2021**
	Capital	0	0		0
	O&M	2,547	2,547		6,678
	Direct **Benefits** (not loaded, not escalated)				
		2007	**2008**		**2009-2021**
	Capital	0	0		0
	O&M	0	0		0

II. DISCUSSION

A. Stakeholders

SDG&E has identified two primary stakeholder groups in a wide scale AMI and dynamic pricing deployment: customers and communities. In order to achieve a smooth transition into an AMI environment, it is important that each of these stakeholder groups be involved in communication, education and awareness efforts.

1. Customers

Customers will be impacted significantly by either of the AMI deployment scenarios. While there are certainly some customers who will be able to easily adjust to AMI and dynamic pricing, many will find this change to be new, complicated and possibly confusing. Accordingly, SDG&E believes that for the deployment to be a success, (e.g., high levels of customers remaining on dynamic rates, effective use of the expanded energy price and consumption information and maintain a high level of customer satisfaction) customers must understand AMI and dynamic pricing and how they can best manage their energy use.

SDG&E will prepare all its customers *in advance* of the AMI deployment and dynamic rate transition with ample notice and information to the customer. SDG&E will educate the customer on the potential benefits, gather and review customer feedback, preview dynamic pricing options, provide solutions for energy management, and lay the foundation for future enhancements.

SDG&E plans a targeted, multi-lingual awareness campaign for all of our residential and unassigned[1] commercial/industrial customers, featuring direct mail, bill inserts, door hangers, brochures, and mass media.

2. Community

Community support is essential for a smooth transition to dynamic pricing under the full deployment scenario. AMI deployment will, involve virtually every neighborhood in SDG&E's service territory. Working with community groups in advance of deployment will provide for a smoother and more coordinated installation process. SDG&E currently maintains an extensive outreach effort with communities that can be leveraged to assist our customers and communities understand the transition to an AMI environment.

SDG&E plans to work with both of these stakeholder groups to introduce new technologies in its service territory, garner support, manage the customer experience, and deliver demand response,

B. Customer Communications Strategy

SDG&E's objective with the proposed communication effort is to build long-term awareness and acceptance of the value of dynamic pricing and the tools that an AMI network can provide customers. SDG&E will develop a comprehensive communications

[1] Unassigned customers are C/I that do not have an Account Executive assigned.

strategy that leverages a broad array of communication mediums and tools. This effort is fully incremental to any existing, planned and approved communications effort. In the full-deployment scenario, SDG&E has identified $21.7 million in labor and non-labor costs; in the partial deployment scenario, SDG&E has identified $11.7 million in labor and non-labor costs. Each scenario includes funding for direct mail, flyers/brochures, door hangers, bill inserts, mass media advertising, and customer orientation information to explain new AMI technology and smart thermostats, fact sheets and other information to help educate customers on dynamic pricing options available to them.

C. Operation and Maintenance Costs (O&M)

SDG&E has estimated costs associated with a communications effort to support either a full or partial deployment scenario. Table PW 12-1 presents a summary of the costs under both a partial and full AMI deployment scenario.

1. Non-Labor

Under the partial deployment scenario, SDG&E will deploy AMI technology to approximately 40% of SDG&E's customers (those located throughout the territory) in the Inland climate zone and commercial customers 20 kW and above. In order to promote the AMI program under the partial deployment scenario, SDG&E has estimated costs of $4.85 million to provide communications and other information to these customers.

It is important that customers understand the new meter installation and the associated dynamic rate options. Communications to residential and commercial customers will be through various channels. SDG&E will educate customers at community outreach events and local city events. For commercial

customers, brochures and other tools will be developed and be disseminated at trade shows, business association meetings, corporate and chamber of commerce presentations and through targeted direct mailings to specific industries.

All communication material produced will also be made available to service technicians for distribution during customer site visits. In addition, during the meter deployment phase, SDG&E will provide brochures and flyers to customers. SDG&E will provide training to the installation technicians so that they are able to answer customer questions and when necessary direct customers to the SDG&E website or Customer Call Center (CCC) for additional information. Once the AMI meter has been installed at the customer premise, the technician will leave an informational door hanger.

2. Additional Resource Requirements

(a) Residential and Small C/I Customers

In order to properly develop and conduct the AMI communication program, SDG&E expects to add resources in the communications group. Areas of effort will include a variety of communications efforts, notification of SDG&E's CCC, billing groups, and other internal departments as each particular customer sector is scheduled for AMI installation.

Other communications efforts will include managing SDG&E's website as a primary forum through which customers can obtain up to date information regarding AMI deployment. In addition, customers will have the ability to view their real-time energy usage. This will provide customers with expanded capability to manage their energy use on a daily basis.

(b) Large Commercial Industrial (C/I) Customers

SDG&E's large C/I customers will continue to receive their communications through Account Executives (AEs). AEs are the first point of contact for large C/I customers. AEs will provide information regarding AMI meter installation and education on the dynamic rates that will affect their business. Among other alert avenues, AEs will notify their customers when a CPP event is called.

During the meter deployment phase, SDG&E expects to add resources to facilitate meter installations at the largest and critical C/I customer facilities. SDG&E will coordinate between the technician and the customer in cases where access is restricted or where the meter installation must be scheduled at specific times.

SDG&E also expects to add support staff to assist the AEs and their large C/I customers. They will primarily be engaged in rate analysis and answering billing and other AMI-related questions.

Finally, SDG&E plans to add engineering resources to assist large C/I customers with evaluation of load control technologies and integration with SDG&E's AMI metering configuration.

D. Benefits

An unquantifiable benefit is informed customers who can knowledgably select a dynamic pricing rate that will best fit their household or business. It is SDG&E's intention and expectation that the transition to an AMI technology and dynamic rates be

1 communicated to all customers allowing a smooth transition to the dynamic pricing

2 environment.

3 This concludes my prepared direct testimony.

Tables PW 12-2 and PW 12-3

Table PW 12-2

Mass Markets, Customer Communications & Education ($ thousands)

FULL Deployment Scenario - Cost Summary

Cost Category Summary

Yearly Total Direct Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Customer Communications & Education															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Customer Communications & Education	4,076	4,376	4,576	1,085	698	699	700	701	702	703	704	705	706	707	708
Total O&M / A&G Costs	4,076	4,376	4,576	1,085	698	699	700	701	702	703	704	705	706	707	708

Cost Category Summary

Yearly Total Fully Loaded Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Customer Communications & Education															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Customer Communications & Education	4,560	4,862	5,063	1,448	1,024	1,025	1,026	1,027	1,028	1,029	1,030	1,031	1,032	1,033	1,034
Total O&M / A&G Costs	4,560	4,862	5,063	1,448	1,024	1,025	1,026	1,027	1,028	1,029	1,030	1,031	1,032	1,033	1,034

Table PW 12-3

Mass Markets, Customer Communications & Education ($ thousands)

PARTIAL Deployment Scenario - Cost Summary

Cost Category Summary

Yearly Total Direct Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Customer Communications & Education															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Customer Communications & Education	2,547	2,547	882	480	481	481	482	482	483	483	484	484	485	485	486
Total O&M / A&G Costs	2,547	2,547	882	480	481	481	482	482	483	483	484	484	485	485	486

Cost Category Summary

Yearly Total Fully Loaded Costs

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Capital Costs															
Customer Communications & Education															
Total Capital Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O & M / A & G Costs															
Customer Communications & Education	2,960	2,960	1,216	738	738	738	739	739	740	740	741	741	742	742	743
Total O&M / A&G Costs	2,960	2,960	1,216	738	738	738	739	739	740	740	741	741	742	742	743

QUALIFICATIONS

OF

PATTI WAGNER

My name is Patti Wagner and I am employed by Southern California Gas Company (SoCalGas). My business address is 555 West Fifth Street, Los Angeles, California 90013-1011.

My present position is Director of Mass Markets, Customer Services Department. My responsibilities include directing the mass market customer programs and providing direction on customer communications for both San Diego Gas & Electric Company (SDG&E) and SoCalGas.

I received a Bachelor of Science degree in Chemical Engineering from California State Polytechnic University. I also earned a Masters degree in Business Administration from Pepperdine University. I joined SoCalGas in 1995 as a market advisor in the marketing department, and have since held positions of increasing responsibility. I assumed my current position in April 2002.

The purpose of my testimony is to sponsor SDG&E's proposal to fund various communications efforts in support of the AMI project.

I have not previously testified before the California Public Utilities Commission.

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 13

PREPARED DIRECT TESTIMONY

OF

DR. STEPHEN S. GEORGE

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

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CHAPTER 13
PREPARED DIRECT TESTIMONY
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DEMAND RESPONSE BENEFITS

The demand response benefits presented in this filing were developed for SDG&E by Charles River Associates. The basic methodology used and the estimated demand response impacts and benefits are described in this section. Demand response impacts refer to the change in energy use by rate period resulting from time-varying tariffs. Demand response benefits refer to reductions in capacity requirements (e.g., avoided megawatts) and the monetary value of reductions in capacity and energy that flow from the changes in energy use induced by new tariffs. The input values underlying the analysis are documented in Appendix C.

1. OVERVIEW OF METHODOLOGY

Demand response benefits largely accrue from system peak load reductions resulting from customer response to dynamic pricing. These benefits include the avoided cost of procuring incremental electric resources during summer peak hours and the reduction in future costs of transmission and distribution upgrades. Additional benefits may include lower energy costs, if the reduction in energy during the peak period times the cost of peak-period energy exceeds the increase in energy use in the off-peak period times the cost of off-peak energy. There may also be environmental benefits if, for example, there is a net reduction in energy use or if the fuel and generation mix are such that peak-period energy use has greater, negative environmental impacts than does any increase in off-peak energy use. In this section of the filing, we discuss the benefits associated with avoided generation capacity and changes in the total cost of energy needed to meet demand. Benefits associated with avoided transmission and

distribution upgrades and environmental benefits are discussed elsewhere, although they are based on the demand response impacts presented at the end of this section.

In brief, the overall benefits discussed here are based on the change in capacity and energy use by rate period valued at the avoided cost of capacity and energy by period. Equations (1) and (2) are simplistic representations of the key equations used to derive demand response benefits.

(1) MW Impact = (Average use per customer during peak period on the current rate) x
(% Drop in peak period use per customer given a change in price) x
(Number of customers in the target population) x
(Customer participation rate)[1]

(2) Total Benefits = [(MW Impact) x (Avoided Capacity Cost)] +
[(MWh Impact by Rate Period) x (Avoided Energy Cost by Rate Period)]

Demand response benefits are estimated separately for the following six customer segments:

1. General residential customers.
2. Single family, residential customers with central air conditioning and with average summer energy use exceeding 1000 kWh/month (e.g., the target market for CPP-F with enabling technology).
3. Commercial and industrial (C&I) customers with energy demand less than 20 kW.
4. C&I customers with energy demand between 20 and 100 kW.
5. C&I customers with energy demand between 100 and 300 kW.
6. C&I customers with energy demand exceeding 300 kW.

[1] A similar equation is used to predict the change in energy use in each rate period for each year of the forecast horizon.

The major variables underlying estimates of demand response benefits are:

- The difference in prices by rate period under the new, time-varying tariffs compared with the previous tariff.
- Participation rates for each tariff.
- The magnitude of energy use by rate period prior to the new tariffs going into effect.
- Customer response to the new tariffs as reflected in summary measures such as the elasticity of substitution and daily price elasticity.[2]
- The marginal cost of capacity and energy by rate period.

Each of these key variables is discussed briefly below. More detailed discussions are contained in Appendices A and B.

1.1 Tariff Options

The tariff options offered vary by customer segment. Table 1 summarizes the options for each customer segment. Only bundled customers are included in this analysis. Nearly all residential customers and loads are bundled but a significant share of C&I load is attributable to direct access customers. Roughly 34 percent of total load of customers above 20 kW is associated with direct access customers.

[2] The elasticity of substitution equals the ratio of the percentage change in the ratio of peak and off-peak energy use to the percentage change in the ratio of peak and off-peak prices. The daily price elasticity equals the percentage change in daily energy use over the percentage change in daily prices. These two measures in combination with the price ratios before and after the new rates go into effect are used to estimate the change in energy use and peak demand by rate period.

Table 1 Tariff Options for Bundled Customers		
Customer Segment	Default Tariff	Tariff Options
neral residential	CPP-F	TOU Current (tiered)
sidential customers with central air conditioning and with average summer monthly energy use >1000 kWh	CPP-F	TOU Current (tiered) CPP-F with technology
&I < 20kW	CPP-F	TOU Current (flat)
&I between 20 and 100 kW	CPP-F	Current (TOU)
&I between 100 and 300 kW	CPP-F	Current (TOU)
&I > 300 kW	CPP-F	Current (TOU)

Each tariff option is constructed to be seasonally revenue neutral vis a vis the current standard tariff for each customer segment. The characteristics of each rate are summarized below.

- **Time of Use (TOU):** For residential customers the TOU tariff has two rate periods. The peak period is from 2 pm to 7 pm on weekdays and the off-peak period is all other times. All of SDG&E's C&I customers with demands above 20 kW are already on a three-period TOU rate and it is assumed that there would be no incremental demand impact from these customers if they were to move to a two-period TOU rate. The current rate for C&I customers with demands below 20 kW is a two-part tariff consisting of a fixed charge and a single price per kWh for all energy use. The TOU rate used to predict demand response for these small customers has the same peak period that exists for SDG&E's current C&I TOU rate, which goes from 11 am to 6 pm in the summer[3] and from 5 pm to 8 pm in the winter. The ratio of peak-to-off-peak prices for both the residential and small C&I customers is roughly three to one.

[3] For residential customers, the summer period is from May 1 through October 31. For C&I customers, the summer is from May through September 30.

Critical Peak Pricing—Fixed (CPP-F): The CPP-F tariff has two rate periods on all weekdays in both the summer and winter seasons for both residential and C&I customers. For 15 CPP days for residential customers and 13 days for C&I customers[4] during the summer period, the peak-period price is significantly higher than on non-CPP days. Customers are notified regarding when CPP-day prices will be in effect according to procedures described elsewhere in this filing. The ratio of peak-to-off-peak prices on CPP days for residential and small C&I customers is roughly eight to one. The ratio of peak-to-off-peak prices for medium and large C&I customers is even greater, as these customers have demand charges that vary across time periods.[5] The peak period for both CPP and non-CPP weekdays is from 2 pm to 7 pm for residential customers and from 11 am to 6 pm for C&I customers during the summer period. During the winter, the peak period is the same for residential customers. For C&I customers, the winter peak period is from 5 pm to 8 pm. The impact estimates presented here assume all CPP days occur during the summer rate period.

In addition to the rate options described above, it is assumed that large residential customers (e.g., those that have average summer monthly energy use greater than 1000 kWh) who stay on the CPP-F rate and who have central air conditioning, will be offered the option of having a smart thermostat installed in their household to facilitate response to critical peak

[4] The reason for the difference of 15 days and 13 days between residential and C&I customers stems from the fact that the peak-period for C&I customers is longer (7 hours compared with 5 hours) and the ACR specifies that the CPP rate should not be in effect for more than 90 hours a year. If the C&I CPP rate were to be triggered on 15 days, it would total 105 hours.

[5] In addition to energy charges, customers above 20 kW pay two demand charges. The Non-coincident Demand charge is based on peak demand regardless of when it occurs, and the On-peak Maximum Demand charge is based on maximum demand during the peak period. For modeling purposes, we spread the On-peak Maximum Demand charges across all peak-period kWhs used in a month, and added this value to the energy price to obtain an effective peak-period price that included both demand and energy charges. Non-coincident Demand charges were spread across all energy used in a month. The net result is that the peak-off-peak price ratio for these effective prices varies with billing demand and, as it turns out, is even higher than the ratio for residential and small C&I customers. Effective prices for each customer segment are shown in Appendix C, filed today under separate confidential seal.

events. Roughly 10 percent of SDG&E's residential customers meet the size threshold and about 75 percent of these households have central air conditioning, so the target population for the technology option is roughly 7.5 percent of the residential customer base. It is assumed that no technology option will be offered to C&I customers.

1.2 Participation Rates

The number of customers on each tariff option in a given year is a function of the eligible population in that year and customer acceptance of each rate. In the first few years of the forecast horizon, the size of the eligible population is significantly influenced by the meter deployment rate, as only customers with smart meters can be on time-varying tariffs. SDG&E's meter deployment plan calls for installing nearly all meters over a three-year period starting near the end of 2006. All meters are installed in the inland climate zone first, followed by the coastal zone. As discussed previously, it is also assumed that direct access customers will not be eligible for new tariffs, so their load is excluded from the eligible population. This exclusion has the greatest impact on the large C&I population.

Estimates of customer acceptance for each rate option are based primarily on market research done by Momentum Marketing Intelligence (MMI) under the auspices of the Statewide Pricing Pilot (SPP). The MMI research involved a complex conjoint survey and analysis that estimated customer preferences for rates structurally similar to those tested in the SPP. The MMI estimates take into consideration customer inertia, customer risk tolerance and awareness of rate options. The detailed market share assumptions are described in Appendix C, filed today under separate confidential seal. In general, for residential customers, the default CPP-F rate with no technology captures roughly 80 percent of the market when implemented on an opt-out basis, the CPP-F rate with technology captures about 2 percent of the market, the TOU rate about 4 percent and the current rate about 13 percent.

Market shares for the smallest C&I segment (e.g., <20 kW) are also based on MMI research. For the base case, the predicted market shares equal 77 percent for CPP-F, 6 percent for TOU and 17 percent for the current rate. The MMI model could not be used directly to predict market shares for medium and large C&I customers because of an assumption that these customers would pay a premium of perhaps 5 percent on average to move from a time-varying rate to a fixed rate option. The MMI model is not designed to predict market shares when the non-default rate option has a higher average price than the default option. In light of the relatively unattractive nature of the alternative rate option, we assumed that 90 percent of C&I customers with demands between 20 and 100 kW would stay on the default option and 95 percent of those with demands above 100 kW would do so.

1.3 Average Energy Use by Rate Period

Estimates of average energy use by rate period for each customer segment under existing rates were developed primarily from SDG&E's load research database. The base-case estimates for each customer segment are derived from data for calendar year 2003. The 2003 values are based on standard load research sampling methods and standard load research estimation methodologies. In SDG&E's judgment, 2003 was a relatively normal weather year—that is, it represents the 1 in 2 year guideline contained in the Assigned Commissioner's Ruling dated July 21, 2004.

1.4 Price Responsiveness

Price responsiveness is reflected in summary measures known as the elasticity of substitution and the daily price elasticity. Estimates of the elasticity of substitution and the daily price elasticity that are used to predict demand response are based on California's Statewide Price Pilot (SPP). The estimates used for the residential CPP-F and TOU tariffs have been tailored to the weather and air conditioning saturations that exist in SDG&E's service territory.

The estimate for the elasticity of substitution for C&I customers also relies on the SPP analysis. The estimate for the daily price elasticity for C&I customers is based on a review of the literature, as daily price did not prove to be statistically significant in the SPP analysis but there are reasons to believe that a modest value should be used (as explained in Appendix C, filed today under separate confidential seal).

1.5 Marginal Capacity and Energy Costs

The marginal cost of capacity underlying the estimated demand response benefits equals a levelized cost of $85/kW-year. This value is constant over the forecast horizon. The marginal cost of energy varies by rate period and year and is based on an internal forecast developed by SDG&E.

1.6 Monte Carlo Simulation

In order to reflect the inherent uncertainty in selected input variables, a Monte Carlo simulation model was used to develop a probability distribution of demand response benefits. Four key drivers of demand response benefits were included in the simulation analysis:

1. The elasticity of substitution and the daily price elasticity of energy demand.
2. Starting values for energy use by rate period on CPP days.
3. Participation rates.
4. Avoided capacity costs.

Each of these variables is represented in the Monte Carlo analysis by a probability distribution with specific characteristics described in Appendix C, filed today under separate confidential seal. The Monte Carlo analysis takes 1000 draws from each probability distribution for each variable and calculates the demand response impacts and benefits associated with each combination of variable draws. For example, the simulation model will select a specific value from the probability distribution for the elasticity of substitution, the daily price elasticity,

starting energy use values, participation rates and avoided capacity costs, and enter each of these randomly chosen values into the CRA CEM model. The model calculates avoided capacity and energy benefits based on this particular set of values, records the output, and the process is repeated a thousand times.

The resulting distribution of outputs reflects uncertainty in the key drivers of demand response. The mean value of the distribution (e.g., the 50th percentile) represents the expected value of demand response benefits. The 90th percentile represents the point on the distribution where there is only a ten percent probability that benefits would exceed that value given the uncertainty reflected in the input values. The 10th percentile is the value where there is a 90 percent probability that the demand response benefits would exceed that amount.

2. SUMMARY OF DEMAND RESPONSE BENEFITS

The primary measures of demand response benefits reported in this section consist of avoided capacity (e.g., MWs) and the present value of monetary savings resulting from avoided capacity and energy use over the forecast horizon. Estimates of avoided capacity presented here are at the end-use level and, therefore, do not reflect reserve margins or line losses. However, estimates of the present value of monetary savings resulting from avoided capacity reflect both a reserve margin of 15 percent and line losses during the peak period of roughly 7.5 percent. Energy benefits reflect line losses, which vary be rate period.

Table 2 contains estimates of the present value of the monetary benefits for the 10th, 50th and 90th percentiles of the probability distribution of benefits as determined by the Monte Carlo simulation analysis. The 50th percentile value is equivalent to the mean or expected value of the distribution.

Table 2 Present Value of Demand Response Benefits (Millions of 2004 $)				
Deployment Scenario	Percentile	Capacity	Energy	Total
Full	10th	$211.9	$13.7	$225.7
	50th	250.7	17.5	268.2
	90th	283.6	21.4	305.0
Partial	10th	$164.4	$9.9	$174.3
	50th	194.2	13.0	207.2
	90th	217.3	16.2	233.5

As seen in the table, the expected value equals roughly $268 million for the full deployment scenario, and $207 million for the partial deployment scenario. The 10th percentile, that is, the value that is likely to be exceeded given 90 percent of the combinations of input values that were assumed to vary, equals $226 million under full deployment and $174 million under partial deployment. The 90th percentile values equal $305 and $234 million for the full and partial deployment scenarios, respectively. In general, roughly 94 percent of the total, monetary value of benefits is attributable to avoided capacity costs and only about 6 percent is attributable to avoided energy costs.

