ATTACHMENT A

Morris, Harvey Y.

From: Rashid, Rashid A.
Sent: Sunday, July 20, 2008 5:28 PM
To: Rashid, Rashid A.; jpong@sempra.com
Cc: gwright@semprautilities.com; glenart@semprautilities.com; kkloberdanz@semprautilities.com; Morris, Harvey Y.; Sabino, Pearlie Z.
Subject: Substitute Exhibit
Attachments: extra sempra bcap testimony.pdf

Johnny:

We will not be using the initial BCAP testimony exhibit emailed on Friday. Instead, attached is a new exhibit from the BCAP that will be used for Cross Examination tomorrow.

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From: Rashid, Rashid A.
Sent: Friday, July 18, 2008 5:24 PM
To: jpong@sempra.com
Cc: 'gwright@semprautilities.com'; 'glenart@semprautilities.com'; kkloberdanz@semprautilities.com; Morris, Harvey Y.; Sabino, Pearlie Z.
Subject: Cross Exhibits

Hi Johnny:

I've attached DRA's Cross Examination Exhibits for SDG&E/SoCalGas' witnesses. In addition to the attachments, DRA will refer to the data responses for this proceeding. I will send a more refined and detailed list will by Sunday. In that list, we will refer to the exact data responses as well.

I've scanned all the hard copy documents on one file (again, these do not include the data responses for the current proceeding).

The attached exhibits include documents that have been:

1) obtained from the docket or record of other proceedings (such as the instant BCAP or current/prior Low Income/CARE budget Applications) or
2) filed by SDG&E/SoCalGas via Advice Letter;
3) in SDG&E/SoCalGas tariffs; and
4) downloaded from SDG&E/SoCalGas' webpage.

Again, please expect DRA's final exhibits, which will most likely be less than the current attached exhibits and identify the Data Responses DRA will use from the instant Application, by Sunday.

Please note that our network will be down over the weekend (and pass the word along) and you will most likely receive an email from my personal email account rashidsf@gmail.com. If you need to contact me, write to that email. Also, I will be checking my work voice mail over the weekend for messages

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2009, in Their Biennial Cost Allocation Proceeding.	Application 08-02-_____ (Filed February 4, 2008)

APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY IN THE 2009 BIENNIAL COST ALLOCATION PROCEEDING

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Southern California Gas Company

February 4, 2008

III. ESTIMATE OF RATE IMPACT

As more fully detailed in the testimony of Mr. Lenart using the preferred Embedded Cost approach for cost allocation, SoCalGas' proposed rates in this Application would result in total annual revenues that are approximately $67 million, or 4 percent, greater than revenues at present rates consistent with the Utilities' already authorized revenue requirement. Revenues from SoCalGas core customers will increase approximately $66 million, a 4.7 percent increase from core revenues at present rates. Revenues from SoCalGas noncore (including wholesale and international) customers will decrease approximately $35 million annually, a 16 percent decrease from noncore revenues at present rates. Revenues from shippers on SoCalGas from the recently approved FAR charge are expected to be $46 million.

As more fully detailed in the testimony of Mr. Bonnett using the preferred Embedded Cost approach for cost allocation, SDG&E's proposed rates in this Application would result in total annual revenues that will decrease approximately $11 million or 3.9 percent from revenues at present rates consistent with the Utilities' already authorized revenue requirement. Revenues from SDG&E core customers will decrease by approximately $3 million, a 1.4 percent decrease from core revenues at present rates. Revenues from noncore customers will decrease by approximately $14 million annually, a 35 percent decrease from noncore revenues at present rates. Revenues from shippers on SDG&E from the recently approved FAR charge are expected to be $7 million.

In the alternative, Applicants have developed rates utilizing the LRMC approach for cost allocation purposes. In that event, SoCalGas rates in this Application would increase total revenues by approximately $48 million, or 2.9 percent, annually, compared

Application No: A.08-02-
Exhibit No.:
Witness: Herbert S. Emmrich

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2009, in Their Biennial Cost Allocation Proceeding.	)	A.08-02-___ (Filed February 4, 2008)

PREPARED DIRECT TESTIMONY

OF HERBERT S. EMMRICH

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

DEMAND FORECASTS AND RELATED ISSUES

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
February 4, 2008

Table 2 shows the composition of SoCalGas' throughput forecast for 2009, 2010 and 2011 under Average Temperature Year conditions and Table 3 shows demand under Cold Year Temperature conditions.

Table 2

Composition of SoCalGas Throughput (MDth) Average Temperature Year

	2009	2010	2011	2-Year Avg. 2009-2010	3-Year Avg. 2009-2011
Core					
Residential	247,209	248,403	249,585	247,806	248,399
Core C&I	98,245	97,129	95,782	97,687	97,052
Gas AC	124	124	116	124	121
Gas Engine	1,819	1,808	1,797	1,813	1,808
NGV	10,332	11,666	13,172	10,999	11,723
Total Core	357,727	359,129	360,453	358,428	359,103
Non-Core					
Non-core C&I	143,918	144,034	144,097	143,976	144,016
Electric Generation	283,888	280,328	283,873	282,108	282,696
EOR	17,684	14,586	14,586	16,135	15,619
Total Retail Non-core	445,490	438,948	442,556	442,219	442,331
Wholesale and International					
Long Beach	11,730	11,684	11,715	11,707	11,709
SDG&E	125,323	127,180	116,583	126,251	123,029
Southwest Gas	7,951	8,174	8,396	8,063	8,174
Vernon	11,500	11,622	11,718	11,561	11,613
Mexicali	5,366	5,414	5,417	5,390	5,399
Total Wholesale & Intl.	161,869	164,074	153,828	162,972	159,924
Average Year Throughput	965,086	962,151	956,836	963,619	961,358

PREPARED DIRECT TESTIMONY
OF GARY LENART

I. QUALIFICATIONS

My name is Gary G. Lenart. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I am employed by the Southern California Gas Company (SoCalGas) as a Principal Regulatory Economic Advisor in the Regulatory Affairs Department for SoCalGas and San Diego Gas & Electric Company (SDG&E).

I hold a Bachelor of Science degree in Business Finance and Computer Science from Bradley University in Peoria, Illinois and a Master of Business Administration from California State University at Northridge, California. I have been employed by SoCalGas since 1988, and have held positions of increasing responsibilities in the Accounting, Strategic Planning, New Product Development, Customer Service & Information, and Regulatory Affairs departments. I have been in my current position as Principle Regulatory Economic Advisor since April, 2006. In my current position, I am responsible for cost allocation and rate design for both utilities.

I have previously testified before the Commission.

II. PURPOSE

The purpose of my testimony is to sponsor SoCalGas' proposed natural gas transportation rates. Appendix A contains the transportation rate tables under our preferred case. The proposed rates rely upon embedded cost (EC) principles for allocating SoCalGas' authorized base margin costs among customer classes as shown in Mr. Emmrich's cost allocation testimony. A discussion of non-margin costs follows to arrive at the total revenue requirement allocated to each customer class. The rate design of each class within core and noncore is then presented.

III. SUMMARY

The proposed changes in SoCalGas' transportation rates are shown below in table 1. These are the class average transportation rates excluding the proposed charges for Firm Access Rights (FAR). The FAR charge will be collected from core customers in the gas procurement rate and from noncore customers through a separate charge. In order to obtain a comparable rate with present rates, Table 2 has included the FAR charge of $0.5/dth/day in the proposed transportation rates.

Appendix A contains a complete set of rate tables using the Embedded Cost allocation method which represents this proposal. This is the preferred case.

Appendix B contains a complete set of rate tables also using the Embedded Cost allocation method which represents this proposal; however, in keeping with the past practice in BCAP applications, the Present Revenue is derived using the present rate for each rate tier applied to the proposed volumes for that tier. The average rates of each class represent the sum of the revenue of each tier divided by the proposed volumes for that class. The proposed rates and volumes are the same as in Appendix A and also represent the preferred case.

