2002 California Gas Report

Prepared by the California Gas and Electric Utilities

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PREPARED BY THE CALIFORNIA GAS UTILITIES

2002 CALIFORNIA GAS REPORT

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FOREWARD

FOREWORD

The 2002 California Gas Report presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2022. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years, in compliance with California Public Utilities Commission Decision D.95-01-039. The projections in the California Gas Report are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

The report is organized into three sections: Executive Summary, Northern California, and Southern California. The Executive Summary provides statewide highlights and consolidated tables on supply and demand. The Northern California section provides detail on requirements and supplies of natural gas for Pacific Gas and Electric Company (PG&E) the Sacramento Municipal Utility District (SMUD) and Wild Goose Storage, Inc. The Southern California section shows similar detail for Southern California Gas Company (SoCalGas), the City of Long Beach Energy Department, San Diego Gas & Electric Company, and the City of Los Angeles Department of Water and Power.

Each participating utility has provided a narrative explaining its assumptions and outlook for natural gas requirements and supplies, including tables showing data on natural gas availability by source, with corresponding tables showing data on natural gas requirements (demand) by customer class. Separate sets of these tables are presented for average cold and hot temperature year conditions. Any forecast, however, is subject to considerable uncertainty. Changes in the economy, energy and environmental policies, natural resource availability, and the continually evolving restructuring of the gas and electric industries can significantly affect the reliability of these forecasts. The further into the future a forecast extends, the more susceptible it is to inaccuracy. This report should not be used by readers as a substitute for full, detailed analysis of their own specific energy requirements.

A Working Committee, comprised of representatives from each utility, was responsible for compiling the report. A General Committee composed of officers from the participating utilities was available to provide policy guidance. The membership of the committees is listed in the Respondents section at the end of this report.

2002 California Gas Report

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

DEMAND OUTLOOK

California natural gas demand, including volumes bypassing utility systems, is expected to grow at an annual average rate of 1.3 percent from 2002 to 2022. Forecast growth is a combination of strong anticipated growth in the electric generation (EG) market segment tempered by slower growth in the residential and commercial markets and virtually no growth in the industrial sector.

EG gas demand is expected to increase at an annual average rate of 2.3 percent due to the assumption that gas-fired generation continues to be the technology of choice to meet the ever-growing demand for electric power. Residential and commercial sector consumption is expected to increase by an average of 0.9 percent per year over the forecast period. This rate of growth is roughly half the rate of growth in underlying drivers such as household and employment growth and reflects increasing penetration of energy efficient homes, appliances and commercial equipment. Demand in the industrial sector is estimated to decline by 0.1 percent annually as California continues its transition from a manufacturing based to a service based economy.

FOCUS ON EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on Customer Energy Efficiency (CEE) and other Demand-Side Management (DSM) programs in their utility electric and gas resource plans. The recent “energy crisis” in California was not limited to electricity, with gas prices at the southern California border reaching levels nearly ten times greater than experienced in recent history. California utilities are committed to helping their customer’s make the best possible choices regarding use of this increasingly valuable resource.

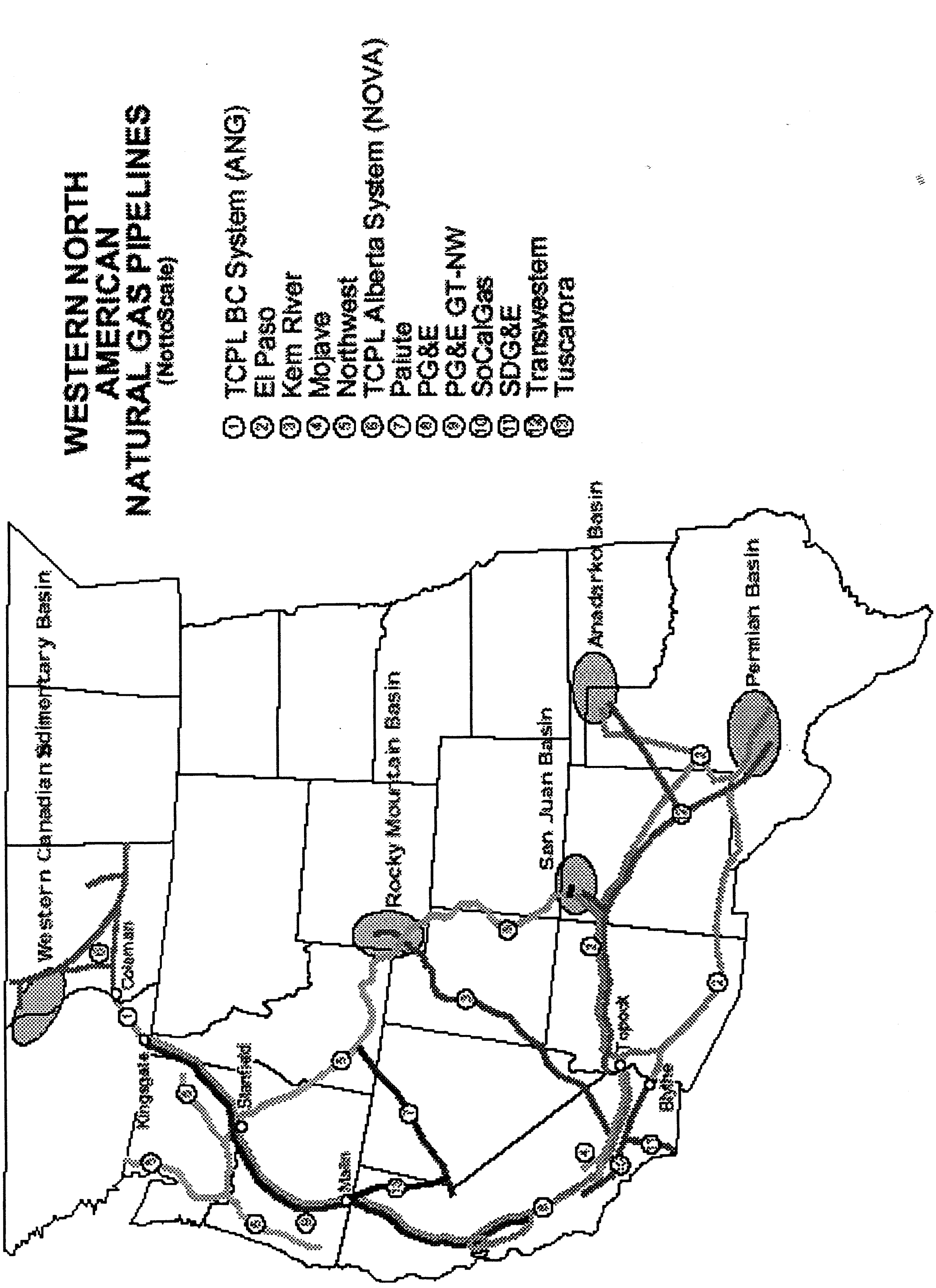
SUPPLY OUTLOOK/PIPELINE CAPACITY

California’s existing gas supply portfolio is regionally diverse and includes supplies from California sources (onshore and offshore), Southwestern U.S. supply sources (the Permian, Anadarko, and San Juan Basins), the Rocky Mountains, and Canada. The map on the following page shows the locations of these supply sources and the natural gas pipelines serving California.

