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 14
COST RECOVERY AND RATE DESIGN

JULY 14, 2006 AMENDMENT

Prepared Supplemental, Consolidating, Superseding and Replacement Testimony of

ROBERT W. HANSEN

SAN DIEGO GAS & ELECTRIC COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

July 14, 2006 Update

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I. INTRODUCTION

The purpose of this *amended* testimony is to update my March 28, 2006 testimony to include material information which impacts my (Chapter 14) testimony in which I: (1) present illustrative electric rate designs that would be enabled with AMI; (2) describe the regulatory balancing account treatment for SDG&E's proposed AMI revenue requirements, and for costs associated with SDG&E's proposed Peak Time Rebate (PTR) program for residential and small commercial customers; and (3) to provide estimates of electric and gas rate impacts for years 2007 through 2011 based on the changes to electric revenue requirements and gas transportation revenues.

Section 2 describes Critical Peak Pricing (CPP) and Time-of-Use (TOU) rate structures that could be employed with AMI. SDG&E does not propose implementation of rate structure changes in this proceeding but, rather, plans to pursue more cost-based rate designs in future rate design proceedings. No residential or small commercial customer rate alternatives are presented in this chapter since SDG&E is instead proposing a demand response program for residential and small commercial customers.

For Medium Commercial & Industrial (C&I) customers with demands up to 200 kilowatts (kW) SDG&E presents a CPP rate structure that may be utilized once AMI meters are deployed. The illustrative C&I CPP rate structure would enable more cost-based price signals and is described in Section 2. As described by SDG&E witness Dr. George in Chapter 6, the illustrative C&I rates presented in this chapter are used to support SDG&E's AMI demand response estimates.

Section 2 also presents an illustrative CPP rate offering for Large C&I customers (with demands of 200 kW or greater) which is consistent with that presented in Application 05-01-016.[1]

Section 3 presents regulatory accounting proposals. The regulatory treatment of SDG&E's proposed annual AMI revenue requirements, applicable to both gas and electric, are discussed in this section. This section also describes the proposed recovery method for credit costs associated with the residential and small commercial PTR program that is sponsored by SDG&E witness Gaines in Chapter 5.

Section 4 presents estimates of gas and electric rate impacts and customer bill impacts. Two versions of rate and bill impacts are presented: (1) impacts due solely to the net changes in SDG&E's electric distribution and gas transportation revenue requirements, and (2) impacts when other benefits are included. The annual revenue requirement adjustments and benefit data used in this impact analysis are based on tables sponsored by SDG&E witness Calabrese in Chapter 15.

This testimony consolidates, supersedes, and replaces all previous direct and supplemental testimony filed by any other SDG&E witness testifying in this docket, on the topics covered herein.

II. ILLUSTRATIVE ELECTRIC RATE DESIGNS

The following rate designs are strictly illustrative, although they are used to forecast expected demand response. They represent SDG&E's best current estimate of the appropriate rate structures, however, the actual rate structure applicable to this proceeding will not be implemented until the next appropriate proceeding (e.g. the Rate Design Window or GRC Phase 2)[2]. In that proceeding and subsequent proceedings, SDG&E will also evaluate and consider changes to the rate structures that may be warranted based on actual participation data. In addition, while the Peak Time Rebate cost recovery is discussed herein, the actual program is discussed in Mr. Gaines' testimony (Chapter 5).

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[1] SDG&E's settlement in the A.05-01-016 was rejected by the Commission on May 25, 2006 in D.06-05-038.

[2] SDG&E has sent a letter to the Executive Director of the Commission for leave to consolidate the Rate Design Window and the General Rate Case – Phase 2 to be filed by June 1, 2007.

A. Residential and Small Commercial (demand less than 20 kW)

As described by SDG&E witness Gaines in Chapter 5, SDG&E recommends a Peak Time Rebate (PTR) program for residential and small commercial customer classes. To evaluate and quantify the impact of more cost-based rate designs for small commercial customers, SDG&E presents an illustrative small commercial time-of-use (TOU) commodity rate structure. This illustrative small commercial TOU rate structure is set forth in Attachment RWH 14-1. Current Schedule A (SDG&E's small commercial electric retail rate tariff) consists of seasonal non-TOU commodity rates with seasonal price differentials of approximately 2.5 cents per kWh.

The default TOU rate schedule would instead be non-seasonal, and would incorporate a price differential between on-peak and off-peak periods of approximately 7.0 cents per kWh. This differential results from recovering the vast majority of generation capacity costs during on-peak hours. SDG&E proposes that season and TOU periods be defined consistently with its current definitions applicable to C&I TOU rate schedules to avoid potential customer confusion. The On-Peak TOU period is defined as 11am to 6pm on weekdays during the summer (excluding holidays), and 5pm to 8pm on weekdays during the winter (excluding holidays).

B. Medium Commercial & Industrial (with demands 20 kW to 200 kW)

A CPP tariff for Medium C&I could be similar to that proposed for Large C&I customers with (with demands greater than 200 kW). For Medium C&I, SDG&E suggests that a CPP rate structure could be designed based on the 13 days with highest system peak demand. This CPP rate design methodology is consistent with the design criteria for the proposed default CPP rate for Large C&I customers.

