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 13
AMI FINANCIAL MODELING

JULY 14, 2006, AMENDMENT

Prepared Supplemental, Consolidating, Superseding and Replacement Testimony
of
SCOTT KYLE

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

July 14, 2006

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I. INTRODUCTION

The purpose of this *amended* testimony is to refresh my March 28, 2006 testimony to include the impact of modifications to the costs, benefits and revenue requirement in the business case that ultimately resulted in changes in the summary tables in my (Chapter 13) testimony in which I describe financial assumptions used to forecast the costs and benefits associated with deploying Advanced Metering Infrastructure at SDG&E. Specifically, this chapter addresses overhead rates; escalation factors; price level; societal benefits discounted cash flow net present value methodology and results; and revenue requirements net discounted cash flow methodology and results. 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.

II. OVERHEAD RATES

SDG&E allocates certain costs to jobs through the use of overhead loading rates, rather than by a direct charge method. SDG&E's 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, the following subset of eight overhead rates has been selected for use in the costs/benefits model for this filing:

TABLE SK 13-1

Overhead Category	Loading Base	Percentage
Payroll Taxes	Direct Labor	9.47%
Vacation and Sick Time	Direct Labor	14.40%
Pension and Benefits (non-balanced only)	Direct Labor	17.72%
Workers' Compensation	Direct Labor	2.49%
Public Liability / Property Damage	Direct Labor	2.20%
Non-Union Incentive Compensation Plan	Non-Union Direct Labor	17.52%
Purchased Services and Materials	Contract Labor, Services and Purchased Materials	.60%
Administrative and General	Capital Total Direct Cost	3.19%

A. Assumptions

The above rates are based on calendar year 2005 actual costs, both for pool funding and loading bases. In the accounting system, overheads are applied to direct labor straight-time and the straight-time portion of overtime. In the AMI costs/benefits model, SDG&E assumed labor inputs to be incremental straight-time equivalents. SDG&E loaded all overhead rates in the model one time on direct costs in the period incurred.

B. Justification

To simplify the planning process and make administering and auditing this filing less burdensome, SDG&E deemed overhead rate classes in the accounting system either 100% incremental or not, rather than developing non-standard overhead pool definitions for this single application, which would make subsequent reporting of as-recorded costs at worst inaccurate and at best a tedious manual reconciliation effort. ICP is the only exception. See below for details.

1. Payroll Taxes (PT)

Payroll Taxes are incremental, except to the extent individuals exceed their FICA maximum. Using the 2005 weighted average payroll tax rate gives full consideration to this fact. The calculated rate is higher than the statutory rate because it only loads on direct productive labor, despite the fact that Vacation and Sick (V&S) and Incentive Compensation Plan (ICP) costs also generate payroll tax expense.

2. Vacation and Sick Time

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. WC 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 up to 150% of target, based on actual financial results. The 17.52% projection used in this filing reflects payment to non-union employees at 100% of target. In the accounting system, non-union ICP loads on all direct labor, making the loading base consistent for all standard labor overheads. However, to reflect ICP as an incremental cost in this filing non-union ICP is loaded on non-union labor only.

7. Purchased Services and Materials

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

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, only A&G costs allocable to Capital are assumed to be incremental.

C. Application of Overheads in the Costs/Benefits Model

See Section V, below for a discussion of the application of overheads in the discounted cash flow model.

III. ESCALATION FACTORS

A. Cost/Benefit Categories and Escalators

Loaded constant-dollar values of AMI incremental cost and operational benefits are escalated for inflation by Cost/Benefit Category, using the following escalation factors for years 2006-2038.

