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
Exhibit No: ______________

CHAPTER 2
AMI BUSINESS VISION, POLICY AND METHODOLOGY

JULY 14, 2006 AMENDMENT

Prepared Supplemental, Consolidating, Superseding and Replacement Testimony of EDWARD FONG

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

JULY 14, 2006

Material changes to this testimony can be found on pages: 1,2,3,4,5,17,18,19,20, and 23

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EDWARD FONG

SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

The purpose of my *amended* testimony is to supplement my testimony and correct several errata identified in my March 28, 2006 testimony (Chapter 2) in which I presented a summary of San Diego Gas & Electric's (SDG&E) business case for requesting California Public Utilities Commission (CPUC) authorization for deploying an advanced metering infrastructure (AMI). Since the March 28, 2006 service of testimony, events have occurred that render material changes to the underlying demand response assumptions of SDG&E's AMI business case. Specifically, an updated demand response impact analysis was necessary to incorporate (1) the revised demand price elasticities in the Statewide Pricing Pilot Program (SPP) for small and medium commercial and industrial customers as discussed in Dr. George's testimony (Chapter 6); (2) a correction in SDG&E's residential demand impact that used the incorrect on-peak time period; and (3) the Commission decision (D.06-05-038) in the Critical Peak Pricing proceeding which rejected the proposed Summer 2007 CPP settlement and which was the basis for the underlying assumptions of the illustrative rate presented in Mr. Hansen's testimony (Chapter 14).

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Dr. George has corrected the residential demand elasticities in which the March 28, 2006 filing incorrectly used residential demand elasticities that reflected weather conditions for a 2-7 PM peak period when SDG&E's peak period for the proposed peak time rebate (PTR) program is actually 11 AM – 6 PM. In addition, this amended testimony includes the results of the corrected summary tables presented in my March 28, 2006 testimony. The tables submitted in this errata and supplemental testimony replace the tables included in my March 28, 2006 testimony in their entirety.

The summary tables included herein reflect the updated demand response impacts and benefits resulting from the recently issued report on the revised price demand elasticities for commercial and industrial (C&I) customers.[1] These updated price demand elasticities and demand response impacts are the most current results from the recently issued Statewide Pricing Pilot (SPP) study of critical peak pricing (CPP) impacts on C&I customers with less 200 kW of peak demand and the corrected residential customer elasticities for the PTR program. The updated testimony of Mr.Gaines (Chapter 5) and Dr. George (Chapter 6) discuss SDG&E's updated C&I demand response impacts and benefits in greater detail. Mr. Gaines also addresses SDG&E's proposed illustrative CPP rate for C&I customers and the associated enabling technology proposal for deployment of programmable communicating thermostats (PCTs). Dr. George converts SDG&E's C&I CPP and enabling technology proposal into the demand response impacts and benefits.

The updated C&I CPP rate assumptions are aligned with SDG&E's AMI meter deployment schedule (discussed by Mr. Reguly and Mr. Charles, Chapters 8 and 9). Small and medium C&I customers in the 20-200 kW range will have the opportunity to have programmable communicating thermostats (PCTs) installed at no charge. These PCTs will automatically provide demand response during critical peak events. Mr. Gaines has included in his updated supplemental testimony, a proposal for approximately 57,000 programmable communicating thermostats (PCTs) for small and medium C&I customers.[2] In addition, due to the assumed revisions of Title 24 standards that would require any new construction or renovation to install PCTs, SDG&E would add approximately 150,000 PCTs by 2035. The costs for the PCTs are included in Mr. Pruschki's testimony (Chapter 11).

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[1] Working Group 3, "California Statewide Pricing Pilot: Commercial & Industrial Analysis Update", Stephen George (Freeman, Sullivan & Co.), Ahmad Faruqui and John Winfield (CRA International), June 28, 2006.

[2] SDG&E small C&I customers are < 20 kW and medium customers are 20-200 kW. SDG&E has approximately 105,000 meters in the small C&I customer range and approximately15,000 meters in the medium C&I customer 20-200 kW range.

Attached in Figure EF-1 below, is a timeline representing the SDG&E's various customer classes and the assumed timing of their transition to the assumed associated dynamic rates as used in Dr. George's demand response impacts and benefits (Chapter 6).

Table SSG-6-1 (Figure EF-1)
Rate and Program Options

Customer Segment	**2008**	**2009**	**2010**	**2011**
Residential	Tiered rate	Tiered rate with PTR available to all with AMI meter	Tiered rate with PTR available to all with AMI meter	Tiered rate with PTR available to all
Small C&I (<20 kW)	Flat rate	Default TOU with PTR or Vol CPP available to all with AMI meter	Default TOU with PTR or Vol CPP available to all with AMI meter	Default TOU with PTR or Vol CPP available to all
Medium C&I (20-200 kW)	Default TOU or voluntary CPP	Default CPP with CRC or opt-out to TOU for all with AMI meter	Default CPP with CRC or opt-out to TOU for all with AMI meter	Default CPP with CRC option
Large C&I (>200 kW)	Default CPP with bill protection or voluntary TDR	Default CPP with CRC option	Default CPP with CRC option	Default CPP with CRC option

The major errata items that are identified and corrected in my summary tables are extracted from the errata filing contained in Mr. Calabrese's testimony (Chapter 15). Mr. Calabrese has reclassified several items that were incorrectly classified as O&M or capital. Because of the capital and O&M expense reclassifications, Mr. Charles (Chapter 9) and Mr. Pruschki's (Chapter 11) testimonies include updated errata corrections in their capital and O&M expenses. In addition, Mr. Calabrese corrects an error in the tax treatment of software development expenses. These accounting corrections in effecting revenue requirement calculations and the changes in demand response impacts and benefits lead to a $3.7 million net decrease in SDG&E's March 28, 2006 net present value of revenue requirement result (from $63.7 million to $60.0 million) as shown in Mr. Kyle's testimony (Chapter 13). The updated NPV of revenue requirements is $60.0 million. Mr. Calabrese completes a revenue requirement calculation that incorporates these changes.