The illustrative rates for the Medium C&I CPP tariff also assume that the current seasonal and TOU definitions applicable to Schedule AL-TOU (General Service – Time Metered) would be applicable. The summer season is defined as the five months of May 1 through September 30. The On-Peak TOU period is defined as 11am to 6pm on weekdays during the summer (excluding holidays), and 5pm to 8pm on weekdays during the winter (excluding holidays). CPP rates would be applicable during the summer CPP event days. The CPP TOU hours on a CPP event day are the same as the summer season On-Peak period.

Attachment RWH 14-2 shows current Schedule AL-TOU commodity rates and illustrative CPP commodity rates for Medium C&I customers. The CPP rates shown are designed to be revenue-neutral with Schedule AL-TOU commodity rates effective February 1, 2006. The CPP rates have been designed to recover the generation capacity costs associated with the customer class using a generation capacity cost of $85 per kW per year. The rationale for using $85 per kW is described in the testimony of SDG&E witness Martin in Chapter 7.

SDG&E has incorporated a Capacity Reservation Charge (CRC). The CRC enables customers to reserve and pay for capacity costs on a monthly basis when they have loads that cannot be curtailed during a CPP event. Customers will have the option under the CPP rate to exempt a portion of their load from the CPP rate by paying a monthly CRC. The magnitude of the monthly CRC charge depends upon the amount of load protected. The protected load will be charged at the non-CPP day rate during CPP events, any load above the protected level will be charged at the CPP price.

C. Large Commercial & Industrial (with demands greater than 200 kW)

Illustrative Large C&I customer CPP rates are revenue-neutral with rates effective February 1, 2006 and are consistently designed to recover the generation capacity costs associated with the customer class using a generation capacity cost of $85 per kW per year. To ensure overall revenue neutrality during a design year with 13 CPP events, the revenue collected through the higher CPP rates is used to reduce rates during summer non-CPP periods. Again, the rate design incorporates a Capacity Reservation Charge (CRC) to enable customers to reserve and pay for capacity costs on a monthly basis when they have loads that cannot be curtailed during a CPP event.

Data used in the CPP rate design are consistent with SDG&E's most recent Rate Design Window marginal cost of service study filed in A.05-02-019.

Attachment RWH 14-3 shows current commodity rates applicable to Schedule AL-TOU and illustrative CPP commodity rates for Large C&I customers.

III. REGULATORY BALANCING ACCOUNT TREATMENT

A. Distribution Revenues

Electric Distribution rates will be adjusted annually during years 2007 through 2011 based on the annual net changes in Distribution revenue requirements presented in the testimony of SDG&E witness Calabrese in Chapter 15. Attachment RWH 14-4 also shows annual revenue requirements and adjustments for "other benefits" by year. Annual revenue requirement and benefit values are based on calculations sponsored by SDG&E witness Calebrese in Chapter 15. SDG&E proposes that net Distribution cost/benefits associated with AMI full deployment be recovered from all customer classes in which AMI will be installed, and accounted for by means of a balancing account mechanism. Distribution rates would never increase as a result of the AMI account balance but rates are subject to downward pressure.

Recovery of the electric AMI revenue requirement would be implemented by first allocating the annual incremental change in revenues to the customer classes. SDG&E proposes that the revenue allocation to the classes be in proportion to the number of meters planned to be installed by class multiplied by the net AMI cost per installed meter. This interim allocation methodology would be employed until SDG&E has incorporated the AMI costs in future marginal cost studies. Once AMI costs are incorporated in a CPUC-approved Distribution marginal cost study then SDG&E would allocate the AMI incremental costs based on an Equal Percent of Marginal Cost (EPMC) methodology consistent with other distribution revenue requirements.

AMI deployment O&M and capital-related costs and benefits should be recorded monthly in a new AMI balancing account. Incremental changes in AMI Distribution benefits would also be incorporated through balancing account adjustments based on the number of installed meters and the dollar benefit per meter. SDG&E proposes to record actual O&M and capital-related costs and make annual adjustments for the variation from the Commission-approved annual

AMI revenue requirement. Benefits will be tied to the annual average number of meters actually installed as compared to the annual average number of installed meters supporting SDG&E's revenue requirement calculations.

If AMI meter installations progress at SDG&E's proposed schedule, adjustments to the AMI balancing account would only be due to O&M and capital-related cost variations. There would be no additional adjustment due to AMI Distribution benefit differences.

If, however, the annual average of monthly installed meters exceeds the proposed schedule, then SDG&E proposes that the AMI balancing account also be credited by a dollar amount that is based upon the difference between the annual average of installed meters and the annual average number of meters on which the proposed revenue requirement is based. Attachment RWH 14-5 sets forth the calculation of benefits per meter based upon the average number of forecasted meters for 2007-2011. Attachment RWH 14-6 includes a scenario for 2008 to illustrate how the benefits calculation works.

As a hypothetical example, assume that the average forecasted meters for 2008 is 150,000 with an associated monthly benefit of $15,000 per 10,000 meters (with 10,000 representing the number of meters associated with a manually read meter route). A hypothetical rate of installation is assumed such that actual installs are greater than forecasted. The actual average number of meter installs is assumed to be 200,000. The difference between the actual and the forecasted averages is adjusted to blocks of 10,000 meters, i.e., 5 in this example, and the dollar benefits per 10,000 meters are applied for a full year. The result is an additional benefit of $900,000 associated with the additional meters ($15,000 x 5 x 12). By assuming the straight-line rate of installation in the calculation of benefits it is not necessary to track each month's level of meters installed and the calculation is simplified by incorporating beginning and ending year meter balances for a given year. This simplifying assumption is consistent with the constant rate of installation forecasted in determining the AMI revenue requirement.