Table 3 contains estimates of the present value of avoided capacity and energy benefits attributable to each market segment. As seen, almost 50 percent of the total benefits are attributable to residential customers. Small C&I customers account for only 7 percent of total benefits and C&I customers with demands greater than 20 kW account for the remaining 43 percent of the present value of benefits.

Table 3 Present Value of Demand Response Benefits (Millions of 2004 $)					
Deployment Scenario	Customer Segment	Capacity	Energy	Total	Segment Percent
Full	Residential	$124.6	$8.9	$133.5	50
	Small C&I (<20 kW)	16.9	2.4	19.3	7
	Medium1 C&I (20-99 kW)	28.3	1.6	29.9	11
	Medium2 C&I (100-300 kW)	29.7	1.4	31.1	12
	Large C&I (>300 kW)	51.2	3.1	54.4	20
	Total	250.7	17.5	268.2	100
	1.				
Partial	2. Residential	$77.1	$5.7	$82.8	40
	Small C&I (<20 kW)	7.9	1.2	9.0	4
	All Medium1 C&I (20-99 kW)	28.3	1.6	29.9	14
	Medium2 C&I (100-300 kW)	29.7	1.4	31.1	15
	Large C&I (>300 kW)	51.2	3.1	54.4	26
	Total	194.2	13.0	207.2	100

Table 4 contains impact estimates for 2010, the first forecast year after which all meters have been installed.[6] Column 1 contains estimates of peak demand by customer segment, defined as the average kWh/hr during the peak period on CPP days. Column 2 shows the contribution of each segment to overall peak demand.[7] Columns 3 and 4 contain estimates of the avoided megawatts attributable to each segment. As seen, residential customers contribute more to the reduction in peak demand (e.g., 48.9 percent of the total reduction) than they do to overall peak

[6] Results are presented for a single year because MW reductions are only pertinent to a single year (e.g., you can't talk about the present value of MW reductions over many years without monetizing them). It should also be noted that the MW reductions reported here are at the end-use level, not at the point of generation. Avoided generation capacity will actually be greater than these values because it must be grossed up for reserves and line losses. This adjustment was made prior to determining the monetary value of avoided generation capacity and energy. In other words, the dollar benefit estimates in each table take into account reserve margin and line losses, but the reported MW savings do not.

[7] These numbers are for illustrative purposes only. They exclude direct access customers and were developed by multiplying the average use per hour for each segment based on SDG&E's load research data times the number of customers in each segment.

demand (e.g., 39.2 percent). This is largely due to the fact that residential price responsiveness tends to be higher than that of C&I customers. In contrast, small C&I customers contribute more to peak demand than they do to peak demand reductions, because they have very low price responsiveness.

Table 4
Demand Response Impacts in 2010
(First Year After Full Meter Deployment)

Deployment Scenario	Customer Segment	MW Forecast		MW Reductions		Benefits $ Millions (Nominal)			
		(1) MW	(2) %	(3) MW	(4) %	(5) Capacity	(6) Energy	(7) Total	(8) %
Full	Residential	1151	39	176	49	$18.5	$1.1	$19.6	49
	Small C&I (<20 kW)	409	14	26	7	2.7	0.3	3.0	8
	Medium1 C&I (20-99 kW)	415	14	42	12	4.4	0.2	4.6	11
	Medium2 C&I (100-300 kW)	338	11	44	12	4.6	0.2	4.8	12
	Large C&I (>300 kW)	626	21	74	20	7.7	0.4	8.1	20
	50th Percentile Total	2938	100	360	100	$37.9	$2.3	$40.2	100
	10th Percentile Total	2816	100	312	100	31.9	1.8	33.7	100
	90th Percentile Total	3060	100	412	100	44.1	2.9	47.0	100
Partial	Residential	545	26	101	37	$10.6	$0.7	$11.3	38
	Small C&I (<20 kW)	176	8	11	4	1.1	0.2	1.3	4
	Medium1 C&I (20-99 kW)	415	20	42	15	4.4	0.2	4.6	15
	Medium2 C&I (100-300 kW)	338	16	44	16	4.6	0.2	4.8	16
	Large C&I (>300 kW)	626	30	74	27	7.7	0.4	8.1	27
	50th Percentile Total	2100	100	271	100	$28.5	$1.7	$30.1	100
	10th Percentile Total	2011	100	235	100	24.0	1.3	25.3	100
	90th Percentile Total	2184	100	309	100	33.1	2.1	35.2	100

Table 4 also shows the 10th, 50th and 90th percentile estimates for aggregate avoided megawatts in 2010. As seen, the 50th percentile value for the full deployment scenario equals 360 MWs (at the end use level), while the 10th percentile value equals 312 MWs and the 90th

percentile value equals 412 MWs. For the partial deployment scenario, the 10th, 50th and 90th percentile values equal 235, 271 and 309 MWs, respectively.

Finally, Tables 5 and 6 show benefit estimates for selected years over the forecast horizon, including each of the first four years over which meter deployment occurs, the year 2015 and the terminal year, 2021. Many underlying factors change from year to year, including size of the eligible population (a function of both meter deployment and population growth), average use prior to application of the new rates, and avoided energy and capacity costs. Price responsiveness and prices are held constant. In the full deployment scenario, avoided capacity grows from a modest 56 MWs in 2007 to almost 450 MWs in 2021.

Table 5
Avoided Capacity for Selected Years
(MW)

Deployment Scenario	Customer Segment	2007	2008	2009	2010	2015	2021
Full	Forecasted Bundled Load	2768	2824	2880	2938	3247	3663
	Residential	33	104	148	176	194	220
	Small C&I (<20 kW)	4	12	20	26	27	28
	All Medium1 C&I (20-99 kW)	5	18	32	42	46	51
	Sub Total	42	134	200	243	267	299
	Medium2 C&I (100-300 kW)	4	16	33	44	49	55
	Large C&I (>300 kW)	10	34	59	74	83	95
	Sub Total	15	50	92	118	131	150
	Total	56	184	292	360	398	449
	Residential	33	97	99	101	112	128
	Small C&I (<20 kW)	4	11	11	11	11	12
	All Medium1 C&I (20-99 kW)	5	18	32	42	46	51
	Sub Total	42	125	142	153	169	191
	Medium2 C&I (100-300 kW)	4	16	33	44	49	55
	Large C&I (>300 kW)	10	34	59	74	83	95
	Sub Total	15	50	92	118	131	150
	Total	56	175	234	271	301	341

Table 6 Avoided Capacity and Energy Benefits ($ millions nominal)							
Deployment Scenario	Customer Segment	2007	2008	2009	2010	2015	2021
Full	Generation capacity	$4.4	$14.1	$21.1	$25.6	$28.0	$31.6
	Energy	0.3	0.9	1.4	1.7	2.2	3.0
	Sub total (all customers <100 kW)	4.7	15.0	22.4	27.3	30.2	34.6
	Generation capacity	1.5	5.2	9.6	12.3	13.7	15.7
	Energy	0.1	0.3	0.5	0.6	0.8	1.0
	Sub total (all customers >100 kW)	1.6	5.5	10.1	12.9	14.5	16.7
	Total	6.3	20.4	32.5	40.2	44.8	51.3
	Generation capacity	$4.4	$13.2	$14.9	$16.2	$17.8	$20.1
	Energy	0.3	0.8	1.0	1.1	1.4	1.9
	Sub total (all customers <100 kW)	4.7	14.0	15.9	17.2	19.2	22.0
	Generation capacity	1.5	5.2	9.6	12.3	13.7	15.7
	Energy	0.1	0.3	0.5	0.6	0.8	1.0
	Sub total (all customers >100 kW)	1.6	5.5	10.1	12.9	14.5	16.7
	Total	6.3	19.5	25.9	30.1	33.7	38.7

This concludes my prepared direct testimony.

QUALIFICATIONS

OF

STEPHEN S. GEORGE

Stephen George, a Vice President in CRA's Oakland, California, office, has more than 25 years of experience consulting to electric and gas utilities and regulatory agencies, and 28 years of experience in the energy field. His areas of expertise include electric industry restructuring, strategic and marketing planning, product and service design, market research, and energy demand modeling. Dr. George has worked for electric utilities in four states on issues concerning innovative electricity pricing, including the design and evaluation of California's Statewide Pricing Pilot, the largest pricing experiment ever performed in the United States. He recently advised the government of Singapore on restructuring the electricity industry and he was extensively involved in Ontario's restructuring, including the lead consultant to the Market Design Committee on retail competition issues and to the Ontario Energy Board on the licensing regime. Dr. George has held previous positions as Vice President at PHB Hagler Bailly, Inc. (formerly Putnam, Hayes & Bartlett, Inc.), Director of Putnam, Hayes and Bartlett, Inc., and Vice President of XENERGY Inc.

APPENDIX C

REDACTED

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 14

PREPARED DIRECT TESTIMONY

OF

NEIL P. BOYLE

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 14

PREPARED DIRECT TESTIMONY

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BEFORE THE PUBLIC UTILITIES COMMISSION
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MARCH 30, 2005

CHAPTER 14

PREPARED DIRECT TESTIMONY

OF

NEIL P. BOYLE

I. INTRODUCTION

The purpose of my testimony is to describe the costs and benefits that would be realized with the deployment of Advanced Metering Infrastructure (AMI) in both a full and partial deployment scenario. The specific categories that I discuss are the benefits associated with the Transmission and Distribution System listed in Tables NB 14-1 through NB 14-2 attached.

Table NB 14-1

Table NB 14-1 Transmission and Distribution ($ thousands)				
	Net Benefits (not loaded, not escalated)			
Full Deployment	2007	2008	2009	2010-2021
Total T&D Capital Item Net Benefits	28	2,628	3,928	5,446
Total T&D O&M Item Net Benefits	0	0	0	2,763
	Net Benefits (not loaded, not escalated)			
Partial Deployment	2007	2008	2009-2021	
Total T&D Capital Item Net Benefits	28	2,542	7,989	
Total T&D O&M Item Net Benefits	0	0	1,199	

II. DISCUSSION

The benefits of implementing AMI for both full and partial deployment scenarios on the Transmission and Distribution (T&D) systems can be grouped into two categories: 1) Demand Reduction Benefits; and 2) Outage Management Benefits. T&D demand

response benefits include the deferral of transmission line projects, the deferral of distribution capacity projects, avoided distribution capacity additions and the improvement of load forecast accuracy. The T&D outage management benefits include a reduction in labor associated with the response to single no-light calls, and a reduction in labor associated with a drop in duplicate secondary orders during storms or major events. Table NB 14-1 provides a summary and description of T&D benefits.

A. Assumptions and Methodology

The potential T&D benefits are estimates based on the following key assumptions. First, AMI and dynamic rates are implemented concurrently and are sustainable to ensure that the full benefits of demand response are realized. Second, CRA forecasted demand reductions accurately predict demand response. Third, the deferral or avoidance of future distribution capacity projects is based on demand reduction assumptions that require peak load reductions to: a) be of a sufficient minimum magnitude, b) be realized at the area of the proposed project(s), c) be fully realized prior to the proposed project(s), d) occur during the peak loads of the equipment effected by the proposed project(s), and e) provide physical assurance that load reductions will actually occur. Fourth, that distribution deferred or avoided capacity projects may lag demand response by 1-3 years.

B. Transmission and Distribution (T&D) Benefits

1. Benefits and Costs of T&D capital deferrals due to peak demand load reductions are reflected in Table NB 14-2

The Charles River Associates (CRA) econometric model predicts peak demand load reductions for partial and full deployment scenarios as further elaborated in Dr. George's testimony (Chapter 13.) SDG&E estimates potential savings associated with

the deferral of transmission capital projects by using CRA predicted peak demand load reductions and reviewing planned projects. SDG&E estimates potential savings associated with the deferral of distribution capacity capital projects by applying CRA predicted peak demand load reductions to expected future distribution capacity projects.

2. Outage management benefits

SDG&E estimates potential O&M savings associated with a reduction in labor associated with the response to single no-light calls, and a reduction in labor associated with a reduction in duplicate secondary orders during storms or major events.

3. Benefits and costs associated with Meter accuracy – improved and more timely load information could increase forecasting accuracy

SDG&E estimates potential capital and O&M savings associated with improved meter accuracy and more timely load information resulting in improved forecasting accuracy. The estimated potential capital savings are due to the deferral of distribution capital capacity projects for non-SCADA substations. The estimated O&M savings are due to the reduction in labor hours associated with eliminating drag hand load reads of non-SCADA substations.

4. Benefits associated with avoided Distribution transformer additions

Based on the CRA predicted peak demand reductions, SDG&E estimates the potential savings associated with avoiding Distribution capacity transformer capital additions.

This concludes my prepared direct testimony.

Table NB 14-2

Table NB 14 - 2

Transmission and Distribution Benefits ($ thousands)
Yearly Direct Costs (not loaded, not escalated)

Full Deployment Scenario

Item	Description	Benefit Type	Description	2005 Yr 1	2006 Yr 2	2007 Yr 3	2008 Yr 4	2009 Yr 5	2010 Yr 6	2011 Yr 7	2012 Yr 8	2013 Yr 9	2014 Yr 10	2015 Yr 11	2016 Yr 12	2017 Yr 13	2018 Yr 14	2019 Yr 15	2020 Yr 16	2021 Yr 17
SB-14.1	Transmission Line Projects Deferred by AMI	Cap	$ Current Projected	0	0	0	0	0	0	1,575	5,400	0	22,170	10,000	13,920	20,000	5,341	1,155	0	0
S-14.1			$ with AMI	0	0	0	0	0	0	0	0	0	0	5,400	0	23,360	10,000	23,850	16,951	0
			Item Net Benefit	0	0	0	0	0	0	1,575	5,400	0	22,170	4,600	13,920	-3,360	-4,659	-22,695	-16,951	0
SB-14.2	Distribution Capacity Project Reductions	Cap	Item Net Benefit	0	0	0	2,600	3,900	5,285	0	0	0	0	0	0	0	0	0	0	0
SB-6.1	SNLT Calls	O&M	Item Net Benefit	0	0	0	0	0	109	109	109	109	109	109	109	109	109	109	109	109
SB-6.2	Storms - Eliminate Duplicate Secondary Orders	O&M	Item Net Benefit	0	0	0	0	0	82	82	82	82	82	82	82	82	82	82	82	82
SB-9.1	Improved Forecasting Accuracy - Dist Projects Deferred by AMI	Cap	$ Current Projected	0	0	0	0	0	1,300	0	1,300	0	1,300	0	1,300	0	1,300	0	1,300	0
S-9.1			$ with AMI	0	0	0	0	0	0	1,300	0	1,300	0	1,300	0	1,300	0	1,300	0	1,300
			Item Net Benefit	0	0	0	0	0	1,300	-1,300	1,300	-1,300	1,300	-1,300	1,300	-1,300	1,300	-1,300	1,300	-1,300
SB-9.2	Improved Forecasting Accuracy-Eliminate Drag Hand Reads	O&M	Item Net Benefit	0	0	0	0	0	18	18	18	18	18	18	18	18	18	18	18	18
SB-10.1	Eliminate Other Load Reads - Xfmr Loading	O&M	Item Net Benefit	0	0	0	0	0	21	21	21	21	21	21	21	21	21	21	21	21
SB-10.2	Avoided Capacity Additions - Transformers	Cap	Item Net Benefit	0	0	28	28	28	28	14	14	14	14	14	14	14	14	14	14	14
	Full Deployment Totals		Total T&D Capital Items Net Benefits	0	0	28	2,628	3,928	6,593	269	6,714	-1,266	23,484	3,314	15,234	-4,646	-3,345	-23,981	-15,637	-1,286
			Total T&D O&M Items Net Benefits	0	0	0	0	0	230	230	230	230	230	230	230	230	230	230	230	230

Partial Deployment Scenario

Item	Description	Benefit Type	Description	2005 Yr 1	2006 Yr 2	2007 Yr 3	2008 Yr 4	2009 Yr 5	2010 Yr 6	2011 Yr 7	2012 Yr 8	2013 Yr 9	2014 Yr 10	2015 Yr 11	2016 Yr 12	2017 Yr 13	2018 Yr 14	2019 Yr 15	2020 Yr 16	2021 Yr 17
SB-14.1	Transmission Line Projects Deferred by AMI	Cap	$ Current Projected	0	0	0	0	0	0	1,575	5,400	0	22,170	10,000	13,920	20,000	5,341	1,155	0	0
S-14.1			$ with AMI	0	0	0	0	0	0	0	0	0	0	5,400	20,000	25,040	2,170	24,921	2,030	0
			Item Net Benefit	0	0	0	0	0	0	1,575	5,400	0	22,170	4,600	-6,080	-5,040	3,171	-23,766	-2,030	0
SB-14.2	Distribution Capacity Project Reductions	Cap	Item Net Benefit	0	0	0	2,514	3,422	4,357	0	0	0	0	0	0	0	0	0	0	0
SB-6.1	SNLT Calls	O&M	Item Net Benefit	0	0	0	0	0	47	47	47	47	47	47	47	48	48	48	48	48
SB-6.2	Storms - Eliminate Duplicate Secondary Orders	O&M	Item Net Benefit	0	0	0	0	0	35	35	35	35	36	36	36	36	36	36	36	36
SB-9.1	Improved Forecasting Accuracy - Dist Projects Deferred by AMI	Cap	$ Current Projected	0	0	0	0	0	1,300	0	0	0	1,300	0	0	0	1,300	0	0	0
S-9.1			$ with AMI	0	0	0	0	0	0	1,300	0	0	0	1,300	0	0	0	1,300	0	0
			Item Net Benefit	0	0	0	0	0	1,300	-1,300	0	0	1,300	-1,300	0	0	1,300	-1,300	0	0
SB-9.2	Improved Forecasting Accuracy-Eliminate Drag Hand Reads	O&M	Item Net Benefit	0	0	0	0	0	8	8	8	8	8	8	8	8	8	8	8	8
SB-10.1	Eliminate Other Load Reads - Xfmr Loading	O&M	Item Net Benefit	0	0	0	0	0	9	9	9	9	9	9	9	9	9	9	9	9
SB-10.2	Avoided Capacity Additions - Transformers	Cap	Item Net Benefit	0	0	28	28	28	28	14	14	14	14	14	14	14	14	14	14	14
	Partial Deployment Totals		Total T&D Capital Items Net Benefits	0	0	28	2,542	3,450	5,685	269	5,414	14	23,484	3,314	-6,066	-5,026	4,485	-25,052	-2,016	14
			Total T&D O&M Items Net Benefits	0	0	0	0	0	99	99	99	100	100	100	100	100	100	101	101	101

QUALIFICATIONS

OF

NEIL P. BOYLE

My name is Neil P. Boyle and I am employed by San Diego Gas & Electric Company (SDG&E). My business address is 8316 Century Park Court, San Diego, California, 92123-1582.

My present position is Manager – Electric Reliability and Distribution Planning in the Transmission and Distribution Planning Department of SDG&E. I have been employed by SDG&E since 1982. Previous positions relevant to my testimony include Distribution Standards Manager, from 2002 to 2003 and Beach Cities District Operations and Engineering Manager, from 2000 to 2002.

I received a Bachelor of Science Degree in Electrical Engineering from the University of Washington, Seattle, Washington in 1982. I am a registered Professional Electrical Engineer with the state of California. I have not previously testified before the California Public Utilities Commission.

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CHAPTER 15

PREPARED DIRECT TESTIMONY

OF

SCOTT KYLE

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03- ____

CHAPTER 15

PREPARED DIRECT TESTIMONY

OF

SCOTT KYLE

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 15, 2005

CHAPTER 15
PREPARED DIRECT TESTIMONY
OF
SCOTT KYLE

I. INTRODUCTION

The purpose of my testimony is to describe the overhead rates used to forecast the costs and benefits associated with deploying Advanced Metering Infrastructure (AMI) in both a full and partial deployment scenario.

II. DISCUSSION

SDG&E allocates certain costs to jobs through the use of overhead loading rates rather than by a direct charge method. SDG&E's production accounting system applies sixteen different classes of overhead rates to various combinations of direct labor, contract labor, purchased materials and services, warehouse issues, and total direct costs. However, many of these costs are fully recovered in base utility rates and, therefore, not applicable to the AMI business case, which is prepared on an incremental basis. Accordingly, SDG&E selected the following subset of eight overhead rates for use in the costs/benefits model for this application:

Table SK 15-1.A

Overhead Category	Loading Base	Percentage
Payroll Taxes	Direct Labor	10.42%
Vacation and Sick Time	Direct Labor	16.65%
Pension and Benefits (non-balanced only)	Direct Labor	14.43%
Workers' Compensation	Direct Labor	3.01%
Public Liability / Property Damage	Direct Labor	2.44%
Non-Union Incentive Compensation Plan	Direct Labor	18.00%
Purchased Services and Materials	Contract Labor, Services and Purchased Materials	.52%
Administrative and General	Capital Total Direct Cost	3.19%

1 **A. Assumptions**

2 The above rates are based on calendar year 2004 actual costs, both for pool
3 funding and loading bases. SDG&E applied overheads to direct labor straight-time and
4 the straight-time portion of overtime. In the AMI costs/benefits model, SDG&E assumed
5 labor inputs to be incremental straight-time equivalents. SDG&E loaded all overhead
6 rates in the model one time on direct costs in the period incurred.

7 **B. Justification**

8 To simplify the planning process and make administering and auditing this
9 application less burdensome, SDG&E deemed overhead rate classes in the SDG&E
10 accounting system as either 100% incremental or not, rather than developing non-
11 standard overhead pool definitions for this application alone, which would make
12 subsequent reporting of as-recorded costs potentially inaccurate and a labor intensive
13 manual reconciliation effort.