Left unchanged from my March 28th testimony (except for errata and SDG&E's C&I CPP proposal and updated tables) are my summaries of SDG&E's (1) management philosophy and business vision regarding AMI and demand response, (2) AMI related demand response impacts and benefits, (3) proposed and illustrative dynamic rate options (4) expected AMI operational benefits, (5) business case analytical methodology, financial modeling assumptions and economic analysis, and (6) net benefits, including net societal and revenue requirement impacts. This testimony consolidates, supersedes, and replaces all previous direct and supplemental testimony filed by me or by any other SDG&E witness testifying in this docket, on the topics covered herein.

SDG&E's AMI business case is summarized in Table EF 2-1 below which reflects net present value calculations from a societal (discounted cash flow) perspective and a ratepayer (revenue requirements) perspective.

Table EF 2-1
Present Value (2006$) of Benefits and Costs
($ millions)

	Operational Benefits		**Demand Resposne Benefits**			**Costs**			
	O&M, Capital	Theft	Demand Response	Other Demand Response Related	Total Benefits	O&M	Capital	Total Costs	**Net Benefits**
Societal	341	69	116	235	762	197	439	635	127
Revenue Requirements	370	69	108	235	783	192	527	719	64

II.

	Operational Benefits		**Demand Response Benefits**			**Costs**			
	O&M, Capital	Theft	Avoided DRPs + Net T&D Benefits	Avoided Capacity and Energy	Total Benefits	O&M	Capital	Total Costs	**Net Benefits**
Societal	336	69	113	262	780	215	456	671	110
Revenue Requirements	362	69	108	262	801	212	530	741	60

II. BACKGROUND

A. SDG&E's supplemental filing is the culmination of a comprehensive, extensive and lengthy statewide proceeding and process on Advanced Metering Infrastructure, Dynamic Rates and Demand Response, R.02-06-001.

SDG&E, Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), the CPUC, the California Energy Commission (CEC), the Governor's office, Division of Ratepayer Advocates (DRA), various consumer groups, industry organizations and AMI technology vendors have actively participated in R.02-06-001, the CPUC's rulemaking to consider advanced metering. The almost three years of lively policy discussion, debate and comprehensive analysis of the Statewide Pricing Pilot (SPP) has provided a solid foundation for California utilities to propose AMI deployment on a wide scale.

The rulemaking also established three working groups. Working Group 1, lead by CPUC President Peevey, CEC Commissioner Rosenfeld and California Power Authority Director McPeak, established overall policy and direction regarding AMI, demand response and dynamic pricing and provided overall guidance to the other two working groups. Working Group 2 focused on demand response programs for large commercial and industrial (C&I) customers ($\geq$ 200kW). Working Group 3 (WG3) focused on AMI and demand response for small customers (residential and small/medium C&I < 200 kW).

WG3 also issued a series of analytical reports on the SPP program conducted in 2003-04. This wide ranging experimental study of dynamic pricing and demand response covered almost 2,500 customers statewide with some 1,500 customers exposed to various dynamic rate treatments.

In response to the 2003-04 SPP program, the Commission issued a Joint Assigned Commissioner and Administrative Law Judge ruling (ACR) ordering the three California electric utilities to submit business case proposals for deploying AMI. The CPUC ordered the three utilities to file their preliminary analyses in October 2004 and January 2005. Specifically the utilities were ordered to file applications requesting authorization to deploy AMI, if justified by their business case analyses, in March 2005.

SDG&E submits this amended testimony to update its estimates of AMI costs and benefits and to revise various prior assumptions in its March 2005 showing.

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B. The Commission direction and statewide energy policy and goals as articulated in Energy Action Plan II (EAPII) clearly state a preference in the loading order for energy efficiency and demand response.

EAPII, Section II, Item 2 states the following regarding demand response:[3]

2. Demand Response

California is in the process of transforming its electric utility distribution network from a system using 1960s era technology to an intelligent, integrated network system that is focused on information technology.

[3] Energy Action Plan II, Implementation Roadmap for Energy Policies, State of California, Energy Resources Conservation and Development Commission and Public Utilities Commission, June 8 2005.

This transformation can decrease the costs of operating and maintaining the system and also provide end-use customers with accurate information on energy use and cost. With the implementation of well-designed dynamic pricing tariffs, California can lower consumer costs and increase system reliability. In order to achieve this transformation, the agencies will increase the emphasis on ensuring that appropriate, cost-effective technologies are chosen, on public education regarding the benefits of such technologies, and on developing tariffs and programs that result in cost-effective savings.

KEY ACTIONS:

1. Issue decisions on the proposals for statewide installation of advanced metering infrastructure for all small commercial and residential IOU customers by early 2006.
2. Adopt, as appropriate, dynamic pricing tariffs for summer 2006, particularly critical peak pricing tariffs for customers with advanced metering systems.
3. Educate Californians about the time sensitivity of energy use and the benefits and effects of dynamic pricing tariffs.
4. Create standardized mechanisms to measure and evaluate demand response to ensure savings are verifiable.
5. Integrate demand response into the IOUs' procurement efforts and California's planning protocols.
6. Facilitate market designs that provide a "level playing field" for demand response opportunities."

C. SDG&E believes that AMI and demand response provides the state and the utility with important future options and flexibility to address potential demand and supply imbalances.

Even if wide scale dynamic pricing and demand response programs are not feasible or needed in the immediate future, AMI provides a foundational technology and infrastructure that will provide state policy and decision makers with the flexibility to adopt a variety of demand response programs. Mass market demand response options were not available during the 2000-01 energy crisis because the metering and communications systems were not available to measure specific peak demand on a customer specific basis. The ability to measure customer specific electric usage during peak demand periods will provide policy and decision makers the ability to more effectively target and design demand response programs. Sufficient levels of demand response could enhance overall system reliability and may, therefore, mitigate the extent, frequency, and duration of rolling blackouts.