TABLE SK 13-2

Cost/Benefit Category	Escalation Factor	Range of Annual % Change
Capital Electric Distribution. Capital Electric AMI Infrastructure	Electric Distribution. Plant Construction	1.5 – 3.0 %
Capital Electric Trans	Electric Transmission Plant Construction	1.4 – 3.5 %
Capital Gas AMI Infrastructure	Gas Distribution Plant Construction	0.7 – 3.4 %
Capital Common AMI Infrastructure	Electric and Gas Distribution Plant Construction	1.5 – 3.0 %
O&M Electric Non-Labor	Electric Distribution Utility O&M Non-Labor	1.9 – 3.6 %
O&M Gas Non-Labor	Gas Utility O&M Non-Labor	2.4 – 3.7 %
O&M Common Non-Labor	Electric and Gas Utility. O&M Non-Labor	2.0 – 3.6 %
O&M Electric Labor O&M Gas Labor O&M Common Labor	Utility Labor O&M	2.4 – 3.6 %

For an explanation of how these factors were applied in deriving the revenue requirements, total costs, and net present values, see Section V below.

Certain costs such as AMI meters are not escalated. This is because the nominal costs of silicon-based AMI technologies are expected to decline enough over time to maintain their current real price level. Historically, similar technology prices have decreased over time in real dollars, and SDG&E expects efficiency improvements in producing the AMI meters to result in a similar trend.

B. Sources of the Escalation Indices

The escalation factors shown above are applied to either capital or O&M. Both types of factors are based on utility cost escalation indices published by Global Insight in its Utility Cost Information Service. The capital factors are based on Global Insight's First-Quarter 2005 25-year Trend Forecast, UCON25Y (2005:1), while the O&M factors are based on Global Insight's February 2005

Trend 25-Year U.S. Economic Outlook, TRENDYR25YEAR0205, and 25-year Trend Forecast, UCON25Y (2005:1).

C. Allocation of Common AMI O&M Non-Labor and Capital Infrastructure

Escalation of AMI costs that are common to both gas and electric is based on a weighted average of unique electric distribution plant and gas distribution plant indices, 75% for electric and 25% for gas, which is supported by SDG&E's historical average costs for 2003 – 2005. These split percentages are currently planned for use in SDG&E's 2008 General Rate Case filing, and used to allocate current Common Plant costs in SDG&E's accounting system.

IV. PRICE LEVEL

AMI incremental costs and benefits are initially expressed in 2006 dollars, which is consistent with the assumption in SDG&E's AMI prime vendor RFP. Section V below describes how the 2006 incremental costs and benefits are loaded, escalated, and ultimately discounted back to present value.

V. SOCIETAL BENEFITS DISCOUNTED CASH FLOW METHODOLOGY AND RESULTS

A. Discounted Cash Flow (DCF) Methodology

Discounted cash flow analysis quantifies the cash flow implications of capital investment scenarios and their corresponding operational costs and benefits. The DCF method SDG&E employed to analyze its AMI investment is called the "societal model[1]", which ignores sales, use, and income taxes. Otherwise, it includes all costs and benefits associated with the project, even those not part of the revenue requirement – for example transmission cost savings and demand response benefits. The DCF analysis evaluates actual capital cash flows, not depreciation expense like the revenue requirement present value analysis discussed later in section VI. The DCF analysis calculates the NPV based on before-tax cash flows, so the annual projections of incremental AMI costs and benefits are discounted to present value using SDG&E's pre-tax authorized rate of return, 8.23%.

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[1] California Standard Practice Manual: Economic Analysis of Demand-side Programs & Projects, July 2002

SDG&E's DCF analysis, as well as its revenue requirements present value (PVRR) analysis, use a project evaluation horizon of 34 years, including a terminal year of 2039, and an initial year, 2006. The 2006 initial year is needed simply to compute net present values in 2006 dollars, despite the fact that costs and benefits do not begin until 2007. In other words, SDG&E forecasted 32 years of costs and benefits, but the DCF and PVRR analysis' contain 34 years.

In a July 21, 2004 Ruling in R.02-06-001,[2] utilities were directed to present their AMI forecasts over a 15 year project evaluation horizon. SDG&E's AMI forecast contains 15 years, as requested, and also goes beyond that in order to address certain technical problems related to determining an accurate net present value. SDG&E's proposed initial deployment takes place over four years. Additional equipment replacements and system growth occurs throughout the life of the project. This results in substantial remaining useful life, i.e. undepreciated assets with various staggered levels of remaining net book value, at the end of 15 years. In a textbook NPV analysis, the entire investment would be used up at the same time, and that would determine the ending year for the NPV evaluation. However, with so much undepreciated value on the books after 15 years, significant and arguable assumptions would be required to reflect the appropriate "terminal value". With that assumption being only 15 years out, it would drive a very large portion of the resulting net present value.