Appendix C contains a complete set of rate tables using the Long Run Marginal Cost allocation method. This is the "compliance" case.

Table 1
Class Average Rates $/therm

	Present	Proposed	Increase (decrease)	% change
Residential	$0.456	$0.488	$0.031	7%
Core C&I	$0.289	$0.257	($0.032)	-11%
Noncore C&I	$0.063	$0.043	($0.020)	-32%
Electric Generation	$0.035	$0.031	($0.004)	-11%
Wholesale & International	$0.013	$0.020	$0.007	51%
Firm Access Rights (FAR)	$0.000	$0.005	$0.005	n/a
System Total	$0.175	$0.183	$0.008	5%

Table 2
Class Average Rates Including FAR charge $/therm

	Present	Proposed	Increase (decrease)	% change
Residential	$0.456	$0.493	$0.036	8%
Core C&I	$0.289	$0.262	($0.027)	-9%
Noncore C&I	$0.063	$0.048	($0.015)	-24%
Electric Generation	$0.035	$0.036	$0.001	3%
Wholesale & International	$0.013	$0.025	$0.012	88%
System Total	$0.175	$0.183	$0.008	5%

The proposed rates reflect a change in the natural gas transportation revenue requirement of $67 million, which is a 4 percent increase over the revenue requirements which comprise present rates. This increase is due to increases in the cost of gas for gas transmission compression and unaccounted for gas, reduction in revenues from the enhanced oil recovery market and a net increase in the regulatory accounts balances.

The rate results in this filing are based on several inputs, including but not limited to, the proposed allocation of base margin costs to specific customer classes, the allocation of other operating costs such as Company-Use Fuel, the amortization of balances in authorized regulatory accounts to specific customer classes, and the class-specific demand forecasts sponsored by other SoCalGas witnesses. Mr. Emmrich's cost allocation testimony sponsors the allocation of base margin costs among customer classes using an EC methodology. The cost allocation process is completed by adding the non-base margin cost allocation results. These non-base margin costs include other operating costs (such as UAF gas and company-use fuel for Transmission, Load Balancing related Storage); Regulatory account amortizations (such as CFCA and NFCA); and miscellaneous cost adjustments (such as the EOR credit and core averaging adjustments). Mr. Ahmed proposes the estimate of the balances in the authorized regulatory accounts to be amortized in rates. In the final cost allocation process, all the costs and demand forecasts are assembled to derive the rates by customer class. In the rate design section, the development of specific unit charges to recover the class specific revenue requirements based on the proposed throughput by customer class for the cost allocation period is discussed.

The following summarizes the proposals that differ from current ratemaking practices:

1) Reflects an EC allocation of authorized base margin costs in effect on January 1, 2008 as discussed in Mr. Emmrich's cost allocation testimony.
2) Reflects an annualized average throughput forecast based on a three-year cost allocation period, January 2009 through December 2011 as sponsored by Mr. Emmrich's demand forecast testimony.
3) Reflects rates consistent with the Commission's Firm Access Rights (FAR) decision (D.06-12-031).

IV. COST ALLOCATION

A. Overview

Cost allocation is a two-step process where an overall revenue requirement is developed and then the revenue requirement is allocated to specific customer classes. The revenue requirement broadly consists of base margin and non-base margin (non-margin) costs. Base margin costs include what is generally considered the utility's authorized gas margin for O&M expenses, return, depreciation and taxes. The cost allocation process sponsored by Mr. Emmrich uses the EC methodology to functionalize these costs into Customer-related, Distribution-related, Transmission-related, Storage-related, and Marketing costs not recovered in other rates and further allocates them to customer classes. Revenue from FAR charges is then deducted in order to arrive at the base margin used in developing transportation rates.

Non-margin costs (for ratemaking purposes) reflect all other costs not considered "margin costs" incurred by the utility to provide basic transportation services to its customers during the forecasted BCAP period. These costs reflect, but are not limited to, unaccounted-for (UAF) gas, company-use fuel, regulatory account amortizations, and the enhanced oil recovery ("EOR") credit.

Except as noted in Section II of this testimony, the methods employed to develop and allocate non-margin costs are consistent with the methods employed to develop the SoCalGas transportation rates adopted in D.00-04-060, SoCalGas' most recent BCAP decision.

B. Non-Margin Costs

Non-margin costs are aggregated into the following three categories:

- Other operating costs (such as UAF gas and company-use fuel for Transmission, Load Balancing related Storage and miscellaneous usage);
- Regulatory account amortizations (such as CFCA and NFCA); and
- Miscellaneous cost adjustments (such as the EOR credit and core de-averaging).

[illegible]

Transportation Rate Revenues

Southern California Gas Company

2009 BIENNIAL COST ALLOCATION PROCEEDING

Embedded Cost

FINAL v2-1-2008

	Present Rates			Proposed Rates			Changes			Proposal w/FAR (3)	
	Jan-1-08 Volumes Mth	Jan-1-08 Revenues $000's	Average Rate $/therm	BCAP Volumes mtherms	Proposed Revenues $000's	Proposed Rate $/therm	Revenue Change $000's	Rate Change $/therm	% Rate change %	Proposed Rate w/FAR	$0.00500 rate change
	A	B	C	E	F	G	H	I	J	K	L
[illegible]											
[illegible]ial	2,546,852	$1,161,988	$0.45624	2,463,989	$1,211,449	$0.48770	$49,461	$0.03146	6.9%	$0.49270	$0.03646
[illegible]ial & Industrial	834,635	$241,371	$0.28919	970,519	$249,439	$0.25702	$8,066	($0.03215)	-11.1%	$0.26302	($0.02718)
[illegible] Pre SempraWide (1)				117,231	$7,704	$0.06571				$0.07071	
[illegible] SempraWide Adjustment					$850						
[illegible] Post SempraWide				117,231	$8,554	$0.07297				$0.07797	
[illegible]C	1,200	$157	$0.13097	1,210	$59	$0.04892	($98)	($0.08205)	-62.6%	$0.05392	($0.07705)
[illegible]ngine	16,040	$1,959	$0.12212	18,080	$2,093	$0.11575	$134	($0.00637)	-5.2%	$0.12075	($0.00137)
[illegible] Core	3,398,727	$1,405,475	$0.41353	3,591,030	$1,471,594	$0.40980	$66,119	($0.00373)	-0.9%	$0.41480	
[illegible]CORE COMMERCIAL & INDUSTRIAL											
[illegible] Level Service	1,156,023	$83,124	$0.07191	982,465	$49,343	$0.05022	($33,782)	($0.02168)	-30.2%	$0.05522	($0.01668)
[illegible] Level Service (2)	300,734	$8,616	$0.02865	457,697	$12,652	$0.02764	$4,036	($0.00101)	-3.5%	$0.03264	$0.00399
[illegible] Noncore C&I	1,456,757	$91,740	$0.06298	1,440,163	$61,994	$0.04305	($29,745)	($0.01993)	-31.6%	$0.04805	($0.01493)
[illegible] ELECTRIC GENERATION											
[illegible] Level Service (2008 is all EG, no separate transmission rate in 2008)											
[illegible] Sempra Wide	2,944,257	$101,873	$0.03460	612,215	$21,451	$0.03504				$0.04004	
[illegible] Wide Adjustment		$1,452			$2,033						
[illegible] Post Sempra Wide	2,944,257	$103,325	$0.03509	612,215	$23,484	$0.03836				$0.04336	
[illegible] Level Service (2)				2,214,749	$64,863	$0.02929				$0.03429	
[illegible] Electric Generation	2,944,257	$103,325	$0.03509	2,826,964	$88,348	$0.03125	($14,979)	($0.00384)	-10.9%	$0.03625	$0.00116
[illegible]SALE & INTERNATIONAL											
[illegible] Long Beach (2)	77,821	$2,589	$0.03327	117,093	$3,419	$0.02920	$830	($0.00407)	-12.2%	$0.03420	$0.00093
[illegible] Wholesale	1,445,680	$14,618	$0.01011	1,230,285	$21,282	$0.01730	$6,664	$0.00719	71.1%	$0.02230	$0.01219
[illegible] SWG (2)	91,672	$2,847	$0.03106	81,737	$2,513	$0.03075	($334)	($0.00031)	-1.0%	$0.03575	$0.00469
[illegible] Vernon (2)	51,620	$1,442	$0.02794	116,135	$3,212	$0.02766	$1,770	($0.00028)	-1.0%	$0.03266	$0.00472
[illegible] (2)	36,419	$1,090	$0.02993	53,990	$1,495	$0.02769	$405	($0.00224)	-7.5%	$0.03269	$0.00276
[illegible] Wholesale & International	1,703,212	$22,566	$0.01325	1,599,240	$31,921	$0.01996	$9,355	$0.00670	50.5%	$0.02496	$0.01170
[illegible] NONCORE	6,104,226	$217,651	$0.03566	5,866,366	$182,263	$0.03107	($35,388)	($0.00459)	-12.9%	$0.03607	$0.00041
[illegible] to NSBA		$15,683					($15,683)				
[illegible] Storage		$21,000			$26,716		$5,716				
[illegible] FAR)	9,502,953	$1,659,808	$0.17466	9,457,396	$1,680,572	$0.17770	$20,764	$0.00304	1.7%	$0.18270	$0.00804
[illegible] (SCG end users only)					$46,274						
[illegible] TOTAL w/BBFAR,TLS,SW	9,502,953	$1,659,808	$0.17466	9,457,396	$1,726,846	$0.18259	$67,038	$0.00793	4.5%		
[illegible]	482,707	$22,790	$0.04719	156,187	$5,157	$0.03302					
[illegible] Throughput	9,985,661			9,613,583							