D. SDG&E completed a preliminary analysis and business case in March 2005 (A.05-03-015).

The preliminary costs and benefits analysis submitted in A.05-03-015 reflected SDG&E's best estimate of AMI implementation and "going forward" operating costs from market data and internal cost benchmarks. At that time, however, SDG&E had not conducted a comprehensive request for proposal (RFP) process for AMI technologies, installation, systems development and integration. Moreover, the results from the SPP were not finalized until the same month SDG&E filed A.05-03-015 March 2005. SDG&E completed the March 2005 analysis on a best efforts basis with the best information available at that time. The demand response impacts and benefits were calculated with the same dynamic rate structures as used in the SPP (i.e. Critical Peak Pricing-Fixed) and market participation default rates were comparable to results from the Momentum Market Intelligence studies.[4]

E. In August, 2005, SDG&E received authorization for $9.3 million of AMI pre-deployment funding to conduct a request-for-proposal and evaluation process to implement AMI.[5]

Mr. Charles' testimony (Chapter 9) describes the overall AMI project management structure and associated costs. My amended testimony and the updated costs and benefits described in associated chapters (Chapters 3, 4, 5, 8, 9, 10, 11 and 12) present an update of operational costs and benefits that reflect the results from SDG&E's AMI RFP process. Of note, SDG&E's updated operational benefits for meter reading, billing, and customer services field activities are contained in Mr. Teeter's testimony (Chapter 3). In addition, Mr. Teeter discusses the reductions expected in energy theft, and the reductions expected in employee safety incidents. Moreover, Mr. Gaines' (Chapter 5) and Dr. George's (Chapter 6) testimonies provide significant revisions to the dynamic rate assumptions that are compatible with the current constraints of the State's electric rate environment and the associated demand response impacts and benefits of such dynamic rates. The proposed demand response program presented in Mr. Gaines' testimony is only possible with the deployment of AMI on a wide scale.

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[4] *See*, Impact Evaluation of the California Statewide Pricing Pilot – Final Report, March 16, 2005; Customer Preference Market Research (CPMR) – C&I, Momentum Market Intelligence (MMI), Research Conducted May to July 2004; and CPMR – Residential, MMI, Research Conducted December 2003.

[5] AMI Pre-deployment funding was authorized for SDG&E in D.05-08-018.

F. SDG&E is proposing a full deployment of AMI within our service territory following an approach that incorporates several risk management strategies.

SDG&E is requesting approval and authorization to deploy AMI technology for all SDG&E electric and gas customers (except those Direct Access and non-core gas customers who already own their meter[6]). Therefore, by 2011, SDG&E expects to deploy an AMI system encompassing approximately 1.4 million electric and 900,000 gas modules / meters, and a supporting communication network.

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SDG&E recognizes that deployment of technology on the scale and complexity of AMI has inherent risks. Mr. Reguly and Mr. Charles address SDG&E's risk mitigation practices related to the overall AMI project in Chapters 8 and 9. The financial analysis for the AMI business case incorporates both additional risk mitigation activities and overall AMI deployment financial contingencies. Mr. Reguly describes the categorization of foreseeable and unforeseeable risks and also addresses risks pertaining to advances in technology or changes in market product offerings. Mr. Charles discusses elements of reducible and irreducible risks. In addition, Mr. Reguly and Mr. Charles describe the possible circumstances that may lead SDG&E to issue an addendum to the AMI RFP (or a completely new RFP) to evaluate such new technologies or market developments.

[6] In the SDG&E service territory, there are currently less than 400 electric meters and 120 gas meters associated with non-utility owned meters.

III. SDG&E AMI BUSINESS VISION AND POLICY

A. AMI provides long-term benefits.

1. AMI is an integral component of SDG&E's longer term operating vision.

SDG&E believes that over the next 10-15 years, significant advances will occur in the deployment of a smart grid. Ms. Welch's (Chapter 10), Mr. Lee's (Chapter 4) and Mr. Pruschki's (Chapter 11) testimonies identify specific elements of SDG&E's longer term operating vision and infrastructure architecture as it pertains to their subject areas.

2. AMI provides operational benefits and streamlines many customer processes.

Implementation of AMI will streamline the daily cycle meter reading process and will provide daily reads for all gas and electric meters. Specifically, AMI will reduce or eliminate the need for "change of account" type reads (customer turn-on and closes). In addition, AMI reads will provide greater billing accuracy and timeliness. Mr. Teeter's (Chapter 3) testimony provides a more detailed analysis of the operational benefits AMI will bring to meter reading, customer services, and collections.

3. SDG&E includes reduced energy theft as a benefit.

SDG&E includes an estimate for reduced energy theft and unmeasured, unbilled customer energy usage as benefits. Eliminating or reducing energy theft results in a direct benefit to paying and law abiding customers. By identifying customers who steal energy or by introducing technology that detects meter tampering, SDG&E will ultimately reduce rates to the overall paying customer base. The current rate components for Unaccounted for Energy (UFE) and Lost and Unaccounted For (LUAF) for electricity and natural gas, respectively, include costs that are imposed on all bill paying customers for energy theft by others. Mr. Teeter provides an estimate for reduced energy theft in his testimony.

4. AMI provides a foundational technology to enable demand response and new dynamic rate designs.

AMI interval meters and frequency of daily reads or on-demand reads are a foundation for implementing dynamic rates. As described in the CPUC's and CEC's six policy goals,[7] the ability to measure and store customer electric usage on an hourly or fifteen minute interval basis is essential for billing dynamic rates. Without dynamic rates and measurement of usage during high price periods, price demand response on an individual customer basis becomes a theoretical exercise. Multiple part dynamic rates or critical peak pricing structures require measurement of customer usage during high price periods for proper and accurate billing and will allow for measurement of the individual customer price demand response impact.

5. AMI provides additional but difficult to quantify benefits, e.g., environmental and increased overall electric reliability.