If the average number of meter installations are in-line with SDG&E's proposed schedule supported in this filing, but O&M and capital-related costs are actually less than the estimates presented in this application, the result would again be a credit to the AMI balancing account. The resulting over-collection in the year-end balance in the AMI balancing account would be credited against the following year's Distribution revenue requirement.

On the other hand, SDG&E would not increase Distribution rates as a result of the AMI balancing account being under-collected. Instead, the under-collected amount would be carried over to the next year's balance and recovered only to the extent that the approved forecasted revenue requirement is not exceeded in total for that year.

B. Commodity Revenues

Illustrative CPP structures have been designed to be revenue-neutral with currently-effective commodity rates, assuming no customer demand response. Commodity revenue shortfalls resulting from C&I demand response would be contained within the commodity rate component. Direct Access (DA) and future Community Choice Aggregation (CCA) customers would be exempt from cost recovery of ERRA revenue shortfalls caused by the CPP rates. Revenue over- or under-collections associated with the CPP rate design, including any future CPP participation credits and first-year bill protection, would flow through SDG&E's ERRA balancing account in the same way as other revenues from the generation portion of the standard tariffs. Generation benefits described by other SDG&E witnesses will flow through SDG&E's existing rate mechanisms, e.g., 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. CPP program costs should be recovered through the Advanced Metering and Demand Response Account (AMDRA).

For transmission revenue accounting, SDG&E has a FERC-authorized ratemaking mechanism that provides for annual true-ups and rate adjustments. Thus, there is no need to include such transmission benefits in the AMI recovery mechanism. Special tracking of revenue shortfalls associated with CPP is also unnecessary for other rate components with balancing account treatment. These components include: Distribution, Public Purpose Programs, Nuclear Decommissioning, Fixed Transition Amounts, Ongoing CTCs, and DWR Bond Charges.

A summary of AMI annual revenue requirements is shown in Attachment RWH 14-4 for the period 2007-2011 based on SDG&E's AMI full deployment proposal. The year 2011 is the final year in which rate impacts are estimated since this testimony assumes that SDG&E will address AMI recovery of post-2011 costs in a Test-Year 2012 General Rate Case (GRC) filing.

C. Residential and Small Commercial Demand Response Cost Recovery

SDG&E proposes that monthly credit payments associated with the new residential and small commercial Peak Time Rebate (PTR) program be recorded in the AM DRA and recovered in the subsequent year's Distribution revenue requirement. The demand response program and credit method is described by SDG&E witness Gaines in Chapter 5. The PTR program costs are proposed to be recovered consistent with other SDG&E demand response program costs which are in the Distribution rate component and from all customer classes. Authorized PTR program costs will be allocated to customer classes consistent with SDG&E's currently-authorized EPMC methodology for Distribution revenue requirements.

IV. 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 2007-2011 AMI revenue requirements in electric and gas rates are described below.

1. Electric Rate Impact

SDG&E proposes to allocate the electric Distribution revenue requirement changes associated with residential Peak Time Rebate (PTR) program based on currently-adopted electric Distribution allocation factors. Electric

Distribution revenue requirements are currently allocated on a Distribution Equal Percent of Marginal Cost (EPMC) basis. SDG&E's Distribution EPMC methodology was approved as part of SDG&E's Rate Design Window proceeding in Decision 05-12-003. Impacts of the PTR program will depend on the amount of credits provided. Rate impacts of the PTR program are not included in this application.

AMI revenue requirements are proposed to be allocated in proportion to meter installation costs per class. Electric revenue allocation percentages are as follows:

Residential	63.79%
Small Commercial	30.27%
Medium and Large C&I	5.08%
Agricultural	0.87%
Lighting	0.00%
Total	100.00%

Class-average rate impacts on total rates, due to changes in Distribution revenue requirements only, are presented in Attachment RWH 14-7. The class-average rates when "other benefits" are included are shown in Attachment RWH 14-8. For illustration of total rate impacts, the other benefits are allocated in the same manner as AMI revenue requirements. Actual rate impacts of the other benefits will differ since the benefits can be associated with other unbundled rate categories, i.e., transmission and commodity revenue requirements are allocated differently than distribution revenue requirements, and the results are shown for years 2007 through 2011. By 2012, it is assumed that AMI Distribution revenue requirement impacts will be incorporated by means of a future General Rate Case proceeding. The proposed rate changes and year-to-year percentage changes, by customer class, are set forth in Attachments RWH 14-7 and RWH 14-8.

Typical monthly residential bill impacts, for each year 2007 – 2011, for a customer using 500 kWh per month are presented in Attachment RWH 14-9. The typical monthly residential bill impacts and year-to-year percentage changes for each year 2007 - 2011, when other benefits are included, are set forth in Attachment RWH 14-10.

Residential monthly bill impacts by usage level and season for customers in the inland climate zone, are presented in Attachment RWH 14-11 for year 2007. Attachment RWH 14-12 sets forth the Residential monthly bill impacts for year 2011, by usage level and season, for customers in the inland climate zone, when excluding and when including other benefits. For both 2007 and 2011, the bill impacts presented are measured from rates effective February 1, 2006.

2. Gas Rate Impact

SDG&E proposes to allocate the gas transportation revenue requirement changes associated with AMI implementation and incremental operating costs primarily to its core customer classes. This allocation method is proposed since non-core customers currently have metering capabilities enabled with SDG&E's Automated Meter Reading (AMR) devices.