[illegible] rates, NGV is not directly allocated costs and is not calculated on Sempra-Wide basis.
[illegible] Table 1. See Table 3 for Present NGV Rates.
[illegible] costs and rates for Transmission Level Service customers represents the average transmission rate and revenue of each class.
[illegible] for actual transmission level service rate.
[illegible] is proposed as a separate rate. Core will pay through procurement rate, noncore as a separate charge.
[illegible] comparison to present rates, this column reflects FAR charge added to each rate.
[illegible] paid will vary based on capacity reserved and volumes used. 100% load factors is implied in column. See Table 5 for actual FAR charge.

TABLE 1

Gas Transportation Rate Revenues

San Diego Gas & Electric

2009 BIENNIAL COST ALLOCATION PROCEEDING

Embedded Cost Approach

v2-1-2008

		At Present Rates			At Proposed Rates			Changes				Proposal w/FAR	
		Jan-1-08 Volumes	Jan-1-08 Revenues	Average Rate	BCAP Volumes	Jan-1-09 Revenues	Average Rate	Revenues	Rates	Rate change		FAR = 2009BCAP	$0.00500 rate
		A	B	D	E	F	G	H	I	J		w/FAR	change
		mtherms	$1,000 1/	$/therm	mtherms	$1,000 1/	$/therm	$1,000	$/therm	%			
	1/	326,207	$189,454	$0.58078	326,003	$183,448	$0.56272	($6,006)	($0.01806)	-3.1%	1	$0.56772	($0.01306)
…GT	1/	129,794	$37,602	$0.28970	158,725	$43,138	$0.27178	$5,537	($0.01792)	-6.2%	2	$0.27678	($0.01292)
	1/	4,030	$3,782	$0.93850	15,238	$1,911	$0.12542	($1,871)	($0.81308)	-86.6%	3	$0.13042	($0.80808)
					15,238	($850)	($0.05581)	($850)	($0.05581)		4		
		4,030	$3,782	$0.93850	15,238	$1,061	$0.06961	($2,721)	($0.86889)	-92.6%	5	$0.07461	($0.86389)
											6		
…stments		460,031	$230,836	$0.50179	499,967	$228,498	$0.45703	($2,340)	($0.04476)	-8.9%	7	$0.46203	($0.03976)
…ustments		460,031	$230,838	$0.50179	499,967	$227,648	$0.45533	($3,190)	($0.04646)	-9.3%	8	$0.46033	($0.04146)
…DISTRIBUTION LEVEL SERVICE											9		
…D	1/	75,085	$6,577	$0.08769	37,270	$4,425	$0.11872	($2,152)	$0.03104	35.4%	10	$0.12372	$0.03604
…(2009 is D&T service)											11		
…wide	1, 2/	897,926	$34,606	$0.03854	179,522	$9,236	$0.05145	($25,370)	$0.01291	33.5%	12	$0.05645	$0.01791
	1, 3/	897,926	($1,452)	($0.00162)	179,522	($2,033)	($0.01133)	($581)	($0.00971)	600.5%	13	($0.00633)	($0.00471)
		897,926	$33,154	$0.03692	179,522	$7,203	$0.04012	($25,951)	$0.00320	8.7%	14	$0.04512	$0.00820
…Distribution		972,931	$39,731	$0.04084	216,792	$11,627	$0.05363	($28,103)	$0.01280	31.3%	15	$0.05863	$0.01780
											16		
…TRANSMISSION LEVEL SERVICE											17		
…T	1/	11,206	$513	$0.04577	3,193	$86	$0.02697	($427)	($0.01880)	-41.1%	18	$0.03197	($0.01380)
…	1, 2/				496,393	$14,388	$0.02899				19	$0.03399	
…Transmission		11,206	$513	$0.04577	499,587	$14,474	$0.02897	$13,961	($0.01680)	-36.7%	20	$0.03397	($0.01180)
											21		
		984,137	$40,243	$0.04089	716,379	$26,102	$0.03644	($14,142)	($0.00446)	-10.9%	22	$0.04144	$0.00054
											23		
…Backbone Transmission											24		
…ip		1,444,168	$272,534	$0.18871	1,216,345	$256,633	$0.21099	($15,900)	$0.02227	11.8%	25	$0.21599	$0.02727
…t -NGV			$0			($850)					26		
…t -EG			($1,452)			($2,033)					27		
…ments		1,444,168	$271,082	$0.18771	1,216,345	$253,749	$0.20862	($17,332)	$0.02091	11.1%	28	$0.21362	$0.02591
											29		
						$6,764		$6,764			30		
											31		
		1,444,168	$271,082	$0.18771	1,216,345	$260,513	$0.21418	($10,568)	$0.02647	14.1%	32		

…Rates reflect gas rates filed in AL 1760-G, effective January 1, 2008.

…Present and Proposed Rates exclude all costs related to SDG&E procurement, including CITCS charges.

…Semprawide reflects a "stand-alone" EG rate for transportation service through both SDG&E and SoCalGas.

…Adjustment reflects the Semprawide rate adjustment to equalize the EG rates of SDG&E and SoCalGas.

ATTACHMENT B

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2009, in Their Biennial Cost Allocation Proceeding.	Application 08-02-______ (Filed February 4, 2008)

APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY IN THE 2009 BIENNIAL COST ALLOCATION PROCEEDING

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Attorneys for:
San Diego Gas & Electric Company and
Southern California Gas Company

February 4, 2008

III. ESTIMATE OF RATE IMPACT

As more fully detailed in the testimony of Mr. Lenart using the preferred Embedded Cost approach for cost allocation, SoCalGas' proposed rates in this Application would result in total annual revenues that are approximately $67 million, or 4 percent, greater than revenues at present rates consistent with the Utilities' already authorized revenue requirement. Revenues from SoCalGas core customers will increase approximately $66 million, a 4.7 percent increase from core revenues at present rates. Revenues from SoCalGas noncore (including wholesale and international) customers will decrease approximately $35 million annually, a 16 percent decrease from noncore revenues at present rates. Revenues from shippers on SoCalGas from the recently approved FAR charge are expected to be $46 million.