SDG&E recognizes that significant, but difficult to quantify, benefits exist as result of price demand response and emergency interruptible programs. Emergency interruptible programs rely on customer compliance to reduce usage when reliability or emergency events are initiated. The Statewide Pricing Pilot (SPP), the cornerstone of R.02-06-001 Working Group 3 experiments, clearly demonstrates demand reductions during CPP periods and that, on net, overall daily electric usage remained the same or declined.[8] SDG&E has not included or attempted to quantify environmental benefits (reduced emissions and green house gases) that would result from system peak period reductions and reductions in daily usage.

Several difficult to quantify customer and utility operational process benefits are described below but are not included in SDG&E's benefit estimates. These benefits include:

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[7] As articulated / detailed in the 'Joint Assigned Commissioner and ALJ's ruling Providing guidance for the Advanced Metering Infrastructure Business Case Analysis' of February 19, 2004.

[8] See Charles River Associates' report of March 16, 2005 titled: "Impact Evaluation of the California Statewide Pricing Pilot"; available on the CEC website at: http://www.energy.ca.gov/demandresponse/documents/group3_final_reports/2005-03-24_SPP_FINAL_REP.PDF

a. AMI provides more accurate and timely meter reads, thereby, potentially increasing customer satisfaction.

b. AMI provides the opportunity for operational redesign of work processes as meter read information is available sooner. For example, AMI may facilitate early detection of slow gas leaks or malfunctioning meters through early detection via new algorithms designed to detect abnormal use within days.

c. AMI provides more opportunity for optional rate structures and billing service offerings.

d. AMI provides more frequent and accurate interval customer specific energy usage data, thereby providing greater geographical precision of load forecast. Demand response programs, distribution capital expenditures and customer education campaigns can be better targeted to specific customers.

B. AMI is consistent with and enhances SDG&E's long standing advocacy of innovative demand response programs.

1. SDG&E was the first utility to introduce and implement default 3-period time-of-use (TOU) pricing for C&I customers in the late 1980's.

SDG&E was the first major electric utility to institute a default 3-period TOU rate for Commercial and Industrial (C&I) customers. SDG&E requires C&I customers with demand as low as 20 kW to be on a default 3-period TOU rate. Some 22,000 C&I customer accounts (meters) are currently on the 3-period AL-TOU rate.

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2. SDG&E was the first utility to propose an hourly pricing option (HPO) for large C&I customers.

During the midst of the 2001 energy crisis, SDG&E was the first and only California utility to propose and submit to the Commission for authorization of an hourly pricing option for large C&I customers (>100 kW). The HPO rate used a proxy day ahead hourly price that represented the C&I hourly load profile to mimic market prices. Even though a robust and transparent hourly market price did not exist in the California market in 2003-04, SDG&E's

attempt to experiment with dynamic prices of various forms for C&I customers demonstrates SDG&E's support of and advocacy for dynamic pricing options.

3. SDG&E was an advocate and supporter of implementing real-time meters for C&I customers.

SDG&E was the first California electric utility to request authorization to implement real-time energy meters (RTEM). SDG&E filed application A.00-07-055 to request such meters for large Commercial and Industrial (C&I) customers (> 100 kW) in July 2000.

In 2001, SDG&E also worked with the Governor's office and the CEC to develop legislative language in AB29X for state funding of interval meters and communications for large C&I customers. Some $35 million of funding was made available to California electric utilities and certain electric municipalities in 2001 for interval meters with communications.

4. SDG&E has implemented several new direct load control programs involving small C&I customers and as well residential customers through third party providers.

SDG&E proposed and implemented an air conditioning (AC) cycling program for small C&I customers that provides performance awards for the third party AC cycle control provider. SDG&E implemented the first residential smart thermostat (programmable and communicating thermostats) beginning in 2001. SDG&E strives to be a leader in supporting enabling demand response technologies with customer pilot programs and continues to evaluate and assess emerging demand response technologies and the market position of such technologies. SDG&E continues to support offering both technical assistance and technology incentives for C&I customers that provide additional demand response capabilities.

C. AMI provides customers greater control over their energy use and enables them to better manage demand when overall supply and demand conditions are tight.

AMI is an essential tool that provides customer energy usage information so that customers can better manage their energy consumption. The measurement, recording, and access to hourly interval data will provide customers a broader and more detailed view of their energy usage patterns. If appropriate dynamic price signals are transparent and provided with sufficient lead time, then customers have the ability to adjust their demand accordingly. Customers have the potential to avoid high price periods (or receive 'rebates' in the case of a modified two part dynamic rate as is detailed in Mr. Gaines' testimony (Chapter 5) if customers know how much usage typically occurs during such periods and, accordingly, can institute behavioral changes or install enabling demand response technologies to reduce demand.

D. AMI provides increased overall safety for customers and employees.

Because meter readers will no longer visit each and every customer premise, a host of meter reading injuries will be avoided. The meter reading classification experiences the highest OSHA recordable rate of any job classification (e.g., from dog bites, knee and ankle injuries, etc.). Moreover, AMI will enhance SDG&E's ability to verify outage restoration or outage identification at the specific customer premise. Increased electric reliability results in a much safer customer environment.

E. SDG&E has adopted a no lay-off policy for SDG&E employees affected by AMI implementation.

SDG&E anticipates normal attrition and proper management of job opportunities for areas of expected reductions to facilitate its commitment to a zero layoff policy regarding AMI deployment. Meter readers and other potential employees impacted by the deployment and installation of an AMI system will have an opportunity to be reassigned to new positions or be trained for other positions. Mr. Teeter (Chapter 3) addresses the estimated reductions in workforce in his testimony.

SDG&E reached an agreement with the local labor union (Local 465 IBEW). Both SDG&E and the labor union anticipate high volumes of work that must be outsourced with contract labor. The installation vendor will partner with Local 465 to provide contract labor. In Chapter 8, Mr. Reguly, and in chapter 12, Mr. Carranza, provide more detail regarding contract labor and union negotiations.