Gas revenue allocation percentages are as follows:

Residential	93.17%
Core C&I	6.82%
NGV	0.01%
Total Core	100.00%
Noncore C&I	0%
System Total	100.00%

Class average rate impacts resulting from the change in gas transportation revenue requirements are presented in Attachment RWH 14-13. Results are shown for years 2007 through 2011. By 2012, it is assumed that AMI transportation revenue requirement impacts will be incorporated by means of a future General Rate Case proceeding. The impacts of including other benefits are shown in Attachment RWH 14-14.

Typical residential bill impacts for a customer using 40 therms per month are presented in Attachment RWH 14-15. Typical customer bills are presented for years 2007 through 2011. The impacts of including other benefits are shown in Attachment RWH 14-16.

This concludes my prepared supplemental testimony.

V. QUALIFICATIONS OF ROBERT W. HANSEN

My name is Robert W. Hansen. My business address is 8330 Century Park Court, San Diego, California, 92123. I am Electric Rate Design Manager in the Regulatory Strategy Department for San Diego Gas & Electric Company (SDG&E). My primary responsibilities include the development of cost-of-service studies, determination of revenue allocation and electric rate design methods, analysis of ratemaking theories, and preparation of various regulatory filings.

I received a Bachelor of Science degree in Mining Engineering from South Dakota School of Mines & Technology in 1981. I received a Master of Science degree in Policy Economics from the University of Illinois in 1987, where my areas of specialization were natural resource and environmental economics. I am a Registered Professional Engineer in the State of Indiana.

From 1991 to 1998, I was employed by SDG&E as a Pricing Design Analyst and Senior Pricing Analyst. From 1998 to July 2000, I was employed by Sempra Energy as a Regulatory Policy Analyst in the Regulatory Affairs Division. From July 2000 to December 2001, I was employed by Enron Energy Services as Director – Utility Risk Management, and Director – Product Management. I have been employed in my current position since April 2002.

I have testified before the FERC and the CPUC in other proceedings.

Attachment RWH 14-1

San Diego Gas & Electric Company

Illustrative Commodity Rates for Small Commercial (20 kW or less)

Line #	Commodity Rates ($ per kWh)	(A) Comparison Rates Applicable to Schedule A[1]	(B) Default TOU Scenario	Line #
1	Summer			1
2	On-Peak	0.08144	0.11792	2
3	Semi-Peak	0.08144	0.06796	3
4	Off-Peak	0.08144	0.04646	4
5				5
6	Winter			6
7	On-Peak	0.05617	0.11792	7
8	Semi-Peak	0.05617	0.06796	8
9	Off-Peak	0.05617	0.04646	9

[1] Reflects rates effective 2/1/06

Attachment RWH 14-2

San Diego Gas & Electric Company

Illustrative Commodity Rates for Medium Commercial & Industrial

(with demands 20 kW to 200 kW)

Line #		(A) Comparison Rates Applicable to Schedule AL-TOU[1]	(B) Default CPP[2]	Line #
1	Capacity Reservation Charge ($ per Month)		7.08	1
2				2
3	Commodity Rates ($ per kWh)			3
4	Summer			4
5	CPP	--	0.90991	5
6	On-Peak	0.11515	0.05815	6
7	Semi-Peak	0.06637	0.05275	7
8	Off-Peak	0.04537	0.04429	8
9	Winter			9
10	On-Peak	0.11515	0.05815	10
11	Semi-Peak	0.06637	0.05275	11
12	Off-Peak	0.04537	0.04429	12

[1] Reflects rates effective 2/1/06
[2] CPP energy rates exclude any participation credits

Attachment RWH 14-3

San Diego Gas & Electric Company

Illustrative Commodity Rates for Large Commercial & Industrial

(with demands greater than 200 kW)

		(A)	(B)	
		Comparison Rates Applicable to Schedule		
Line #		AL-TOU[1]	Default CPP[2]	Line #
1	Capacity Reservation Charge ($ per Month)		7.08	1
2				2
3	Commodity Rates ($ per kWh)			3
4	Summer			4
5	CPP	--	0.94347	5
6	On-Peak	0.11515	0.06137	6
7	Semi-Peak	0.06637	0.05352	7
8	Off-Peak	0.04537	0.04436	8
9	Winter			9
10	On-Peak	0.11515	0.06137	10
11	Semi-Peak	0.06637	0.05352	11
12	Off-Peak	0.04537	0.04436	12

[1] Reflects rates effective 2/1/06
[2] CPP energy rates exclude any participation credits

Attachment RWH 14-4

San Diego Gas & Electric Company

Annual AMI Revenue Changes Used in Rate Impact Analyses

Electric:

Year	Revenue Requirement (RR) ($000)	RR plus Other Benefits ($000)
2007	($6,693)	($6,693)
2008	$10,315	$9,299
2009	$40,659	$18,481
2010	$55,294	$25,061
2011	$56,281	$18,988

Gas:

Year	Revenue Requirement (RR) ($000)	RR plus Other Benefits ($000)
2007	($976)	($976)
2008	$7,764	$7,671
2009	$19,847	$19,588
2010	$24,042	$23,607
2011	$22,221	$21,766