14 **(1) Payroll Taxes (PT)**

15 Payroll Taxes are generally incremental, individuals who exceed their
16 FICA maximum present an exception to this rule. The 2004 weighted
17 average payroll tax rate gives full consideration to this fact. The
18 calculated rate is higher than the statutory rate because it only loads on
19 direct productive labor, despite the fact that Vacation and Sick (V&S) and
20 Incentive Compensation Plan (ICP) costs also generate payroll tax
21 expense.

22 **(2) Vacation and Sick Time**

23 Incremental direct labor for this multi-year project causes SDG&E to incur

incremental V&S costs.

(3) Pension and Benefits (P&B), Non-Balanced Only

Incremental direct labor for this multi-year project causes SDG&E to incur incremental non-balanced P&B costs.

(4) Workers' Compensation (WC)

SDG&E is self-insured for Workers' Compensation costs. Worker's Compensation is deemed incremental because costs are driven by and directly proportional to the risks associated with incremental hours worked.

(5) Public Liability / Property Damage (PLPD)

Like WC, PLPD insurance and claims costs are proportional to the total activity insured, making this cost incremental.

(6) Non-Union Incentive Compensation Plan (ICP)

ICP is a part of SDG&E's base compensation package and proportional to wages earned, making this cost incremental. SDG&E's Incentive Pay Plan costs can vary from 100% to 150% of target, based on actual financial results. 18.00% reflects payment at 100% of target.

(7) Purchased Services and Materials

The SDG&E Supply Management department expects to add labor and non-labor resources to support this project in proportion to additional AMI direct non-labor costs. The department allocates costs in the production accounting system as overhead, and for consistency they are handled the same way in this application.

(8) Administrative and General (A&G)

A&G costs are driven by total organizational workload. To the extent that the AMI project increases SDG&E's total direct costs, incremental A&G costs (management, payroll, accounting, HR, etc.) are expected to increase proportionally. To be conservative in the analysis, SDG&E assumed that only A&G costs allocable to Capital are incremental.

C. Application of Overheads in the Costs/Benefits Model

See testimony of Witness Edward Fong, Chapter 6.

This concludes my prepared direct testimony.

QUALIFICATIONS

OF

SCOTT KYLE

My name is Scott Kyle. I am employed by San Diego Gas & Electric Company (SDG&E). My business address is Mail Stop CP31B, 8330 Century Park Court, San Diego, CA 92123.

My present position is Manager of the Affiliate Billing and Costing (ABC) Departments of SDG&E and Southern California Gas Company (SoCalGas). ABC is responsible for overseeing the production cost accounting system, managing overhead rates, developing cost studies for internal cost allocation and billing purposes, and supporting shared service organizations in properly billing their costs to other Sempra Energy affiliates.

I have been employed by SDG&E since 2002. In the capacity of Acting Manager of ABC, I testified before the California Public Utilities Commission in late 2003 as SDG&E and SoCalGas' Cost of Service witness for shared service billings, overhead loadings applied to shared service billings, shared assets, and capitalization/reassignment. Previously I worked for the Salt River Project (SRP), an electric utility based in Phoenix, Arizona, for eighteen years. At SRP I held various positions of increasing responsibility in planning, budgeting, accounting, procurement, and most recently Manager of Business Services at the Navajo Generating Station (NGS), which is a large participant-owned coal-fired plant.

I received a B.A. in Economics from the University of California at Los Angeles in 1981, and I became a licensed Certified Public Accountant in Arizona in 1986.

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CHAPTER 16

PREPARED DIRECT TESTIMONY

OF

JOHANNES VAN LIEROP

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

CHAPTER 16

PREPARED DIRECT TESTIMONY

OF

JOHANNES VAN LIEROP

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

MARCH 30, 2005

PREPARED DIRECT TESTIMONY

OF

JOHANNES VAN LIEROP

I. PURPOSE AND SUMMARY

The purpose of my supplemental testimony is to identify the forecasted Advanced Metering Infrastructure (AMI) revenue requirements based on the estimated AMI costs and benefits presented in San Diego Gas and Electric Company's (SDG&E) AMI direct testimony. More specifically, this testimony describes the development of the forecasted AMI revenue requirements calculated under SDG&E's recommended full deployment case for the following timeframes: (a) pre-deployment period 2005-2006; (b) first year of AMI deployment in 2007; and (c) the period 2005-2010.

As stated in my direct testimony, SDG&E proposes to establish balancing accounts for gas and electric for recovery of AMI 2005-2006 pre-deployment costs and 2007 deployment costs and for subsequent periods until a different mechanism is adopted by the California Public Utilities Commission (Commission). Under SDG&E's proposal, upon Commission approval of the deployment plan, SDG&E will file an advice letter to include in rates the forecasted AMI revenue requirements for 2005-2006 for a twelve-month period effective January 1, 2006. The revenue requirements will consist of the forecasted 2006 AMI revenue requirement identified in Table A-1 of Attachment A and the projected year-end balance of 2005 AMI costs recorded in the Advanced Metering Infrastructure Balancing Accounts (AMIBA). Table A-1 reflects SDG&E's estimate of the 2005 and 2006 AMI revenue requirement that will need to be recovered in 2006 electric distribution and gas transportation rates. Tables D-1 and D-2 of

Attachment D show the projected electric and gas rate impacts, respectively, that result from recovery of the forecasted 2005-2006 revenue requirements in 2006 rates.

SDG&E will also file an advice letter in late 2006 to recover the forecasted 2007 AMI revenue requirement identified in Table A-2 of Attachment A and the projected year-end 2006 balance recorded in the AMIBA in 2007 electric distribution and gas transportation rates. Tables D-1 and D-2 show the projected electric and gas rate impacts, respectively, that result from recovery of the forecasted 2007 AMI revenue requirement in 2007 rates.

Finally, for illustrative purposes SDG&E provides forecasted AMI annual revenue requirements in Table A-3 of Attachment A for the period 2005-2010 based on SDG&E's full AMI deployment Proposal. As stated in Chapter 5 of my direct testimony, SDG&E will address AMI recovery of post-2007 year costs in its Test Year 2008 Cost of Service (COS) filing.

II. DESCRIPTION OF INCREMENTAL AMI COSTS AND BENEFITS

A. Summary

The forecasted AMI revenue requirements identified in Attachment A include the incremental electric distribution and gas transportation AMI capital and O&M costs/benefits presented in the direct testimony of various SDG&E witnesses, as identified in Table B-2 and Table B-3 of Attachment B. As described in my direct testimony, only electric distribution and gas transportation costs and benefits are included in the AMI revenue requirements for recovery under the proposed ratemaking framework since these incremental costs and benefits do not currently have a mechanism in place to ensure cost recovery outside a COS proceeding. These costs and benefits were adjusted to include applicable sales taxes, overhead loaders, and price escalation, with the adjusted costs and benefits presented in Table B-1 of Attachment B. Table JVL-1 below provides,

at the aggregate level, the adjusted AMI capital and O&M costs/benefits that are reflected in the AMI revenue requirements for electric and gas operations for years 2005-2007.

TABLE JVL-1
Capital and O&M Costs/Benefits
(includes escalations, sales taxes, and loaders)

Line No.	Description	2005 ($000)	2006 ($000)	2007 ($000)
1	**Electric**			
2	Capital			
3	*Costs*	$10,298.2	$18,514.2	$107,517.7
4	*Benefits*	$0.0	$654.8	$2,550.5
5				
6	O&M			
7	*Costs*	$892.1	$7,162.6	$20,187.9
8	*Benefits*	$0.0	$30.2	$2,327.7
9				
10	**Gas**			
11	Capital			
12	*Costs*	$3,432.7	$5,411.3	$35,300.2
13	*Benefits*	$0.0	$213.7	$426.7
14				
15	O&M			
16	*Costs*	$277.5	$2,227.5	$6,278.3
17	*Benefits*	$0.0	$9.4	$723.9

B. Capital Costs and Benefits

This section describes the incremental capital costs and benefits that will be included in the revenue requirement. Table B-2 of Attachment B identifies the capital costs and benefits included in the AMI revenue requirements, and the SDG&E witness for the particular cost or benefit. The capital costs include (a) information technology (IT) systems development and implementation costs (Chapter 4, SDG&E witness Richard Carusa), (b) AMI-compatible electric meters and communication equipment (Chapter 8,

SDG&E witness Paul Pruschki), and (c) AMI gas meters and modules, along with installation costs of both gas and electric meters (Chapter 9, SDG&E witness Ted Reguly).

The capital benefits comprise (a) reduced meter reading IT expense (Chapter 4, SDG&E witness Richard Carusa), (b) avoided load research meter requirements (Chapter 7, SDG&E witness Patrick K. Charles), (c) reduced electromechanical meters replacement costs for new customer growth (Chapter 8, SDG&E witness Paul Pruschki), (d) reduction in replacement costs and inventory of existing gas meters, and customer field service savings (Chapter 9, SDG&E witness Ted Reguly), (e) reduced meter reading equipment and equipment maintenance costs (Chapter 11, SDG&E witness James S. Teeter), and (f) deferral of distribution capacity projects and avoided distribution capacity additions (Chapter 14, Neil P. Boyle).

C. Operating and Maintenance (O&M) Costs and Benefits

This section describes the incremental operating and maintenance (O&M) costs and benefits that will be incurred from the pre-deployment and deployment of AMI. Table B-3 of Attachment B identifies the O&M cost and benefit elements included in the AMI revenue requirements and the SDG&E witness for the particular cost or benefit element. These O&M costs and benefits comprise numerous elements associated with the following areas and addressed by the following witnesses: (a) IT (Chapter 4, SDG&E witness Richard Carusa); (b) Load Research, Project Management, and Human Resources (Chapter 7, SDG&E witness Patrick K. Charles); (c) Electric Meters and Communication Equipment & Installation (Chapter 8, SDG&E witness Paul Pruschki); (d) Gas Meters, Gas Modules, Facilities, and Customer Field Services (Chapter 9, SDG&E witness Ted

Reguly); (e) Customer Contact and Load Control Technology (Chapter 10, SDG&E witness Edward Fong); (f) Meter Reading and Billing (Chapter 11, SDG&E witness James S. Teeter); (g) Customer Communications (Chapter 12, SDG&E witness Patricia Wagner); and (h) Distribution (Chapter 14, Neil P. Boyle).

D. Adjustments to Direct Costs

AMI costs and benefits reflect direct capital and O&M costs/benefits adjusted to include appropriate escalation factors, sales taxes, Allowance for Funds Used During Construction (AFUDC), and overhead rates, if applicable.

1. Escalation

As discussed in the direct testimony of SDG&E witness Edward Fong (Chapter 6), direct AMI costs stated in 2004 dollars are escalated for annual utility input price inflation based on the Global Insight First Quarter 2004 Utility Cost Forecast. Until the next 25-year utility cost forecast is released by Global Insight in May 2005, this is the latest available forecast that extends through 2021[1]. Costs for new electric distribution plant are escalated with forecast annual percentage changes in the Handy-Whitman Utility Construction Cost Index for Electric Distribution Plant in the Pacific Region (JUEPD@PCF). Costs for electric distribution O&M materials, services, and labor are escalated with forecast annual percentage changes in the electric distribution O&M cost index. The O&M cost index is a component of the electric distribution input price index

[1] The First Quarter 2005 Global Insight Utility Cost Forecast is expected to be released in May 2005. This 25-year forecast update will extend beyond 2021.

that SDG&E proposed for post-test-year ratemaking in Phase II of the 2004 COS case.

The electric distribution O&M cost index is calculated as a weighted average of the following utility O&M cost components forecast by Global Insight Utility Cost Forecasting Service:

1. A labor cost index based on average hourly earnings of utility workers (CEU4422000006);
2. A non-labor total electric distribution plant O&M cost index (JEDOMMS);
3. A non-labor customer accounts operation cost index (JECAOMS);
4. A non-labor customer services and information operation cost index (JECSIOMS), and
5. A non-labor electric administrative and general O&M cost index (JEADGOMMS).

The fixed expenditure weights used to combine these component indexes into the electric distribution O&M cost index are based on SDG&E 2004 electric distribution expenditures in the December 19, 2003 settlement filing in Phase I of the SDG&E 2004 COS case.

2. Sales Taxes

AMI costs also include applicable sales taxes on purchased materials and services. Tables B-2 and B-3 identify the capital and O&M costs/benefits that include sales taxes.

3. Allowance for Funds Used During Construction (AFUDC)

SDG&E will finance AMI capital projects using debt, equity and preferred stock in proportions matching its Commission-authorized capital structure.

SDG&E recovers new project financing costs through the AFUDC mechanism while projects are in Construction Work in Progress (CWIP). Consequently, SDG&E has projected AFUDC for AMI related IT capital projects that are in CWIP. AFUDC is applied until such time as the project is completed and transferred into service at which time AFUDC is no longer applied since the capital project then earns SDG&E's authorized return on rate base. AFUDC has been applied using SDG&E's authorized capital structure and rates of return as shown in Table JVL-3 of Section III.C of this testimony.

Monthly capital expenditures were projected for years 2005 through 2007 together with project-completion dates. The capital expenditure schedule along with the authorized capital structure and cost percentages are the input variables that determine the AFUDC amounts.

4. Overhead Rates

As described in the direct testimony of SDG&E witnesses Edward Fong (Chapter 6) and Scott Kyle (Chapter 15), eight overhead rates are applied to each direct cost and benefit input, according to its classification as union or non-union labor, contract labor, purchased materials and services, and capital. The overhead loaders are presented in Table EF 6-1 of Mr. Fong's testimony and Table SK 15-1.A of Mr. Kyle's testimony.

III. REVENUE REQUIREMENTS

The forecasted AMI revenue requirements for the pre-deployment period 2005-2006, first year of AMI deployment in 2007, and period 2005-2010 are presented in Tables A-1, A-2, and

A-3 of Attachment A, respectively. The various components of the revenue requirements are discussed below.

A. Net Rate Base

This section presents the net rate base used in the calculation of the return on rate base, as addressed in Section III.C of this testimony. Net rate base reflects the sum of all AMI capital costs minus AMI capital benefits. The average net rate base and its components used in the calculation of the 2005-2007 AMI revenue requirements are presented in Table JVL-2 below:

TABLE JVL-2
AMI Average Net Rate Base

Line No.	Description	Average 2005 ($000)	Average 2006 ($000)	Average 2007 ($000)
1	**Electric Rate Base**			
2	Electric Plant	$632.5	$13,184.9	$77,287.7
	Working Cash	$102.2	$854.4	$2,139.5
3	Accumulated Depreciation	($26.6)	($1,186.1)	($6,042.2)
4	Accumulated Deferred Taxes	($58.2)	($439.4)	($1,150.0)
5	Total Rate Base	$650.0	$12,413.8	$72,235.0
6				
7	**Gas Rate Base**			
8	Gas Plant	$210.0	$3,824.5	$24,948.2
	Working Cash	$31.8	$265.7	$665.4
9	Accumulated Depreciation	($8.8)	($391.4)	($2,184.6)
10	Accumulated Deferred Taxes	($19.4)	($143.3)	($304.2)
11	Total Rate Base	$213.5	$3,555.5	$23,124.8

Note: Totals may not add up due to rounding.

B. Net O&M Costs

As stated above, net O&M costs reflect the sum of AMI O&M costs minus benefits. The net O&M costs used in the calculation of the 2005-2007 AMI revenue requirements for both electric and gas operations are presented in Table JVL-1.

C. Return

The return on rate base included in the AMI revenue requirements is calculated by multiplying SDG&E's currently authorized Rate of Return (ROR) of 8.18 percent by the AMI average net rate base for each year. The average net rate bases used in the return calculations are identified in Table JVL-2. The authorized ROR is based on SDG&E's authorized capital structure, authorized cost of debt, cost of preferred stock, and authorized Return on Equity (ROE), effective January 1, 2005. The ROR calculation is shown in Table JVL-3 below:

TABLE JVL-3
SDG&E Rate of Return (ROR) Calculation

Capital Structure	Weighting	Cost	ROR
Debt	45.25%	5.90%	2.67%
Preferred Stock	5.75%	7.45%	0.43%
Common Equity	49.00%	10.37%	5.08%
Total	100.00%		8.18%

D. Depreciation

This section addresses the depreciation expense and accumulated reserve for depreciation of the AMI assets.

The proposed depreciation uses the straight-line remaining life depreciation method consistent with Standard Practice U-4, Determination of Straight-Line Remaining

Life Depreciation Accruals. The CPUC issued this standard practice in 1961 as a guide for determining proper depreciation accruals.

For the interim period 2005-2007, SDG&E proposes depreciable lives of 5 years for IT assets, 9 years for AMI gas modules, 15 years for AMI electric meters, and 34 years for gas meters.[1] The 5-year book life for IT assets and 34-year book life for gas meters are in accordance with the book lives adopted for these assets in D.04-12-015 issued in Phase 1 of SDG&E's COS proceeding. As stated in the prepared direct testimony of SDG&E witness Paul Pruschki (Chapter 8) AMI electric meters and communication equipment are estimated to have a useful life of 15 years. Finally, as stated in the prepared direct testimony of Ted Reguly (Chapter 9) AMI gas modules are assumed to have a useful life of 9 years. The resulting depreciation rates equal 20% for IT assets, 11.11% for AMI gas modules, 6.67% for AMI electric meters, and 2.94% for gas meters.

E. Taxes

1. Property Taxes

The forecasted property tax expenses for AMI assets are calculated by multiplying the projected assessed annual value of the assets as of the given year by the estimated tax rate of 1.1493081 percent.

The assessed value is based on a Historical Cost Less Depreciation (HCLD) indicator of value, which is the primary value indicator for rate base regulated utility property. HCLD is the estimated cost of property that is subject

[1] For modeling convenience SDG&E also uses a 34-year book life for the calculation of benefits associated with the reduction in electromechanical meter replacement costs and the deferral and/or avoidance of distribution capacity project costs.

to assessment by the State Board of Equalization (SBE) less depreciation on this property. The deferred federal income tax reserve related to taxable property further reduces the HCLD indicator.

2. Income Taxes

This section provides SDG&E's estimate of income taxes that will be incurred due to AMI investments, and discusses the assumptions and methodology used to make the income tax estimates.

California Corporation Franchise Tax (CCFT) and federal income tax expense are estimated based on net operating income before income taxes. The estimated federal and state income tax expenses are identified in the forecasted AMI revenue requirements provided in Attachment A.

Current tax law has been utilized to compute income taxes for AMI investments. Since the bonus depreciation provisions of the Jobs and Growth Tax Relief Reconciliation Act of 2003 expired on December 31, 2004, which is prior to the investment in AMI, bonus depreciation has not been reflected in the calculation of tax depreciation in either case. Federal income tax expense, including deferred income tax, is calculated by multiplying the currently effective corporate federal income tax rate of 35 percent by applicable federal taxable income. Similarly, state income tax expense is calculated by multiplying the statutory rate of 8.84 percent of state taxable income.

Following established Commission policy, federal income taxes are computed on a normalized basis. Deferred federal income taxes are calculated as the difference between book depreciation and federal tax depreciation times the

federal tax rate. The Accumulated Deferred Federal Income Tax Reserve is included as a credit in rate base. State income taxes are calculated on a flow-through basis.

For AMI federal tax depreciation is calculated in accordance with the Tax Reform Act of 1986, as amended. State tax depreciation is based on the Asset Depreciation Range system specified by California law.

3. Tax Lives

In classifying property for tax depreciation purposes, SDG&E has followed IRS guidelines under the Modified Accelerated Cost Recovery System (MACRS). Accordingly, capitalized computer software is depreciated over a three-year period using a straight-line method. Other advanced metering property is depreciated over the normal 20-year period for utility property. While certain advanced metering components have a recovery period of 9 years and 15 years for book purposes, there is no IRS guidance that would provide for a shorter recovery period than 20 years for tax purposes. SDG&E, in conjunction with other affected utilities, would welcome the opportunity to seek a ruling from the IRS providing for a shorter recovery period for certain advanced metering property. If approval to use a shorter recovery period were obtained from the IRS, SDG&E proposes that the benefit be reflected in rates at that time.

4. Computer Software

Computer Software is comprised of purchased software and internally developed software. Purchased software is capitalized and depreciated over three

years using a straight-line method for both federal and state taxes. Self-developed software may be deducted currently as an expense. SDG&E has flowed through the deductible portion of internally developed software costs in calculating income tax expense for ratemaking purposes, thereby lowering ratemaking income tax expense. This treatment results in a forecast of negative revenue requirements in 2005.

F. Working Cash

The Working Cash requirement is computed by multiplying total estimated annual O&M expenses (excluding depreciation and fuel costs) by one-eighth. The resulting amount represents 45 days of O&M expenses. This method, which is accepted by the Federal Energy Regulatory Commission (FERC), is used for this filing because a traditional working cash study based on historical data related to AMI operations is not available.

G. Franchise Fees and Uncollectibles (FF&U)

Franchise Fees and Uncollectibles (FF&U) is the revenue requirement needed to pay required franchise fees on electric and gas sales and to recover estimated uncollectibles expenses. The FF&U factor used in calculating the proposed revenue requirement is 4.10 percent for electric and 2.45 percent for gas, which are the factors adopted in D.04-12-015 for Phase I of SDG&E's COS proceeding.

IV. AMI BENEFIT FORMULA

As discussed in my direct testimony (Chapter 5), SDG&E proposes a formula calculation to generate benefit estimates that will be credited to the AMI balancing accounts. Sections A and B, below, describe the details of the formula that SDG&E proposes to use in years 2006 and 2007, respectively. Due to the larger range of cost savings achieved in the first year of AMI deployment versus the Beta Phase, as well as the unique meter deployment schedule for the Beta Phase, SDG&E plans to compute the benefit formula separately for 2006 and 2007.

For both years, the formula includes the capital-related and O&M benefits used to offset AMI costs in determining the revenue requirements identified in this testimony. SDG&E reviewed the projected number of meters upon which achievement of the operational benefits was based, and then calculated an average dollar amount of benefits that would be reasonable to expect from deployment of 10,000 meters. SDG&E proposes to base the formula on dollars per 10,000 meters, rather than some smaller number because many benefits (such as meter reading) are not achieved until a substantial number of meters are deployed. For example, a meter reading route cannot be eliminated with the deployment of only a few hundred meters. SDG&E selected the 10,000 meter number since this will allow benefits from completing the proposed Beta Phase in 2006 to be used to offset AMI costs.