Additional pipeline capacity and open access have contributed to long-term supply availability and gas-on-gas competition. Interstate pipelines currently serving California include El Paso Natural Gas Company (El Paso), Kern River Transmission Company (Kern River), Mojave Pipeline Company (Mojave), PG&E Gas Transmission-Northwest (PG&E GT-NW), Transwestern Pipeline Company (Transwestern), and Tuscarora Pipeline.

NATURAL GAS PROJECT PROPOSALS

To meet the growing demand for natural gas during the next 20 years, a number of pipeline projects have been proposed. Several are under construction, others are in the permitting phase and others are still developing the necessary support to move forward. In total these proposed projects would provide an estimated 4,835 MMcfd in new delivery capacity to California. The California Energy Commission (CEC) is posting a natural gas project list on their website, which track the development of these proposed projects. To review this project list check the CEC's website at www.energy.ca.gov.


WESTERN NORTH AMERICAN NATURAL GAS PIPELINES
(NottoScale)
1 TCPL BC System (ANG)
2 El Paso
3 Kern River
4 Mojave
5 Northwest
6 TCPL Alberta System (NOVA)
7 Paiute
8 PG&E
9 PG&E GT-NW
10 SoCalGas
11 SDG&E
12 Transwestern
13 Tuscarora
Western Canadian Sedimentary Basin
Coleman
Kingsgate
Stanfield
Malin
Rocky Mountain Basin
San Juan Basin
Anadarko Basin
Permian Basin
Topock
Blythe

STATEWIDE CONSOLIDATED SUMMARY TABLES

The consolidated summary tables on the following pages show the statewide aggregations of gas supplies and gas requirements (demand).

Gas sales and transportation volumes are consolidated under the general category of system gas requirements. Details of gas transportation for individual utilities are given in the tabular data for northern California and southern California. The wholesale category includes the City of Long Beach Energy Department, San Diego Gas & Electric Company, Southwest Gas Corporation, Los Angeles Department of Water and Power, Alpine Natural Gas, Island Energy, West Coast Gas, Inc, and the municipalities of Coalinga and Palo Alto. Wholesale gas service to the City of Vernon is scheduled to commence during the forecast period.

Some columns may not sum precisely, because of modeling accuracy and rounding differences, and do not imply curtailments.

STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
MMCF/DAY

Total California's Supply Sources	2002	2003	2007	2015	2020	2022
California Sources	660	660	660	660	660	660
Out-of-State	4,068	3,626	4,227	4,850	5,246	5,409
Net Withdrawal (Injection)	-	-	-	-	-	-
Utility Total	4,728	4,286	4,887	5,510	5,906	6,069
Pipeline Bypass (1)	769	836	859	922	915	913
Total	5,497	5,122	5,746	6,432	6,821	6,982

Total California's Requirements	2002	2003	2007	2015	2020	2022
Residential	1,284	1,293	1,436	1,450	1,524	1,555
Commercial	493	499	532	563	579	582
Natural Gas Vehicles	17	22	31	48	59	65
Industrial	863	859	824	787	774	769
Electric Generation (2)	1,549	1,170	1,663	2,060	2,332	2,446
Enhanced Oil Recovery	28	28	28	21	21	21
Wholesale/Resale	384	315	360	450	475	487
Company Use and Unaccounted for	87	79	89	99	106	108
Utility Total	4,705	4,265	4,963	5,478	5,870	6,033
Pipeline Bypass (1)	769	836	859	922	915	913
Total	5,474	5,101	5,822	6,400	6,785	6,946

NOTES:
(1) Bypass is defined in the Glossary.
(2) Includes utility and non-utility generation.

STATEWIDE TOTAL SUPPLY SOURCES - TAKEN
MMCF/DAY

Northern California	2002	2003	2007	2015	2020	2022
California Sources (1)	150	150	150	150	150	150
Out-of-State	1,962	1,866	2,135	2,554	2,788	2,882
Net Withdrawal/(Injection)	-	-	-	-	-	-
Utility Total	2,112	2,016	2,285	2,704	2,938	3,032
Pipeline Bypass (2)	366	366	366	366	366	366
Northern California Total	2,478	2,382	2,651	3,070	3,304	3,398

Southern California	2002	2003	2007	2015	2020	2022
California Sources (1)	510	510	510	510	510	510
Out-of-State	2,106	1,760	2,092	2,296	2,458	2,527
Net Withdrawal/(Injection)	-	-	-	-	-	-
Utility Total	2,616	2,270	2,602	2,806	2,968	3,037
Pipeline Bypass (2)	403	470	493	556	549	547
Northern California Total	3,019	2,740	3,095	3,362	3,517	3,584

NOTES:
(1) Includes utility purchases and exchange/transport gas.
(2) Bypass is defined in the Glossary.

STATEWIDE ANNUAL GAS REQUIREMENTS (1)
MMCF/DAY

Northern California	2002	2003	2007	2015	2020	2022
Residential	563	565	687	632	656	665
Commercial-Core	233	235	245	261	270	273
Natural Gas Vehicles-Core	2	3	4	6	7	8
Natura Gas Vehicles-Noncore	1	2	2	2	2	2
Industrial-Noncore	450	453	451	443	435	432
Wholesale/Resale	10	11	11	12	12	12
SMUD Electric Generation	65	67	125	185	185	185
Electric Generation (2)	746	640	815	1,113	1,317	1,400
Enchanced Oil Recovery	-	-	-	-	-	-
Southwest Gas Exchange	-	-	-	10	10	10
Company Use and Unaccounted for	32	31	34	40	43	44
Utility Total	2,102	2,007	2,374	2,704	2,937	3,031
Pipeline Bypass (3)	366	366	366	366	366	366
Northern California Total	2,468	2,373	2,740	3,070	3,303	3,397

Southern California	2002	2003	2007	2015	2020	2022
Residential	721	728	749	818	868	890
Commercial-Core	204	214	234	247	253	253
Commercial-Noncore	56	50	53	55	56	56
Natural Gas Vehicles-Core	14	17	25	40	50	55
Industrial-Core	57	67	75	70	69	68
Industrial-Noncore	356	339	298	274	270	269
Wholesale/Resale	374	304	349	438	463	475
Electric Generation	738	463	723	762	830	861
Enchanced Oil Recovery - Steaming	28	28	28	21	21	21
Company Use and Unaccounted for	55	48	55	59	63	64
Utility Total	2,603	2,258	2,589	2,784	2,943	3,012
Pipeline Bypass (3)	403	470	493	556	549	547
Southern California Total	3,006	2,728	3,082	3,340	3,492	3,559

NOTES:

(1) Includes transportation gas.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) Bypass is defined in the Glossary.