To address this problem, SDG&E extended its analysis timeframe to substantially capture two lifecycles of the electric meter and gas module assets, which account for most of the total capital cost. The resulting 34 year analysis also captures one full lifecycle of the longest lived AMI asset, gas meters. Extending the model in this manner places any necessary terminal value assumptions far enough in the future that the associated NPV becomes relatively immaterial.

In fact, the DCF analysis, as presented, contains the most conservative possible assumption, which is to ignore terminal value completely. For the PVRR analysis, an assumption about terminal value is still required, since revenue

[2] Administrative Law Judge and Assigned Commissioner Ruling Adopting a Business Case Analysis Framework for Advanced Metering Infrastructure, Attachment A, Section2.1 Base Case.

requirements are largely based on depreciation, rather than cash flows. In addition to minimizing the impact through timing, the PVRR terminal value assumptions impact is further minimized by SDG&E's choice of one of the most conservative possible terminal value treatments, which is to assume a liquidation event in which the assets in service at the end of 2038 are simply sold for their undepreciated or net book value.

1. Modeling Details

The capital and O&M incremental productive-labor and non-labor costs and benefits of AMI were forecasted by each operational witness over a 16-year planning horizon (2007-2022), expressed in 2006 dollars.

Each operational witness forecasted direct costs for initial deployment, and additional meters due to growth and failure replacements. Failure rate assumptions are described in the testimony of Mr. Pruschki (Chapter 11). Growth rate estimates are based on meter location climate zone estimates prepared by the AMI program office, which average 1.6% per year for gas and 1.44% per year for electric, as explained in the testimony of Mr. Carranza (Chapter 12). Direct costs for failure meters are estimated net of warranty coverage (.5% deductible on equipment for 1 year after installation, with SDGE paying for associated labor).

2007-2022 incremental cost and benefit estimates were extended an additional 16 years to 2038 in order to arrive at a total investment evaluation horizon that substantially captures two expected replacement lifecycles of the project's most costly asset classes, electric meters and gas modules, and one lifecycle of the longest lived AMI asset, gas meters. The forecast extensions were based on replacement cycle and growth assumptions provided by each operational witness. Certain benefits have a finite duration which is less than the total forecast period. Each operational witness provided estimates for the appropriate benefit duration.

Modeled expected equipment lives do not always equal accounting depreciation lives, because actual experience has indicated that certain assets last longer on average than their accounting lives, or can be maintained indefinitely through O&M expenditures. Examples include modeling electric meters on a 17 year replacement cycle, rather than using their 15 year accounting life, as well as certain 5 year accounting depreciation IT equipment that is replaced only once or not at all in the analysis, before converting to O&M throughout the rest of the 32 year forecast period.

With respect to electric meters and gas modules, failure replacements modeled in the first 17 year lifecycle of the analysis were deducted from the number of meters needing to be replaced in the second equipment life cycle, spread evenly over 2025, 2026, and 2027. All meters, including growth and replacement meters, were assumed to be replaced at the end of their expected lives.

Composite overhead loading factors were applied to each direct cost and benefit input over the entire 32 year forecast period, based on the accounting classifications of Union Labor, Non-union Labor, Contract Labor, Purchased Materials and Services, and Capital. As shown in the table below, each composite factor consists of one or more incremental loader, as described above in Section II.