Attachment RWH 14-5

San Diego Gas & Electric Company

Calculation of Benefit Adjustment for AMI Balancing Account

Line No.		2007	2008	2009	2010	2011	Line No.
1							1
2	**Total Electric Revenue Requirement**	($6,692,623)	$10,314,974	$40,658,842	$55,294,190	$56,281,315	2
3	**Total Electric Benefits**	($291,597)	($1,944,249)	($8,156,986)	($16,205,210)	($20,558,987)	3
4							4
5	**Total Gas Revenue Requirement**	($976,375)	$7,763,647	$19,846,961	$24,041,564	$22,221,088	5
6	**Total Gas Benefits**	($56,478)	($509,547)	($2,475,075)	($4,999,087)	($6,214,888)	6
7							7
8	**Total Electric & Gas Revenue Requirement**	($7,668,998)	$18,078,621	$60,505,803	$79,335,755	$78,502,403	8
9	**Total Electric & Gas Benefits**	($348,074)	($2,453,797)	($10,632,061)	($21,204,296)	($26,773,875)	9
10							10
11	**Per Year Forecasted EOY Installed Electric Meters**	500	321,223	550,667	550,667	20,453	11
12	Cumulative EOY Forecasted Electric Meters	500	321,723	872,390	1,423,057	1,443,510	12
13	AVG. Number Electric Meters (Assumes Straight Line Rate)	500	160,862	275,334	275,334	10,227	13
14							14
15	**Per Year Forecasted EOY Installed Gas Meters**	500	201,188	344,894	344,894	14,264	15
16	Cumulative EOY Forecasted Gas Meters	500	201,688	546,582	891,476	905,740	16
17	AVG. Number Gas Meters (Assumes Straight Line Rate)	500	101,094	172,447	172,447	7,132	17
18							18
19	**Average Number of Meters Installed**						19
20	Electric	500	160,862	275,334	275,334	10,227	20
21	Gas	500	101,094	172,447	172,447	7,132	21
22							22
23	**Per 10,000 Meters Benefit Formula Offset -- Annual**						23
24	Formula - $/Meter Electric	$ 485,994	$ 10,072	$ 24,688	$ 49,047	$ 1,675,303	24
25	Formula - $/ Meter Gas	$ 94,129	$ 4,200	$ 11,961	$ 24,158	$ 726,174	25
26	Total	$ 580,123	$ 14,272	$ 36,649	$ 73,205	$ 2,401,477	26

Attachment RWH 14-6

San Diego Gas & Electric Company

Example of AMI Benefit Adjustments for AMI Balancing Account

Line No.	Benefits Tracked to Balancing Account	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Total
1	Forecasted Elec Installed Mtrs Per Month:Straight-Line Rate	36,769	26,769	26,769	26,769	26,769	26,769	26,769	26,769	26,769	26,769	26,769	26,769	331,223
2	Average Number of Meters (EOY - BOY)/2													160,862
3	Cumulative Meters Per Month	36,769	63,537	90,306	117,074	143,843	170,612	197,380	224,149	250,917	277,686	304,454	331,223	
4														
5	Scenario Installs -- Increasing Rate & Total > Forecasted:	10,000	10,724	11,911	13,699	16,317	20,126	25,708	34,008	46,587	66,092	97,099	147,730	500,000
6	Average Number of Meters (EOY - BOY)/2													245,000
7	Cumulative Installs	10,000	20,724	32,635	46,334	62,651	82,777	108,485	142,493	189,080	255,172	352,270	500,000	
8	Average Installs Less Forecasted Average (per 10,000)													8
9	$ per 10,000 meter benefits monthly													$10,072
10	Balancing Account Adjustment - $ Benefits													$966,918

Attachment RWH 14-7
San Diego Gas & Electric Company
Class-Average Electric Rate Impacts
Excluding Other Benefits
Year-to-Year Changes

	2006	2007			2008			2009			2010			2011		
			Change			Change			Change			Change			Change	
	¢/kWh	¢/kWh	¢/kWh	%	¢/kWh	¢/kWh	%	¢/kWh	¢/kWh	%	¢/kWh	¢/kWh	%	¢/kWh	¢/kWh	%
Residential	15.376	15.317	-0.059	-0.4%	15.407	0.090	0.6%	15.731	0.324	2.1%	15.859	0.128	0.8%	15.868	0.009	0.1%
Small Comm.	15.757	15.659	-0.098	-0.6%	15.810	0.151	1.0%	16.353	0.543	3.4%	16.567	0.215	1.3%	16.582	0.014	0.1%
Med. & Lg. C&I	11.819	11.816	-0.003	0.0%	11.821	0.005	0.0%	11.839	0.018	0.2%	11.846	0.007	0.1%	11.847	0.000	0.0%
Agriculture	14.290	14.223	-0.067	-0.5%	14.326	0.103	0.7%	14.694	0.368	2.6%	14.840	0.146	1.0%	14.850	0.010	0.1%
Lighting	14.203	14.203	0.000	0.0%	14.203	0.000	0.0%	14.203	0.000	0.0%	14.203	0.000	0.0%	14.203	0.000	0.0%
System Total	13.531	13.497	-0.034	-0.2%	13.549	0.052	0.4%	13.735	0.186	1.4%	13.809	0.074	0.5%	13.814	0.005	0.0%