STATEWIDE SOURCES AND DISPOSITION

The Statewide Sources and Disposition Summary is intended to complement the existing five-year recorded data tables included in the tabular data sections for each utility.

The information shown on the following tables shows by customer class the composition of supplies from both out-of-state and California sources and is based on the utilities' accounting records and on available gas nomination and preliminary gas transaction information obtained daily from customers or their appointed agents and representatives. It should be noted that data on daily gas nominations are frequently subject to reconciling adjustments. In addition, some of the data are based on allocations and assignments that, by necessity, rely on estimated information. These tables have been updated to reflect the most current information.

Some columns may not sum exactly, because of factored allocation and rounding differences, and do not imply curtailments.

2002 California Gas Report
Recorded 1997 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E	Kern River	Mojave	Other [1]	Total
Southern California Gas Company								
Core (2)	77	487	212	26	6	76	3	886
Noncore Commercial/Industrial	56	179	57	111	32	6	(5)	435
EG (3)	103	328	105	203	58	11	0	808
EOR	5	17	5	10	3	1	(0)	41
Wholesale/Resale/International (4)	49	156	50	96	28	5	(5)	379
Total	290	1,166	429	447	126	98	(7)	2,549
Pacific Gas and Electric Company								
Core (5)	29	139	1	565	4	0	4	742
Noncore (6)	118	77	52	456	67	0	34	804
UEG	0	137	52	203	3	0	22	418
EOR	*	*	*	*	*	*	*	*
Wholesale/Resale	0	0	0	23	0	0	0	23
Total	147	353	106	1,246	75	0	60	1,987
Other Northern California								
Core (7)	0	0	0	0	0	0	9	9
Non-Utilities								
Direct Sales/Bypass	329	7	4	0	434	202	0	976
TOTAL SUPPLIER	766	1,526	539	1,693	635	300	62	5,521

NOTES:

(1) Includes storage withdrawals.

(2) Includes NGV volumes.

(3) EG includes UEG, COGEN, and EOR Cogen.

(4) Includes SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E	Kern River	Mojave	Other	Total
San Diego Gas & Electric Company								
Core	11	57	19	24	1	0	6	118
Noncore Commercial/Industrial	3	47	16	6	0	0	2	73
UEG	13	64	21	28	1	0	8	134
Total	26	168	56	57	2	0	16	325

(5) Core includes residential and commercial volumes.

(6) Noncore includes industrial, resale, and non-utility EG volumes.

(7) Includes customers served by Southwest Gas Corp. and Avista.

2002 California Gas Report
Recorded 1998 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E	Kern River	Mojave	Other (1)	Total
Southern California Gas Company								
Core (2)	81	589	246	52	23	34	(32)	993
Noncore Commercial/Industrial	60	177	107	69	50	7	(30)	440
EG (3)	96	282	171	110	80	11	0	750
EOR	4	11	7	4	3	0	0	29
Wholesale/Resale/International (4)	56	166	100	64	47	7	(17)	423
Total	298	1,224	631	299	204	60	(79)	2,636
Pacific Gas and Electric Company								
Core (5)	13	103	102	595	44	0	0	858
Noncore (6)	128	182	33	577	34	0	20	974
UEG	3	46	40	230	15	0	8	343
EOR	*	*	*	*	*	*	*	*
Wholesale/Resale	3	4	4	8	3	0	0	22
Total	147	334	181	1,410	97	0	28	2,197
Other Northern California								
Core (7)	0	0	0	0	0	0	11	11
Non-Utilities								
Direct Sales/Bypass	407	0	0	0	337	264	8	1,016
TOTAL SUPPLIER	852	1,558	812	1,709	638	324	(32)	5,860

NOTES:

(1) Includes storage withdrawals.
(2) Includes NGV volumes.
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes SDG&E data as shown.

San Diego Gas & Electric Company								
Core	14	62	28	22	0	0	9	135
Noncore Commercial/Industrial	8	68	31	14	0	0	5	126
UEG	17	70	33	25	0	0	12	157
Total	39	200	92	61	0	0	26	418

(5) Core includes residential and commercial volumes.
(6) Noncore includes industrial, resale, and non-utility EG volumes.
(7) Includes customers served by Southwest Gas Corp., Avista and Tuscarora.

2002 California Gas Report
Recorded 1999 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E	Kern River	Mojave	Other [1]	Total
Southern California Gas Company								
Core (2)	97	557	276	44	19	47	(23)	1,018
Noncore Commercial/Industrial	59	175	87	48	49	12	18	448
EG (3)	117	349	173	95	98	25	0	856
EOR	3	10	5	3	3	1	0	25
Wholesale/Resale/International (4)	55	164	81	45	46	12	11	413
Total	330	1,255	622	235	215	97	6	2,761
Pacific Gas and Electric Company								
Core (5)	8	134	76	595	62	0	0	875
Noncore (6)	134	196	52	824	28	0	31	1,265
UEG	6	19	12	46	16	0	3	103
EOR	*	*	*	*	*	*	*	*
Wholesale/Resale	3	4	3	5	4	0	0	19
Total	151	353	143	1,470	110	0	34	2,262
Other Northern California								
Core (7)	0	0	0	0	0	0	11	11
Non-Utilities								
Direct Sales/Bypass	508	0	0	0	296	294	0	1,098
TOTAL SUPPLIER	989	1,608	765	1,705	621	391	51	6,132

NOTES:

(1) Includes storage withdrawals.

(2) Includes NGV volumes.

(3) EG includes UEG, COGEN, and EOR Cogen.

(4) Includes DGN volumes and SDG&E data as shown.