IV. SUMMARY OF THE BUSINESS CASE

A. The planning horizon for the business case analysis begins with 2007 AMI expenditures and terminates in 2038 to include one complete cycle of the AMI electric meter, gas module and communications equipment replacement.[9]

SDG&E's business case analysis reflects the following:

1. Initial deployment costs reflect meter system growth from 2008-2010. AMI meters from customer growth as well as equipment and labor costs for replacement of failed meters during 2011-2038 are also included in the cost benefit analysis.
2. As detailed in Mr. Kyle's testimony (Chapter 13) all dollar values in the case are reflected in 2006 dollars.
3. As further detailed in Mr. Kyle's testimony (Chapter 13), the analysis period of 2007-2038 incorporates at least one replacement cycle for major plant equipment expenditures during the initial deployment phase between 2008-2010 (i.e., electric meters, gas modules, communications equipment, and information systems).
4. Table EF 2-2, below, maps the various cost and benefits described in this section to the supporting respective witness testimony chapters.

[9] In Chapter 13, Mr. Kyle more fully describes SDG&E's rationale regarding the analysis period. Also note that 2005 and 2006 costs are covered in SDG&E's 'pre-deployment' period as approved by D.05-08-018.

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Deleted: AMI O&M and Capital Costs and Benefits by Chapter¶

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Chapter Number	Description	Witness	O&M Cost	Capital Costs	Total Costs	O&M Benefit	Capital Benefit	Oth	
5	Marketing, Load Research, Demand Response Programs, CCC	Gaines	$ 24	-	**$ 24**	$ 102	$ 8	-	**$ 110**
6	Avoided Capacity and Energy	George	-	-	-	-	-	$235	**$ 235**
10	Information Technology Systems	Welch	$ 93	$ 64	**$ 156**	$ 6	$ 2	-	**$ 7**
11	Communication System and Electric Meters	Pruschki	$ 38	$ 185	**$ 223**	-	$ 18	-	**$ 18**
12	Gas Meters and Modules, Gas & Electric Meter Installation, Gas Maintenance Materials	Carranza	$ 17	$ 119	**$ 136**	$ 3	$ 2	-	**$ 5**
12	Billing, Meter Reading, CSF Benefits	Teeter	$ 13	-	**$ 13**	$ 350	$ 4	-	**$ 354**
14	T&D	Lee	-	-	-	$ 10	$ 22	-	**$ 32**
16	AMI Proj Mgmt, Contingency, HR & Facilities	Charles	$ 12	$ 71	**$ 83**	-	-	-	**-**
	Total		**$ 197**	**$ 439**	**$ 635**	**$ 471**	**$ 55**	**$ 235**	**$ 762**

Table EF 2-2

AMI O&M and Capital Costs and Benefits by Chapter

Loaded, Escalated, Present Value, Dollars in Millions

Chapter Number	Description	Witness	O&M Cost	Capital Costs	Total Costs	O&M Benefit	Capital Benefit	Other	Total Benefits
3	Billing, Meter Reading, CSF Benefits	Teeter	$13	$ -	**$13**	$350	$4	$ -	**$354**
4	T&D	Lee	$ -		**$ -**	$6	$18	$ -	**$24**
5	Research, Demand Response Programs, CCC	Gaines	$28	$ -	**$28**	$102	$8	$ -	**$110**
6	Avoided Capacity and	George	$ -	$ -	**$0**	$ -	$ -	$262	**$262**
9	Contingency, HR & Facilities	Charles	$21	$62	**$82**	$ -	$ -	$ -	**$ -**
10	Information Technology Systems	Welch	$93	$64	**$156**	$6	$2	$ -	**$7**
11	Communication System and Electric Meters	Pruschki	$44	$196	**$239**	$ -	$18	$ -	**$18**
12	Gas Meters and Modules, Gas & Electric Meter Installation, Gas Maintenance Materials	Carranza	$17	$134	**$151**	$3	$2	$ -	**$5**
	Total		**$215**	**$456**	**$671**	**$468**	**$51**	**$262**	**$780**

B. Operational costs and benefits have been updated to reflect the results from SDG&E's RFP process.

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Table EF 2-3, below represents the present value of AMI cost and benefit cash flows. In addition, the present value of costs and benefits from a revenue requirements perspective and other rate impacts are included. Note that the major difference between a societal perspective versus a revenue requirements perspective is the treatment of capital expenditures. See Mr. Calabrese's testimony (Chapter 15) for greater detail regarding the annual revenue requirements forecast.

Table EF 2-3

Cash Flow and Revenue Requirement Summary

Loaded, Escalated, Present Value, Dollars

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($Millions

Cash Flow (societal perspective)					
Costs	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 439	$ 329	$ 48	$ 40	$ 22
O&M	$ 197	$ 47	$ 95	$ 17	$ 38
Total Costs	**$ 635**	**$ 376**	**$ 143**	**$ 58**	**$ 59**
Benefits	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 36	$ 9	$ 19	$ 2	$ 6
O&M	$ 374	$ 28	$ 208	$ 35	$ 104
Avoided Capacity/Energy	$ 235	$ 22	$ 148	$ 19	$ 46
DR Related Benefits*	$ 116	$ 17	$ 69	$ 9	$ 22
Total Benefits	**$ 762**	**$ 75**	**$ 444**	**$ 64**	**$ 179**
NPV of Benefits	**$ 127**	**$ (301)**	**$ 301**	**$ 7**	**$ 120**
*Transmission Deferrals ($18.9) / Avoided Programs ($97.6)					
Revenue Requirement (ratepayer perspective)					
Costs	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 527	$ 118	$ 332	$ 23	$ 54
O&M	$ 192	$ 46	$ 92	$ 17	$ 37
Total Costs	**$ 719**	**$ 164**	**$ 425**	**$ 40**	**$ 91**
Benefits	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 62	$ 5	$ 40	$ 6	$ 11
O&M	$ 308	$ 21	$ 172	$ 29	$ 86
Avoided Capacity/Energy	$ 235	$ 22	$ 148	$ 19	$ 46
Avoided /Reduced Theft	$ 69	$ 7	$ 38	$ 6	$ 18
Transmission Deferral	$ 11	$ -	$ 14	$ (1)	$ (2)
Avoided Programs	$ 98	$ 11	$ 56	$ 8	$ 22
Total Benefits	**$ 783**	**$ 66**	**$ 468**	**$ 67**	**$ 183**
NPV of Benefits	**$ 64**	**$ (98)**	**$ 44**	**$ 26**	**$ 92**