A. 2006 Benefit Formula – Beta Phase

As described above, the benefit formula for 2006 includes the capital-related and O&M benefits used to offset AMI costs in determining the revenue requirement. These capital and O&M benefits resulting from the Beta Phase meter deployment that are reflected in the revenue requirement are identified in Table JVL-1, above. The O&M benefits are from the Meter Reading and Billing areas, and include avoided meter reading

and avoided rebills resulting from the 10,000 meter deployment. In addition, an avoided capital-related benefit for replacing meter reading handheld devices is included in the formula calculation.

Based on the Beta Phase meter deployment plan described in Chapter 3 of witness Patrick K. Charles, SDG&E anticipates installing 10,000 meters over a 6-month period from January through June of 2006. AMI benefits for 2006 were determined based on this deployment schedule, and anticipated to accrue over the 6-month period between July and December of 2006. Therefore, SDG&E proposes to divide the estimated capital-related and O&M benefits by 6 to determine a monthly amount to record to the AMIBA-Electric and AMIBA-Gas upon completion of the Beta Phase meter installation.

The advantage of this approach is that the balancing account will be credited on a monthly basis upon the installation of the first 10,000 AMI meters, rather than a specific date. In addition, this approach accounts for the fact that many benefits (such as meter reading) are not achieved until a substantial number of meters are deployed. This calculation is shown in Table C-1 of Attachment C.

B. 2007 Benefit Formula – AMI Deployment

Benefits in 2007 resulting from the first year of AMI meter deployment and proposed to be included in the benefit formula are from the Billing, Meter Reading, Customer Service Field, Customer Contact Center, Customer Services Staff, Electric Metering, Electric Distribution, and Electric Load Research areas. These benefits are described by other SDG&E witnesses supporting these areas and include both O&M and capital-related benefits resulting from the first full year of AMI meter deployment.

O&M benefits include: avoided meter reading costs, avoided customer service field orders, avoided rebills, avoided non-capitalized portion of labor costs for gas meter changeouts as well as electric growth and load research meter installations, and reduced call volumes in the Customer Contact Center.

Capital benefits include: avoided replacement of meter reading handheld devices, avoided gas and electric meters as a result of customers receiving new AMI meters, avoided capital costs to install gas and electric meters, and avoided costs of electric distribution transformers due to the estimated demand response resulting from AMI deployment.

Since estimates for AMI benefits are based on a specific meter deployment schedule, SDG&E determined an average number of meters over the year for use in the formula calculation. Once full-scale AMI deployment begins, SDG&E anticipates installing roughly the same number of meters each month over the year, and therefore only beginning of the year and year-end meter counts were used to calculate the average number of meters for 2007. Meter counts for 2007 are cumulative, and therefore include the 10,000 meters deployed in the Beta Phase, since benefits are also based on the cumulative number of meters deployed. Table C-1 identifies the average number of meters in 2007.

The capital-related and O&M benefits divided by the average number of meters in 2007 multiplied by 10,000 and divided by 12 yields the monthly dollar amount that SDG&E proposes to record to the AMIBA-Gas and AMIBA-Electric. This calculation is shown in Table C-1.

V. CUSTOMER CLASS RATE IMPACTS

A. Rate Impact from Revenue Requirement Recovery

SDG&E proposes to recover revenue requirements associated with AMI implementation from its gas and electric customers through electric distribution and gas transportation rates, as explained in my direct testimony. The projected rate impacts that will result from recovering forecasted 2005-2007 AMI revenue requirements in electric and gas rates are described below.

1. Electric Rate Impact

SDG&E proposes to allocate the electric revenue requirement associated with AMI implementation and incremental operating costs to its electric customer classes based on the allocation factors presented in Table 1 of my direct testimony. The illustrative rate impacts that result from recovering the forecasted 2005-2006 and 2007 AMI revenue requirements listed in Attachment A using these allocation factors is shown in Table D-1 of Attachment D.

2. Gas Rate Impact

SDG&E proposes to allocate the gas revenue requirement associated with AMI implementation and incremental operating costs to its gas customer classes based on the allocation factors presented on Table 2 of my direct testimony. The illustrative rate impacts that result from recovering the forecasted 2005-2006 and 2007 AMI revenue requirements listed in Attachment A using these allocation factors is shown in Table D-2 of Attachment D.

B. System-Average Net Rate Impact from Net Revenue Impact

AMI will also result in benefits that are not reflected in SDG&E's COS authorized electric distribution and gas transportation rates and thus, not reflected in the revenue requirement calculation. As addressed in the direct testimony of Edward Fong (Chapter 10), SDG&E expects to reduce demand response program costs by the amounts identified in Table EF 10-3[1] of his testimony. In addition, as described in the testimony of SDG&E witness Dr. Stephen S. George (Chapter 13) the deployment of AMI is projected to result in avoided capacity and energy costs by the amounts identified in Table 6 of his testimony. The projected dollar amount of these other benefits along with the system-average net rate impact from the revenue impact of these benefits combined with the revenue requirements is presented in Table A-3 of Attachment A.

This concludes my prepared direct testimony.

[1] The reduction in demand response program costs identified in Table EF 10-3 are presented in 2004 dollars. These demand response benefits were escalated for purposes of presenting the net revenue and rate impact in Table A-3.

Attachments A-D

San Diego Gas & Electric
Advanced Metering Infrastructure (AMI)
Monthly Revenue Requirement - 2005-2006
Total AMI Revenue Requirement (Combined Electric and Gas Operations)

Line No.	Description	Jan-05 ($000)	Feb-05 ($000)	Mar-05 ($000)	Apr-05 ($000)	May-05 ($000)	Jun-05 ($000)	Jul-05 ($000)	Aug-05 ($000)	Sep-05 ($000)	Oct-05 ($000)	Nov-05 ($000)	Dec-05 ($000)	Total 2005 ($000)
1	Franchise Fees & Uncollectibles	-	-	-	-	-	-	(13.6)	(13.1)	(12.6)	(12.1)	(11.7)	(11.2)	(74.4)
2	O&M expenses	-	-	-	-	-	-	194.9	194.9	194.9	194.9	194.9	194.9	1,169.6
3	Property Taxes	-	-	-	-	-	-	0.4	1.0	1.4	1.9	2.3	2.8	9.8
4	Preferred Equity Interest	-	-	-	-	-	-	0.1	0.4	0.5	0.7	0.9	1.0	3.7
5	Interest Expense	-	-	-	-	-	-	0.9	2.3	3.4	4.5	5.5	6.5	23.1
6	Depreciation Expense	-	-	-	-	-	-	9.3	18.7	28.0	37.3	46.7	56.0	196.1
7	Income Tax Expense	-	-	-	-	-	-	(578.4)	(578.4)	(578.4)	(578.4)	(578.4)	(578.4)	(3,470.6)
8	Return on Equity	-	-	-	-	-	-	1.7	4.4	6.5	8.5	10.5	12.4	43.9
9														
10	**Revenue Requirement**	-	-	-	-	-	-	(384.7)	(369.8)	(356.2)	(342.7)	(329.3)	(316.0)	(2,098.8)
11														
12														

13														Total	Total
14		Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	2006	2005-2006
15	Description	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
16															
17	Franchise Fees & Uncollectibles	27.3	29.3	29.9	30.6	31.2	31.8	33.6	33.7	33.8	33.9	33.9	34.0	383.1	308.7
18	O&M expenses	779.2	779.2	779.2	779.2	779.2	779.2	779.2	779.2	779.2	779.2	779.2	779.2	9,350.6	10,520.2
19	Property Taxes	7.6	12.9	13.8	14.7	15.7	16.6	17.0	16.9	16.8	16.6	16.5	16.4	181.5	191.3
20	Preferred Equity Interest	2.9	4.9	5.2	5.6	5.9	6.2	6.4	6.4	6.3	6.3	6.2	6.2	68.4	72.1
21	Interest Expense	17.8	30.3	32.5	34.7	36.8	38.9	39.8	39.6	39.4	39.1	38.9	38.6	426.3	449.4
22	Depreciation Expense	200.9	210.4	219.9	229.4	238.9	248.4	251.5	254.6	257.8	260.9	264.1	267.2	2,903.9	3,099.9
23	Income Tax Expense	(306.0)	(306.0)	(306.0)	(306.0)	(306.0)	(306.0)	(266.2)	(266.2)	(266.2)	(266.2)	(266.2)	(266.2)	(3,433.2)	(6,903.8)
24	Return on Equity	33.8	57.7	61.8	66.0	70.0	74.1	75.8	75.4	74.9	74.5	74.0	73.4	811.4	855.3
25															
26	**Revenue Requirement**	763.4	818.7	836.4	854.1	871.7	889.2	937.2	939.6	942.0	944.3	946.6	948.9	10,691.9	8,593.1

San Diego Gas & Electric
Advanced Metering Infrastructure
Monthly Revenue Requirement - 2005-2006
Electric AMI Revenue Requirement

Line No.	Description	Jan-05 ($000)	Feb-05 ($000)	Mar-05 ($000)	Apr-05 ($000)	May-05 ($000)	Jun-05 ($000)	Jul-05 ($000)	Aug-05 ($000)	Sep-05 ($000)	Oct-05 ($000)	Nov-05 ($000)	Dec-05 ($000)	Total 2005 ($000)
1	Franchise Fees & Uncollectibles	-	-	-	-	-	-	(11.3)	(10.9)	(10.4)	(10.0)	(9.7)	(9.3)	(61.6)
2	O&M expenses	-	-	-	-	-	-	148.7	148.7	148.7	148.7	148.7	148.7	892.1
3	Property Taxes	-	-	-	-	-	-	0.3	0.7	1.1	1.4	1.8	2.1	7.4
4	Preferred Equity Interest	-	-	-	-	-	-	0.1	0.3	0.4	0.5	0.7	0.8	2.8
5	Interest Expense	-	-	-	-	-	-	0.7	1.7	2.6	3.4	4.1	4.9	17.4
6	Depreciation Expense	-	-	-	-	-	-	7.0	14.0	21.0	28.0	35.0	42.0	147.1
7	Income Tax Expense	-	-	-	-	-	-	(433.7)	(433.7)	(433.7)	(433.7)	(433.7)	(433.7)	(2,602.0)
8	Return on Equity	-	-	-	-	-	-	1.3	3.3	4.9	6.4	7.9	9.3	33.0
9														
10	**Revenue Requirement**	-	-	-	-	-	-	(286.9)	(275.7)	(265.5)	(255.3)	(245.2)	(235.2)	(1,563.8)
11														
12														

13														Total	Total
14		Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	2006	2005-2006
15	Description	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
16															
17	Franchise Fees & Uncollectibles	23.0	24.7	25.3	25.8	26.4	26.9	28.5	28.6	28.7	28.7	28.8	28.9	324.4	262.8
18	O&M expenses	594.4	594.4	594.4	594.4	594.4	594.4	594.4	594.4	594.4	594.4	594.4	594.4	7,132.4	8,024.6
19	Property Taxes	5.7	9.8	10.6	11.4	12.2	12.9	13.3	13.2	13.1	13.0	12.9	12.9	141.1	148.4
20	Preferred Equity Interest	2.2	3.7	4.0	4.3	4.6	4.9	5.0	5.0	4.9	4.9	4.9	4.8	53.2	56.0
21	Interest Expense	13.5	23.1	24.9	26.8	28.6	30.4	31.2	31.0	30.8	30.6	30.4	30.2	331.4	348.8
22	Depreciation Expense	150.8	158.0	165.3	172.5	179.8	187.1	189.4	191.8	194.1	196.5	198.8	201.2	2,185.2	2,332.2
23	Income Tax Expense	(229.8)	(229.8)	(229.8)	(229.8)	(229.8)	(229.8)	(196.5)	(196.5)	(196.5)	(196.5)	(196.5)	(196.5)	(2,557.6)	(5,159.6)
24	Return on Equity	25.6	43.9	47.5	50.9	54.4	57.8	59.3	59.0	58.6	58.3	57.9	57.5	630.8	663.8
25															
26	**Revenue Requirement**	585.4	627.9	642.2	656.4	670.5	684.6	724.6	726.4	728.1	729.9	731.6	733.3	8,240.8	6,677.0

San Diego Gas & Electric
Advanced Metering Infrastructure
Monthly Revenue Requirement - 2005-2006
Gas AMI Revenue Requirement

Line No.	Description	Jan-05 ($000)	Feb-05 ($000)	Mar-05 ($000)	Apr-05 ($000)	May-05 ($000)	Jun-05 ($000)	Jul-05 ($000)	Aug-05 ($000)	Sep-05 ($000)	Oct-05 ($000)	Nov-05 ($000)	Dec-05 ($000)	Total 2005 ($000)
1	Franchise Fees & Uncollectibles	-	-	-	-	-	-	(2.3)	(2.3)	(2.2)	(2.1)	(2.0)	(1.9)	(12.8)
2	O&M expenses	-	-	-	-	-	-	46.2	46.2	46.2	46.2	46.2	46.2	277.5
3	Property Taxes	-	-	-	-	-	-	0.1	0.2	0.4	0.5	0.6	0.7	2.4
4	Preferred Equity Interest	-	-	-	-	-	-	0.0	0.1	0.1	0.2	0.2	0.3	0.9
5	Interest Expense	-	-	-	-	-	-	0.2	0.6	0.8	1.1	1.4	1.6	5.7
6	Depreciation Expense	-	-	-	-	-	-	2.3	4.7	7.0	9.3	11.7	14.0	49.0
7	Income Tax Expense	-	-	-	-	-	-	(144.8)	(144.8)	(144.8)	(144.8)	(144.8)	(144.8)	(868.6)
8	Return on Equity	-	-	-	-	-	-	0.4	1.1	1.6	2.1	2.6	3.1	10.9
9														
10	**Revenue Requirement**	-	-	-	-	-	-	(97.8)	(94.1)	(90.8)	(87.4)	(84.1)	(80.8)	(535.0)
11														
12														
13														Total
14		Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	2006
15	Description	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)	($000)
16														
17	Franchise Fees & Uncollectibles	4.3	4.6	4.7	4.7	4.8	4.9	5.1	5.1	5.1	5.1	5.2	5.2	58.7
18	O&M expenses	184.8	184.8	184.8	184.8	184.8	184.8	184.8	184.8	184.8	184.8	184.8	184.8	2,218.1
19	Property Taxes	1.8	3.1	3.2	3.4	3.5	3.6	3.7	3.7	3.6	3.6	3.6	3.6	40.4
20	Preferred Equity Interest	0.7	1.2	1.2	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.3	15.2
21	Interest Expense	4.3	7.2	7.6	7.9	8.2	8.5	8.7	8.6	8.6	8.5	8.4	8.4	94.9
22	Depreciation Expense	50.1	52.4	54.6	56.8	59.1	61.3	62.1	62.9	63.7	64.5	65.2	66.0	718.7
23	Income Tax Expense	(76.2)	(76.2)	(76.2)	(76.2)	(76.2)	(76.2)	(69.7)	(69.7)	(69.7)	(69.7)	(69.7)	(69.7)	(875.7)
24	Return on Equity	8.2	13.8	14.4	15.0	15.6	16.3	16.5	16.4	16.3	16.2	16.1	15.9	180.7
25														
26	**Revenue Requirement**	178.1	190.7	194.2	197.7	201.2	204.6	212.6	213.2	213.8	214.4	215.0	215.6	2,451.1

Line No.	Description	Total 2005-2006 ($000)
17	Franchise Fees & Uncollectibles	45.9
18	O&M expenses	2,495.6
19	Property Taxes	42.8
20	Preferred Equity Interest	16.1
21	Interest Expense	100.6
22	Depreciation Expense	767.7
23	Income Tax Expense	(1,744.2)
24	Return on Equity	191.5
26	**Revenue Requirement**	1,916.1

San Diego Gas & Electric
Advanced Metering Infrastructure
Monthly Revenue Requirement - 2007
Total AMI Revenue Requirement (Combined Electric and Gas Operations)

Line No.	Description	Jan-07 ($000)	Feb-07 ($000)	Mar-07 ($000)	Apr-07 ($000)	May-07 ($000)	Jun-07 ($000)	Jul-07 ($000)	Aug-07 ($000)	Sep-07 ($000)	Oct-07 ($000)	Nov-07 ($000)	Dec-07 ($000)	Total 2007 ($000)
1	Franchise Fees & Uncollectibles	112.9	121.1	126.6	132.0	137.4	142.8	148.2	153.6	158.9	164.3	169.6	174.9	1,742.3
2	O&M expenses	1,951.2	1,951.2	1,951.2	1,951.2	1,951.2	1,951.2	1,951.2	1,951.2	1,951.2	1,951.2	1,951.2	1,951.2	23,414.7
3	Property Taxes	29.2	48.0	57.8	67.4	77.1	86.6	97.1	105.6	115.0	124.3	133.6	142.8	1,084.5
4	Preferred Equity Interest	11.0	18.1	21.8	25.4	29.1	32.7	36.2	39.8	43.3	46.9	50.4	53.8	408.5
5	Interest Expense	68.6	112.9	135.7	158.5	181.1	203.5	225.9	248.1	270.1	292.1	313.9	335.6	2,545.9
6	Depreciation Expense	607.3	677.6	748.0	818.3	888.7	959.0	1,029.4	1,099.7	1,170.1	1,240.4	1,310.8	1,381.1	11,930.3
7	Income Tax Expense	255.1	255.1	255.1	255.1	255.1	255.1	255.1	255.1	255.1	255.1	255.1	255.1	3,061.2
8	Return on Equity	130.6	214.8	258.3	301.6	344.6	387.4	429.9	472.1	514.1	555.9	597.4	638.7	4,845.5
9														
10	**Revenue Requirement**	3,166.0	3,398.9	3,554.5	3,709.6	3,864.2	4,018.3	4,173.0	4,325.2	4,477.9	4,630.2	4,782.0	4,933.3	49,032.9

San Diego Gas & Electric
Advanced Metering Infrastructure
Monthly Revenue Requirement - 2007
Electric AMI Revenue Requirement

Line No.	Description	Jan-07 ($000)	Feb-07 ($000)	Mar-07 ($000)	Apr-07 ($000)	May-07 ($000)	Jun-07 ($000)	Jul-07 ($000)	Aug-07 ($000)	Sep-07 ($000)	Oct-07 ($000)	Nov-07 ($000)	Dec-07 ($000)	Total 2007 ($000)
1	Franchise Fees & Uncollectibles	94.7	101.4	105.8	110.2	114.6	118.9	123.3	127.6	132.0	136.3	140.6	144.9	1,450.4
2	O&M expenses	1,488.4	1,488.4	1,488.4	1,488.4	1,488.4	1,488.4	1,488.4	1,488.4	1,488.4	1,488.4	1,488.4	1,488.4	17,860.2
3	Property Taxes	22.5	36.6	43.9	51.2	58.4	65.6	73.5	79.9	87.0	94.0	101.0	108.0	821.5
4	Preferred Equity Interest	8.5	13.8	16.6	19.3	22.0	24.7	27.4	30.1	32.8	35.4	38.1	40.7	309.4
5	Interest Expense	52.8	86.0	103.2	120.3	137.3	154.2	171.0	187.7	204.3	220.9	237.3	253.7	1,928.5
6	Depreciation Expense	451.0	498.6	546.2	593.9	641.5	689.1	736.7	784.3	831.9	879.5	927.1	974.8	8,554.6
7	Income Tax Expense	187.8	187.8	187.8	187.8	187.8	187.8	187.8	187.8	187.8	187.8	187.8	187.8	2,253.4
8	Return on Equity	100.4	163.7	196.4	228.9	261.2	293.4	325.4	357.2	388.9	420.4	451.7	482.8	3,670.5
9														
10	**Revenue Requirement**	2,406.0	2,576.3	2,688.2	2,799.8	2,911.1	3,022.1	3,133.5	3,243.0	3,353.0	3,462.6	3,572.0	3,680.9	36,848.5

San Diego Gas & Electric
Advanced Metering Infrastructure
Monthly Revenue Requirement - 2007
Gas AMI Revenue Requirement

Line No.	Description	Jan-07 ($000)	Feb-07 ($000)	Mar-07 ($000)	Apr-07 ($000)	May-07 ($000)	Jun-07 ($000)	Jul-07 ($000)	Aug-07 ($000)	Sep-07 ($000)	Oct-07 ($000)	Nov-07 ($000)	Dec-07 ($000)	Total 2007 ($000)
1	Franchise Fees & Uncollectibles	18.2	19.7	20.8	21.8	22.8	23.9	24.9	25.9	27.0	28.0	29.0	30.0	291.9
2	O&M expenses	462.9	462.9	462.9	462.9	462.9	462.9	462.9	462.9	462.9	462.9	462.9	462.9	5,554.4
3	Property Taxes	6.8	11.4	13.9	16.3	18.6	21.0	23.6	25.7	28.0	30.3	32.6	34.9	263.0
4	Preferred Equity Interest	2.5	4.3	5.2	6.1	7.0	7.9	8.8	9.7	10.6	11.4	12.3	13.1	99.1
5	Interest Expense	15.9	26.9	32.6	38.2	43.8	49.4	54.9	60.4	65.8	71.2	76.6	81.9	617.4
6	Depreciation Expense	156.2	179.0	201.7	224.5	247.2	269.9	292.7	315.4	338.2	360.9	383.6	406.4	3,375.7
7	Income Tax Expense	67.3	67.3	67.3	67.3	67.3	67.3	67.3	67.3	67.3	67.3	67.3	67.3	807.8
8	Return on Equity	30.2	51.1	62.0	72.7	83.4	93.9	104.5	114.9	125.3	135.5	145.7	155.9	1,175.0
9														
10	**Revenue Requirement**	760.0	822.6	866.3	909.7	953.0	996.2	1,039.5	1,082.2	1,124.9	1,167.5	1,210.0	1,252.3	12,184.4

San Diego Gas & Electric
Advanced Metering Infrastructure (AMI)
Forecasted AMI Annual Revenue Requirement - 2005-2010
Total AMI Revenue Requirement (Combined Electric and Gas Operations)