	California Sources	El Paso	Trans western	PG&E	Kern River	Mojave	Other	Total
San Diego Gas & Electric Company								
Core	12	70	33	29	0	0	5	148
Noncore	7	119	58	15	0	0	3	201
Total	19	188	91	43	0	0	8	349

(5) Core includes residential and commercial volumes.

(6) Noncore includes industrial, resale and non-utility EG volumes.

(7) Includes Southwest Gas Corporation, Avista and tuscarora data.

2002 California Gas Report
Recorded 2000 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other [1]	Total
Southern California Gas Company								
Core (2)	28	600	263	11	6	40	10	957
Noncore Commercial/Industrial	49	167	80	53	48	11	55	463
EG (3)	144	492	235	155	141	32	0	1,199
EOR	4	14	6	4	4	1	0	33
Wholesale/Resale/International (4)	52	178	85	56	51	12	13	446
Total	276	1,450	670	278	250	95	78	3,098
Pacific Gas and Electric Company								
Core (5)	12	130	79	604	28	0	0	853
Noncore (6)	142	255	101	929	17	0	0	1,444
UEG	7	8	7	8	7	0	0	37
EOR	*	*	*	*	*	*	*	*
Wholesale/Resale	2	1	2	2	0	0	0	7
Total	163	394	189	1,543	52	0	0	2,341
Other Northern California								
Core (7)	0	0	0	0	0	0	9	9
Non-Utilities								
Direct Sales/Bypass	552	0	0	0	294	243	0	1,089
TOTAL SUPPLIER	991	1,844	859	1,821	596	338	87	6,536

NOTES:

(1) Includes storage withdrawals.

(2) Includes NGV volumes.

(3) EG includes UEG, COGEN, and EOR Cogen.

(4) Includes DGN volumes and SDG&E data as shown.

San Diego Gas & Electric Company								
Core	9	63	25	36	0	0	5	139
Noncore Commercial/Industrial	1	171	70	6	0	0	1	250
Total	10	234	95	42	0	0	6	388

(5) Core includes residential and commercial volumes.

(6) Noncore includes industrial, resale and non-utility EG volumes.

(7) Includes Southwest Gas Corporation, Avista, and Tuscarora data.

2002 California Gas Report
Recorded 2001 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other [1]	Total
Southern California Gas Company								
Core (2)	38	556	274	58	30	10	31	998
Noncore Commercial/Industrial	82	204	91	47	53	14	(93)	399
EG (3)	209	522	233	121	136	36	0	1,257
EOR	5	12	5	3	3	1	0	29
Wholesale/Resale/International (4)	80	201	90	47	52	14	(9)	475
Total	415	1,495	694	276	275	75	(70)	3,158
Pacific Gas and Electric Company								
Core (5)	29	110	94	574	6	0	0	813
Noncore (6)	157	563	81	864	78	0	0	1,743
EOR	*	*	*	*	*	*	*	0
Total	186	673	175	1,438	84	0	0	2,556
Other Northern California								
Core (7)	0	0	0	0	0	0	9	9
Non-Utilities								
Direct Sales/Bypass	417	0	0	0	319	208	0	945
TOTAL SUPPLIER	1,018	2,168	869	1,714	678	283	(61)	6,668

NOTES:

(1) Includes storage activities.

(2) Includes NGV volumes.

(3) EG includes UEG, COGEN, and EOR Cogen.

(4) Includes DGN volumes and SDG&E data as shown.

San Diego Gas & Electric Company	California Sources	El Paso	Trans western	PG&E GT-NW	Kern River	Mojave	Other	Total
Core	9	45	17	44	4	4	16	139
Noncore Commercial/Industrial	1	172	65	7	1	1	3	250
Total	10	217	81	51	5	4	19	388

(5) Core includes residential and commercial volumes.

(6) Noncore includes industrial, resale and non-utility EG volumes.

(7) Includes Southwest Gas Corporation, Avista and Tuscarora data.

2002 California Gas Report

NORTHERN CALIFORNIA

INTRODUCTION

Pacific Gas and Electric Company (PG&E) provides natural gas procurement, transportation, and storage services to 3.8 million residential customers and 200,000 businesses in northern and central California. In addition to serving residential, commercial, and industrial markets, PG&E provides gas transportation and storage services to a variety of gas-fired electric generation plants in its service area. Other wholesale distribution systems, which receive gas transportation service from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are located in 37 counties from south of Bakersfield to north of Redding, with high concentrations in the San Francisco Bay Area and the Sacramento and San Joaquin valleys. In addition, customers also utilize the PG&E system to meet their gas needs in southern California.

The forecast in this report covers the years 2002 through 2022. However, as a matter of convenience, the tabular data at the end of the section show only the years 2002 through 2007 and the years 2010, 2015, 2020 and 2022.

The northern California section of the report begins with the demand forecast, including a discussion of economic conditions, forecast methodology, and other factors affecting demand in various markets. Following the gas demand forecast are discussions of gas supply and pipeline capacity. Abnormal peak day demands and supply resources, as well as gas balances, are discussed at the end of this section.

GAS DEMAND REQUIREMENTS

OVERVIEW

PG&E's 2002 California Gas Report average year demand forecast projects total on-system demand growing at an annual average rate of 1.8 percent between 2002 and 2022. This overall growth rate is a combination of 0.9 percent annual growth in the core market and 2.4 percent annual growth in the noncore market. By comparison, the 2000 California Gas Report estimated an annual average growth rate of 1.4 percent per year, based on growth of 1.6 percent per year for the core market and 1.3 percent per year for the noncore market.[1]

Decreases in the estimated rate of growth in the core market are due to incorporation of more recent historic usage, economic, and demographic data; more recent forecasts of economic and demographic drivers; and re-specification of the econometric models used to forecast core demand. Increases in the projected rate of growth in the noncore market are largely due to changes in the electric generation gas consumption portion of that market.

In the 2002 CGR, gas demand by electric generators (EG) is estimated to decrease slightly from 2002 through 2004, and then increase at over four percent per year through 2022. The estimated EG demand for 2002 is 30 percent lower than actual demand in 2001, when a drought in the western states caused gas-fired generators to increase output to make up for reduced hydroelectric generation.

The slight decrease in EG gas demand during 2003 and 2004 stems from displacement of gas-fired steam-turbine power plants by new, more efficient gas-fired combined cycle plants. After 2004, EG gas demand on PG&E escalates due to the assumptions that (1) electricity demand increases, (2) few non-gas power plants are built, and (3) gas-fired plants are built near electricity demand centers, rather than near natural gas supply basins or interstate pipelines.