As more fully detailed in the testimony of Mr. Bonnett using the preferred Embedded Cost approach for cost allocation, SDG&E's proposed rates in this Application would result in total annual revenues that will decrease approximately $11 million or 3.9 percent from revenues at present rates consistent with the Utilities' already authorized revenue requirement. Revenues from SDG&E core customers will decrease by approximately $3 million, a 1.4 percent decrease from core revenues at present rates. Revenues from noncore customers will decrease by approximately $14 million annually, a 35 percent decrease from noncore revenues at present rates. Revenues from shippers on SDG&E from the recently approved FAR charge are expected to be $7 million.

In the alternative, Applicants have developed rates utilizing the LRMC approach for cost allocation purposes. In that event, SoCalGas rates in this Application would increase total revenues by approximately $48 million, or 2.9 percent, annually, compared

Application No: A.08-02-001
Exhibit No.:
Witness: Herbert S. Emmrich

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2009, in Their Biennial Cost Allocation Proceeding.

A.08-2-001
(Filed February 4, 2008)

PREPARED DIRECT TESTIMONY

OF HERBERT S. EMMRICH

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

DEMAND FORECASTS AND RELATED ISSUES

PHASE II

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
April 24, 2008

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PREPARED DIRECT TESTIMONY OF HERBERT S. EMMRICH

I. QUALIFICATIONS

My name is Herbert S. Emmrich. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011. I am employed by Southern California Gas Company (SoCalGas) as Gas Demand Forecasting Manager in the Regulatory Affairs Department. I am responsible for the development of natural gas demand forecasts for San Diego Gas & Electric Company (SDG&E) and SoCalGas. I have been in this position since March 2004. I have previously testified before the California Public Utilities Commission ("Commission").

My academic and professional qualifications are as follows: I earned an undergraduate degree in Economics and Behavioral Sciences from California State University at Dominguez Hills in 1970 and a Master of Arts Degree in Economics from California State University at Long Beach in 1974. In addition, during the past 21 years, I held analyst, manager and director level positions in the Regulatory Affairs, Planning, Customer Services, Marketing, Gas Supply and Commercial and Industrial Services Departments of SoCalGas:

- Demand Forecasting and Economic Analysis Manager, Regulatory Affairs Department (March 2004 – Present);
- Regulatory Strategy Manager, Regulatory Affairs Department (2003 –2004);
- Principal Regulatory Policy Analyst, Regulatory Affairs Department (2002 – 2003);
- Director of Special Projects, Commercial and Industrial Services Department (1997 - 1998);
- Director of Sales and Gas Supply Forecasting, Commercial and Industrial Services Department, (1995 - 1997);
- Project Manager, Gas Supply Department (1994 - 1995);
- Gas Supply Planning and Forecasting Manager, Gas Supply Department (1993 - 1994);
- Gas Demand Forecast Manager, Marketing Department (1991 – 1993);

- Project Manager, Customer Services Department, Southern California Gas Company (1990 - 1991);
- Senior Analyst, Strategic Planning Department (1984 - 1990).

My employment outside of SoCalGas has been in the areas of economics, environmental assessment, and business planning and energy sector development. I held the positions of: Economist, Regional Economist and Environmental Assessment Manager at the U.S. Bureau of Land Management's Pacific Outer Continental Shelf Office, in Los Angeles, from 1975 to 1979; Economic Policy Supervisor and Issues and Policy Manager of Getty Oil Company from 1979 to 1984; and, Senior Energy Advisor of the U.S. Agency for International Development's Caucasus Office in Tbilisi, Republic of Georgia, from 1998 to 2002.

II. PURPOSE

The purpose of my testimony is to present the average temperature year, cold temperature year and extreme design peak day gas demand forecasts for the years 2009 through 2011 for SDG&E and SoCalGas' residential, core commercial and industrial, non-core commercial and industrial, enhanced oil recovery (EOR), natural gas vehicle (NGV), wholesale customer classes, and ECOGAS in Mexicali, Mexico. The details of the electric generation (EG) and cogeneration forecasts of gas demand are shown in the prepared direct testimony of Mr. Anderson. My testimony also presents the gas prices used to forecast demand by customer segment. My testimony presents SDG&E and SoCalGas' unaccounted-for (UAF) gas and company-use fuel requirements and their allocation to the core and non-core customer classes.

III. SOCALGAS' GAS DEMAND FORECASTS (2009 – 2011)

A. Introduction

SoCalGas is the principal distributor of natural gas in southern California, providing retail and wholesale customers with procurement, transportation, and storage services. In addition to serving the residential, commercial, and industrial markets, SoCalGas provides gas for the EOR and EG markets in southern California. SDG&E, Southwest Gas Corporation (SWG), the City of Vernon (Vernon), and the City of Long Beach Gas and Oil Department (Long Beach) are SoCalGas' four wholesale customers. SoCalGas also provides gas service to

ECOGAS in Mexicali, Mexico. The forecast begins with a discussion of the economic conditions facing the utilities, followed by a discussion of the factors affecting gas demand in various market sectors.. Summary tables and figures underlying the forecast are provided.

B. Economics and Customer Growth

From 2006 through 2011, SoCalGas service-area non-farm jobs should see nearly 1.1% average annual growth. Area industrial jobs should remain essentially flat during this period, and we expect the industrial share of non-farm employment to fall from 11.1% to 10.3%. Commercial jobs should average 1.2% annual growth from 2006 through 2011. Mainly as a result of growing numbers of residents, we expect SoCalGas' total active meters to increase an average of about 1.3% per year from 5.392 million in 2006 to 5.745 million in 2011. Table 1 details SoCalGas' expected meter counts during the 2009 to 2011 BCAP period.

Table 1

SoCalGas Active Meters (annual averages)

	2009	2010	2011	2-Year Avg. 2009-2010	3-Year Avg. 2009-2011
Core					
Residential	5,383,344	5,455,319	5,527,388	5,419,331	5,455,350
Core C&I	214,540	215,333	215,986	214,936	215,286
Gas AC	16	16	15	16	16
Gas Engine	850	845	840	848	845
NGV	257	273	289	265	273
Total Core	5,599,007	5,671,785	5,744,517	5,635,396	5,671,770
Non-Core					
Non-core C&I	706	705	705	706	705
Electric Generation	226	219	213	223	219
EOR	32	32	32	32	32
Total Retail Non-core	964	956	950	960	957
Wholesale and International	5	5	5	5	5
System Total Active Meters	5,599,976	5,672,746	5,745,472	5,636,361	5,672,732

SoCalGas uses econometric and statistical techniques to develop forecasts of residential single family, residential multi-family, commercial and industrial meters. Major economic and demographic assumptions underlying the meter forecast are from Global Insight's Spring 2007

Regional forecast (state-level and the six most populous counties in SoCalGas' service territory) released in May 2007.

Connected residential single-family and multi-family meters are a function of lagged authorized housing permits. A small third sector of the residential class --master meters (including sub-metered customers) -- is forecasted to decline at a steady 0.8% annual rate. Connected meters in the industrial and commercial sectors are forecasted based on lagged employment in those corresponding sectors.

Once the number of connected meters is forecasted for each customer class, it is split into active and inactive meters, where inactive meters are those with no billed gas use during a billing period. Inactive meters are forecasted by applying a factor to each customer class of forecasted connected meters. The factors used are based on seasonal and multi-year historical patterns of inactive meters for that particular customer class. The number of active meters is equal to the number of connected meters less the number of inactive meters.

Both the core commercial and core industrial active meters are forecasted based on recent historical ratios of those core active meters to their total active commercial and industrial meters, respectively. For gas air conditioning (GAC), we expect 16 meters for years 2009 and 2010 and 15 for year 2011. The number of gas engine meters is expected to decline from 878 in 2006 to 840 in 2011.