Line No.	Description	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)	2009 ($000)	2010 ($000)
1	Franchise Fees & Uncollectibles	($74.4)	$383.1	$1,742.3	$2,713.4	$3,390.5	$3,070.9
2	O&M expenses	$1,169.6	$9,350.6	$23,414.7	$21,959.4	$16,679.0	($1,753.0)
3	Property Taxes	$9.8	$181.5	$1,084.5	$2,413.6	$3,593.0	$3,972.6
4	Preferred Equity Interest	$3.7	$68.4	$408.5	$909.9	$1,354.5	$1,497.6
5	Interest Expense	$23.1	$426.3	$2,545.9	$5,670.8	$8,441.8	$9,333.7
6	Depreciation Expense	$196.1	$2,903.9	$11,930.3	$23,199.2	$33,516.7	$38,851.8
7	Federal Tax Expense	($2,319.0)	($2,200.5)	$2,891.3	$7,214.1	$10,070.8	$10,848.8
8	State Tax Expense	($1,151.6)	($1,232.7)	$169.9	$1,864.5	$3,145.7	$4,031.1
9	Return on Equity	$43.9	$811.4	$4,845.5	$10,793.1	$16,067.2	$17,764.7
10							
11	**Revenue Requirement**	($2,098.8)	$10,691.9	$49,032.9	$76,738.1	$96,259.3	$87,618.3
12							
13							
14	**Other Benefits Not Included in Revenue Requirement**						
15	Demand Response Program Cost Reductions	-	-	(5,428)	(11,127)	(17,140)	(17,586)
16	Avoided Capacity and Energy Costs	$0.0	$0.0	($6,254.6)	($20,442.7)	($32,496.4)	($40,196.9)
17	Subtotal	$0.0	$0.0	($11,682.4)	($31,569.7)	($49,636.4)	($57,782.6)
18							
19	**Net Revenue Impact**	($2,098.8)	$10,691.9	$37,350.5	$45,168.4	$46,622.9	$29,835.7

San Diego Gas & Electric
Advanced Metering Infrastructure (AMI)
Forecasted AMI Annual Revenue Requirement - 2005-2010
Electric AMI Revenue Requirement

Line No.	Description	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)	2009 ($000)	2010 ($000)
1	Franchise Fees & Uncollectibles	($61.6)	$324.4	$1,450.4	$2,235.8	$2,771.0	$2,483.2
2	O&M expenses	$892.1	$7,132.4	$17,860.2	$16,750.2	$12,722.4	($1,337.1)
3	Property Taxes	$7.4	$141.1	$821.5	$1,817.5	$2,696.8	$2,979.1
4	Preferred Equity Interest	$2.8	$53.2	$309.4	$685.2	$1,016.7	$1,123.1
5	Interest Expense	$17.4	$331.4	$1,928.5	$4,270.1	$6,336.3	$6,999.5
6	Depreciation Expense	$147.1	$2,185.2	$8,554.6	$16,246.7	$23,121.7	$26,617.9
7	Federal Tax Expense	($1,738.6)	($1,635.6)	$2,166.6	$5,388.8	$7,514.6	$8,115.1
8	State Tax Expense	($863.4)	($922.0)	$86.8	$1,282.0	$2,161.4	$2,787.0
9	Return on Equity	$33.0	$630.8	$3,670.5	$8,127.3	$12,059.7	$13,322.1
10							
11	**Revenue Requirement**	($1,563.8)	$8,240.8	$36,848.5	$56,803.4	$70,400.6	$63,090.0
12							
13	**System-Average Rate Impact from Revenue Requirement ($/kWh)**	NA	$0.00034	$0.00182	$0.00275	$0.00335	$0.00295
14							
15							
16	**Other Benefits Not Included in Revenue Requirement**						
17	Demand Response Program Cost Reductions	-	-	(5,427.8)	(11,127.0)	(17,140.0)	(17,585.7)
18	Avoided Capacity and Energy Costs	-	-	(6,254.6)	(20,442.7)	(32,496.4)	(40,196.9)
19	Subtotal	$0.0	$0.0	($11,682.4)	($31,569.7)	($49,636.4)	($57,782.6)
20							
21	**Net Revenue Impact (Line No. 11 plus Line No. 19)**	($1,563.8)	$8,240.8	$25,166.1	$25,233.7	$20,764.2	$5,307.4
22	**System-Average Net Rate Impact from Net Revenue Impact ($/kWh)**	NA	$0.00034	$0.00124	$0.00122	$0.00099	$0.00025

San Diego Gas & Electric
Advanced Metering Infrastructure (AMI)
Forecasted AMI Annual Revenue Requirement - 2005-2010
Gas AMI Revenue Requirement

Line No.	Description	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)	2009 ($000)	2010 ($000)
1	Franchise Fees & Uncollectibles	(12.8)	58.7	291.9	477.6	619.6	587.7
2	O&M expenses	277.5	2,218.1	5,554.4	5,209.2	3,956.6	(415.8)
3	Property Taxes	2.4	40.4	263.0	596.2	896.2	993.5
4	Preferred Equity Interest	0.9	15.2	99.1	224.7	337.8	374.5
5	Interest Expense	5.7	94.9	617.4	1,400.7	2,105.6	2,334.2
6	Depreciation Expense	49.0	718.7	3,375.7	6,952.5	10,395.0	12,233.8
7	Federal Tax Expense	(580.4)	(564.9)	724.7	1,825.4	2,556.2	2,733.7
8	State Tax Expense	(288.2)	(310.7)	83.1	582.5	984.3	1,244.1
9	Return on Equity	10.9	180.7	1,175.0	2,665.9	4,007.5	4,442.6
10							
11	**Revenue Requirement**	(535.0)	2,451.1	12,184.4	19,934.7	25,858.7	24,528.3
12							
13	**System-Average Rate Impact from Revenue Requirement ($/therm)**	NA	$0.00133	$0.00992	$0.01622	$0.01954	$0.01854

Note: Unlike electric, AMI is not projected to result in Other Benefits for gas, additional benefits above what is already reflected in the revenue requirements.

San Diego Gas & Electric
Advanced Metering Infrastructure (AMI)
AMI Costs & Benefits - 2005-2010
Capital and O&M Costs/Benefits Details (includes overhead loaders, sales tax, and escalation)

Line No.	Expense Type	Book Life (Years)	Fuel Type	2005 ($000)	2006 ($000)	2007 ($000)	2008 ($000)	2009 ($000)	2010 ($000)
1	**Capital Costs**	5	Both G&E	$13,333.4	$14,669.4	$6,418.6	$1,133.3	$687.6	$2,384.0
2	**Capital Costs**	5	Electric	$384.3	$2,118.4	$1,263.3	$555.2	$0.0	$0.0
3	**Capital Costs**	9	Gas	$0.0	$1,012.3	$27,577.1	$28,498.5	$29,503.6	$1,944.2
4	**Capital Costs**	15	Electric	$13.3	$5,806.5	$101,774.9	$101,641.5	$104,619.3	$5,303.3
5	**Capital Costs**	15	Gas	$0.0	$125.0	$53.9	$55.2	$56.7	$0.0
6	**Capital Costs**	34	Gas	$0.0	$194.0	$5,730.2	$5,873.4	$6,029.5	$0.0
7		**Total - Capital Costs**		$13,730.9	$23,925.5	$142,817.9	$137,757.0	$140,896.7	$9,631.5
8									
9	**Capital Benefits**	5	Both G&E	$0.0	$32.4	$33.2	$0.0	$0.0	$0.0
10	**Capital Benefits**	5	Electric	$0.0	$0.0	$0.0	$11.2	$21.8	$34.3
11	**Capital Benefits**	5	Gas	$0.0	$0.0	$0.0	$6.7	$13.8	$20.1
12	**Capital Benefits**	15	Both G&E	$0.0	$836.0	$952.2	$0.0	$0.0	$0.0
13	**Capital Benefits**	34	Electric	$0.0	$0.0	$1,352.0	$4,799.9	$6,891.2	$10,387.0
14	**Capital Benefits**	34	Gas	$0.0	$0.0	$639.9	$550.8	$761.4	$250.7
15		**Total - Capital Benefits**		$0.0	$868.5	$2,977.2	$5,368.6	$7,688.3	$10,692.2
16									
17	**O&M Costs**		Both G&E	$0.0	$1,550.1	$4,298.8	$5,426.7	$5,346.2	$5,411.1
18	**O&M Costs**		Electric	$1,169.6	$6,822.9	$18,629.2	$22,045.2	$23,393.3	$13,401.8
19	**O&M Costs**		Gas	$0.0	$1,017.1	$3,538.3	$3,726.9	$3,966.4	$346.4
20		**Total - O&M Costs**		$1,169.6	$9,390.1	$26,466.2	$31,198.9	$32,705.9	$19,159.3
21									
22	**O&M Benefits**		Both G&E	$0.0	$36.3	$2,729.1	$7,720.2	$13,217.2	$16,640.7
23	**O&M Benefits**		Electric	$0.0	$1.6	$163.1	$938.5	$1,747.0	$2,849.4
24	**O&M Benefits**		Gas	$0.0	$1.6	$159.3	$580.8	$1,062.8	$1,422.1
25		**Total - O&M Benefits**		$0.0	$39.5	$3,051.5	$9,239.5	$16,026.9	$20,912.2

TABLE B-2

REDACTED

TABLE B-3

REDACTED

San Diego Gas & Electric
Advanced Metering Infrastructure (AMI)
Description of Cost Elements Included in Revenue Requirements

Line No.	Cost Elements	Capital and O&M Costs
1	C-1	Costs to review and specify systems to ensure physical and logical security, securing data transmission, infrastructure to support security, etc.
2	C-2	Perform and review site surveys to determine placement of network equipment
3	C-3	Mapping of network equipment on company facilities (asset facility mapping)
4	C-5	Review and develop strategies to retrieve data from meters and process within billing system
5	C-5.5	Review and develop strategies to retrieve data from meters and process within billing system - systems specific related costs
6	C-6.1	Administration of contracts/supervision of installer workforce (communications network)
7	C-6.3	Installation and testing equipment costs (tools, equipment and vehicles) (communications network)
8	C-6.5	Installation labor (incl workers comp, P&B, payroll taxes, etc.) (communications network)
9	C-7	Costs of Pole replacement - to "fit" concentrators
10	C-9	Install costs of Cross arms (e.g. streetlight arms for pole top installations) and other mounting
11	C-10	Purchase network communications equipment and hardware
12	C-11	Training for installation of WAN/LAN equipment (including install labor for wireless circuits)
13	C-12.5	Cost of attaching comm. concentrators (e.g., rent or lease charges by cities or other 3rd parties-not owned by utility)
14	C-14	Dispatching and O&M of field LAN/WAN and infrastructure equipment
15	C-14.5	Cost of public network connections (WAN common carrier costs / ie: Verizon / SBC / Cingular costs)
16	C-15	Electric power consumed by LAN/WAN equipment and/or meter modules
17	C-15.5	Electric power consumed by LAN/WAN equipment and/or meter modules
18		
19	I-1	Network planning and engineering - coverage studies, technology selection, field testing & engineering
20	I-2	Computing system implementation in data center (new hardware/software, IT security review & compliance)
21	I-4	Develop and process dynamic rates in CIS billing systems
22	I-5	New information management software applications
23	I-7	Update work management interface to process additional volume of meter changes, data scripts
24	I-9	Aggregating, validating and creating billing determinant data for electric billing
25	I-11	Exceptions processing (develop, update, and execute data cleanup routines)
26	I-12	License and O&M software fees
27	I-13	Ongoing data storage and handling costs/incl test, QA environments, business continuity, disaster recovery
28	I-14	Ongoing IT system operations & maintenance (usage, software, internet application)
29	I-15	Operating costs - retrieval and delivery of meter, maint & outage information systems data and alarms
30	I-16	Server replacements (every 3-4 years) for 15 year life cycle
31	I-18	Billing
32		
33	MS-1	Additional temporary meter reading staff for transitional period/meter reader transition costs
34	MS-2	Administration of contracts/supervision of installer workforce
35	MS-3	Cost of purchasing meters, comm modules and related vendor support equipment & software
36	MS-4	Installation and testing equipment costs (tools, equipment and vehicles)
37	MS-5	Installation and testing equipment costs (tools, equipment and vehicles)
38	MS-5.5	Installation labor (incl workers comp, P&B, payroll taxes, etc.)
39	MS-6	Meter installation tracking systems (Endpoint Link-other), Meter info/records admin/GPS
40	MS-7	Panel reconfiguration/replacement costs (A base, other)/Meter socket repairs
41	MS-8	Potential customer claims related to damages during meter installation and/or panel upgrades
42	MS-10	Supply chain management including development of staging facilities, shipment & handling of new meters
43	MS-10.6	Supply chain management including development of staging facilities, shipment & handling of new meters - systems specific
44	MS-11	Training (meter installers, handlers, shippers)
45	MS-12.5	Additional costs to O&M/more complex metering & comm infrastructure (labor, tools, equip, vehicles)
46	MS-14	Potentially higher meter replacement costs relative to existing mechanical meters (shorter life cycle)
47	MS-15	Energy theft from meter tampering

Source: Appendix B of Application

San Diego Gas & Electric
Advanced Metering Infrastructure (AMI)
Description of Cost Elements Included in Revenue Requirements

Line No.	Cost Elements	Capital and O&M Costs
1	CU-1	Customer records/billing and collections work associated with roll-out of meter change process
2	CU-2	Increased call center activity during transition from existing to new rates /meter change appointments
3	CU-4	Process meter changes for new meter installations and DA accounts
4	CU-5	Additional rate analysis due to multiple TOU options.
5	CU-7	Cost of reduced customer safety (meter readers no longer available)
6	CU-8	Customer education of rate changes/customer communications campaign
7	CU-9	Customer support for internet based usage data communication
8	CU-10	Out-bound communications (mass media costs, e.g., print, radio, TV)./CPP or other rate notifications
9		
10	M-3	Customers access to usage information through communications medium
11	M-5	Employee training for deployment and O&M of new systems, rate structures, etc.
12	M-7	Overall project mgmt costs (and overhead) including customer service, IT and other functions
13	M-8	Recruiting of incremental workers
14	M-9	Supervision/overhead of contracts and technology personnel assigned to hardware and systems development
15	M-11	Work management tools
16	M-13	Cost of increased load during mid-peak and off-peak periods
17	M-14	Customer acquisition and marketing costs for new tariffs
18	M-15	Risk contingencies (e.g., technology obsolescence/reliability)
19	M-16	Billing
20		
21	GS-1	Gas Index/Module Purchases
22	GS-2	Purchase/replacement of non-retrofittable gas meters
23	GS-5	Aggregation/Validation of monthly/hourly reads for gas billing
24	GS-8	Increased O&M on gas meters/modules due to addition of electronic modules
25		
26		**Capital and O&M Benefits**
27		
28	SB-1	Reduction in Meter Readers, Mgmt & Admin Support (and associated costs)
29	SB-2	Field service savings (turn-on's / turn-off's) and lower need for pickup reads
30	SB-4	Phone Centers - Reduced FTEs in the long term due to anticipated lower customer call volume (estimated / disputed bills)
31	SB-5	Possible productivity enhancement / rate changes simplified / possible reprogram rather than meter change
32	SB-6.1	Distribution system avoided activity
33	SB-6.2	Distribution system avoided activity
34	SB-7	Better meter functionality / equipment modernization
35	SB-9.1	Distribution system operation benefits
36	SB-9.2	Distribution system operation benefits
37	SB-10.1	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and when they need to be replaced/repaired
38	SB-10.2	System planning design efficiency- savings from more accurate information on status of transformers and distribution lines and when they need to be replaced/repaired
39	SB-14.2	Distribution system upgrade deferrals
40		
41	CB-1	Improves billing accuracy - provides solution for inaccessible / difficult to access sites - eliminates "lock-outs"
42	CB-4	Improves billing accuracy - reduced estimated reads / estimated billing - reduced exception billing processing
43	CB-10	Load Survey- AMI systems allow utilities to perform load surveys remotely and no longer require recruitment and site visits
44		
45	MB-1	Reduced equipment and equip maintenance costs (software maintenance & system support, handheld reading devices, uniforms, etc.)
46	MB-2	Reduced misc. support expenses (including office equipment and supplies)
47	MB-3	Reduced battery replacement / calendar resets / meter programming
48	MB-4	Reduced meter inventories / inventory management expenses due to expanded uniformity
49	MB-12	Benefits associated with avoided vehicle accidents and other safety mishaps as a result of phasing out manual meter reading.
50	MB-13	Avoided meter purchase expense (ie: approx 25% of SDG&E's gas meters are not 'retrofittable' with a gas module and these meters need to be changed out during the deployment. These
51	MB-15	IT Capital Avoidance

Source: Appendix B of Application

San Diego Gas & Electric
Advanced Metering Infrastructure (AMI)
Formula Approach - 2006

Line No.	AMI Benefits	
1	Electric	$132,785
2	Gas	$42,009
3	Total Benefits	$174,795
4		
5	**Assumed Number of Months w/ Meters Installed**	
6	Electric	6
7	Gas	6
8		
9	**Benefit Formula Offset (after completion of the Beta Phase)**	
10	Formula - $/Month Electric	$22,100
11	Formula - $/Month Gas	$7,000
12	Total per month offset	$29,100

San Diego Gas & Electric
Advanced Metering Infrastructure (AMI)
Formula Approach - 2007

Line No.	AMI Benefits	
1	Electric	$2,779,605
2	Gas	$823,036
3	Total Benefits	$3,602,641
4		
5	**Average Number of Meters Installed**	
6	Electric	236,874
7	Gas	154,492
8		
9	**Benefit Formula Offset**	
10	Formula - $/10,000 Meters Electric per Month	$9,775
11	Formula - $/10,000 Meters Gas per Month	$4,442
12	Total per 10,000 meter offset per Month	$14,217

San Diego Gas & Electric
Advanced Meter Infrastructure (AMI)
Full Deployment - Illustrative Electric Rate Impacts for 2006 & 2007

Line No.	Customer Class	2/01/05 Rates (AL 1649-E) Current Total Rates (¢/kWh)	Illustrative 1/1/06 AMI Rates Proposed Total Rates (¢/kWh)	Total Rate Change (¢/kWh)	Total Rate Change (%)
1	**Residential**	14.902	14.970	**0.068**	**0.45%**
2					
3	**Small Commercial**	16.884	16.952	**0.067**	**0.40%**
4					
5	**Med. & Large C&I**	11.633	11.636	**0.003**	**0.03%**
6					
7	**Agriculture**	15.229	15.274	**0.045**	**0.29%**
8					
9	**Lighting**	16.137	16.137	**0.000**	**0.00%**
10					
11	**System Total**	13.537	13.571	**0.034**	**0.25%**
12					
13					
14		**Illustrative 1/1/06 AMI Rates Current Total Rates**	**Illustrative 1/1/07 AMI Rates Proposed Total Rates**	**Total Rate Change**	
15					
16	**Customer Class**	**(¢/kWh)**	**(¢/kWh)**	**(¢/kWh)**	**(%)**
17					
18	**Residential**	14.902	15.268	**0.366**	**2.46%**
19					
20	**Small Commercial**	16.884	17.251	**0.367**	**2.17%**
21					
22	**Med. & Large C&I**	11.633	11.650	**0.017**	**0.14%**
23					
24	**Agriculture**	15.229	15.473	**0.243**	**1.60%**
25					
26	**Lighting**	16.137	16.137	**0.000**	**0.00%**
27					
28	**System Total**	13.537	13.719	**0.182**	**1.34%**

San Diego Gas & Electric
Advanced Meter Infrastructure (AMI)
Full Deployment - Illustrative Gas Rate Impacts for 2006 & 2007

Line No.	Customer Class	2/1/05 Rates (AL 1503-G) Current Total Rate (¢/therm)	Illustrative 1/1/06 AMI Rates Proposed Total Rate (¢/therm)	Total Rate Change (¢/therm)	Total Rate Change (%)
1	**Residential**	109.408	109.955	**0.547**	**0.50%**
2					
3	**Core C&I**	88.000	88.101	**0.101**	**0.11%**
4					
5	**Natural Gas Vehicles**	97.924	97.927	**0.004**	**0.00%**
6					
7	**Noncore C&I**	68.573	68.573	**0.000**	**0.00%**
8					
9	**Electric Generation**	62.781	62.781	**0.000**	**0.00%**
10					
11	**System Total**	76.024	76.156	**0.133**	**0.17%**
12					
13					
14		**Illustrative 1/1/06 AMI Rates Current Total Rate**	**Illustrative 1/1/07 AMI Rates Proposed Total Rate**	**Total Rate Change**	
15					
16	**Customer Class**	**(¢/therm)**	**(¢/therm)**	**(¢/therm)**	**(%)**
17					
18	**Residential**	108.839	112.244	**3.404**	**3.13%**
19					
20	**Core C&I**	80.570	81.046	**0.475**	**0.59%**
21					
22	**Natural Gas Vehicles**	76.866	76.876	**0.010**	**0.01%**
23					
24	**Noncore C&I**	81.314	81.314	**0.001**	**0.00%**
25					
26	**Electric Generation**	64.104	64.104	**0.000**	**0.00%**
27					
28	**System Total**	79.202	80.194	**0.992**	**1.25%**

Notes:
(1) Noncore and EG customers generally purchase their own gas supplies.
The total rate for these customers reflect an estimate of procurement costs incurred by these customers.

(2) 2006 and 2007 rates reflect changes associated only with SDG&E's proposed AMI program.

QUALIFICATIONS

OF

JOHANNES VAN LIEROP

My name is Johannes Van Lierop. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011.

I am employed by Southern California Gas Company (SoCalGas) as a Director of Regulatory Policy and Analysis. One of my responsibilities is to analyze regulatory issues and develop regulatory and rate proposals for San Diego Gas & Electric Company (SDG&E) and SoCalGas in proceedings before the Commission.