The third assumption is less certain than the first two. Gas pipelines are generally cheaper to build and operate than electric transmission lines. Under some proposals to the Federal Energy Regulatory Commission (FERC), however, generators would not bear the cost of new or upgraded electric transmission lines. If that becomes policy, generators will tend to minimize their own costs, not overall costs, by building near gas supply basins or interstate pipelines rather than electric demand centers as envisioned in this report.

In the 2002 CGR, demand in the industrial sector portion of the noncore market is estimated to be virtually flat, as compared to the 2000 CGR where growth in this sector was projected to be 1.3 percent.[2] Industrial gas customers are primarily large manufacturing firms. The California manufacturing sector has been in recession for well over a year (gas demand from this sector fell by nearly 20 percent in 2001), but is projected to begin a recovery in the third quarter of 2002. That recovery, coupled with

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[1] The period used for calculating the 2000 CGR growth rates is 2000-2020. The 2000 CGR did not include the 2021-2022 period in the forecast horizon.

[2] As stated in note 1 above, the 2000 CGR growth rates are calculated over the period 2000-2020.

a return to more modest gas prices which occurred in the second half of 2001, are expected to boost demand for this sector in the near-term. However, long-term growth is expected to be slightly negative as the state continues its transition to a more services-oriented economy.

FORECAST METHOD

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed from econometric models. Forecasts for other sectors (electric generation, NGV, wholesale) are developed from market information. While variation in short-term gas use depends mainly on prevailing weather conditions, longer-term trends in gas demand are driven primarily by underlying economic, demographic, and technological changes, such as growth in population and employment; changes in prevailing prices; and changes in the efficiency profiles of residential and commercial buildings and the appliances within them.

MARKET SENSITIVITY

The average-year gas demand forecast presented here is a reasonable projection for an uncertain future. However, point forecasts cannot capture the uncertainty in the major determinants of gas demand (e.g., weather, economic activity, appliance saturation, and efficiencies). In order to give some flavor of the possible variation in gas demand, PG&E has developed forecasts of gas demand under assumed high demand and low demand conditions. The assumptions for these scenarios are described below.

Temperature

Because space heating accounts for a high percentage of use, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's average-year forecast assumes that temperatures in the forecast period will be equivalent to the average of observed temperatures during the past twenty years.

Of course, actual temperatures in the forecast period will be higher or lower than those assumed in the average-year scenario and gas use will vary accordingly. PG&E's low demand forecast assumes that winter temperatures in the forecast horizon will be two standard deviations above the twenty-year average. Conversely, the high demand forecast assumes that winter temperatures in the forecast horizon will be two standard deviations below the twenty-year average. Seasonal variations in temperature have relatively little effect on power plant gas demand and, consequently, PG&E's forecasts of yearly power plant gas demand in the 2002 CGR are based on average temperatures

Hydro Conditions

The 2002 CGR includes a dry-hydro case in response to concerns raised by the drought in water year 2001 (October 2000 through September 2001). EG gas demand during that water year increased almost 200 MMcf/day over the roughly average water year 2000. In California, water year 2001 was dry in both the Sacramento and San

Joaquin River basins. The Pacific Northwest, which typically generates five times as much hydroelectric energy as California, was extremely dry. By some measures, water year 2001 it was the second driest in the western U.S. since 1929. For this CGR, PG&E selected a less extreme case, namely water year 1994. Water year 1994 represents a roughly 1 in 10 to 1 in 20 dry hydro year in the western states.[3]

MARKET SECTORS

Residential

Households in the PG&E service area are forecast to grow 1.2 percent annually from 2002 to 2022. However, gas use per household has been falling in recent years due to improvements in appliance and building-shell efficiencies. This decline accelerated sharply in 2001 when gas prices spiked causing temperature-adjusted residential gas demand to fall by close to 10 percent. Gas use per household is expected to partially recover in 2002, as prices have returned to more moderate levels. However, in 2003 and beyond, residential use per household is expected to revert to its long-term trend due to continuing upgrades in appliance and building efficiencies. As a result, PG&E forecasts residential demand to grow at 0.8 percent per year from 2002 to 2022, implying an average decrease in use per household of nearly 0.4 percent per year.

Commercial

The 2000-2001 run-up in gas prices (as well as a flagging economy) depressed sales to the commercial market, but also fostered a certain amount of noncore to core migration that overall increased temperature-adjusted commercial sales by about 3 percent. Because some of these customers did not migrate until mid to late 2001, their sales were not fully reflected in 2001 commercial throughput. As a result, 2002 commercial sales are expected to be more than five percent above those of a year earlier. Over the next 20 years, sales for this sector are expected to grow about one percent per year.

Natural Gas Vehicles

Growing concern over air quality in California is focusing public attention on vehicles that emit less harmful exhaust. PG&E has a program to educate customers of the merits of including natural gas vehicles (NGVs) in their fleets. Both the National Energy Policy Act and the California Air Resources Board's low emission vehicle regulations should continue to increase this market.

Additionally, the U.S. Congress recently passed energy legislation that includes significant tax incentives for alternative fueled vehicles and infrastructure, including NGVs. If signed into law, this new legislation will create new demand for these vehicles. Under current law, NGVs are expected to account for approximately 5 MMcf/day of demand by year 2004, increasing to 10 MMcf/day by the year 2022.

[3] To rank early Water Years against more recent ones, one must estimate hydroelectric generation for each year given that historical year's runoff and current dams and fishery rules. The uncertainty of this estimation makes it difficult to specify a precise probability of exceedance for Water Year 1994.

Industrial

Gas requirements for PG&E's industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector plummeted by close to 20 percent in 2001 due to a combination of soaring gas prices, noncore to core migration and a manufacturing sector mired in a severe downturn. In the near-term, requirements for this sector are expected in rise as demand responds to a return to more moderate gas prices and the northern California manufacturing sector begins to recover. However, industrial gas consumption is expected to slowly decline by about 0.20 percent annually over the next 20 years as California's manufacturing sector continues to gradually shrink.

Electric Generation

The Western electricity crisis of 2000-2001 increased attention on the demand for natural gas by EG plants. Annual EG gas demand on the PG&E system peaked in 2001 as a result of slow construction of power plants and severe drought. New, more efficient power plants that are operational or near completion, and the return to near-average hydroelectric conditions, are reducing EG gas demand in 2002. PG&E's forecast shows EG gas demand falling below the 2002 level in 2003 and 2004, followed by growth over 4 percent per year through 2022. This forecast is critically dependent on the assumption that most new generation will be gas fired and that new generation will be built near electric demand centers. Although this forecast is plausible, alternative assumptions (discussed in the risk section) may produce significantly different forecasts.