C. Gas Demand

We expect continued gas demand growth in the residential market, as well as in associated service-oriented businesses in the commercial market. These markets, along with small- and medium-sized industrial customers, comprise the core market. The remaining large customers make up the non-core market. There has been some movement between the two markets. Since the last BCAP in 1999, through 2007, a net number of 337 customers shifted from the non-core to the core market; in 2007 this resulted in a net throughput shift of 3,214 MDth from the non-core to the core market.

Table 2 shows the composition of SoCalGas' throughput forecast for 2009, 2010 and 2011 under Average Temperature Year conditions and Table 3 shows demand under Cold Year Temperature conditions.

Table 2

Composition of SoCalGas Throughput (MDth) Average Temperature Year

	2009	2010	2011	2-Year Avg. 2009-2010	3-Year Avg. 2009-2011
Core					
Residential	247,209	248,403	249,585	247,806	248,399
Core C&I	98,245	97,129	95,782	97,687	97,052
Gas AC	124	124	116	124	121
Gas Engine	1,819	1,808	1,797	1,813	1,808
NGV	10,332	11,666	13,172	10,999	11,723
Total Core	357,727	359,129	360,453	358,428	359,103
Non-Core					
Non-core C&I	143,918	144,034	144,097	143,976	144,016
Electric Generation	283,888	280,328	283,873	282,108	282,696
EOR	17,684	14,586	14,586	16,135	15,619
Total Retail Non-core	445,490	438,948	442,556	442,219	442,331
Wholesale and International					
Long Beach	11,730	11,684	11,715	11,707	11,709
SDG&E	125,323	127,180	116,583	126,251	123,029
Southwest Gas	7,951	8,174	8,396	8,063	8,174
Vernon	11,500	11,622	11,718	11,561	11,613
Mexicali	5,366	5,414	5,417	5,390	5,399
Total Wholesale & Intl.	161,869	164,074	153,828	162,972	159,924
Average Year Throughput	965,086	962,151	956,836	963,619	961,358

Table 3

Composition of SoCalGas Throughput (MDth) 1-in-35 Cold Temperature Year

	2009	2010	2011	2-Year Avg. 2009-2010	3-Year Avg. 2009-2011
Core					
Residential	271,041	272,350	273,646	271,695	272,346
Core C&I	103,027	101,858	100,446	102,442	101,777
Gas AC	124	124	116	124	121
Gas Engine	1,819	1,808	1,797	1,813	1,808
NGV	10,332	11,666	13,172	10,999	11,723
Total Core	386,342	387,805	389,178	387,073	387,775
Non-Core					
Non-core C&I	144,375	144,491	144,553	144,433	144,473
Electric Generation	283,888	280,328	283,873	282,108	282,696
EOR	17,684	14,586	14,586	16,135	15,619
Total Retail Non-core	445,946	439,405	443,013	442,676	442,788
Wholesale and International					
Long Beach	12,385	12,339	12,370	12,362	12,364
SDG&E	130,649	132,532	121,950	131,590	128,377
Southwest Gas	8,149	8,380	8,610	8,264	8,380
Vernon	11,500	11,622	11,718	11,561	11,613
Mexicali	5,366	5,414	5,417	5,390	5,399
Total Wholesale & Intl.	168,048	170,286	160,065	169,167	166,133
Cold Year Throughput	1,000,336	997,496	992,255	998,916	996,696

D. SoCalGas' Customer Segment Demand

1. Residential

Active residential meters averaged 5.18 million in 2006, an increase of about 1.3% from the 2005 average. From 2009 through 2011, SoCalGas' active residential customer base is expected to grow at an average annual rate of 1.3%, reaching nearly 5.53 million by 2011.

Residential gas demand adjusted for temperature decreased to 250,616 MDth in 2006 from 259,267 MDth in 2005. Temperature-adjusted residential demand is projected to grow from 247,209 MDth in 2009 to 249,585 MDth in 2011, an increase of about 2,376 MDth or 0.5% per year. This forecast reflects the savings from SoCalGas' energy efficiency programs, which are described in Commission Decision 04-09-060, and in SoCalGas' Advice Letter 3588 of February 1, 2006.

2. Commercial

On a temperature-adjusted basis, core commercial market demand in 2006 totaled 79,429 MDth, up 409 MDth from the 2005 commercial load totaling 79,020 MDth. This increase is largely the result of economic growth in southern California. Over the BCAP period, core commercial market demand is forecasted to decrease about 1.2% per year dropping from 76,832 MDth in 2009 to 75,059 MDth by 2011. This decrease is due to Commission-mandated energy efficiency savings programs.

During the BCAP period from 2009 to 2011, non-core commercial demand is forecasted to average nearly 22,500 MDth per year, slightly higher than 2006 actual usage of 22,400 MDth. Most of the increasing demand from the lodging, health, office buildings and agricultural sectors is being offset by decreased demand in the construction sector. The net gain of 1.2% from economic growth is expected to be reduced by a loss of -0.7% from mandated demand-side management (DSM) savings, and by the departure in 2008 of two customers to the City of Vernon (a wholesale customer).

Table 4

Average Year Commercial Demand Forecast in MDth

	2009	2010	2011	2 Year Avg. 2009-2010	3 Year Avg. 2009-2011
Core Commercial	76,832	76,046	75,059	76,439	75,979
Non-core Commercial	22,367	22,491	22,588	22,429	22,482
Total	99,199	98,537	97,647	98,868	98,461

3. Industrial

In 2006, temperature-adjusted core industrial demand was 23,926 MDth, an increase of 76 MDth (0.3%) over 2005 deliveries. Core industrial market demand is projected to decrease by 2.8% per year from 2006 to 20,723 MDth in 2011. This demand decrease stems mainly from Commission-mandated energy efficiency savings for the years 2006 through 2011.

Retail non-core industrial demand grew from 62,600 MDth in 2005 to 63,200 MDth in 2006 due to increased activities in the food processing and petroleum sectors. However, this growth is not sustained in the BCAP period from 2009 through 2011, and annual gas demand for this market is expected to drop below 58,000 MDth -- an 8% drop from the 2006 level. Twenty-two percent of this drop is caused by an overall decrease in manufacturing activities, especially the textile and primary metal manufacturing sectors. Seventy-three percent of this drop is caused by the 2008 departure of more than two dozen large industrial customers to the City of Vernon (a wholesale customer), and the other 5% of the drop by caused by Commission-mandated energy efficiency savings during the BCAP period.

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, hydrogen producers and petroleum refined product transporters. Refinery industrial demand is forecasted separately from other industrial demand due to the complex nature of these customers. These customers are characterized by a complex interaction of refinery operations, on-site production of alternate fuels, and changing regulatory requirements impacting the production of petroleum products. Refinery industrial demand is forecasted to be stable at nearly 64,000 MDth per year for calendar years 2009 through 2011. This is 3,000 MDth lower than the 67,000 MDth recorded in 2006. This decrease is mainly due to the refineries' use of alternate fuels such as butane during summer months where natural gas prices are forecasted to be less competitive than the alternate fuel prices. The reduction of refinery gas demand also reflects savings from both Commission-mandated energy efficiency programs and other refinery process-related energy-efficient improvements that are ineligible for SoCalGas' energy efficiency programs.

Table 5

Average Year Industrial Demand Forecast in MDth

	2009	2010	2011	2 Year Avg. 2009-2010	3 Year Avg. 2009-2011
Core Industrial	21,412	21,083	20,723	21,247	21,073
Non-core Industrial	57,819	57,872	57,920	57,845	57,870
Industrial Refinery	63,732	63,671	63,588	63,701	63,664
Total	142,963	142,626	142,231	142,794	142,607

4. Electric Power Generation

This sector includes the markets for all industrial/commercial cogeneration, and non-cogeneration EG. Small Industrial/Commercial and refinery cogeneration demand is included in this testimony; the other sectors of electric power generation demand are sponsored by Mr. Anderson and are discussed in his prepared direct testimony.