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Cash Flow (societal perspective)					
Costs	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 456	$ 327	$ 50	$ 59	$ 20
O&M	$ 215	$ 50	$ 106	$ 18	$ 41
Total Costs	**$ 671**	**$ 377**	**$ 156**	**$ 76**	**$ 60**
Benefits	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital Pure Op Benefits	$ 35	$ 9	$ 18	$ 2	$ 6
O&M Pure Op Benefits	$ 370	$ 28	$ 207	$ 34	$ 101
Avoided Capacity/Energy	$ 262	$ 22	$ 166	$ 22	$ 53
DR Related Benefits*	$ 113	$ 13	$ 70	$ 8	$ 22
Total Benefits	**$ 780**	**$ 72**	**$ 462**	**$ 65**	**$ 182**
NPV of Benefits	**$ 110**	**$ (306)**	**$ 305**	**$ (11)**	**$ 122**
*Transmission Deferrals ($18.9) / Avoided Programs ($97.6)					
Revenue Requirement (ratepayer perspective)					
Costs	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 530	$ 109	$ 326	$ 28	$ 66
O&M	$ 212	$ 50	$ 104	$ 17	$ 40
Total Costs	**$ 741**	**$ 160**	**$ 430**	**$ 46**	**$ 105**
Benefits	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 57	$ 4	$ 38	$ 5	$ 9
O&M	$ 304	$ 21	$ 171	$ 28	$ 84
Avoided Capacity/Energy	$ 262	$ 22	$ 166	$ 22	$ 53
Avoided /Reduced Theft	$ 69	$ 7	$ 38	$ 6	$ 18
Transmission Deferral	$ 11	$ -	$ 14	$ (1)	$ (2)
Avoided Programs	$ 98	$ 11	$ 56	$ 8	$ 22
Total Benefits	**$ 801**	**$ 65**	**$ 484**	**$ 67**	**$ 185**
NPV of Benefits	**$ 60**	**$ (95)**	**$ 53**	**$ 22**	**$ 80**

C. From the Societal Perspective, Operational benefits represent approximately 60% of the total SDG&E Costs (($35 + $370) / $671). From the Revenue Requirement Perspective, Operational benefits represent approximately 58% of the total SDG&E costs (($57 + $304 + $69) / $741).

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The majority of operational benefits are identified in Mr. Teeter's testimony (Chapter 3). Mr. Teeter discusses the following operational benefits:

1. AMI will deliver improved accuracy and timeliness of meter reads. The largest numbers of billing adjustments are due to meter reading errors. Reducing the volume of billing adjustments reduces the billing exception processing and billing work queue.

2. Most move-in/move-out services requiring a final or initial read of the meter can be performed remotely without delay for scheduling and dispatching a field visit.
3. SDG&E expects to achieve operational benefits from an anticipated decline in safety incidents associated with diminution in meter reading and customer services field personnel. AMI enables a less intrusive means of gathering meter readings to facilitate customer billings.
4. AMI will allow SDG&E to detect energy theft and tampering, meters stuck without movement and meters registering consumption use when in the "off" position. All customers benefit from this early energy theft detection because of the savings from the associated avoided costs.
5. Other operational benefits are detailed in Ms. Welch's testimony (Chapter 10), Mr. Carranza's testimony (Chapter 12) and Mr. Lee's testimony (Chapter 14).

D. Avoided capacity and energy benefits represent approximately 39% Societal (39% = $262/$671) or 35% Revenue Requirements (35%=$262/$741), while other benefits[10] represent approximately 17% Societal (17%=$113/$671) or 15% Revenue Requirements (15%= ($98+$11)/$741), of the total SDG&E costs.

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The demand response impacts (MW) and benefits are calculated using CRA's PRISM and CEM model. CRA's PRISM and CEM model reflects the elasticities and demand equations estimated from the Statewide Pricing Pilot (*see* Dr. George's testimony (Chapter 6)). By 2011 (the first year following the completion of AMI deployment), SDG&E customers are forecasted to provide 219 MW of demand response. Residential customers provide 105 MW of demand response by 2011. Small C&I (< 20 kW) customers provide 8 MW of demand response. Medium C&I (20-200 kW) customers provide 53 MW of demand response. Large C&I (≥ 200kW) provide 53 MW of demand response by 2011. *See* Dr. George's testimony (Chapter 6, Table SSG 6-6).

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[10] i.e. T&D deferrals and avoided program costs.

The value of avoided generation capacity is assumed to be $85 per kW year. Mr. Martin addresses the assumptions and discusses the rationale for the value of avoided generation capacity in Chapter 7. A voluntary Peak Time Rebate (PTR) program is assumed for residential customers. Specifically, all residential customers with AMI meters will be subject to their current tiered rate and have an opportunity to earn rebates for reducing their electricity demand during peak periods as detailed in Mr. Gaines' testimony (Chapter 5). As a result of Dr. George's analysis, SDG&E expects 105 MW of dynamic response from residential customers by 2011. This residential demand response will be achieved through a completely voluntary demand response program. This residential demand response of 105 MW represents an average 8% decrease over the peak hours of 11am – 6pm. Table SSG 6-3 (below) from Dr. Georges testimony's (Chapter 6) shows the present value of demand response benefits.