Looking back, peak EG gas demand in 2001 followed a decade in which growth in electricity demand outpaced construction of new power plants. During the 1990s, electricity demand in the Western Electricity Coordinating Council (WECC)[4] grew from 72,000 average MW in 1989 to 90,000 aMW in 2000[5]. As demand grew by 18,000 aMW, electric generating capacity increased by about 9,000 aMW. In other words, construction of new, highly efficient power plants lagged behind demand growth. As a result, older power plants that burn relatively large amounts of natural gas to generate each MWh were kept in service. Those older plants were extensively used during the 2000-2001 drought.

A significant change is now occurring in electric generation. Through the 1980s and 1990s, most gas-fired power plants in the WECC were steam turbines. A very large number of combined-cycle plants (CCs) are now operating or are under construction. These more efficient CCs will displace many older steam turbines, causing a short-term decline in EG gas demand. These new CCs consume about 30 percent less natural gas per MWh generated.

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4 The Western Electricity Coordinating Council, or WECC, covers an area consisting of the Western U.S. roughly from Colorado to the Pacific coast, plus Alberta, British Columbia, and northwestern Baja California. This area is electrically interconnected by a grid of high-voltage electric transmission lines, but has few electrical connections to areas farther east. Consequently it can be considered a separate market for electricity, isolated from the remainder of North America. The WECC was formed on April 18, 2002 by combining other agencies, notably the Western Systems Coordinating Council or WSCC.

5 One aMW is an electricity demand that averages 1 MW over 1 year. Because there are 8760 hours per year (365*24), 1 aMW equals 8760 MWh.

Longer term, the forecasting picture is much less clear and is highly dependent on the following factors:

Electricity Demand: PG&E's EG gas forecast is derived from an electric demand forecast. That forecast projects electric demand growth for California and the WECC to average 1.7 percent per year from 2002 through 2022.[6] The growth in electric demand recorded from 1980 through 2000 was 2.6 percent per year. The California electric demand forecast used in this report is consistent with the "most likely" case scenario as shown in the California Energy Commission publication, *2002-2012 Electricity Outlook Report*, February 2002.

Type of new power plants: PG&E's forecast assumes that new power plants with low running costs, such as coal-fired plants and wind turbines, are brought on-line in amounts that offset any decline in production from existing low-cost power plants, such as coal-fired, nuclear and geothermal plants. PG&E's forecast further assumes that most increases in electricity demand after 2002 are met by construction of gas-fired combined-cycle plants.

Gas-fired CCs seem to be the first choice for new power plants throughout the United States. Extrapolation of current trends leads to very large EG gas demand nationwide, which might require shipping gas long distances (e.g., by pipeline from Alaska or Jamaica, or by tanker from other continents). At some point, the cost of shipping may drive up gas prices and encourage a shift to non-gas alternatives.

Location of new power plants: PG&E's forecast assumes that, starting in 2007, new CCs will be built in each region of the WECC in proportion to that region's growth in electricity demand. This is a key assumption, and it depends largely on the relative prices for electric and gas transmission.

PG&E's forecast assumes that power plant siting decisions will generally be based on lowest overall costs. Under this assumption, power plants will be built near electricity demand centers, because pipelines are cheaper to build and operate than electric transmission lines. However, in some proposals to the FERC, the investment cost of building or expanding electric transmission lines will be charged directly to end-use customers, or spread equally over all power plants regardless of location.[7] This type of pricing may cause remote siting of new power plants, reducing PG&E's EG gas deliveries below forecast levels.

Risks to the EG Forecast

In addition to the electric/gas transmission pricing issue discussed earlier, there are other market dynamics that could significantly affect the level of EG gas demand. For example, if fewer new CCs or coal-fired plants are built, steeper increases in EG gas demand will occur because if fewer new plants were built, the old and less efficient gas-fired steam turbine plants will pick up the slack.

[6] Based on an agreement between the CGR Working Committee and the California Energy Commission

[7] Many proposals for electric transmission pricing include "congestion pricing", in which electricity prices are higher downstream of bottlenecks in the electric transmission grid. In theory, such pricing would incent siting of power plants downstream of bottlenecks. In practice, building a new power plant downstream of a bottleneck may reduce or even eliminate the congestion, and thereby weaken or eliminate the price difference that was supposed to be an incentive.

More efficient use of gas or a shift to non-gas technologies could lead to more moderate increases in EG gas demand than are forecast in the report. Wide-scale deployment of gas-fired fuel cells, for example, could reduce EG gas demand because they are 15 to 30 percent more efficient than CC plants. A greater reliance on non-gas alternatives such as new coal-fired power plants, wind turbines, and solar power could also reduce the growth in EG gas demand.

Moreover, conservation programs and market structures aimed at decreasing the growth in the demand for electricity could also significantly moderate the growth in EG gas demand.

SMUD EG

The Sacramento Municipal Utility District is the sixth largest municipal electric utility in the United States and provides electric service to over 500,000 customers within the greater Sacramento area. SMUD currently has 519 MW of gas fired electric generation capacity and is currently in the process of developing an additional 500 MW that is expected to be in service in 2005. SMUD owns approximately 3.6 percent of the PG&E's Backbone Line 300 and 5 percent of Line 401. SMUD also has the following long-term interstate capacity contracts: 10 MMcf/day on Transwestern, 31 MMcf/day of PG&E GT-NW and Transcanada Pipeline Ltd.'s BC and Alberta, and 20 MMcf/day of the Kern River expansion expected to be in service in May 2003. Further, SMUD has a five-year storage contract with the Wild Goose expansion project expected to be in service in 2003.

GAS SUPPLY SOURCES

California-Source Gas

Northern California-source gas supplies come primarily from gas fields in the Sacramento Valley. In 2001, PG&E's customers obtained on average 186 MMcf/day of California source-gas.

U. S. Southwest Gas

PG&E's customers have access to three major U.S. Southwest gas producing basins--Permian, San Juan, and Anadarko--via the El Paso and Transwestern pipeline systems.

PG&E's customers can purchase U.S. Southwest gas supplies in the basins and transport it to California via interstate pipelines. Customers can also purchase these supplies at the California-Arizona border or at the PG&E Citygate from marketers who hold inter- or intra-state pipeline capacity.

Canadian Gas

PG&E's customers can purchase Canadian gas from various suppliers in Canada and transport it to California primarily through PG&E GT-NW. Customers can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold inter- or intra-state pipeline capacity.