Attachment RWH 14-8

San Diego Gas & Electric Company

Class-Average Electric Rate Impacts

Including Other Benefits

Year-to-Year Changes

	2006	2007			2008			2009			2010			2011		
			Change			Change			Change			Change			Change	
	¢/kWh	¢/kWh	¢/kWh	%	¢/kWh	¢/kWh	%	¢/kWh	¢/kWh	%	¢/kWh	¢/kWh	%	¢/kWh	¢/kWh	%
Residential	15.376	15.317	-0.059	-0.4%	15.398	0.081	0.5%	15.537	0.139	0.9%	15.595	0.058	0.4%	15.542	-0.053	-0.3%
Small Comm.	15.757	15.659	-0.098	-0.6%	15.795	0.136	0.9%	16.028	0.233	1.5%	16.124	0.096	0.6%	16.035	-0.089	-0.6%
Med. & Lg. C&I	11.819	11.816	-0.003	0.0%	11.820	0.005	0.0%	11.828	0.008	0.1%	11.831	0.003	0.0%	11.828	-0.003	0.0%
Agriculture	14.290	14.223	-0.067	-0.5%	14.316	0.093	0.7%	14.474	0.158	1.1%	14.539	0.065	0.5%	14.479	-0.060	-0.4%
Lighting	14.203	14.203	0.000	0.0%	14.203	0.000	0.0%	14.203	0.000	0.0%	14.203	0.000	0.0%	14.203	0.000	0.0%
System Total	13.531	13.497	-0.034	-0.2%	13.544	0.047	0.3%	13.624	0.080	0.6%	13.657	0.033	0.2%	13.626	-0.031	-0.2%

Attachment RWH 14-9

San Diego Gas & Electric Company

Electric - Residential Typical Customer Bill Impact

Excluding Other Benefits

2006	2007			2008			2009			2010			2011		
Typical	Typical	Change		Typical	Change		Typical	Change		Typical	Change		Typical	Change	
Bill	Bill	$	%	Bill	$	%	Bill	$	%	Bill	$	%	Bill	$	%
70.05	69.96	-0.09	-0.1%	70.19	0.23	0.3%	70.60	0.41	0.6%	70.79	0.20	0.3%	70.81	0.01	0.0%

- Current Typical Bill based Inland Climate Zone and Schedule DR rates effective 2/1/06.

Attachment RWH 14-10

San Diego Gas & Electric Company

Electric - Residential Typical Customer Bill Impact

Including Other Benefits

2006	2007			2008			2009			2010			2011		
Typical	Typical	Change		Typical	Change		Typical	Change		Typical	Change		Typical	Change	
Bill	Bill	$	%	Bill	$	%	Bill	$	%	Bill	$	%	Bill	$	%
70.05	69.96	-0.09	-0.1%	70.17	0.21	0.3%	70.30	0.12	0.2%	70.39	0.09	0.1%	70.30	-0.08	-0.1%

- Current Typical Bill based Inland Climate Zone and Schedule DR rates effective 2/1/06.

Attachment RWH 14-11

San Diego Gas & Electric Company

Residential Electric Bill Impacts – Year 2007

(INLAND CUSTOMERS)
Schedule DR (Summer Billing Period)

LINE NO.	ENERGY (KWH) (A)	2006 PRESENT BILL ($) (B)	2007 PROPOSED BILL ($) (C)	CHANGE ($) (D)	CHANGE (%) (E)	LINE NO.
1	25	$5.10	$5.10	$0.00	0.0%	1
2	50	6.44	6.44	0.00	0.0%	2
3	75	9.67	9.67	0.00	0.0%	3
4	100	12.89	12.89	0.00	0.0%	4
5	150	19.33	19.33	0.00	0.0%	5
6	200	25.78	25.78	0.00	0.0%	6
7	250	32.22	32.22	0.00	0.0%	7
8	300	38.67	38.67	0.00	0.0%	8
9	350	45.11	45.11	0.00	0.0%	9
10	400	52.38	52.38	0.00	0.0%	10
11	450	59.84	59.84	0.00	0.0%	11
12	500	69.63	69.57	(0.06)	-0.1%	12
13	600	91.64	91.38	(0.26)	-0.3%	13
14	700	113.65	113.19	(0.45)	-0.4%	14
15	800	136.40	135.75	(0.65)	-0.5%	15
16	900	159.31	158.47	(0.85)	-0.5%	16
17	1000	182.23	181.18	(1.04)	-0.6%	17
18	1500	303.49	301.48	(2.02)	-0.7%	18
19	2000	425.98	422.98	(2.99)	-0.7%	19
20	3000	670.95	666.00	(4.94)	-0.7%	20

Schedule DR (Winter Billing Period)

LINE NO.	ENERGY (KWH) (A)	2006 PRESENT BILL ($) (B)	2007 PROPOSED BILL ($) (C)	CHANGE ($) (D)	CHANGE (%) (E)	LINE NO.
31	25	5.10	5.10	0.00	0.0%	31
32	50	6.44	6.44	0.00	0.0%	32
33	75	9.67	9.67	0.00	0.0%	33
34	100	12.89	12.89	0.00	0.0%	34
35	150	19.33	19.33	0.00	0.0%	35
36	200	25.78	25.78	0.00	0.0%	36
37	250	32.22	32.22	0.00	0.0%	37
38	300	38.67	38.67	0.00	0.0%	38
39	350	45.13	45.13	0.00	0.0%	39
40	400	52.58	52.58	0.00	0.0%	40
41	450	60.04	60.04	0.00	0.0%	41
42	500	70.05	69.96	(0.09)	-0.1%	42
43	600	90.52	90.24	(0.28)	-0.3%	43
44	700	111.01	110.53	(0.48)	-0.4%	44
45	800	132.36	131.68	(0.68)	-0.5%	45
46	900	153.71	152.84	(0.87)	-0.6%	46
47	1000	175.06	174.00	(1.07)	-0.6%	47
48	1500	290.01	287.97	(2.04)	-0.7%	48
49	2000	405.81	402.80	(3.02)	-0.7%	49
50	3000	637.41	632.44	(4.97)	-0.8%	50