Table SK 13-3

Application of Overhead Loaders

	Factor 1 = 46.28%	Factor 2 = 3.79%	Factor 3 = 0.60%	Factor 4 = 49.47%	Factor 5 = 63.80%	Factor 6 = 66.99%
Payroll Taxes = 9.47%	X			X	X	X
Vacation & Sick Time = 14.40%	X			X	X	X
Non-Balanced Pension & Benefits = 17.72%	X			X	X	X
Workers' Comp = 2.49%	X			X	X	X
Liability Insurance = 2.20%	X			X	X	X
Non-Union ICP = 17.52%					X	X
Purchased Services & Materials = 0.60%		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

The loaded cost and benefit numbers were then escalated using factors described above in section III. As an alternative to the SDGE in-house escalation factors, in some cases vendor costs were escalated using vendor supplied escalation assumptions provided by the operational witnesses.

Transmission related net avoided cost benefits were calculated by subtracting the NPV of what will be spent with AMI from the NPV of what would have been spent without AMI. This methodology allowed these net benefits to be included in the AMI DCF NPV without overstating gross costs and associated benefits relevant to the AMI revenue requirement. Avoided capacity and energy benefits are also included in the DCF results. These benefits are further described in the testimony of Mr. Gaines, Dr. George, and Mr. Martin (Chapters 5, 6 and 7). The DCF model finally discounts fully loaded and escalated costs back into 2006 dollars. The model uses annual cost increments, treating capital costs and benefits with a beginning of the year convention and O&M costs and benefits with an end of the year convention.

B. Discounted Cash Flow (DCF) Results

AMI Cash Flow Summary

($000)	2007	2008	2009	2010	2011-2038	Total
Unescalated, Unloaded Direct Costs and Benefits						
Cap Costs	38,465	91,476	122,640	119,458	483,309	855,348
O&M Costs	4,235	11,082	17,987	19,683	308,500	361,487
Total Costs	42,700	102,558	140,627	139,141	791,809	1,216,834
Cap Benefits	1,401	2,853	2,975	5,200	69,074	81,503
O&M Benefits	94	1,209	6,024	11,854	485,252	504,433
Other Benefits	-	1,060	21,155	28,900	1,317,662	1,368,777
Total Benefits	1,495	5,122	30,154	45,955	1,871,987	1,954,713
Net Benefits	(41,205)	(97,436)	(110,472)	(93,186)	1,080,179	737,879
Fully Loaded Direct Costs and Benefits						
Cap Costs	43,918	99,557	129,883	125,908	505,445	904,711
O&M Costs	4,674	13,695	21,910	23,787	395,129	459,196
Total Costs	48,592	113,252	151,793	149,695	900,575	1,363,906
Cap Benefits	1,696	3,107	3,184	5,584	72,888	86,459
O&M Benefits	150	1,628	8,449	16,849	691,712	718,789
Other Benefits	-	1,066	21,750	29,505	1,336,298	1,388,619
Total Benefits	1,847	5,801	33,383	51,939	2,100,898	2,193,868
Net Benefits	(46,745)	(107,451)	(118,410)	(97,756)	1,200,323	829,961
Fully Loaded and Escalated Costs and Benefits						
Cap Costs	44,445	101,392	132,861	129,877	565,080	973,653
O&M Costs	4,777	14,362	23,616	26,419	742,192	811,366
Total Costs	49,221	115,754	156,477	156,296	1,307,272	1,785,020
Cap Benefits	1,720	3,193	3,351	6,020	112,384	126,668
O&M Benefits	154	1,712	9,180	18,916	1,370,581	1,400,544
Other Benefits	-	1,109	22,437	30,668	1,648,183	1,702,397
Total Benefits	1,874	6,014	34,968	55,604	3,131,149	3,229,609
Net Benefits	(47,347)	(109,740)	(121,509)	(100,692)	1,823,877	1,444,589
Fully Loaded and Escalated Costs and Benefits Net Present Value						
Cap Costs	41,065	86,558	104,798	94,654	128,646	455,721
O&M Costs	4,078	11,328	17,211	17,790	164,478	214,886
Total Costs	45,143	97,887	122,010	112,445	293,124	670,608
Cap Benefits	1,589	2,726	2,643	4,388	33,166	44,511
O&M Benefits	132	1,350	6,691	12,738	279,573	300,484
Other Benefits	-	875	17,012	21,568	395,954	435,408
Total Benefits	1,720	4,951	26,345	38,693	708,693	780,403
Net Benefits	(43,422)	(92,936)	(95,664)	(73,751)	415,569	109,795