Rocky Mountain Gas

PG&E's customers have access to gas supplies from the Rocky Mountain area via the Kern River Pipeline and via the PG&E GT-NW Pipeline interconnect at Stanfield, Oregon. Rocky Mountain supplies increase diversity of gas supplies in northern and central California.

Storage

In addition to storage services offered by PG&E, Wild Goose Storage, Inc. and Aquila, Inc. (Lodi facilities) provide storage services from the Wild Goose and Lodi facilities, respectively.

Supplemental Gas Supplies

Supplemental gas supplies are included in PG&E's forecast to meet customer's gas requirements and avoid curtailments.

PG&E anticipates that sufficient supplemental supplies will be available from a variety of sources at market-competitive prices to meet existing and projected market demands in its service area. The supplemental supplies shown in this report could be delivered through a variety of sources, including new interstate pipeline facilities and expansion of PG&E's existing transmission facilities, or PG&E's or others' storage facilities.

GAS SUPPLY/PIPELINE CAPACITY

OVERVIEW

Competition for gas supply, market share, and transportation access has increased significantly over the past few years. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity have provided all customers with direct access to gas supplies, intra- and inter-state transportation, and related services.

Almost all of PG&E's noncore customers buy all or most of their gas supply needs directly from the market. They use PG&E's transportation and storage services to meet their gas supply needs.

INTERSTATE GAS PIPELINE CAPACITY

In recent years, the natural gas pipeline industry has taken significant steps to expand the nation's already extensive pipeline network. These efforts have allowed California utilities and end-users improved access to supply basins and enhanced gas-on-gas and pipeline-to-pipeline competition. Interstate pipelines serving northern and central California include the El Paso, Mojave, Transwestern, PG&E Gas Transmission - Northwest, and Kern River pipelines. These pipelines provide northern and central California with access to gas producing regions in the U. S. Southwest and Rocky Mountain areas, and in Western Canada.

U.S. Southwest and Rocky Mountains

Total PG&E intrastate capacity connected to U.S. Southwest pipeline systems (Transwestern, El Paso, and Kern River) is limited to 1,140 MMcf/day, which is the maximum capacity of PG&E's Baja Path (Line 300). In developing the forecast of gas supply takes, PG&E has assumed continued annual supply availability of 1,140 MMcf/day from the U. S. Southwest for the entire forecast period.

Canada

PG&E's Redwood Path (Lines 400/401) is connected to PG&E GT-NW at Malin, Oregon. The Redwood Path has an average capacity of approximately 1,850 MMcf/day to serve both northern and southern California markets, although that will be increasing in late 2002 to about 2,050 MMcf/day.

PG&E has assumed seasonal supply availability of 1,800 MMcf/day in the winter and 1,900 MMcf/day in the summer for the forecast period of 2002 - 2022.

The actual capacity or supplies taken could differ from those shown above. Operational conditions could limit the capacity during certain times of the year. In addition, market conditions could reduce supplies taken by PG&E's customers.

ABNORMAL PEAK DAY SUPPLY AND DEMAND

APD DEMAND FORECAST

The Abnormal Peak Day (APD) forecast is a projection of *core demand* under extremely adverse conditions. The design criteria for PG&E, as required under CPUC regulation, is a 29 degree Fahrenheit system-weighted mean temperature. This corresponds to a roughly 1 in 90 extreme temperature event. The APD load forecast shown here excludes all noncore demand and, in particular, excludes all EG demand. PG&E estimates that total noncore demand during an APD event would be 1.5 Bcf/day, with EG demand comprising between one-half to two-thirds of the total noncore demand.

The APD forecast is developed using statistical tools to estimate the relationship of daily core gas usage to daily weather conditions during several recent winters. This relationship is then used to simulate what the core load would be under the adverse weather conditions that occurred on December 11, 1932, the coldest day on record in PG&E's service area.

FORECAST OF APD SUPPLY AVAILABILITY

For APD planning purposes, supplies will flow under core's firm capacity, any as-available capacity, and capacity made available pursuant to supply diversion arrangements. Also, a significant part of the APD demand will be met by storage withdrawals from PG&E's underground storage facilities located at McDonald Island, Los Medanos, and Pleasant Creek. Flowing supplies may be from Canada, U.S. Southwest, Rocky Mountain Region, SoCalGas, and California-source gas. Supplies could also be purchased from noncore customers once gas enters the PG&E system. PG&E Gas Procurement Department is responsible for managing the flowing supplies to PG&E's core customers in the event of an APD occurrence. Core aggregators serving core transport customers on PG&E's system have the obligation to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

In previous extreme cold weather events PG&E has observed a drop in flowing pipeline supplies. Supply from Canada is affected as the cold weather front drops down from Canada with a two to three day lag before hitting PG&E's service territory. There is also impact on supply from the southwest. While prices can influence the availability of supply to our system, cold weather can affect producing wells in the basins which, in turn, can affect the total supply to our system and others.

Under APD conditions, PG&E can, if necessary, divert gas from the noncore (including gas fired electric generators) to meet core demand. Diversion of noncore supply in lieu of expanding firm core supplies has been the basis for infrastructure system planning for years, based on the assumption that the noncore market would either shut down their use of gas or switch to an alternate fuel. However, little, if any, alternate fuel burn capability exists today, so supply diversions from the noncore would necessitate that noncore customers (including EG) shut down operations. The implication for the future is that under APD conditions a significant portion of the EG customers could be shut down with the impact on electric system reliability left as an uncertainty.

As mentioned above, PG&E projects that in the near term, noncore demand (including gas fired electric generation) on an APD would be 1.5 Bcf/day. With the recent additions of the Wild Goose and Lodi storage facilities, more noncore demand will be satisfied in the event of an APD. However, looking to the future, if gas fired electric generation grows as forecasted, supplemental supplies will eventually be needed if the goal is to serve the core load and most, if not all, noncore load. These supplemental supplies could be in the form of additional storage facilities or incremental pipeline capacity.

PACIFIC GAS AND ELECTRIC COMPANY
Forecast of Core Gas Demand and Supply on an Abnormal Peak Day (APD)
MMcf/Day

	2002-2003	2003-2004	20042005	2005-2006	2006-2007
APD Core Demand[(1)]	3,152	3,168	3,203	3,234	3,266
Firm Storage Withdrawal	1,006	1,006	1,006	1,006	1,006
Required Flowing Supplies[(2)]	2,146	2,162	2,197	2,228	2,260
Total APD Resources (to meet demands)	3,152	3,168	3,204	3,237	3,272

NOTES:

(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD planning criterion: system temperature on APD is 29 degrees F.

(2) Includes supplies flowing under firm and as-available capacity, and capacity made available pursuant to supply diversion arrangements.