In 1981, I graduated from the University of Toronto with a Ph.D. in Economics. From 1981 to 1983, I was employed as an Assistant Professor of Economics at California State University at Fullerton, where I lectured on econometrics and micro-economics. In 1984, I joined SoCalGas as Market Forecasting Analyst. Subsequently, I have held positions in Demand Forecasting, Gas Supply, and Regulatory Affairs. On July 1, 1995, I assumed the position of Director of Governmental and PUC Regulatory Affairs, and on July 1, 1998, I assumed the position of Director of Regulatory and Business Analysis. I assumed my current position on March 31, 2002.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

AMENDED APPLICATION

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Attorneys for:
SAN DIEGO GAS & ELECTRIC COMPANY

March 30, 2005

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Attorneys for:
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Application of San Diego Gas & Electric Company (U-902-E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	Application 05-03-015

AMENDED APPLICATION

I.

INTRODUCTION

In accordance Rule 2.6 of the Commission's Rules of Practice and Procedure, San Diego Gas & Electric Company ("SDG&E") submits this amendment to Application 05-03-015 seeking Commission authorization of SDG&E's advanced metering infrastructure ("AMI") deployment proposal and associated cost recovery mechanisms ("Amended Application").[1] The Amended Application provides additional testimony, specifically the direct testimony of SDG&E witness Johannes Van Lierop (Chapter 16). Witness Van Lierop supplements SDG&E's initial showing by identifying the forecasted AMI revenue requirements for the following time frames: (a) the pre-deployment period 2005-2006; (b) the first year of AMI deployment in 2007 and (c) the period 2005-2010,[2] along with the illustrative rate impacts by customer class.

In addition, the Amended Application contains the revised direct testimonies of Patrick Charles (Chapter 3), Johannes Van Lierop (Chapter 5), Edward Fong (Chapter 6) Ted Reguly (Chapter 9), James Teeter (Chapter 11), Patricia Wagner (Chapter 12), Stephen George (Chapter 13) and Neil Boyle (Chapter 14).

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[1] SDG&E filed Application, A. 05-03-015 on March 15, 2005.
[2] For illustrative purposes, Chapter 16 provides forecasted AMI annual revenue requirements 2005-2010 based on SDG&E's proposed deployment strategy.

As afforded by Rule 2.6 [3] and to avoid complicating and over-burdening the record, the testimony and exhibits submitted in support of the Amended Application supersede SDG&E's March 15th application filing. The Amended Application contains SDG&E's entire AMI showing. Accordingly, parties should not refer to the earlier version of the Application, testimony or exhibits submitted on March 15, 2005.

II.

OVERVIEW OF APPLICATION

As directed by the Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure, dated July 21, 2004, ("July 21, 2004 Ruling") as amplified and amended by the Assigned Commissioner and Administrative Law Judge's Ruling, dated November 24, 2004,[4] ("November 24, 2004 Ruling"), San Diego Gas & Electric Company ("SDG&E") submits its preferred AMI deployment scenario. SDG&E is recommending aggressive implementation of AMI. Accordingly, SDG&E must commence start-up and design efforts no later than third quarter 2005 in order to begin program implementation in 2007.

SDG&E anticipates that AMI design and start-up expenses will be in excess of $40 million. Given the substantial size and immediacy of the initial pre-deployment effort, SDG&E respectfully requests that the Commission consider pre-deployment activities and cost recovery on the proposed schedule set forth in Section IV (E) below and subsequently consider approval of SDG&E's preferred full deployment strategy for its AMI system and its estimated costs as presented in subsequent hearings and according to the second schedule also set forth in Section IV (E).

Specifically, the Amended Application seeks expedited approval of SDG&E's: (1) preferred full scale AMI pre-deployment plan (as described in Chapter 3, the testimony of witness Charles); (2) expected costs for 2005-2006 full scale pre-deployment activities (also described in Chapter 3 and in Chapter 4, the testimony of

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[3] Rule 2.6 (a) states: "An amendment is a document that replaces and supersedes a previously filed document or adds new material to an existing document."

[4] "Assigned Commission 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 Proposal for Large Customers."

witness Carusa); (3) the proposed cost recovery mechanism and revenue requirement for pre- and initial deployment costs in years 2005-2007 (as described in Chapter 5 and Chapter 16, sponsored by witness Van Lierop); and (4) SDG&E's preferred full deployment strategy for 2007 implementation and the estimated costs of full deployment (as described in Chapters 2 and 6, the testimony of witness Fong).

As the July 21, 2004 Ruling directs at page 3 (and more specifically in Attachment A of the Ruling), SDG&E submits its preferred advanced metering infrastructure deployment strategy and the cost/benefit analysis for "full" and a "partial" advanced metering infrastructure deployment scenario, along with its recommendation for full deployment planning and pre-deployment activities to begin immediately, with actual implementation of AMI in early 2007. Note, however, that while the ALJ Ruling acknowledges the legislative constraints that may inhibit full realization of demand response benefits, the recommendation in this Application is premised on a full demand response (capacity and energy) in addition to operational benefits. SDG&E strongly believes that without the demand response benefits, neither strategy may be cost effective. So that the Commission's ambitious goals of peak period load reduction can be realistically achieved, SDG&E urges the Commission to act now and initiate action that will bring about concurrent implementation of dynamic rates that effectively encourage customers to shift electricity usage away from peak periods.

Consistent with Commission directives, SDG&E provides the analysis and underlying assumptions that support its recommendation in the witnesses' prepared direct testimony as summarized below.

Chapter 1: Business Vision and Policy

William Reed, Senior Vice President, Regulatory Strategy and Planning, recommends that the Commission authorize aggressive wide scale deployment of AMI in SDG&E's service territory. Mr. Reed explains that SDG&E continues to be a strong proponent of, and leader in, integrating AMI, dynamic rates and demand response efforts and believes that AMI will revolutionize the utility industry. Mr. Reed also explains that the Commission must concurrently adopt dynamic rates so that the benefits of AMI and demand response can be fully realized.

Chapter 2: Demand Response and Dynamic Pricing Long-term Vision and Policy Implications

Edward Fong, Director of Measurement and Advanced Metering Infrastructure, provides the rationale supporting SDG&E's preference for full AMI deployment, including discussion of the varied demand response benefits that will accrue from AMI. Mr. Fong adds further background and actions that support SDG&E's management philosophy and AMI vision. In addition, Mr. Fong proposes several "off-ramps" in the event that dynamic rates are not implemented, associated demand response anticipated operational benefits do not materialize, or actual benefits vary from those expected.

Chapter 3: Pre-deployment Plan and Sequencing

Patrick Charles, Manager of Planning and Analysis, Electric Measurement and AMI Department, describes the AMI pre-deployment plan, the overall full and partial deployment plans and sequences, as well as pre-deployment costs and benefits, exclusive of information technology (IT) related costs and benefits.

Chapter 4: Information Technology System

Richard Caursa, Manager of the IT Customer Care Department, describes the pre-deployment costs and benefits for IT systems that would be realized with both the full and partial deployment scenarios of AMI.

Chapter 5: Pre-Deployment Cost Recovery Mechanism

Johannes Van Lierop, Director of Regulatory Policy and Analysis, presents SDG&E's interim cost recovery proposal for the period 2005-2007. SDG&E proposes creating new balancing accounts to record AMI costs and benefits and AMI-related revenues for annual true-up.

Chapter 6: Methodology Used to Determine the Discounted Cash Flow

Edward Fong describes SDG&E's use of a discounted cash flow process for evaluating the incremental operational costs and benefits of the full and partial AMI roll-out scenarios.

Chapter 7: Project Management, Human Resources and Load Research

Patrick Charles describes the costs and benefits associated with overall AMI project management, human resources and load research areas that SDG&E anticipates with the deployment of an AMI system.

Chapter 8: Functional Requirements of the Communications Network & Electric Meters

Paul Pruschki, Manager of Measurement Data Communications, Electric Measurement & Advanced Metering Infrastructure Department, describes the estimated costs and benefits associated with the communication system and electric meters, and describes the AMI Communication system architecture that SDG&E would deploy with AMI.

Chapter 9: Gas Meters/Modules Electric and Gas Meter Installation, Claims, Facilities and Customer Services Field Department ("CSF")

Ted Reguly, Director of Customer Service Field South Inland Region in the CSF, describes the incremental operational costs and benefits associated with the gas and electric meter installation, gas meters, gas modules, CSF, claims and facilities.

Chapter 10: Customer Contact Center, Demand Response Programs and Enabling Technologies

Edward Fong describes the costs and benefits of AMI associated with the Customer Contact Center, demand response programs and enabling technologies.

Chapter 11: Meter Reading, Safety, Billing and Meter Revenue Protection

James Teeter, Billing Manager, Customer Billing Operations Department, describes the costs and benefits of AMI associated with the meter reading, safety, billing and meter revenue protection.

Chapter 12: Customer Communications and Education

Patricia Wagner, Director of Mass Markets, Customer Services Department, describes the costs and benefits of SDG&E's efforts targeting customer communications, education and feedback for the AMI program and dynamic rates.

Chapter 13: Demand Response

Dr. Stephen George of Charles River Associates discusses the estimated demand response impacts and benefits SDG&E believes will be derived from AMI deployment and dynamic rates, and the basic methodology SDG&E used to derive these values.

Chapter 14: Cost and Benefits to Electric Transmission and Distribution Systems

Neil Boyle, Manager of Electric Reliability and Distribution Planning, Transmission and Distribution Planning Department, describes the transmission and distribution benefits of implementing AMI.

Chapter 15: Overhead Labor Loaders

Scott Kyle, Manager of Affiliate Billing and Costing, describes the subset of overhead rates that were included in the costs/benefits modeling of the AMI business case analysis.

Chapter 16: Revenue Requirement, Rate Design and Bill Impacts

Johannes Van Lierop identifies the forecasted revenue requirement that reflects the pre-deployment and incremental operating costs through 2007, to be recovered by the mechanism as shown in Chapter 5. Witness Van Lierop also describes the gas and electric customer bill impact analysis.

III.

EFFECT ON GAS AND ELECTRIC RATES

As directed by Rule 23, the Amended Application contains a table of proposed gas and electric rates which can be found below and in Chapter 16, the testimony of Johanes Van Lierop. A statement of SDG&E's presently effective gas and electric rates can be found at Attachment A to this Amended Application.

San Diego Gas & Electric
Advanced Meter Infrastructure (AMI)
Full Deployment - Illustrative Electric Rate Impacts for 2006

Line No.	Customer Class	2/01/05 Rates (AL 1649-E) Current Total Rates (¢/kWh)	Illustrative 1/1/06 AMI Rates Proposed Total Rates (¢/kWh)	Total Rate Change (¢/kWh)	(%)
1	Residential	14.902	14.970	0.068	0.45%
2					
3	Small Commercial	16.884	16.952	0.067	0.40%
4					
5	Med. & Large C&I	11.633	11.636	0.003	0.03%
6					
7	Agriculture	15.229	15.274	0.045	0.29%
8					
9	Lighting	16.137	16.137	0.000	0.00%
10					
11	System Total	13.537	13.571	0.034	0.25%

San Diego Gas & Electric
Advanced Meter Infrastructure (AMI)
Full Deployment - Illustrative Gas Rate Impacts for 2006

Line No.	Customer Class	2/1/05 Rates (AL 1503-G) Current Total Rate (¢/therm)	Illustrative 1/1/06 AMI Rates Proposed Total Rate (¢/therm)	Total Rate Change (¢/therm)	(%)
1	Residential	109.408	109.955	0.547	0.50%
2					
3	Core C&I	88.000	88.101	0.101	0.11%
4					
5	Natural Gas Vehicles	97.924	97.927	0.004	0.00%
6					
7	Noncore C&I	68.573	68.573	0.000	0.00%
8					
9	Electric Generation	62.781	62.781	0.000	0.00%
10					
11	System Total	76.024	76.156	0.133	0.17%

Notes:
(1) Noncore and EG customers generally purchase their own gas supplies.
Procurement prices for these customers reflect an estimate of procurement costs incurred by these customers.

(2) 2006 rates reflect changes associated only with SDG&E's proposed AMI program.

IV.

ADDITIONAL INFORMATION

A. Rule 15

The Amended Application is filed pursuant to Sections 454, 454.5 and 701 of the California Public Utilities Code; in compliance the Commission's Orders and Rules of Practice and Procedure and as directed by the ACR and ALJ rulings described above.

Applicant San Diego Gas & Electric Company is a corporation organized and existing under the laws of the State of California. It is a gas and electric corporation subject to the jurisdiction of this Commission and is engaged in the business of providing public utility electric service to portions of southern Orange County and gas and electric service throughout San Diego County.

The exact legal name of the Applicant is San Diego Gas & Electric Company. The location of Applicant's principal place of business is 8330 Century Park Court, San Diego, California. SDG&E's attorneys in this matter are Vicki L. Thompson and Kelly M. Morton. Their office address, telephone/facsimile numbers and e-mail address are:

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B. Rule 16

A certified copy of SDG&E's Restated Articles of Incorporation as last amended and certified by the California Secretary of State, was filed with the Commission on December 4, 1997, in connection with SDG&E's Application 97-12-012, and is incorporated herein by reference.

C. Rule 23

A statement of SDG&E's presently effective gas and electric rates can be viewed electronically by accessing www.sdge.com/tariff. Attachment A to this Amended Application are the tables of contents from SDG&E's gas and electric tariffs on file with the Commission.

A balance sheet as of the latest available date, together with an income statement covering a period from the close of the last year for which an annual report has been filed with the Commission to the date of the balance sheet is attached to this Application as Attachment B.

A summary of earnings is included in Attachment C to this Application. SDG&E's most recent Proxy Statement was submitted with SDG&E's Application 04-05-010, filed May 3, 2004, and is incorporated herein by reference.

A general description of SDG&E's property was filed with the Commission on October 5, 2001, in connection with Application 01-10-005, and is incorporated herein by reference. A statement of Original Cost and Depreciation Reserve is attached as Attachment D.

For financial statement purposes, depreciation of utility plant has been computed on a straight-line remaining life basis, at rates based on the estimated useful lives of plant properties. For federal income tax accrual purposes, SDG&E generally computes depreciation using the straight-line method for tax property additions prior to 1954, and liberalized depreciation, which includes Class Life and Asset Depreciation Range Systems, on tax property additions after 1954 and prior to 1981. For financial reporting and rate-fixing purposes, "flow through accounting" has been adopted for such properties. For tax property additions in years 1981 through 1986, SDG&E has computed its tax depreciation using the Accelerated Cost Recovery System. For years after 1986, SDG&E has computed its tax depreciation using the Modified Accelerated Cost Recovery Systems and, since 1982, has normalized the effects of the depreciation differences in accordance with the Economic Recovery Tax Act of 1981 and the Tax Reform Act of 1986.

D. Rule 24 Notice and Service of Application

The Amended Application, as filed today, does not present SDG&E's projected revenues. Accordingly, SDG&E can neither calculate nor notice potential rate changes at this time. As previously stated, however, SDG&E will provide the applicable revenue requirements and the proposed rate changes in its March 30, 2005 amendment. Accordingly, filing the amendment will trigger the noticing provisions of Rule 24. Therefore, once the amendment is filed with the Commission on March 30th, SDG&E

will provide the requisite rate change notices to our customers, the State, and the cities and counties within our service territory as directed by this Rule (Attachment E).

E. SB 960/Rule 6

Rule 6 of the procedural rules adopted pursuant to SB 960, requires that applications filed after January 1, 1998, state the proposed category for the proceeding, the need for hearing, the issues to be considered, and a proposed schedule. SDG&E proposes that this Amended Application be treated as a "ratesetting" proceeding, consistent with the definition provided under Rule 5(c).

The issues to be considered are described in this Amended Application and the accompanying testimony. The need for hearings will depend on the degree to which other parties contest the proposals contained herein. SDG&E believes strongly that the Commission must process a portion of this Amended Application, as described above, immediately to ensure that pre-deployment activities can commence. Accordingly, SDG&E proposes the expedited procedural schedule stated below to consider the pre-deployment plan and cost recovery, culminating with a final decision no later than July, 2005.

Procedural Schedule	**Proposed Date**
Application Filing	March 15, 2005
Pre-hearing Conference	April 7, 2005
Discovery Commences	April 8, 2005
ORA and Intervenor Testimony	April 21, 2005
Discovery Ends	May 6, 2005
Rebuttal Testimony	May 9, 2005
Hearings Begin	May 16, 2005
Hearings End	May 20, 2005
Initial Briefs	June 3, 2005
Reply Briefs	June 6, 2005
Proposed Decision	June 21, 2005
Final Decision	July 21, 2005

SDG&E proposes that all other issues, including deliberation of each utility's preferred AMI deployment strategy, be considered on the following schedule:

Proposed Deployment Plan

Procedural Schedule	**Proposed Date**
Pre-hearing Conference	July 22, 2005
Discovery Commences	July 25, 2005
Discovery Ends	August 8, 2005
ORA and Intervenor Testimony	September 9, 2005
Rebuttal Testimony	September 20, 2005
Hearings Begin	October 3, 2005
Hearings End	October 21, 2005
Initial Briefs	November 4, 2005
Reply Briefs	November 18, 2005
Proposed Decision	December 22, 2005
Comments	January 6, 2006
Reply comments	January 21, 2006
Final Decision	January 26, 2006

WHEREFORE, SAN DIEGO GAS & ELECTRIC COMPANY respectfully requests that the Commission: (1) approve SDG&E's preferred AMI pre-deployment plan; (2) find reasonable SDG&E's forecasted full scale pre-deployment costs for years 2005-2006; (3) approve SDG&E's proposed cost recovery mechanism and revenue requirement for pre- and initial deployment costs in years 2005-2007; (4) approve SDG&E's preferred full deployment plan and estimated costs; (5) find reasonable SDG&E's forecasted AMI Annual Revenue Requirement (2005-2010); and (6) grant such additional relief as the Commission believes is just and reasonable.

//

SDG&E is ready to proceed with its showing.

Respectfully submitted,

SAN DIEGO GAS & ELECTRIC COMPANY

By: _____
PAMELA J. FAIR
Vice President of Customer Operations

By: _____
VICKI THOMPSON
KELLY M. MORTON

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DATED at San Diego, California, this 30th day of March 2005.

OFFICER VERIFICATION

OFFICER VERIFICATION

I, Pamela J. Fair, am an officer of the applicant corporation herein, to wit: Vice President of Customer Operations, and am authorized to make this verification on its behalf. The content of this document is true, except as to matters that are stated on information and belief. As to those matters, I believe them to be true. I declare under penalty of perjury that the foregoing is true and correct.

Executed on March 30, 2005 at San Diego, California.

Pamela J. Fair
Vice President of Customer Operations
San Diego Gas & Electric Company

CERTIFICATE OF SERVICE

I hereby certify that I have this day served a **NOTICE OF AVAILABILITY** of the foregoing **AMENDED APPLICATION** on all known interested parties of record in R.02-06-001 via email to those whose email address is listed in the official service list and via first-class mail to those who email address is not available.

Dated at San Diego, California, this 30th day of March 2005.