(a) Industrial/Commercial Cogeneration <20 Megawatts (MW)

Most of the cogeneration units in this non-core segment are installed mainly to generate electricity for customers' internal consumption rather than for power sales to electric utilities. In 2006, gas deliveries to this market were 18,093 MDth, down almost 1,700 MDth from 2005's deliveries of 19,786 MDth. Small Industrial/Commercial cogeneration demand is projected to average 18,668 MDth per year during the BCAP period. The forecast includes an anticipated downward adjustment due to a change in eligibility requirements which will cause some of the non-core cogeneration customers to switch to core service starting in late 2009.

(b) Refinery Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. Refinery-related cogeneration is forecast to remain steady at 18,200 MDth for the 2009 to 2011 BCAP period. This is almost the same as the year 2006 recorded throughput.

5. Enhanced Oil Recovery—Cogeneration and Steaming

The EOR demand forecast is prepared based on historical throughput, knowledge of customer operations, and general market conditions. For the 2009 to 2011 BCAP period, SoCalGas forecasts EOR–related cogeneration usage to average 4,900 MDth per year. This is a decrease from the 2006 recorded gas deliveries of 18,100 MDth. This decrease is mainly due to forecasted increased bypass to the Kern River/Mojave Interstate Pipeline (Kern/Mojave) as EOR long-term gas transportation contracts (LTKs) with SoCalGas expire. Because most of the EOR producers are already connected directly to Kern/Mojave or own laterals in close proximity to facilities that are not currently connected, it is unlikely that SoCalGas will be able to retain much, if any, of the load contracted under the LTKs. The price of intrastate transportation on Kern/Mojave is usually less than SoCalGas' short-run marginal cost and is expected to continue to be so during the BCAP period.

For the 2009 to 2011 BCAP period, SoCalGas forecasts EOR steaming usage to average 10,700 MDth per year. This is a decrease from the 2006 recorded gas deliveries of 14,800 MDth. As explained above, the decrease in this market is mainly due to forecasted increased bypass to Kern/Mojave as EOR LTKs with SoCalGas expire. However, the decrease is partially

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PREPARED DIRECT TESTIMONY

OF GARY LENART

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
July 2, 2008

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APPENDICES A, B, AND C

PREPARED DIRECT TESTIMONY
OF GARY LENART

I. QUALIFICATIONS

My name is Gary G. Lenart. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I am employed by the Southern California Gas Company (SoCalGas) as a Principal Regulatory Economic Advisor in the Regulatory Affairs Department for SoCalGas and San Diego Gas & Electric Company (SDG&E).

I hold a Bachelor of Science degree in Business Finance and Computer Science from Bradley University in Peoria, Illinois and a Master of Business Administration from California State University at Northridge, California. I have been employed by SoCalGas since 1988, and have held positions of increasing responsibilities in the Accounting, Strategic Planning, New Product Development, Customer Service & Information, and Regulatory Affairs departments. I have been in my current position as Principal Regulatory Economic Advisor since April, 2006. In my current position, I am responsible for cost allocation and rate design for both utilities.

I have previously testified before the Commission.

II. PURPOSE

The purpose of my testimony is to sponsor SoCalGas' proposed natural gas transportation rates. Appendix A contains the transportation rate tables under our preferred case. The proposed rates rely upon embedded cost (EC) principles for allocating SoCalGas' authorized base margin costs among customer classes as shown in Mr. Emmrich's cost allocation testimony. A discussion of non-margin costs follows to arrive at the total revenue requirement allocated to each customer class. The rate design of each class within core and noncore is then presented.

III. SUMMARY

The proposed changes in SoCalGas' transportation rates are shown below in table 1. These are the class average transportation rates excluding the proposed charges for Firm Access Rights (FAR). The FAR charge will be collected from core customers in the gas procurement rate and from noncore customers through a separate charge. In order to obtain a comparable rate with present rates, Table 2 has included the FAR charge of $0.05/dth/day in the proposed transportation rates.

Appendix A contains a complete set of rate tables using the Embedded Cost allocation method which represents this proposal. This is the preferred case.

Appendix B contains a complete set of rate tables also using the Embedded Cost allocation method which represents this proposal; however, in keeping with the past practice in BCAP applications, the Present Revenue is derived using the present rate for each rate tier applied to the proposed volumes for that tier. The average rates of each class represent the sum of the revenue of each tier divided by the proposed volumes for that class. The proposed rates and volumes are the same as in Appendix A and also represent the preferred case.

Appendix C contains a complete set of rate tables using the Long Run Marginal Cost allocation method. This is the "compliance" case.

Table 1
Class Average Rates $/therm

	Present	**Proposed**	**Increase (decrease)**	**% change**
Residential	$0.456	$0.489	$0.033	7%
Core C&I	$0.289	$0.255	($0.034)	-12%
Noncore C&I	$0.063	$0.043	($0.020)	-31%
Electric Generation	$0.035	$0.032	($0.004)	-10%
Wholesale & International	$0.013	$0.018	$0.005	36%
Firm Access Rights (FAR)	$0.000	$0.005	$0.005	n/a
System Total	$0.175	$0.183	$0.009	5%

Table 2
Class Average Rates Including FAR charge $/therm

	Present	**Proposed**	**Increase (decrease)**	**% change**
Residential	$0.456	$0.494	$0.038	8%
Core C&I	$0.289	$0.260	($0.029)	-10%
Noncore C&I	$0.063	$0.048	($0.015)	-23%
Electric Generation	$0.035	$0.037	$0.001	4%
Wholesale & International	$0.013	$0.023	$0.010	74%
System Total	$0.175	$0.183	$0.009	5%

The proposed rates reflect a change in the natural gas transportation revenue requirement of $73 million, which is a 5 percent increase over the revenue requirements which comprise present rates. This increase is due to increases in the cost of gas for gas transmission compression and unaccounted for gas, reduction in revenues from the enhanced oil recovery market and a net increase in the regulatory accounts balances.

The rate results in this filing are based on several inputs, including but not limited to, the proposed allocation of base margin costs to specific customer classes, the allocation of other operating costs such as Company-Use Fuel, the amortization of balances in authorized regulatory accounts to specific customer classes, and the class-specific demand forecasts sponsored by other SoCalGas witnesses. Mr. Emmrich's cost allocation testimony sponsors the allocation of base margin costs among customer classes using an EC methodology. The cost allocation process is completed by adding the non-base margin cost allocation results. These non-base margin costs include other operating costs (such as UAF gas and company-use fuel for Transmission, Load Balancing related Storage); Regulatory account amortizations (such as CFCA and NFCA); and miscellaneous cost adjustments (such as the EOR credit and core averaging adjustments). Mr. Ahmed proposes the estimate of the balances in the authorized regulatory accounts to be amortized in rates. In the final cost allocation process, all the costs and demand forecasts are assembled to derive the rates by customer class. In the rate design section, the development of specific unit charges to recover the class specific revenue requirements based on the proposed throughput by customer class for the cost allocation period is discussed.

The following summarizes the proposals that differ from current ratemaking practices:

1) Reflects an EC allocation of authorized base margin costs in effect on January 1, 2008 as discussed in Mr. Emmrich's cost allocation testimony.
2) Reflects an annualized average throughput forecast based on a three-year cost allocation period, January 2009 through December 2011 as sponsored by Mr. Emmrich's demand forecast testimony.