Attachment RWH 14-12

(Sheet 1 of 2)

Residential Electric Bill Impacts – Year 2011

Excluding Other Benefits

(INLAND CUSTOMERS)
Schedule DR (Summer Billing Period)

LINE NO.	ENERGY (KWH) (A)	2006 PRESENT BILL ($) (B)	2011 PROPOSED BILL ($) (C)	CHANGE ($) (D)	CHANGE (%) (E)	LINE NO.
1	25	$5.10	$5.10	$0.00	0.0%	1
2	50	6.44	6.44	0.00	0.0%	2
3	75	9.67	9.67	0.00	0.0%	3
4	100	12.89	12.89	0.00	0.0%	4
5	150	19.33	19.33	0.00	0.0%	5
6	200	25.78	25.78	0.00	0.0%	6
7	250	32.22	32.22	0.00	0.0%	7
8	300	38.67	38.67	0.00	0.0%	8
9	350	45.11	45.11	0.00	0.0%	9
10	400	52.38	52.38	0.00	0.0%	10
11	450	59.84	59.84	0.00	0.0%	11
12	500	69.63	70.17	0.54	0.8%	12
13	600	91.64	93.82	2.18	2.4%	13
14	700	113.65	117.47	3.82	3.4%	14
15	800	136.40	141.86	5.47	4.0%	15
16	900	159.31	166.42	7.11	4.5%	16
17	1000	182.23	190.97	8.75	4.8%	17
18	1500	303.49	320.45	16.95	5.6%	18
19	2000	425.98	451.14	25.16	5.9%	19
20	3000	670.95	712.52	41.57	6.2%	20
21						21
22						22
23		Schedule DR (Winter Billing Period)				23
24						24
25		2006	2011			25
26		PRESENT	PROPOSED			26
27	ENERGY	BILL	BILL	CHANGE	CHANGE	27
28	(KWH)	($)	($)	($)	(%)	28
29	(A)	(B)	(C)	(D)	(E)	29
30						30
31	25	5.10	5.10	0.00	0.0%	31
32	50	6.44	6.44	0.00	0.0%	32
33	75	9.67	9.67	0.00	0.0%	33
34	100	12.89	12.89	0.00	0.0%	34
35	150	19.33	19.33	0.00	0.0%	35
36	200	25.78	25.78	0.00	0.0%	36
37	250	32.22	32.22	0.00	0.0%	37
38	300	38.67	38.67	0.00	0.0%	38
39	350	45.13	45.13	0.00	0.0%	39
40	400	52.58	52.58	0.00	0.0%	40
41	450	60.04	60.04	0.00	0.0%	41
42	500	70.05	70.81	0.75	1.1%	42
43	600	90.52	92.92	2.40	2.6%	43
44	700	111.01	115.05	4.04	3.6%	44
45	800	132.36	138.04	5.68	4.3%	45
46	900	153.71	161.03	7.32	4.8%	46
47	1000	175.06	184.03	8.96	5.1%	47
48	1500	290.01	307.18	17.17	5.9%	48
49	2000	405.81	431.19	25.37	6.3%	49
50	3000	637.41	679.20	41.79	6.6%	50

Attachment RWH 14-12

(Sheet 2 of 2)
Residential Electric Bill Impacts – Year 2011
Including Other Benefits

(INLAND CUSTOMERS)
Schedule DR (Summer Billing Period)

LINE NO.	ENERGY (KWH) (A)	2006 PRESENT BILL ($) (B)	2011 PROPOSED BILL ($) (C)	CHANGE ($) (D)	CHANGE (%) (E)	LINE NO.
1	25	$5.10	$5.10	$0.00	0.0%	1
2	50	6.44	6.44	0.00	0.0%	2
3	75	9.67	9.67	0.00	0.0%	3
4	100	12.89	12.89	0.00	0.0%	4
5	150	19.33	19.33	0.00	0.0%	5
6	200	25.78	25.78	0.00	0.0%	6
7	250	32.22	32.22	0.00	0.0%	7
8	300	38.67	38.67	0.00	0.0%	8
9	350	45.11	45.11	0.00	0.0%	9
10	400	52.38	52.38	0.00	0.0%	10
11	450	59.84	59.84	0.00	0.0%	11
12	500	69.63	69.82	0.18	0.3%	12
13	600	91.64	92.38	0.74	0.8%	13
14	700	113.65	114.94	1.29	1.1%	14
15	800	136.40	138.24	1.84	1.4%	15
16	900	159.31	161.71	2.40	1.5%	16
17	1000	182.23	185.18	2.95	1.6%	17
18	1500	303.49	309.21	5.72	1.9%	18
19	2000	425.98	434.46	8.49	2.0%	19
20	3000	670.95	684.97	14.03	2.1%	20
21						21
22						22
23		**Schedule DR (Winter Billing Period)**				23
24						24
25		2006	2011			25
26		PRESENT	PROPOSED			26
27	ENERGY	BILL	BILL	CHANGE	CHANGE	27
28	(KWH)	($)	($)	($)	(%)	28
29	(A)	(B)	(C)	(D)	(E)	29
30						30
31	25	5.10	5.10	0.00	0.0%	31
32	50	6.44	6.44	0.00	0.0%	32
33	75	9.67	9.67	0.00	0.0%	33
34	100	12.89	12.89	0.00	0.0%	34
35	150	19.33	19.33	0.00	0.0%	35
36	200	25.78	25.78	0.00	0.0%	36
37	250	32.22	32.22	0.00	0.0%	37
38	300	38.67	38.67	0.00	0.0%	38
39	350	45.13	45.13	0.00	0.0%	39
40	400	52.58	52.58	0.00	0.0%	40
41	450	60.04	60.04	0.00	0.0%	41
42	500	70.05	70.30	0.25	0.4%	42
43	600	90.52	91.33	0.81	0.9%	43
44	700	111.01	112.37	1.36	1.2%	44
45	800	132.36	134.28	1.92	1.4%	45
46	900	153.71	156.18	2.47	1.6%	46
47	1000	175.06	178.09	3.02	1.7%	47
48	1500	290.01	295.81	5.79	2.0%	48
49	2000	405.81	414.37	8.56	2.1%	49
50	3000	637.41	651.51	14.10	2.2%	50