Lisa Fucci-Ortiz

Lisa Fucci-Ortiz

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

Proceeding: R0206001 - CPUC - OIR ON POLICI
Filer: CPUC - PG&E, EDISON, SDG&E
List Name: LIST
Last changed: March 28, 2005

Download the Comma-delimited File
About Comma-delimited Files

Back to Service Lists Index

Appearance

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Attachment A

SDG&E'S Gas & Electric Rates

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S	Standby Service	17576, 15929, 15137-E	T
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SE	Service Establishment Charge	5598, 11594-E	
DA	Transportation of Electric Power for Direct Access Customers	14952, 14953, 14954, 14955, 15111, 16976-E 14957-E	
NDA	UDC Meter Services for Non-Direct Access Customers	16425, 11850, 11851, 16426, 16427-E	
E-Depart	Departing Load Nonbypassable ND & PPP Charges	16154-E	
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OBMC	Optional Binding Mandatory Curtailment Plan	14625, 15198, 14627, 14628, 14629, 15199-E	
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20/20	California Rebate Program	15200, 14674, 14599, 15201, 15202-E	
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DBP	Demand Bidding Program	16406, 16407, 16408, 16409, 16410-E	
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NEM-FC	Net Energy Metering for Fuel Cell Customer-Generators	16962, 16963, 16964, 16965-E	
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EECC-HPO	Electric Energy Commodity Cost – Hourly Pricing Option	16554, 16555, 16556, 17149-E	
EECC CPP-V	Electric Energy Commodity Cost – Experimental Domestic Critical Peak Pricing Service – Variable	17579, 17580, 17581, 17085, 16220-E	T
EECC CPP-F	Electric Energy Commodity Cost – Experimental Domestic Critical Peak Pricing Service – Fixed	17582, 17583, 17584, 17086, 16221-E	T
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2	Description of Service	6147, 6148, 6149, 6150, 6151, 6152, 6153, 6154-E 6155, 6156, 9101, 11451, 9103, 9104, 9105, 9106-E
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15	Distribution Line Extensions	11220, 11221, 11222, 13235, 13202, 13203, 13204, 12777-E 17074, 17075, 17076, 17077, 17078, 17079-E
16	Service Extensions	11233, 13237, 10501, 11235, 11236, 13238-E 11238, 11239, 11240, 11241, 11242, 11243-E 11244, 11245-E
18	Meter Tests and Adjustment of Bills	9744, 9739, 9740, 9741-E
19	Supply to Separate Premises and Resale	10504, 10505, 14101-E
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21	Interconnection Standards for Non-Utility Owned Generation	14111, 14112, 14694, 14114, 14695, 141116 to 14151-E
21	Final Standard Offer 4 Qualifying Facilities	7966 to 7989-E
22	Special Service Charges	8713, 8714-E
23	Competition Transition Charge Responsibility	12718, 15189, 15190, 15191, 15192, 15123, 10623, 10624-E 10625, 11899, 12721, 12722, 12723, 12724-E
24	The Hourly EECC Rate Option Rules	13986, 13987, 13988, 13989, 13990-E 13991, 13992, 13993, 13994-E
25	Direct Access Rules	10526, 14978, 10528 to 10533, 11901, 10535, 10536-E 12198, 10538, 10539, 12199, 10903 to 11930-E
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101-4152G	6-69	Sign Up Notice for Service	1768-E	
106-1202	6-96	Contract for Special Facilities	9118-E	
106-1502C	5-71	Contract for Agricultural Power Service	1919-E	
106-1959A	5-71	Absolving Service Agreement, _____ Service from Temporary Facilities	1921-E	
106-2759L	4-91	Agreement for Replacement of Overhead with Underground Facilities	7063-E	
106-3559	---	Assessment District Agreement	6162-E	
106-3559/1	---	Assessment District Agreement	6202-E	
106-3859	01-01	Request for Service at Secondary/Primary Substation Level Rates	14102-E	
106-3959	6-96	Contract for Special Facilities Refund	9120-E	
106-4059	6-96	Contract for Buyout Special Facilities	9121-E	
106-5140A	10-72	Agreement for _____ Service	2573-E	
106-15140	5-71	Agreement for Temporary Service	1920-E	
106-36140	11-73	Agreement for Street Lighting - Schedule LS-1	2575-E	
106-37140	11-73	Agreement for Street Lighting - Schedule LS2-A	2576-E	
106-38140	11-73	Agreement for Street Lighting - Schedule LS2-B	2577-E	
106-39140	11-71	Agreement for Street Lighting - Schedule LS4-A	2578-E	
106-40140	11-73	Agreement for Street Lighting - Schedule LS4-B	2579-E	
106-13140	6-95	General Street Lighting Contract	8785-E	
106-14140A	1-79	Street Lighting Contract, Supplement	3593-E	
106-2059A	6-69	Contract for Outdoor Area Lighting Service	1773-E	
106-23140	9-72	Contract for Residential Walkway Lighting Service	2581-E	
106-35140E	11-85	Underground Electric General Conditions	5547-E	
106-43140	11-85	Overhead Line Extension General Conditions	5548-E	
106-44140	5-04	Agreement for Extension and Construction of _____	17138-E	T
65502	5-04	Statement Of Applicant's Contract Anticipated Cost For Applicant Installation Project	17139-E	T
107-00559	3-98	Proposal to Purchase and Agreement for Transfer of Ownership of Distribution Systems	11076-E	
117-2159B	---	Standard Offer for Power Purchase and Interconnection - Qualifying Facilities Under 100 Kw	5113-E	
117-2259	8-95	Electronic Data Interchange (EDI) and Funds Transfer Agreement	8802-E	
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118-1228	05-92	Operating Entity Agreement for Illuminated Transit Shelters	7410-E
124-363	---	Declaration of Eligibility for Lifeline Rates	2857-E
124-463	10-94	Continuity of Service Agreement	8413-E
124-463/1	11-94	Continuity of Service Agreement Change Request	8414-E
124-5152F	08-73	Application for Gas/Electric Service	2496-E
132-150	07-02	Medical Baseline Allowance Application	15554-E
132-150/1	07-02	Medical Baseline Allowance Self-Certification	15555-E
132-01199	02-99	Historical Energy Usage Information Release (English)	11886-E
132-01199/1	02-99	Historical Energy Usage Information Release (Spanish)	11887-E
132-1259C	06-74	Contract for Special Electric Facilities	2580-E
--------		Contract for Electric Service - Agua Caliente – Canebrake	1233-E
132-2059C		Resident's Air Conditioner Cycling Agreement	4677-E
132-6262	06-94	DSM Program Facility Financing Agreement	8220-E
132-6262/1	06-94	Amendment to DSM Program Facility Financing Agreement	8221-E
135-00061	12-00	Voluntary Rate Stabilization Program Contract for Fixed Price Electric Energy with True-p	14001-E
135-559	07-87	Power Line Analysis and/or Engineering Study Agreement	5978-E
135-659	10-92	Annual Certification Form - Master Metered Accounts	7542-E
140-00100	07-03	Demand Bidding Program Contract	16564-E
140-00101	07-03	Amendments to Demand Bidding Program Contract	16565-E
142-00012	02-03	Scheduled Load Reduction Program Contract	16102-E
142-140	08-93	Request for Service on Schedule LR	7912-E
142-259		Contract for Service, Schedule S-I (Standby Service - Interruptible)	5975-E
142-359A		Contract for Service, Schedule S (Standby Service)	5974-E
142-459	03-89	Agreement for Standby Service	6507-E
142-732	06-03	Application and Statement of Eligibility for the California Alternate Rates for Energy (CARE) Program	17104-E
142-732/2	06-03	Submetered Household Application and Statement of Eligibility for Califofnia Alternate Rates for Energy (CARE) Program	17105-E
142-732/3	06-04	CARE Program Recertification – Application & Statement of Eligibility	17130-E T
142-732/4	06-04	CARE Program Recertification – Application & Statement of Eligibility for Submetered Customers	17131-E T
142-00832	06-04	Application for California Alternate Rates for Energy (CARE) Program for Qualified Nonprofit Group Living Facilities	17129-E T
142-859	03-94	Request for Service on Schedule NJ - New Job Incentive Rate Service	8100-E

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142-1059	06-96	Standard Form Contract for Service New Job Connection Credit	9130-E
142-1159	03-94	Standard Form Contract - Use of Rule 20A Conversion Funds to Fund New Job Connection Credit	8103-E
142-1359	05-95	Request for Contract Minimum Demand	8716-E
142-1459	05-95	Agreement for Contact Closure Service	8717-E
142-1559	05-95	Request for Conjunctive Billing	8718-E
142-1659	05-95	Standard Form Contract - Credits for Reductions in Overhead to Underground Conversion Funding Levels	8719-E
142-01959	01-01	Consent Agreement	14172-E
142-02559	01-98	Contract to Permit the Billing of a Customer on Schedule AV-1 Prior to Installation of all Metering and Equipment Required to Provide a Contract Closure in Compliance With Special Condition 12 of Schedule AV-1	11023-E
142-02760	02-02	Interconnection Agreement for Net Energy Metering Solar or Wind Electric Generating Facilities for Other than Residential or Small Commercial of 10 Kilowatts or Less	16707-E
142-02761	10-03	Biogas Digester Generating Facility Net Energy Metering and Interconnection Agreement	16697-E 5380-E
142-3201	---	Residential Hotel Application for Residential Rates	
142-3242		Agreement for Exemption from Income Tax Component on Contributions and Refundable Advances	6041-E
142-4032	06-02	Application for California Alternate Rates for Energy (CARE) Program for Qualified Agricultural Employee Housing Facilities	15379-E 16086-E
142-5201	01-03	Request for Service on Schedule AL-TOU-CP	14152-E
142-05302	01-01	Generating Facility Interconnection Application Agreement	14698-E
142-05203	07-01	Generating Facility Interconnection Application	
142-05204	06-01	Mandatory Pay-for-Load Demand Responsiveness Program Contract	14540-E 15475-E
142-05205	07-02	Optional Binding Mandatory Curtailment Plan Contract	15476-E
142-05207	07-02	Base Interruptible Program Contract	14447-E
142-05209	04-01	No Insurance Declaration	15209-E
142-05210	06-04	Rolling Blackout Reduction Program Contract	17152-E T
142-05211	06-04	Bill Protection Application	17153-E T
142-05212	07-03	Demand Bidding Program Non-Disclosure Agreement	16567-E
142-05213	07-03	Technical Assistance Incentive Application	15384-E
142-0541	06-02	Customer Generation Agreement	15385-E
142-0542	06-02	Generating Facility Interconnection Agreement (3rd Party Inadvertent Export)	15386-E
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143-359		Resident's Agreement for Water Heater Switch Credit	3542-E
143-00212		Service Agreement between the Customer and SDG&E for Optional UDC Meter Services	11854-E
143-359		Resident's Agreement for Water Heater Switch Credit	3542-E
143-459		Resident's Agreement for Air Conditioner or Water Heater Switch	3543-E
143-559		Owner's Agreement for Air Conditioner or Water Heater Switch Payment	3544-E
143-659		Owner's Agreement for Air Conditioner or Water Heater Switch	3545-E
143-759	12-97	Owner's Agreement for Air Conditioner Switch Payment	3699-E
143-859	1-99	Occupant's Agreement for Air Conditioner Switch Payment	3700-E
143-01212		Letter of Understanding between the Customer's Authorized Meter Supplier and SDG&E for Optional UDC Meter Services	11855-E
143-1459B	12-97	Thermal Energy Storage Agreement	5505-E
143-01759	12-97	Meter Data and Communications Request	11004-E
143-01859	2-99	Energy Service Provider Service Agreement	10572-E
143-01959	8-98	Request for the Hourly PX Rate Option Service Agreement	11005-E
143-01959/1	2-99	Request for the Hourly PX Rate Option (Spanish)	11888-E
143-02059	12-99	Direct Access Service Request (DASR)	13196-E
143-02159	12-97	Termination of Direct Access (English)	11889-E
143-02159/1	12-97	Termination of Direct Access (Spanish)	11890-E
143-2259	12-97	Departing Load Competition Transition Charge Agreement	10629-E
143-02359	12-97	Customer Request for SDG&E to Perform Telecommunication Service	11007-E
143-02459	12-97	ESP Request for SDG&E to Perform ESP Meter Services	11008-E
143-02659	3-98	ESP Request to Receive Meter Installation and Maintenance Charges	11175-E
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101-363	10-96	Guarantor's Statement	9167-E
101-1652B	03-68	Receipt of Payment	2501-E
103-1750-E		Return of Customer Deposit	2500-E
		Bills and Statements	
108-01214	02-01	Residential Meter Re-Read Verification	14280-E
110-00432	02-04	Form of Bill - General, Domestic, Power, and Lighting Service - Opening, Closing, and Regular Monthly Statements	17386-E T
110-01332	08-98	Monthly Billing Invoice	11661-E
110-01332/1	12-98	Monthly Billing Invoice	11662-E
		Collection Notices	
101-00433	02-04	Final Notice Before Disconnection (mailed)	16942-E
101-00752	02-04	Final Notice Before Disconnect (delivered)	16943-E
101-00753	02-04	Back of Urgent Notice Applicable to Forms 101-00753/1 through 101-00753/11	16944-E
101-00753/1	02-04	Urgent Notice Payment Request Security Deposit to Establish Credit	16945-E
101-00753/2	02-04	Urgent Notice Payment Request Security Deposit to Re-Establish Credit	16946-E
101-00753/3	02-04	Urgent Notice Payment Request for Past Due Security Deposit	16947-E
101-00753/4	02-04	Urgent Notice Payment Request for Past Due Bill	16948-E
101-00753/5	02-04	Urgent Notice Payment Request for Returned Payment	16949-E
101-00753/6	02-04	Urgent Notice Payment Request for Final Bill.	16950-E
101-00753/7	02-04	Urgent - Sign Up Notice for Service	16951-E
101-00753/8	02-04	Reminder Notice – Payment Request for Past Due Bill	16952-E
101-00753/9	02-04	Closing Bill Transfer Notification	16953-E
101-00753/10	02-04	Payment Agreement Confirmation	16954-E
101-00753/11	02-04	ESP Reminder Notice – Payment Request for Past Due Bill	16955-E
101-00754	02-04	Notice of Past Due Closing Bill and Notice of Past Due Closing Bill Final Notice	16956-E
101-01071	02-04	Notice of Disconnect	16957-E
101-02171	02-04	Notice to Landlord - Termination of Tenant's Gas/Electric Service (two or more units)	16958-E
101-2452G	02-04	Customer Payment Notification	16959-E

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101-2371	11-95	No Access Notice	8826-E
101-3052B	3-69	Temporary "After Hour" Turn On Notice	2512-E
101-15152B		Door Knob Meter Reading Card	2515-E
107-04212	4-99	Notice of Temporary Electric Service Interruption (English & Spanish)	12055-E
115-00363/2	9-00	Sorry We Missed You	13905-E
115-002363	9-00	Electric Meter Test	13906-E
115-7152A		Access Problem Notice	3694-E
124-70A		No Service Tag	2514-E

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Attachment B

SDG&E'S Balance Sheet

SAN DIEGO GAS & ELECTRIC COMPANY
BALANCE SHEET
ASSETS AND OTHER DEBITS
SEPTEMBER 2004

	1. UTILITY PLANT	2004
101	UTILITY PLANT IN SERVICE	$6,530,627,480
102	UTILITY PLANT PURCHASED OR SOLD	-
105	PLANT HELD FOR FUTURE USE	57,456
106	COMPLETED CONSTRUCTION NOT CLASSIFIED	-
107	CONSTRUCTION WORK IN PROGRESS	341,033,110
108	ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT	(3,622,906,934)
111	ACCUMULATED PROVISION FOR AMORTIZATION OF UTILITY PLANT	(143,484,987)
118	OTHER UTILITY PLANT	458,436,797
119	ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF OTHER UTILITY PLANT	(87,672,221)
120	NUCLEAR FUEL - NET	26,918,495
	TOTAL NET UTILITY PLANT	3,503,009,196

	2. OTHER PROPERTY AND INVESTMENTS	
121	NONUTILITY PROPERTY	8,908,264
122	ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION OF NONUTILITY PROPERTY	(1,344,615)
123	INVESTMENTS IN SUBSIDIARY COMPANIES	3,290,000
124	OTHER INVESTMENTS	-
125	SINKING FUNDS	-
128	OTHER SPECIAL FUNDS	575,207,707
	TOTAL OTHER PROPERTY AND INVESTMENTS	586,061,356

SAN DIEGO GAS & ELECTRIC COMPANY
BALANCE SHEET
ASSETS AND OTHER DEBITS
SEPTEMBER 2004

3. CURRENT AND ACCRUED ASSETS

		2004
131	CASH	$9,152,694
132	INTEREST SPECIAL DEPOSITS	-
134	OTHER SPECIAL DEPOSITS	-
135	WORKING FUNDS	87,300
136	TEMPORARY CASH INVESTMENTS	-
141	NOTES RECEIVABLE	-
142	CUSTOMER ACCOUNTS RECEIVABLE	126,732,128
143	OTHER ACCOUNTS RECEIVABLE	27,005,776
144	ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS	(1,873,652)
145	NOTES RECEIVABLE FROM ASSOCIATED COMPANIES	35,652,345
146	ACCOUNTS RECEIVABLE FROM ASSOCIATED COMPANIES	43,035,468
151	FUEL STOCK	-
152	FUEL STOCK EXPENSE UNDISTRIBUTED	-
154	PLANT MATERIALS AND OPERATING SUPPLIES	38,275,820
156	OTHER MATERIALS AND SUPPLIES	(253)
163	STORES EXPENSE UNDISTRIBUTED	-
164	GAS STORED	47,249,786
165	PREPAYMENTS	9,194,943
171	INTEREST AND DIVIDENDS RECEIVABLE	54,955,252
173	ACCRUED UTILITY REVENUES	47,799,000
174	MISCELLANEOUS CURRENT AND ACCRUED ASSETS	11,534,752
175	DERIVATIVE INSTRUMENT ASSETS	516,143,001
	TOTAL CURRENT AND ACCRUED ASSETS	964,944,360

4. DEFERRED DEBITS

181	UNAMORTIZED DEBT EXPENSE	12,473,427
182	UNRECOVERED PLANT AND OTHER REGULATORY ASSETS	691,716,631
183	PRELIMINARY SURVEY & INVESTIGATION CHARGES	6,820,284
184	CLEARING ACCOUNTS	(1,331,066)
185	TEMPORARY FACILITIES	(844,026)
186	MISCELLANEOUS DEFERRED DEBITS	12,813,899
188	RESEARCH AND DEVELOPMENT	-
189	UNAMORTIZED LOSS ON REACQUIRED DEBT	47,332,947
190	ACCUMULATED DEFERRED INCOME TAXES	177,555,695
	TOTAL DEFERRED DEBITS	946,537,791
	TOTAL ASSETS AND OTHER DEBITS	$6,000,552,703

SAN DIEGO GAS & ELECTRIC COMPANY
BALANCE SHEET
LIABILITIES AND OTHER CREDITS
SEPTEMBER 2004

5. PROPRIETARY CAPITAL

		2004
201	COMMON STOCK ISSUED	$291,458,395
204	PREFERRED STOCK ISSUED	78,475,400
207	PREMIUM ON CAPITAL STOCK	592,222,753
210	GAIN ON RETIRED CAPITAL STOCK	-
211	MISCELLANEOUS PAID-IN CAPITAL	79,618,042
214	CAPITAL STOCK EXPENSE	(25,990,045)
216	UNAPPROPRIATED RETAINED EARNINGS	304,589,757
219	ACCUMULATED OTHER COMPREHENSIVE INCOME	(43,023,967)
	TOTAL PROPRIETARY CAPITAL	1,277,350,335

6. LONG-TERM DEBT

221	BONDS	636,905,000
223	ADVANCES FROM ASSOCIATED COMPANIES	360,064,924
224	OTHER LONG-TERM DEBT	274,970,000
225	UNAMORTIZED PREMIUM ON LONG-TERM DEBT	-
226	UNAMORTIZED DISCOUNT ON LONG-TERM DEBT	(545,280)
	TOTAL LONG-TERM DEBT	1,271,394,644

7. OTHER NONCURRENT LIABILITIES

227	OBLIGATIONS UNDER CAPITAL LEASES - NONCURRENT	-
228.2	ACCUMULATED PROVISION FOR INJURIES AND DAMAGES	32,178,138
228.3	ACCUMULATED PROVISION FOR PENSIONS AND BENEFITS	2,241,467
228.4	ACCUMULATED MISCELLANEOUS OPERATING PROVISIONS	(27,469)
230	ASSET RETIREMENT OBLIGATIONS	334,184,395
	TOTAL OTHER NONCURRENT LIABILITIES	368,576,531

SAN DIEGO GAS & ELECTRIC COMPANY
BALANCE SHEET
LIABILITIES AND OTHER CREDITS
SEPTEMBER 2004

8. CURRENT AND ACCRUED LIABILITES

		2004
232	ACCOUNTS PAYABLE	159,709,383
233	NOTES PAYABLE TO ASSOCIATED COMPANIES	65,800,000
234	ACCOUNTS PAYABLE TO ASSOCIATED COMPANIES	22,370,353
235	CUSTOMER DEPOSITS	42,483,993
236	TAXES ACCRUED	158,707,794
237	INTEREST ACCRUED	9,787,699
238	DIVIDENDS DECLARED	1,204,917
241	TAX COLLECTIONS PAYABLE	6,854,873
242	MISCELLANEOUS CURRENT AND ACCRUED LIABILITIES	133,010,978
243	OBLIGATIONS UNDER CAPITAL LEASES - CURRENT	-
244	DERIVATIVE INSTRUMENT LIABILITIES	516,143,001
	TOTAL CURRENT AND ACCRUED LIABILITIES	1,116,072,991

9. DEFERRED CREDITS

252	CUSTOMER ADVANCES FOR CONSTRUCTION	30,918,881
253	OTHER DEFERRED CREDITS	303,785,503
254	OTHER REGULATORY LIABILITIES	827,478,855
255	ACCUMULATED DEFERRED INVESTMENT TAX CREDITS	37,754,509
257	UNAMORTIZED GAIN ON REACQUIRED DEBT	-
281	ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED	4,901,000
282	ACCUMULATED DEFERRED INCOME TAXES - PROPERTY	458,343,220
283	ACCUMULATED DEFERRED INCOME TAXES - OTHER	303,976,234
	TOTAL DEFERRED CREDITS	1,967,158,202
	TOTAL LIABILITIES AND OTHER CREDITS	$6,000,552,703

SAN DIEGO GAS & ELECTRIC COMPANY
STATEMENT OF INCOME AND RETAINED EARNINGS
NINE MONTHS ENDED SEPTEMBER 2004

1. UTILITY OPERATING INCOME

400	OPERATING REVENUES		$1,655,501,316
401	OPERATING EXPENSES	$1,036,351,603	
402	MAINTENANCE EXPENSES	89,342,806	
403-7	DEPRECIATION AND AMORTIZATION EXPENSES	203,090,306	
408.1	TAXES OTHER THAN INCOME TAXES	32,646,710	
409.1	INCOME TAXES	119,820,251	
410.1	PROVISION FOR DEFERRED INCOME TAXES	50,862,000	
411.1	PROVISION FOR DEFERRED INCOME TAXES - CREDIT	(47,183,000)	
411.4	INVESTMENT TAX CREDIT ADJUSTMENTS	(1,928,000)	
411.6	GAIN FROM DISPOSITION OF UTILITY PLANT	-	
	TOTAL OPERATING REVENUE DEDUCTIONS		1,483,002,676
	NET OPERATING INCOME		172,498,640

2. OTHER INCOME AND DEDUCTIONS

415	REVENUE FROM MERCHANDISING, JOBBING AND CONTRACT WORK	-	
417.1	EXPENSES OF NONUTILITY OPERATIONS	(114,796)	
418	NONOPERATING RENTAL INCOME	241,076	
418.1	EQUITY IN EARNINGS OF SUBSIDIARIES	-	
419	INTEREST AND DIVIDEND INCOME	24,889,415	
419.1	ALLOWANCE FOR OTHER FUNDS USED DURING CONSTRUCTION	6,769,699	
421	MISCELLANEOUS NONOPERATING INCOME	598,135	
421.1	GAIN ON DISPOSITION OF PROPERTY	-	
	TOTAL OTHER INCOME	32,383,529	
426	MISCELLANEOUS OTHER INCOME DEDUCTIONS	(814,200)	
408.2	TAXES OTHER THAN INCOME TAXES	174,695	
409.2	INCOME TAXES	5,610,000	
410.2	PROVISION FOR DEFERRED INCOME TAXES	1,180,000	
411.2	PROVISION FOR DEFERRED INCOME TAXES - CREDIT	(184,000)	
	TOTAL TAXES ON OTHER INCOME AND DEDUCTIONS	6,780,695	
	TOTAL OTHER INCOME AND DEDUCTIONS		26,417,034
	INCOME BEFORE INTEREST CHARGES		198,915,674
	NET INTEREST CHARGES*		55,695,020
	NET INCOME		$143,220,654

**NET OF ALLOWANCE FOR BORROWED FUNDS USED DURING CONSTRUCTION, (2,417,302)*

SAN DIEGO GAS & ELECTRIC COMPANY
STATEMENT OF INCOME AND RETAINED EARNINGS
NINE MONTHS ENDED SEPTEMBER 2004

3. RETAINED EARNINGS

RETAINED EARNINGS AT BEGINNING OF PERIOD, AS PREVIOUSLY REPORTED	$369,983,854
NET INCOME (FROM PRECEDING PAGE)	143,220,654
DIVIDEND TO PARENT COMPANY	(205,000,000)
DIVIDENDS DECLARED - PREFERRED STOCK	(3,614,751)
OTHER RETAINED EARNINGS ADJUSTMENTS	0
RETAINED EARNINGS AT END OF PERIOD	$304,589,757

SAN DIEGO GAS & ELECTRIC COMPANY
FINANCIAL STATEMENT
SEPTEMBER 2004

(a) Amounts and Kinds of Stock Authorized:

Preferred Stock	1,375,000	shares	Par Value $27,500,000
Preferred Stock	10,000,000	shares	Without Par Value
Common Stock	255,000,000	shares	Without Par Value

Amounts and Kinds of Stock Outstanding:

PREFERRED STOCK			
5.0%	375,000	shares	$7,500,000
4.50%	300,000	shares	6,000,000
4.40%	325,000	shares	6,500,000
4.60%	373,770	shares	7,475,400
$1.7625	850,000	shares	21,250,000
$1.70	1,400,000	shares	35,000,000
$1.82	640,000	shares	16,000,000
COMMON STOCK	116,583,358	shares	291,458,395

(b) Terms of Preferred Stock:
Full information as to this item is given in connection with Application No. 96-03-053, to which reference is hereby made.