3) Reflects rates consistent with the Commission's Firm Access Rights (FAR) decision (D.06-12-031).
   - FAR charge is $0.05/dth/day;
   - FAR charges for Core customers are excluded from transportation rates and collected through the core procurement rate;
   - FAR charges for noncore customers are excluded from transportation rates and recovered through a separate FAR charge from those customers purchasing FAR.
4) Disposition of four regulatory accounts as discussed by Mr. Ahmed. These accounts are
   - Company-Use Fuel for Load Balancing Account (CUFLBA);
   - Blythe Operational Flow Requirement Memorandum Account (BOFRMA);
   - Firm Access & Storage Rights Memorandum Account (FARSMA);
   - Otay Mesa System Reliability Memorandum Account (OMSRMA).
5) Modifies the allocation of the Noncore Fixed Cost Account and the Core Fixed Cost Account to reflect different allocation methods for the base margin and non-base margin portions of these accounts. SoCalGas is proposing to allocate base margin portions on the basis of Equal Percent Marginal Cost, and the non-base margin portions will continue to be allocated on an Equal Cents-Per-Therm (ECPT) basis. This proposal will not be implemented until the second year of the BCAP period.
6) Modifies the rate design for core commercial and industrial (C&I) customers by reducing the number of monthly customer charges from two to one; removing seasonality in the tier 1 usage threshold; and, allocating base margin costs and core averaging adjustment to rate tiers in proportion to the rate tier differential in current rates and for non base margin costs on an ECPT basis.
7) Removes the cap on the Gas Engine rate.

8) Reflects "Sempra-wide" natural gas vehicle (NGV) rates applicable to both SDG&E and SoCalGas, as sponsored by Mr. Schwecke; and, NGV class will receive an allocation of non-margin items, similar to all other Core classes.

9) SoCalGas proposes to have 100% fully de-averaged core rates by the end of the 3-year cost allocation period.

10) Modifies the rate design for noncore C&I customers by allocating base margin costs to rate tiers in proportion to the rate tier differential in current rates and for non base margin costs on an ECPT basis.

11) Reflects the proposed transmission-level service (TLS) rate for noncore customers of SDG&E and SoCalGas served directly from the transmission system, regardless of end-use, as discussed by Mr. Schwecke. This rate allows for a noncore customer served directly from the transmission system to choose between two rate design options for firm service. Option #1 is a reservation-charge, and Option #2 is a volumetric rate. While both of these options are available for Firm service, only Option #2 is available for Interruptible service. Option #2 is the same rate for both firm and interruptible service. This TLS rate is incurred in addition to any FAR that a noncore customer may purchase.

12) Modifies the rate design for noncore C&I customers by replacing the existing noncore C&I transmission rate with the proposed TLS rate which is applicable to all noncore customers served directly from the transmission system, regardless of end-use.

13) Due to the proposed TLS rate, the "Sempra-wide" electric generation (EG) rate applies to EG customers served from the distribution system. EG customers served from the transmission system pay the proposed TLS rate which is applicable to all customers of SDG&E and SoCalGas that are served from the transmission system.

14) Reflects the elimination of the peaking service rate as proposed by Mr. Schwecke.

15) SoCalGas proposes to remove the allocation of any costs comprising the G-PPPS rate from customer classes that do not pay the G-PPPS rate.

16) Elimination of CARE surcharge for cushion gas.

17) Core customer classes will pay for fuel that is used in storage operations through the procurement rate.

IV. COST ALLOCATION

A. Overview

Cost allocation is a two-step process where an overall revenue requirement is developed and then the revenue requirement is allocated to specific customer classes. The revenue requirement broadly consists of base margin and non-base margin (non-margin) costs. Base margin costs include what is generally considered the utility's authorized gas margin for O&M expenses, return, depreciation and taxes. The cost allocation process sponsored by Mr. Emmrich uses the EC methodology to functionalize these costs into Customer-related, Distribution-related, Transmission-related, Storage-related, and Marketing costs not recovered in other rates and further allocates them to customer classes. Revenue from FAR charges is then deducted in order to arrive at the base margin used in developing transportation rates.

Non-margin costs (for ratemaking purposes) reflect all other costs not considered "margin costs" incurred by the utility to provide basic transportation services to its customers during the forecasted BCAP period. These costs reflect, but are not limited to, unaccounted-for (UAF) gas, company-use fuel, regulatory account amortizations, and the enhanced oil recovery ("EOR") credit.

Except as noted in Section II of this testimony, the methods employed to develop and allocate non-margin costs are consistent with the methods employed to develop the SoCalGas transportation rates adopted in D.00-04-060, SoCalGas' most recent BCAP decision.

B. Non-Margin Costs

Non-margin costs are aggregated into the following three categories:

- Other operating costs (such as UAF gas and company-use fuel for Transmission, Load Balancing related Storage and miscellaneous usage);
- Regulatory account amortizations (such as CFCA and NFCA); and
- Miscellaneous cost adjustments (such as the EOR credit and core de-averaging).

1. Other Operating Costs

Other operating costs include, but are not limited to, UAF gas costs. UAF gas costs were allocated 71% to core customers and 29% to noncore customers based on the core and noncore allocation of UAF as shown in Mr. Emmrich's demand forecast testimony. Within the core and noncore classes, these costs were allocated on an ECPT basis. A notable difference in this filing is that the level of UAF gas costs is substantially higher than UAF gas costs embedded in current rates. This increase is due to substantial increases in gas commodity prices that have been experienced in the marketplace since those costs were adopted several years earlier in the last BCAP decision, D.00-04-060. UAF gas volumes are discussed in Mr. Emmrich's demand forecast testimony.

SoCalGas will continue to recover the three types of company-use fuel costs (Transmission, Load Balancing related Storage and miscellaneous usage) in the transportation rate. Company-use fuels are allocated to customer classes on an ECPT basis. Gas volumes for company-use fuel are developed in the workpapers supporting Mr. Emmrich's demand forecast testimony.

2. Regulatory Account Amortizations

Balances in the authorized regulatory accounts are allocated among customer classes using various parameters, including average-year throughput and allocated base margin costs. For example, the Core Fixed Cost Account (CFCA) balance is allocated on an ECPT basis to core customers only, while the Noncore Fixed Cost Account (NFCA) balance is allocated on an ECPT basis to noncore customers only. Mr. Ahmed explains in his testimony the estimated

TABLE 1
Transportation Rate Revenues
Southern California Gas Company
2009 BIENNIAL COST ALLOCATION PROCEEDING