Table SSG 6-3
Present Value of Demand Response Benefits
(Millions of 2006 $)

Customer Segment	Capacity	Energy	Total	Segment Percent
Residential	$110.4	$12.8	$123.2	47%
Small C&I (<20 kW)	12.8	1.3	14.2	5
Medium C&I (20- 200 kW)	60.5	2.2	62.7	24
Large C&I (> 200 kW)	59.9	1.9	61.8	24
Total	$243.7	$18.3	$261.9	100%

A default CPP dynamic rate is assumed for all C&I customers that are at least 20 kW by 2009. Currently, most SDG&E C&I customers that have 20 kW demand or more are already on a 3-period TOU rate. Beginning in 2009, SDG&E proposes for small C&I customers whose demands are less than 20 kW a 3-period TOU rate. In addition, these small C&I customers (< 20 kW)

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will also have an optional or opportunity to take advantage of the Peak Time Rebate program similar to the one envisioned for residential customers.[11]

Transmission and distribution (T&D) benefits representing avoided and deferred capital expenditures as a result of demand response impacts are reflected in Mr. Lee's testimony (Chapter 4). Mr. Lee also discusses several T&D operational efficiency gains as a direct result of customer premise endpoint data from AMI meters. Reduction in the level of avoided program funding is discussed in Mr. Gaines' testimony (Chapter 5). Because of AMI and the proposed PTR program, SDG&E believes that the statewide demand response goals can be achieved with a lesser level of funding for demand response program outreach, recruitment, enrollment and administration activities.

E. SDG&E has modeled and calculated the AMI business case using a societal total resource cost (TRC) perspective and a revenue requirements perspective (see Table EF 2-3, above).

Deployment of AMI is viable under both perspectives, i.e., in both cases (societal and revenue requirements/ratepayer perspectives) the present value of the benefits are greater than the present value of the costs. SDG&E's benefits include operational cost reductions, avoided generation and avoided energy use, reduced energy theft (and other Unaccounted for Energy or UFE benefits), reduced need for on-going demand response programs and avoided transmission and distribution capital expenditures.

Table EF 2-1 above summarizes the net present value of costs and benefits from a societal perspective and a revenue requirements perspective.

[11] The default CPP dynamic rate was modeled in Dr. George's testimony beginning in 2011. If the default CPP were to be instituted sooner, then benefits would accrue sooner. See Mr. Gains' testimony (Chapter 5).

F. The estimated rate impacts from distribution revenue requirements, estimated reduction in unaccounted for energy, avoided generation capacity, reduction in demand response programs and avoided transmission capacity are shown in the attachments to Mr. Hansen's testimony (Chapter 14).

Table EF 2-3, below, depicts the present value of revenue requirement impacts (distribution cost of service, reduced unaccounted for energy, reduced demand response programs, avoided generation capacity and avoided transmission capacity). Table EF 2-4 shows the revenue requirement of costs and benefits by AMI deployment (2007-2010), first AMI technology life cycle (2011-2024), AMI replacement (2025-2027) and replacement cycle (2028-2038) periods.

Table EF 2-4

Present Value of Revenue Requirement
Loaded, Escalated, PV Dollars
($Millions

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Distribution Revenue Requirement (ratepayer perspective)					
Costs	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 527	$ 118	$ 332	$ 23	$ 54
O&M	$ 192	$ 46	$ 92	$ 17	$ 37
Total Costs	**$ 719**	**$ 164**	**$ 425**	**$ 40**	**$ 91**
Benefits	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 62	$ 5	$ 40	$ 6	$ 11
O&M	$ 308	$ 21	$ 172	$ 29	$ 86
Avoided Capacity/Energy	$ 235	$ 22	$ 148	$ 19	$ 46
Avoided /Reduced Theft	$ 69	$ 7	$ 38	$ 6	$ 18
Transmission Deferral	$ 11	$ -	$ 14	$ (1)	$ (2)
Avoided Programs	$ 98	$ 11	$ 56	$ 8	$ 22
Total Benefits	**$ 783**	**$ 66**	**$ 468**	**$ 67**	**$ 183**
NPV of Benefits	**$ 64**	**$ (98)**	**$ 44**	**$ 26**	**$ 92**

Revenue Requirement (ratepayer perspective)					
Costs	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 530	$ 109	$ 326	$ 28	$ 66
O&M	$ 212	$ 50	$ 104	$ 17	$ 40
Total Costs	**$ 741**	**$ 160**	**$ 430**	**$ 46**	**$ 105**
Benefits	**Total**	**2007-2010**	**2011-2024**	**2025-2027**	**2028-2038**
Capital	$ 57	$ 4	$ 38	$ 5	$ 9
O&M	$ 304	$ 21	$ 171	$ 28	$ 84
Avoided Capacity/Energy	$ 262	$ 22	$ 166	$ 22	$ 53
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Transmission Deferral	$ 11	$ -	$ 14	$ (1)	$ (2)
Avoided Programs	$ 98	$ 11	$ 56	$ 8	$ 22
Total Benefits	**$ 801**	**$ 65**	**$ 484**	**$ 67**	**$ 185**
NPV of Benefits	**$ 60**	**$ (95)**	**$ 53**	**$ 22**	**$ 80**

The AMI revenue requirements based net present value is approximately $60 million. SDG&E's business case assumes that AMI technology is replaced after the 17 years of expected service life, beginning in 2025. Because SDG&E included the costs of a replacement life cycle, SDG&E also forecasted the operational benefits and demand response benefits for the remaining replacement life cycle of the AMI technology.

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G. The AMI financial model to calculate the discounted cash flow of total societal benefits captures fully loaded costs and benefits, escalation (inflation) and at least one replacement life-cycle of all major assets deployed or installed during the initial AMI deployment phase, 2008-2010.