Attachment RWH 14-13
San Diego Gas & Electric Company
Gas Transportation Rate Impacts
Excluding Other Benefits

	2006	2007			2008			2009			2010			2011		
			Change			Change			Change			Change			Change	
	¢/thm	¢/thm	¢/thm	%	¢/thm	¢/thm	%	¢/thm	¢/thm	%	¢/thm	¢/thm	%	¢/thm	¢/thm	%
1 Residential	54.863	54.577	-0.29	-0.5%	57.135	2.56	4.7%	60.670	3.54	6.2%	61.898	1.23	2.0%	61.365	-0.53	-0.9%
2 Core C&I	30.677	30.625	-0.05	-0.2%	31.095	0.47	1.5%	31.745	0.65	2.1%	31.971	0.23	0.7%	31.873	-0.10	-0.3%
3 NGV	90.151	90.149	0.00	0.0%	90.166	0.02	0.0%	90.189	0.02	0.0%	90.197	0.01	0.0%	90.193	0.00	0.0%
4 Total Core	48.348	48.131	-0.22	-0.4%	50.077	1.95	4.0%	52.768	2.69	5.4%	53.702	0.93	1.8%	53.297	-0.41	-0.8%
5 Noncore C&I	11.581	11.581	0.00	0.0%	11.581	0.00	0.0%	11.581	0.00	0.0%	11.581	0.00	0.0%	11.581	0.00	0.0%
6 System Total	19.056	18.986	-0.069	-0.4%	19.606	0.620	3.3%	20.464	0.857	4.4%	20.761	0.298	1.5%	20.632	-0.129	-0.6%

Attachment RWH 14-14

San Diego Gas & Electric Company

Gas Transportation Rate Impacts

Including Other Benefits

	2006	2007			2008			2009			2010			2011		
			Change			Change			Change			Change			Change	
	¢/thm	¢/thm	¢/thm	%	¢/thm	¢/thm	%	¢/thm	¢/thm	%	¢/thm	¢/thm	%	¢/thm	¢/thm	%
1 Residential	54.863	54.577	-0.29	-0.5%	57.107	2.53	4.6%	60.595	3.49	6.1%	61.771	1.18	1.9%	61.232	-0.54	-0.9%
2 Core C&I	30.677	30.625	-0.05	-0.2%	31.090	0.47	1.5%	31.731	0.64	2.1%	31.948	0.22	0.7%	31.849	-0.10	-0.3%
3 NGV	90.151	90.149	0.00	0.0%	90.166	0.02	0.0%	90.188	0.02	0.0%	90.196	0.01	0.0%	90.193	0.00	0.0%
4 Total Core	48.348	48.131	-0.22	-0.4%	50.056	1.93	4.0%	52.710	2.65	5.3%	53.605	0.90	1.7%	53.195	-0.41	-0.8%
5 Noncore C&I	11.581	11.581	0.00	0.0%	11.581	0.00	0.0%	11.581	0.00	0.0%	11.581	0.00	0.0%	11.581	0.00	0.0%
6 System Total	19.056	18.986	-0.069	-0.4%	19.600	0.613	3.2%	20.445	0.845	4.3%	20.730	0.285	1.4%	20.600	-0.131	-0.6%

Attachment RWH 14-15

San Diego Gas & Electric Company

Gas - Residential Typical Customer Bill Impacts

Excluding Other Benefits

2006	2007			2008			2009			2010			2011		
Typical Bill	Typical Bill	Change $	Change %	Typical Bill	Change $	Change %	Typical Bill	Change $	Change %	Typical Bill	Change $	Change %	Typical Bill	Change $	Change %
$ 55.06	$ 54.95	-0.11	-0.2%	$ 55.94	0.99	1.8%	$ 57.30	1.36	2.4%	$ 57.78	0.47	0.8%	$ 57.57	-0.21	-0.4%

Attachment RWH 14-16

San Diego Gas & Electric Company

Gas - Residential Typical Customer Bill Impacts

Including Other Benefits

2006	2007			2008			2009			2010			2011		
Typical	Typical	Change		Typical	Change		Typical	Change		Typical	Change		Typical	Change	
Bill	Bill	$	%	Bill	$	%	Bill	$	%	Bill	$	%	Bill	$	%
$ 55.06	$ 54.95	-0.11	-0.2%	$ 55.93	0.98	1.8%	$ 57.27	1.34	2.4%	$ 57.73	0.45	0.8%	$ 57.52	-0.21	-0.4%