VI. REVENUE REQUIREMENTS PRESENT VALUE METHODOLOGY AND RESULTS

A. Revenue Requirements Present Value Methodology

The net present value of the AMI revenue requirements (RRPV) was calculated using the same DCF process described above used to determine the societal net present value. The main difference is that revenue requirements are calculated from the ratepayer's perspective and therefore include all tax implications, as well as cash flows based on capital depreciation rather than actual expenditures. Also, only cost and benefit items that impact the CPUC jurisdiction revenue requirements are included in revenue requirements. Mr. Calabrese discusses the detailed components of the AMI revenue requirement in Chapter 15.

Using the same input dataset as the societal DCF analysis described above, each fully loaded and escalated cost or benefit line item was adjusted to remove AMI costs which are not related to the revenue requirement before calculating the RRPV. Therefore, items like avoided transmission costs and benefits, transmission related aspects of costs and benefits related to common items like communications equipment, and demand response benefits that would flow through the Energy Resource Recovery Account (ERRA) are excluded. Specific exclusion assumptions were provided by each operational witness.

Sales taxes were added at 7.75% to lines identified as applicable by each operational witness. An adjustment was made to flow through to ratepayers the IRS allowable tax benefit related to utility developed software in the year incurred, rather than through depreciation.

The revenue requirements net present value methodology discounted the annual stream of cash flows from 2007-2038 using SDG&E's pre-tax authorized rate of return of 8.23%, since all tax implications were modeled as specific cash flows. As described previously in Section V, the RRPV analysis necessarily assumed a very conservative terminal value in 2039 equal to the un-depreciated net book value of AMI assets at the end of 2038.

The annual present values of all adjusted Capital and O&M costs and benefits were summed to yield the RRPV. The present value of certain items that are not part of the calculated revenue requirement, but do benefit CPUC customers, were added back in “below the line” to determine the overall net present value of the AMI program from a ratepayer perspective. Items include distribution avoided costs and benefits (including demand response program administration), deferred costs and benefits, gas and electric theft estimates, and demand response benefits.