The application of labor and non-labor loaders is discussed in Mr. Kyle's testimony (Chapter 13). Some specific items or assets were excluded from standard escalation because the expected cost of replacement should remain the same or decrease during the planning horizon. Specifically, AMI technology, including AMI electric meters, gas modules, gas meters, AMI communication equipment, and computer servers are not subject to annual escalation for inflation.[12]

Costs and benefits from both the societal and revenue requirements/ ratepayer perspective include one complete replacement cycle of each of the major capital asset classes installed during the initial 2008-2010 deployment (i.e. new solid state electric meters, gas modules, AMI communications components, computer servers and information systems. *See* the testimony of Mr. Pruschki (Chapter 11), Mr. Carranza (Chapter 12) and Ms. Welch (Chapter 10), respectively, for further details).

H. Revenue requirements and subsequent rate impacts represent the total impact of cost of service distribution revenue requirements, avoided generation or energy revenue requirements (ERRA), demand response programs (refundable), FERC revenue requirements and unaccounted for energy (UFE).

Specific components of the distribution revenue requirements that reflect depreciation, taxes, interest cost and authorized return of AMI plant investment are described in Mr. Calabrese's testimony (Chapter 15). The distribution revenue requirements incorporate most of the operational benefits, on-going operational costs and the cost of the AMI plant over the planning horizon through 2038.

[12] Holding the silicon based technology costs constant is seen as a conservative assumption given Moore's Law, which has held steady for nearly 40 years.
See http://www.intel.com/technology/magazine/silicon/moores-law-0405.htm, and Mr. Kyle's Chapter 13 testimony for further details regarding this assumption.

In addition, benefits reflect avoided generation capacity and customer energy savings. These benefits result in reduced customer bills from reduced capacity requirements and energy use. Avoided generation capacity costs utilize an $85 per kW year value. SDG&E believes that the $85 per kW year most accurately reflects the value marginal generation capacity over the life of the planning period. See Mr. Martin's testimony (Chapter 7) for further details.

Reductions in energy theft (gas and electric) are also included in the overall customer impact analysis because the overall customer population benefits from reduced per unit energy costs as a result of reduced unaccounted for energy and unmeasured energy losses. Mr. Teeter (Chapter 3) reviews the underlying assumptions for calculating reductions in unaccounted for energy.

VI. DIRECT ACCESS (DA) METERING AND NON-CORE GAS METERING

A. All current DA customers with Energy Service Provider (ESP) metering will continue with their existing meters and will not have a new SDG&E AMI meter installed as part of the AMI deployment. As referenced above, the number of customers in this situation is a relatively small.

These DA customers will continue to receive the current DA Revenue Cycle Service (RCS) meter credit. Energy Service Providers (ESPs) will continue to have the option to move their customers to SDG&E AMI metering and have SDG&E act as their meter service provider (MSP) and meter data management agent (MDMA). As of March 23, 2006, of SDG&E's 6163 DA accounts, only 375 have non-SDG&E meters and 150 use someone other than SDG&E as their MDMA.

B. SDG&E proposes that all new DA customers from the time of their bundled service AMI meter installation date will have continuous service with SDG&E's AMI meter and meter services.

Under current DA rules, all DA customers of 50 kW demand or greater are required to have interval meters that record usage in 15 minute intervals. The DA customer's ESP is obligated to provide the interval meter, meter services and MDMA services. Since SDG&E will be installing AMI meters (interval meters with two-way communications) for all bundled service customers, any new DA customer (i.e., a bundled customer that becomes a new DA customer account) will have metering capabilities as envisioned when DA was instituted in 1998. The customer's ESP will continue to have the option to choose a third party MDMA or select SDG&E as the MDMA. SDG&E will continue to own, operate and maintain the AMI meter for new DA customers. If a new DA customer has an ESP that chooses a third party MDMA, then the customer will receive the RCS MDMA credit.

DA customers with SDG&E AMI meters will receive all of the capabilities and features of bundled customers under AMI. These capabilities and features are, but not limited to: (1) access to customer's previous day interval usage data via the Internet; (2) access to customer's historical interval usage data via the Internet; (3) on-premise information display monitors that integrate with the AMI system; (4) KYZ interfaces to third party energy management systems for customers that are greater than 100 kW; and (5) integration of load profile data with automated demand response technologies.

VI. COST RECOVERY AND OTHER ISSUES

A. Disposition and Recovery of Replaced Meters

SDG&E proposes to recover the remaining book value of the installed costs for existing meters consistent with current ratemaking treatment adopted by the Commission, using the normal straight-line remaining life depreciation method. SDG&E will recover the installed cost of the existing meters over the remaining life prior to implementation of AMI technology.

B. Cost Recovery and Balancing Account Treatment

SDG&E proposes specific cost recovery mechanisms in Mr. Hansen's testimony (Chapter 14). Through balancing account treatment of recorded AMI costs and estimated operational benefits, SDG&E proposes to offset AMI recorded costs with forecasted operational benefits. This accounting would be included in SDG&E's distribution revenue requirements.

C. SDG&E May Require Bridge Funding Beyond Year-end 2006

If the Commission is unable to render a final decision on SDG&E's AMI application for authorized funding before year-end 2006, SDG&E will file a request to extend pre-deployment funding through 2007. SDG&E will provide an estimate of carry-over funding to 2006 from the original $9.3 million of unspent pre-deployment funds (D.05-08-018) and necessary additional funding to continue with AMI technology field testing activities and IT systems development and integration design activities.

This concludes my testimony.

VII. QUALIFICATIONS OF EDWARD FONG

Mr. Fong is currently the Director of Customer Operations, Remittance Processing & Special Projects for San Diego Gas & Electric (SDG&E). He is responsible for directing, managing and planning the remittance processing, branch office operations and several special projects, including Advanced Metering Infrastructure (AMI) Regulatory Policy and Strategy for SDG&E. Prior to assuming his current position in October 2005, Mr. Fong was Director of AMI Regulatory Policy & Strategy and from 2002-04, Director of Measurement & Meter Reading, Director of Customer Services Solutions from 2000-01, 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.

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.

Mr. Fong has testified before the California Public Utilities Commission on numerous occasions covering a variety of topics ranging from cost of service, measurement and meter reading to billing systems implementation.

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