v6-30-2008 Embedded Cost

		Present Rates			Proposed Rates			Changes			Proposal w/FAR (3)	
		Jan-1-08 Volumes Mth	Jan-1-08 Revenues $000's	Average Rate $/therm	BCAP Volumes mtherms	Proposed Revenues $000's	Proposed Rate $/therm	Revenue Change $000's	Rate Change $/therm	% Rate change %	Proposed Rate w/FAR	$0.00500 rate change
		A	B	C	E	F	G	H	I	J	K	L
1	CORE											
2	Residential	2,546,852	$1,161,988	$0.45624	2,483,989	$1,214,829	$0.48906	$52,842	$0.03282	7.2%	$0.49406	$0.03782
3	Commercial & Industrial	834,635	$241,371	$0.28919	970,519	$247,626	$0.25515	$6,255	($0.03405)	-11.8%	$0.26015	($0.02905)
4	NGV - Pre SempraWide (1)				117,231	$6,482	$0.05529				$0.06029	
5	SempraWide Adjustment					$977						
6	NGV - Post SempraWide				117,231	$7,459	$0.06363				$0.06863	
7	Gas A/C	1,200	$157	$0.13097	1,210	$62	$0.05115	($95)	($0.07982)	-60.9%	$0.05615	($0.07482)
8	Gas Engine	16,040	$1,959	$0.12212	18,080	$2,185	$0.12084	$226	($0.00128)	-1.0%	$0.12584	$0.00372
9	Total Core	3,398,727	$1,405,475	$0.41353	3,591,030	$1,472,162	$0.40996	$66,687	($0.00357)	-0.9%	$0.41496	
10												
11	NONCORE COMMERCIAL & INDUSTRIAL											
12	Distribution Level Service	1,156,023	$83,124	$0.07191	982,465	$49,892	$0.05078	($33,232)	($0.02112)	-29.4%	$0.05578	($0.01612)
13	Transmission Level Service (2)	300,734	$8,616	$0.02865	457,697	$12,314	$0.02690	$3,698	($0.00174)	-6.1%	$0.03190	$0.00326
14	Total Noncore C&I	1,456,757	$91,740	$0.06298	1,440,163	$62,206	$0.04319	($29,534)	($0.01978)	-31.4%	$0.04819	($0.01478)
15												
16	NONCORE ELECTRIC GENERATION											
17	Distribution Level Service (2008 is all EG, no separate transmission rate in 2008)											
18	Pre Sempra Wide	2,944,257	$101,873	$0.03460	612,215	$21,822	$0.03564				$0.04064	
19	Sempra Wide Adjustment		$1,452			$1,718						
20	Post Sempra Wide	2,944,257	$103,325	$0.03509	612,215	$23,540	$0.03845				$0.04345	
21	Transmission Level Service (2)				2,214,749	$65,688	$0.02966				$0.03466	
22	Total Electric Generation	2,944,257	$103,325	$0.03509	2,826,964	$89,228	$0.03156	($14,097)	($0.00353)	-10.1%	$0.03656	$0.00147
23												
24	WHOLESALE & INTERNATIONAL											
25	Wholesale Long Beach (2)	77,821	$2,589	$0.03327	117,093	$3,314	$0.02830	$725	($0.00496)	-14.9%	$0.03330	$0.00004
26	SDGE Wholesale	1,445,680	$14,618	$0.01011	1,230,285	$18,603	$0.01512	$3,986	$0.00501	49.5%	$0.02012	$0.01001
27	Wholesale SWG (2)	91,672	$2,847	$0.03106	81,737	$2,617	$0.03201	($230)	$0.00096	3.1%	$0.03701	$0.00596
28	Wholesale Vernon (2)	51,620	$1,442	$0.02794	116,135	$2,939	$0.02531	$1,497	($0.00263)	-9.4%	$0.03031	$0.00237
29	International (2)	36,419	$1,090	$0.02993	53,990	$1,365	$0.02528	$275	($0.00465)	-15.5%	$0.03028	$0.00035
30	Total Wholesale & International	1,703,212	$22,586	$0.01326	1,599,240	$28,838	$0.01803	$6,252	$0.00477	36.0%	$0.02303	$0.00977
31												
32	TOTAL NONCORE	6,104,226	$217,651	$0.03566	5,866,366	$180,273	$0.03073	($37,378)	($0.00493)	-13.8%	$0.03573	$0.00007
33	Unalloc.Costs to NSBA		$15,683					($15,683)				
34	Unbundled Storage		$21,000			$27,759		$6,759				
35												
36	Total (excluding FAR)	9,502,953	$1,659,808	$0.17466	9,457,396	$1,680,194	$0.17766	$20,385	$0.00300	1.7%	$0.18266	$0.00800
37												
38	FAR Revenues					$53,038						
39												
40	SYSTEM TOTALw/SI,FAR,ITLS,SW	9,502,953	$1,659,808	$0.17466	9,457,396	$1,733,232	$0.18327	$73,423	$0.00860	4.9%		
41	EOR Revenues	482,707	$22,780	$0.04719	156,187	$4,241	$0.02716					
42												
43	Total w/EOR Throughput	9,985,661			9,613,583							

1) Under present rates, NGV is not directly allocated costs and is not calculated on Sempra-Wide basis.
It is not shown in Table 1. See Table 3 for Present NGV Rates.

2) These proposed costs and rates for Transmission Level Service customers represents the average transmission rate and revenue of each class.
See Table 5 for actual transmission level service rate.

3) FAR charge is proposed as a separate rate. Core will pay through procurement rate, noncore as a separate charge.
To make comparison to present rates, this column reflects FAR charge added to each rate.
Average rate paid will vary based on capacity reserved and volumes used. 100% load factors is implied in column. See Table 5 for actual FAR charge.

TABLE 1

Gas Transportation Rate Revenues

San Diego Gas & Electric

2009 BIENNIAL COST ALLOCATION PROCEEDING

Embedded Cost

v6-30-2008

		At Present Rates			At Proposed Rates			Changes			Proposal w/FAR (2)	
		Jan-1-08 Volumes mtherms	Jan-1-08 Revenues $1,000	Average Rate $/therm	BCAP Volumes mtherms	Jan-1-09 Revenues $1,000	Average Rate $/therm	Revenues $1,000	Rates $/therm	Rate change %	Proposed Rate w/FAR	$0.00500 rate change
		A	B	C	D	E	F	G	H	I	J	K
1	CORE											
2	Residential	326,207	$189,454	$0.58078	326,003	$182,707	$0.56045	($6,747)	($0.02033)	-3.5%	$0.56545	($0.01533)
3	Comml & Industrial	129,794	$37,602	$0.28970	158,725	$43,757	$0.27568	$6,156	($0.01402)	-4.8%	$0.28068	($0.00902)
4	NGV Pre SW	4,030	$3,782	$0.93850	15,238	$1,904	$0.12495	($1,878)	($0.81355)	-86.7%	$0.12995	($0.80855)
5	SW Adjustment					($981)		($981)				
6	NGV Post SW	4,030	$3,782	$0.93850	15,238	$923	$0.06055	($2,860)	($0.87796)	-93.5%	$0.06555	($0.87296)
7	Total CORE	460,031	$230,838	$0.50179	499,967	$227,387	$0.45481	($3,451)	($0.04698)	-9.4%	$0.45981	($0.04198)
8												
9	NONCORE COMMERCIAL & INDUSTRIAL											
10	Distribution Level Service	75,005	$6,577	$0.08769	37,270	$4,244	$0.11386	($2,333)	$0.02618	29.9%	$0.11886	$0.03118
11	Transmission Level Service (1)	11,206	$513	$0.04577	3,193	$78	$0.02449	($435)	($0.02128)	-46.5%	$0.02949	($0.01628)
12	Total Noncore C&I	86,211	$7,090	$0.08224	40,463	$4,322	$0.10681	($2,768)	$0.02457	29.9%	$0.11181	$0.02957
13												
14	NONCORE ELECTRIC GENERATION											
15	Distribution Level Service (2008 is all EG, no separate transmission rate in 2008)											
16	Pre Sempra Wide	897,926	$34,606	$0.03854	179,522	$8,967	$0.04995	($25,639)	$0.01141	29.6%	$0.05495	$0.01641
17	Sempra Wide Adjustment		($1,452)			($1,726)		($274)				
18	Post Sempra Wide	897,926	$33,154	$0.03692	179,522	$7,241	$0.04033	($25,913)	$0.00341	9.2%	$0.04533	$0.00841
19	Transmission Level Service (1)				496,393	$13,992	$0.02819				$0.03319	
20	Total Electric Generation	897,926	$33,154	$0.03692	675,916	$21,233	$0.03141	($11,921)	($0.00551)	-14.9%	$0.03641	($0.00051)
21												
22	TOTAL NONCORE	984,137	$40,243	$0.04089	716,379	$25,555	$0.03567	($14,689)	($0.00522)	-12.8%	$0.04067	($0.00022)
23												
24	Total (excluding FAR)	1,444,168	$271,082	$0.18771	1,216,345	$252,942	$0.20795	($18,139)	$0.02024	10.8%	$0.21295	$0.02524
25												
26												
27												
28	System Total	1,444,168	$271,082	$0.18771	1,216,345	$252,942	$0.20795	($18,139)	$0.02024	10.8%		

1) These proposed costs and rates for Transmission Level Service customers represents the average transmission rate and revenue of each class.
See Table 5 for actual transmission level service rate.

2) FAR charge is proposed as a separate rate. Core will pay through procurement rate, noncore as a separate charge.
To make comparison to present rates, this column reflects FAR charge added to each rate.
Average rate paid will vary based on capacity reserved and volumes used. 100% load factors is implied in column. See Table 5 for actual FAR charge.