B. Revenue Requirements Present Value Results

AMI Revenue Requirement Summary

($000)	2007	2008	2009	2010	2011-2038	2039*	Total
Adjusted Unescalated, Unloaded Direct Costs and Benefits							
Cap Costs	36,004	90,492	124,636	121,947	499,463		872,541
O&M Costs	4,661	12,180	19,994	22,029	338,722		397,587
Total Costs	40,666	102,672	144,630	143,976	838,185		1,270,128
Cap Benefits	1,466	2,984	3,176	5,359	72,180		85,165
O&M Benefits	106	1,347	6,771	13,344	546,435		568,002
Other Benefits	-	1,060	21,155	28,900	1,317,662		1,368,777
Total Benefits	1,572	5,391	31,102	47,603	1,936,277		2,021,944
Net Benefits	(39,093)	(97,281)	(113,528)	(96,373)	1,098,091		751,816
Adjusted Fully Loaded Direct Costs and Benefits							
Cap Costs	41,113	98,294	131,908	128,490	521,957		921,762
O&M Costs	5,154	15,015	24,233	26,475	431,394		502,270
Total Costs	46,267	113,309	156,140	154,964	953,351		1,424,031
Cap Benefits	1,764	3,244	3,392	5,749	76,107		90,256
O&M Benefits	169	1,818	9,499	18,963	778,660		809,110
Other Benefits	-	1,066	21,750	29,505	1,336,298		1,388,619
Total Benefits	1,934	6,128	34,641	54,217	2,191,065		2,287,984
Net Benefits	(44,334)	(107,181)	(121,499)	(100,747)	1,237,715		863,953
Adjusted Fully Loaded and Escalated Costs and Benefits							
Cap Costs	41,602	99,977	134,691	132,212	574,858		983,340
O&M Costs	5,268	15,745	26,113	29,395	809,567		886,086
Total Costs	46,870	115,722	160,803	161,606	1,384,424		1,869,426
Cap Benefits	1,789	3,334	3,570	6,198	117,815		132,705
O&M Benefits	173	1,912	10,321	21,288	1,542,780		1,576,474
Other Benefits	-	1,109	22,437	30,668	1,648,183		1,702,397
Total Benefits	1,962	6,355	36,328	58,155	3,308,778		3,411,577
Net Benefits	(44,908)	(109,367)	(124,475)	(103,452)	1,924,353		1,542,151
Revenue Requirement Fully Loaded and Escalated Cost and Benefit Cash Flows							
Cap Costs	(10,991)	25,774	58,301	83,197	1,582,324	(131,271)	1,607,334
O&M Costs	4,738	14,160	23,484	26,436	728,075	-	796,892
Total Costs	(6,254)	39,934	81,785	109,632	2,310,399	(131,271)	2,404,225
Cap Benefits	416	1,147	1,778	2,801	241,534	(37,868)	209,808
O&M Benefits	156	1,719	9,282	19,146	1,387,482	-	1,417,785
Total Rev. Req. Benefits	572	2,866	11,061	21,947	1,629,016	(37,868)	1,627,593
Total Rev. Req. Net Benefits	6,826	(37,068)	(70,724)	(87,686)	(681,383)	93,403	(776,633)
Other Benefits not in Rev. Req.	-	1,109	22,437	30,668	1,654,184	11,627	1,720,025
Total Net Benefits	6,826	(35,959)	(48,288)	(57,017)	972,801	105,030	943,393
Revenue Requirement Costs and Benefits Net Present Value							
Cap Costs	(9,383)	20,330	42,490	56,023	429,705	(9,654)	529,511
O&M Costs	4,044	11,169	17,115	17,801	161,462		211,592
Total Costs	(5,339)	31,499	59,605	73,824	591,166	(9,654)	741,103
Cap Benefits	355	905	1,296	1,886	55,719	(2,785)	57,376
O&M Benefits	133	1,356	6,765	12,892	283,035		304,181
Total Rev. Req. Benefits	488	2,261	8,061	14,779	338,753	(2,785)	361,557
Total Rev. Req. NPV	5,827	(29,238)	(51,544)	(59,046)	(252,413)	6,869	(379,546)
Other Benefits not in Rev. Req.	-	875	17,012	21,568	399,230	855	439,540
Grand Total NPV	5,827	(28,364)	(34,532)	(37,478)	146,817	7,724	59,994

* Terminal Value

This concludes my testimony.

VII. QUALIFICATIONS OF SCOTT KYLE

My name is Scott Kyle. I am employed by San Diego Gas and Electric Company (SDG&E). My business address is Mail Stop CP32A, 8330 Century Park Court, San Diego, CA 92123.

My present position is Manager of Financial Analysis and Performance for SDG&E and SoCalGas. The Financial Analysis and Performance group is responsible for defining consistent standards for all project evaluation at SDG&E and SoCalGas, participating as a consultant on all major project development teams, and validating the results of all financial models and project evaluations results presented to executive management and the SEU Board of Directors.

I have been employed by SDG&E since 2002. Until August of 2005, I was Manager of Affiliate Billing and Costing (ABC) at SDG&E and 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. In that capacity I testified before the CPUC 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.

I worked for the Salt River Project (SRP), an electric utility based in Phoenix, Arizona, from 1984 to 2002. At SRP I held various positions of increasing responsibility in financial analysis, planning, budgeting, procurement, and accounting, eventually becoming Manager of Business Services at the Navajo Generating Station (NGS), a large participant-owned coal-fired plant. In that capacity I managed the function of capital project evaluation and financial analysis for NGS's participant owners – LADWP, SRP, APS, NPC, TEP, and the USBR.

I received a B.A. in Economics from the University of California at Los Angeles in 1981, and I became a Certified Public Accountant in Arizona in 1986. I have completed more than 40 hours of continuing professional education per year since 1986, much of it focused on project evaluation and discounted cash flow analysis.