(c) Brief Description of Mortgage:
Full information as to this item is given in Application No. 96-03-053, to which reference is hereby made.

(d) Number and Amount of Bonds Authorized and Issued:

First Mortgage Bonds:	Nominal Date of Issue	Par Value Authorized and Issued	Par Value Outstanding	Interest Paid in 2003
6.8% Series KK, due 2015	12-01-91	14,400,000	14,400,000	979,200
Var% Series NN, due 2018 & 2019	09-01-92	118,615,000	118,615,000	7,366,360
Var% Series OO, due 2027	12-01-92	250,000,000	225,000,000	15,300,000
5.9% Series PP, due 2018	04-29-93	70,795,000	68,295,000	4,029,405
5.85% Series RR, due 2021	06-29-93	60,000,000	60,000,000	3,510,000
5.9% Series SS, due 2018	07-29-93	92,945,000	92,945,000	5,483,755
Var% Series TT, due 2020	06-06-95	57,650,000	57,650,000	656,122
Unsecured Bonds:				
5.9% CPCFA96A, due 2014	06-01-96	129,820,000	129,820,000	7,659,380
Var% CV96A, due 2021	08-02-96	38,900,000	38,900,000	468,279
Var% CV96B, due 2021	11-21-96	60,000,000	60,000,000	678,230
Var% CV97A, due 2023	10-31-97	25,000,000	25,000,000	1,687,500

SAN DIEGO GAS & ELECTRIC COMPANY
FINANCIAL STATEMENT
SEPTEMBER 2004

Other Indebtedness:	Date of Issue	Date of Maturity	Interest Rate	Outstanding	Interest Paid 2003
Commercial Paper & ST Bank Loans	Various	Various	Various	-	$0

Amounts and Rates of Dividends Declared:
The amounts and rates of dividends during the past five fiscal years are as follows:

Preferred Stock	Shares Outstanding 12-31-03	Dividends Declared 1999	2000	2001	2002	2003
5.0%	375,000	$375,000	$375,000	$375,000	$375,000	$375,000
4.50%	300,000	270,000	270,000	270,000	270,000	270,000
4.40%	325,000	286,000	286,000	286,000	286,000	286,000
4.60%	373,770	343,868	343,868	343,868	343,868	343,868
$ 1.7625	950,000	1,762,500	1,762,500	1,762,500	1,762,500	1,674,375
$ 1.70	1,400,000	2,380,000	2,380,000	2,380,000	2,380,000	2,380,000
$ 1.82	640,000	1,164,800	1,164,800	1,164,800	1,164,800	1,164,800
	4,363,770	$6,582,168	$6,582,168	$6,582,168	$6,582,168	$6,494,043
Common Stock Amount		$0	$400,000,000	$150,000,000	$200,000,000	$200,000,000 [1]

A balance sheet and a statement of income and retained earnings of Applicant for the three months ended September 30, 2004, are attached hereto.

[1] San Diego Gas & Electric Company dividend to parent.

Attachment C

SDG&E'S Summary of Earnings

SAN DIEGO GAS & ELECTRIC COMPANY
SUMMARY OF EARNINGS
NINE MONTHS ENDED SEPTEMBER 2004
(DOLLARS IN MILLIONS)

Line No.	Item	Amount
1	Operating Revenue	1,656
2	Operating Expenses	1,483
3	Net Operating Income	173
4	Weighted Average Rate Base	2,677
5	Rate of Return*	8.77%

*Authorized Cost of Capital

ATTACHMENT D

SDG&E'S Original Cost and Depreciation Reserve

SAN DIEGO GAS & ELECTRIC COMPANY

COST OF PROPERTY AND
DEPRECIATION RESERVE APPLICABLE THERETO
AS OF SEPTEMBER 30, 2004

No.	Account	Original Cost	Reserve for Depreciation and Amortization
ELECTRIC DEPARTMENT			
302	Franchises and Consents	$ 222,841	$ 202,900
303	Misc. Intangible Plant	22,934,626	12,537,187
	TOTAL INTANGIBLE PLANT	23,157,467	12,740,087
310.1	Land	46,518	46,518
310.2	Land Rights	0	0
311	Structures and Improvements	8,125,342	8,125,342
312	Boiler Plant Equipment	10,633,963	19,732,200
314	Turbogenerator Units	7,484,308	7,484,308
315	Accessory Electric Equipment	2,172,934	2,172,934
316	Miscellaneous Power Plant Equipment	239,053	239,053
	Steam Production Decommissioning	0	0
	TOTAL STEAM PRODUCTION	28,702,119	37,800,356
320.1	Land	0	0
320.2	Land Rights	283,677	283,677
321	Structures and Improvements	265,270,692	265,194,987
322	Boiler Plant Equipment	392,749,128	392,749,128
323	Turbogenerator Units	135,444,115	135,444,115
324	Accessory Electric Equipment	166,600,388	166,600,388
325	Miscellaneous Power Plant Equipment	201,528,419	194,518,430
107	ICIP CWIP	0	7,362,753
	TOTAL NUCLEAR PRODUCTION	1,161,876,420	1,162,153,478
340.1	Land	143,476	0
340.2	Land Rights	2,428	2,428
341	Structures and Improvements	0	0
342	Fuel Holders, Producers & Accessories	0	0
343	Prime Movers	0	0
344	Generators	389,278	0
345	Accessory Electric Equipment	0	0
	Other Production Decommissioning	0	0
	TOTAL OTHER PRODUCTION	535,181	2,428
	TOTAL ELECTRIC PRODUCTION	1,191,113,720	1,199,956,262

No.	Account	Original Cost	Reserve for Depreciation and Amortization
350.1	Land	$ 17,352,556	$ 0
350.2	Land Rights	41,115,412	7,624,319
352	Structures and Improvements	62,766,721	22,126,630
353	Station Equipment	399,756,929	111,316,456
354	Towers and Fixtures	93,799,585	67,201,984
355	Poles and Fixtures	72,208,091	37,150,596
356	Overhead Conductors and Devices	157,231,904	122,556,855
357	Underground Conduit	38,156,719	5,620,667
358	Underground Conductors and Devices	26,016,559	8,542,055
359	Roads and Trails	12,183,248	4,087,405
	TOTAL TRANSMISSION	920,587,724	386,226,967
360.1	Land	11,061,399	0
360.2	Land Rights	60,705,450	21,920,975
361	Structures and Improvements	3,322,441	1,821,450
362	Station Equipment	256,887,571	68,888,211
364	Poles, Towers and Fixtures	314,500,580	175,901,382
365	Overhead Conductors and Devices	254,178,462	80,128,474
366	Underground Conduit	667,101,265	257,953,965
367	Underground Conductors and Devices	834,118,555	423,710,527
368.1	Line Transformers	302,639,591	57,320,157
368.2	Protective Devices and Capacitors	25,256,429	4,827,783
369.1	Services Overhead	82,491,988	112,148,756
369.2	Services Underground	222,333,068	119,978,952
370.1	Meters	78,353,352	29,061,540
370.2	Meter Installations	36,950,477	9,819,604
371	Installations on Customers' Premises	5,701,854	7,159,911
373.1	St. Lighting & Signal Sys.-Transformers	0	0
373.2	Street Lighting & Signal Systems	22,391,340	15,929,029
	TOTAL DISTRIBUTION PLANT	3,177,993,823	1,386,570,714
389.1	Land	1,572,703	0
389.2	Land Rights	0	0
390	Structures and Improvements	24,498,863	7,443,893
392.1	Transportation Equipment - Autos	0	49,884
392.2	Transportation Equipment - Trailers	175,979	110,584
393	Stores Equipment	54,331	42,532
394.1	Portable Tools	8,927,582	3,177,285
394.2	Shop Equipment	579,577	247,475
395	Laboratory Equipment	483,721	135,953
396	Power Operated Equipment	92,162	149,134
397	Communication Equipment	84,138,779	36,265,483
398	Miscellaneous Equipment	72,849	(159,960)
	TOTAL GENERAL PLANT	120,596,546	47,462,263
101	TOTAL ELECTRIC PLANT	5,433,449,281	3,032,956,293

No.	Account	Original Cost	Reserve for Depreciation and Amortization
GAS PLANT			
302	Franchises and Consents	$ 86,104	$ 86,104
303	Miscellaneous Intangible Plant	713,559	503,553
	TOTAL INTANGIBLE PLANT	799,663	589,657
360.1	Land	10,205	0
361	Structures and Improvements	412,998	554,836
362.1	Gas Holders	989,283	1,012,573
362.2	Liquefied Natural Gas Holders	0	0
363	Purification Equipment	0	0
363.1	Liquefaction Equipment	0	0
363.2	Vaporizing Equipment	0	0
363.3	Compressor Equipment	558,651	612,455
363.4	Measuring and Regulating Equipment	0	0
363.5	Other Equipment	0	0
363.6	LNG Distribution Storage Equipment	407,546	310,538
	TOTAL STORAGE PLANT	2,378,682	2,490,402
365.1	Land	4,649,144	0
365.2	Land Rights	2,217,185	880,320
366	Structures and Improvements	10,680,998	6,398,281
367	Mains	118,652,979	40,021,826
368	Compressor Station Equipment	58,309,703	29,062,950
369	Measuring and Regulating Equipment	13,703,208	7,986,356
371	Other Equipment	0	0
	TOTAL TRANSMISSION PLANT	208,213,217	84,349,733
374.1	Land	102,187	0
374.2	Land Rights	7,634,200	4,253,943
375	Structures and Improvements	43,447	61,253
376	Mains	448,125,367	232,316,076
378	Measuring & Regulating Station Equipment	7,467,308	5,145,419
380	Distribution Services	217,230,553	217,294,266
381	Meters and Regulators	64,367,746	30,098,161
382	Meter and Regulator Installations	54,126,547	21,199,282
385	Ind. Measuring & Regulating Station Equipment	1,457,603	565,060
386	Other Property On Customers' Premises	0	0
387	Other Equipment	4,446,936	3,547,755
	TOTAL DISTRIBUTION PLANT	805,001,895	514,481,215

No.	Account	Original Cost	Reserve for Depreciation and Amortization
392.1	Transportation Equipment - Autos	$ 0	$ 25,503
392.2	Transportation Equipment - Trailers	76,210	76,210
394.1	Portable Tools	5,563,672	1,300,043
394.2	Shop Equipment	84,597	(16,729)
395	Laboratory Equipment	421,222	(221,552)
396	Power Operated Equipment	246,939	(25,808)
397	Communication Equipment	3,165,769	1,222,961
398	Miscellaneous Equipment	198,414	12,055
	TOTAL GENERAL PLANT	9,756,824	2,372,683
101	TOTAL GAS PLANT	1,026,150,281	604,283,690
COMMON PLANT			
303	Miscellaneous Intangible Plant	151,742,533	95,115,787
350.1	Land	0	0
360.1	Land	0	0
389.1	Land	4,980,210	0
389.2	Land Rights	2,026,582	27,275
390	Structures and Improvements	112,005,925	37,624,531
391	Office Furniture and Equipment	82,217,751	16,232,988
392.1	Transportation Equipment - Autos	33,942	(338,930)
392.2	Transportation Equipment - Trailers	41,567	(118,466)
393	Stores Equipment	169,246	(229,198)
394.1	Portable Tools	68,328	(25,561)
394.2	Shop Equipment	319,947	111,465
394.3	Garage Equipment	2,480,706	97,016
395	Laboratory Equipment	2,129,346	815,625
396	Power Operated Equipment	0	(192,979)
397	Communication Equipment	71,410,036	33,003,449
398	Miscellaneous Equipment	3,105,948	692,280
118.1	TOTAL COMMON PLANT	432,732,066	182,815,283
	TOTAL ELECTRIC PLANT	5,433,449,281	3,032,956,293
	TOTAL GAS PLANT	1,026,150,281	604,283,690
	TOTAL COMMON PLANT	432,732,066	182,815,283
101 & 118.1	TOTAL	6,892,331,629	3,820,055,266
101	PLANT IN SERV-SONGS FULLY RECOVERED	$ (1,168,016,202)	$ (1,168,016,202)

No.	Account	Original Cost	Reserve for Depreciation and Amortization
102	Plant Purchased or Sold		
	Electric	$ 0	$ 0
	Gas	0	0
	TOTAL PLANT PURCHASED OR SOLD	0	0
105	Plant Held for Future Use		
	Electric	57,456	0
	Gas	0	0
	TOTAL PLANT HELD FOR FUTURE USE	57,456	0
107	Construction Work in Progress		
	Electric	341,263,366	
	Gas	8,821,148	
	Common	25,704,731	
	TOTAL CONSTRUCTION WORK IN PROGRESS	375,789,246	0
108.5	Accumulated Nuclear Decommissioning		
	Electric	0	477,524,604
	TOTAL ACCUMULATED NUCLEAR DECOMMISSIONING	0	477,524,604
111.3	Capitalized Leases		
	Electric	0	0
	Gas	0	0
	Common	0	0
	TOTAL CAPITALIZED LEASES	0	0
114	ELECTRIC PLANT ACQUISITION ADJUSTMENT	0	0
120	NUCLEAR FUEL FABRICATION	41,321,694	23,454,604
143	FAS 143 ASSETS - Legal Obligation	71,027,918	(443,515,728)
143	FAS 143 ASSETS - Non-legal Obligation	0	(882,366,000)
	TOTAL FAS 143	71,027,918	(1,325,881,728)
	UTILITY PLANT TOTAL	$ 6,212,511,740	$ 1,827,136,545

Book cost is calculated by taking Original Cost less Reserve for Depreciation and Amortization.

ATTACHMENT E

SDG&E'S Rule 24 Service List

State of California
Attorney General
1515 K St Ste 511
Sacramento CA 94244
USA

City of Chula Vista
Attn City Attorney
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California Public Utilities
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Los Angeles CA 90012
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State of California
Attn Director Dept of General Services
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City of Carlsbad
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City of Coronado
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Dana Point CA 92629
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City of Dana Point
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33282 Golden Lantern
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Sempra Energy
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Imperial Beach CA 92032
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Attn City Attorney
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Oceanside CA 92054-2885
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City of San Diego
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City of San Diego
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USA

City of Vista
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USA

City of Solana Beach
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USA

City of Solana Beach
Attn City Clerk
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United States Government
General Services Administration
300 N Los Angeles
Los Angeles CA 90012
USA

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U 902 E) for Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design.	)))))	Application 05-03-015

NOTICE OF AVAILABILITY OF THE AMENDED APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E)

The Amended Application of San Diego Gas & Electric Company ("SDG&E") for a Adoption of an Advanced Metering Infrastructure Deployment Scenario and Associated Cost Recovery and Rate Design ("Application") filed with the California Public Utilities Commission (the "Commission") on March 30, 2005, is available to all interested parties and to the public. Consistent with Rule 2.3(c) of the Commission's Rules of Practice and Procedure, SDG&E is issuing this Notice of Availability of the above-referenced application. Because the **AMENDED APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E)** and its related attachments exceed 75 pages in length, this Notice of Availability is being served on all parties in R.02-06-001. Any recipient of this Notice of Availability may request a copy of the above document.

SDG&E is filing this Amended Application pursuant to Administrative Law Judge and Assigned Commissioner's Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure ("AMI"), date July 21, 2004, as amplified and amended by the Assigned Commissioner and Administrative Law Judge's Ruling, dated November 24, 2004.

SDG&E includes the following appendices to its Amended Application pursuant to the Commission's Rules of Practice and Procedure:

Attachment A SDG&E's Gas and Electric Rates

Attachment B SDG&E's Balance Sheet

Attachment C	SDG&E's Summary of Earnings
Attachment D	SDG&E's Original Cost and Depreciation Reserve
Attachment E	SDG&E's Rule 24 Service List

SDG&E includes the following testimony to support its application:

Chapter 1: Business Vision and Policy

William Reed, Senior Vice President, Regulatory Strategy and Planning, recommends that the Commission authorize aggressive wide scale deployment of AMI in SDG&E's service territory. Mr. Reed explains that SDG&E continues to be a strong proponent of, and leader in, integrating AMI, dynamic rates and demand response efforts and believes that AMI will revolutionize the utility industry. Mr. Reed also explains that the Commission must concurrently adopt dynamic rates so that the benefits of AMI and demand response can be fully realized.

Chapter 2: Demand Response and Dynamic Pricing Long-term Vision and Policy Implications

Edward Fong, Director of Measurement and Advanced Metering Infrastructure, provides the rationale supporting SDG&E's preference for full AMI deployment, including discussion of the varied demand response benefits that will accrue from AMI. Mr. Fong adds further background and actions that support SDG&E's management philosophy and AMI vision. In addition, Mr. Fong proposes several "off-ramps" in the event that dynamic rates are not implemented, associated demand response anticipated operational benefits do not materialize, or actual benefits vary from those expected.

Chapter 3: Pre-deployment Plan and Sequencing

Patrick Charles, Manager of Planning and Analysis, Electric Measurement and AMI Department, describes the AMI pre-deployment plan, the overall full and partial deployment plans and sequences, as well as pre-deployment costs and benefits, exclusive of information technology (IT) related costs and benefits.

Chapter 4: Information Technology System

Richard Caursa, Manager of the IT Customer Care Department, describes the pre-deployment costs and benefits for IT systems that would be realized with both the full and partial deployment scenarios of AMI.

Chapter 5: Pre-Deployment Cost Recovery Mechanism

Johannes Van Lierop, Director of Regulatory Policy and Analysis, presents SDG&E's interim cost recovery proposal for the period 2005-2007. SDG&E proposes creating new balancing accounts to record AMI costs and benefits and AMI-related revenues for annual true-up.

Chapter 6: Methodology Used to Determine the Discounted Cash Flow

Edward Fong describes SDG&E's use of a discounted cash flow process for evaluating the incremental operational costs and benefits of the full and partial AMI roll-out scenarios.

Chapter 7: Project Management, Human Resources and Load Research

Patrick Charles describes the costs and benefits associated with overall AMI project management, human resources and load research areas that SDG&E anticipates with the deployment of an AMI system.

Chapter 8: Functional Requirements of the Communications Network & Electric Meters

Paul Pruschki, Manager of Measurement Data Communications, Electric Measurement & Advanced Metering Infrastructure Department, describes the estimated costs and benefits associated with the communication system and electric meters, and describes the AMI Communication system architecture that SDG&E would deploy with AMI.

Chapter 9: Gas Meters/Modules Electric and Gas Meter Installation, Claims, Facilities and Customer Services Field Department ("CSF")

Ted Reguly, Director of Customer Service Field South Inland Region in the CSF, describes the incremental operational costs and benefits associated with the gas and electric meter installation, gas meters, gas modules, CSF, claims and facilities.

Chapter 10: Customer Contact Center, Demand Response Programs and Enabling Technologies

Edward Fong describes the costs and benefits of AMI associated with the Customer Contact Center, demand response programs and enabling technologies.

Chapter 11: Meter Reading, Safety, Billing and Meter Revenue Protection

James Teeter, Billing Manager, Customer Billing Operations Department, describes the costs and benefits of AMI associated with the meter reading, safety, billing and meter revenue protection.

Chapter 12: Customer Communications and Education

Patricia Wagner, Director of Mass Markets, Customer Services Department, describes the costs and benefits of SDG&E's efforts targeting customer communications, education and feedback for the AMI program and dynamic rates.

Chapter 13: Demand Response

Dr. Stephen George of Charles River Associates discusses the estimated demand response impacts and benefits SDG&E believes will be derived from AMI deployment and dynamic rates, and the basic methodology SDG&E used to derive these values.

Chapter 14: Cost and Benefits to Electric Transmission and Distribution Systems

Neil Boyle, Manager of Electric Reliability and Distribution Planning, Transmission and Distribution Planning Department, describes the transmission and distribution benefits of implementing AMI.

Chapter 15: Overhead Labor Loaders

Scott Kyle, Manager of Affiliate Billing and Costing, describes the subset of overhead rates that were included in the costs/benefits modeling of the AMI business case analysis.

Chapter 16: Revenue Requirement, Rate Design and Bill Impacts

Johannes Van Lierop identifies the forecasted revenue requirement that reflects the pre-deployment and incremental operating costs through 2007, to be recovered by the mechanism as shown in Chapter 5. Witness Van Lierop also describes the gas and electric customer bill impact analysis.

A copy of the above document will be provided immediately upon the request of the party receiving this notice. All requests should be directed to:

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An electronic version of the above document can also be found at URL:

http://www.sdge.com/regulatory/tariff/cpuc_openProceedings.shtml

Dated at San Diego, California this 30th day of March, 2005.

Respectfully Submitted,

By: _____
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