GAS BALANCES

OVERVIEW

Although available gas supplies exceed requirements on an average basis, on particularly cold winter days heightened demand could require the use of gas from underground storage. The balances listed in this report represent one possible combination of demand and supply necessary to deliver incremental supplies. They are not intended to reflect actual choices by customers, or an outcome sought or preferred by PG&E.

SEQUENCING

Sequencing describes the order in which gas supplies are purchased in accordance with PG&E's gas purchase policy and operational considerations. The gas balances presented in this report are based on sequencing assumptions consistent with these guidelines.

BALANCE RESULTS

The gas balances show full service to all customers under an average year for the forecast period. Beginning in 2010, supplemental supplies of 100 MMcf/day and increasing to 150 MMcf/day by 2015 and 500 MMcf/day by 2022 are assumed to be available to the PG&E system for all three temperature-year cases. No curtailments occur in any of the temperature cases.

2002 California Gas Report

PACIFIC GAS AND ELECTRIC COMPANY TABULAR DATA

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 1997-2001
MMCF/DAY

LINE		1997	1998	1999	2000	2001	LINE
	GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS						
	Core Purchases	29	13	8	12	29	
	Customer Gas Transport & Exchange	118	134	143	151	157	
	Total California Source Gas	147	147	151	163	186	
	OUT-OF-STATE GAS						
	Core Purchases						
	Rocky Mountain Gas	4	44	62	28	6	
	U.S. Southwest Gas	140	205	210	209	204	
	Canadian Gas	565	595	595	604	574	
	Customer Gas Transport						
	Rocky Mountain Gas	71	53	48	24	78	
	U.S. Southwest Gas	319	310	286	374	644	
	Canadian Gas	681	815	875	939	864	
	Total Out-of-State Gas	1,780	2,022	2,076	2,178	2,370	
12	STORAGE WITHDRAWAL	113	107	60	92	94	12
13	Total Gas Supply Taken	2,040	2,276	2,287	2,433	2,650	13
	GAS SENDOUT						
	CORE						
15	Residential	528	618	644	581	543	15
16	Commercial	208	224	232	218	244	16
17	NGV	1	1	1	2	2	17
18	Total Throughput-Core	737	843	877	801	789	18
	NONCORE						
19	Industrial	588	514	473	537	420	19
20	Electric Generation (2)	566	688	703	941	1100	20
21	EOR	4	1	0	0	1	21
22	NGV	1	1	1	1	1	22
23	Wholesale/Resale	10	12	12	11	11	23
24	Total Throughput-Noncore	1169	1216	1189	1490	1533	24
25	Total Throughput	1906	2059	2066	2291	2322	25
33	CALIFORNIA EXCHANGE GAS	12	14	0	0	0	33
34	STORAGE GAS (3)	74	146	63	40	252	34
35	SHRINKAGE Company Use / Unaccounted for	48	57	158	102	76	35
36	Total Gas Send Out (4)	2,040	2,276	2,287	2,433	2,650	36
	CURTAILMENT / ALTERNATIVE FUEL BURNS (5)						
37	Residential, Commercial, Industrial and EO	0	1	0	0	0	37
38	Utility Electric Generation	0	0	0	0	0	38
39	TOTAL CURTAILMENT	0	1	0	0	0	39

NOTES:

(1) Also includes Wholesale/Resale and non-utility generation.
(2) Electric generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
(3) Includes both PG&E and third party storage
(4) Total gas send-out excludes off-system transportation.
(5 UEG curtailments include voluntary oil burns due to economic, operational, and inventory reduction reasons as well as involuntary curtailments due to supply shortages and capacity constraints.

ANNUAL GAS SUPPLY
FORECAST YEARS 2002-2006
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas(1)	1115	1115	1115	1115	1115	2
3	Canadian Gas(2)	1684	1684	1684	1684	1684	3
4	Supplemental(3)	0	0	0	0	0	4
5	*Total out of state gas*	2799	2799	2799	2799	2799	5
6	Total supplies Available(4)	2949	2949	2949	2949	2949	6
7	Pipeline Bypass(5)	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3315	3315	3315	8
	GAS SUPPLY TAKEN						
	California Source Gas						
9	PG&E Purchases(6)	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases(6)	192	196	204	212	220	12
13	Customer Transport	119	71	77	148	186	13
14	*Total U.S. Southwest Gas*	311	267	281	360	406	14
	Canadian Gas						
15	PG&E Purchases(6)	600	600	600	600	600	15
16	Customer Transport	1051	999	1010	1052	1064	16
17	*Total Canadian Gas*	1651	1599	1610	1652	1664	17
	Supplemental						
18	PG&E Purchases(6)	0	0	0	0	0	18
19	Customer Transport	0	0	0	0	0	19
20	*Total Supplement*	0	0	0	0	0	20
21	Total out of state	1962	1866	1891	2012	2070	21
22	Subtotal (all pipeline)	2112	2016	2041	2162	2220	22
23	Storage Injection	172	175	174	174	175	23
24	Pipeline Bypass(5)	366	366	366	366	366	24
25	*Total Throughput*	2650	2557	2581	2702	2761	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2002-2006
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
	REQUIREMENTS FORECAST BY END USE (1)						
	CORE						
1	Residential	563	565	570	576	581	1
2	Commercial	233	235	238	240	243	2
3	NGV	2	3	3	3	4	3
4	Total Core	798	803	811	819	828	4
	NONCORE						
5	Industrial	450	453	453	452	452	5
6	SMUD Electric Generation	65	67	54	88	124	6
7	PG&E Electric Generation(2)	746	640	669	747	761	7
8	EOR	0	0	0	0	0	8
9	NGV	1	2	2	2	2	9
10	Resale	10	11	11	11	11	10
11	Southwest Exchange Gas	0	0	0	0	0	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1273	1174	1190	1301	1351	13
	SHRINKAGE						
14	Company use and Unaccounted for	32	31	31	32	33	14
15	TOTAL END USE SERVED BY UTILITY(3)	2103	2008	2032	2152	2212	15
16	Storage Injection (Includes Wild Goose)	172	175	174	174	175	16
17	Subtotal - including injection	2275	2183	2206	2326	2387	17
18	Pipeline Bypass	366	366	366	366	366	18
19	Total Requirements	2641	2549	2572	2692	2753	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2007-2022
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas(1)	1115	1115	1115	1115	1115	2
3	Canadian Gas(2)	1684	1684	1684	1684	1684	3
4	Supplemental(3)	0	0	1	64	136	4
5	*Total out of state gas*	2799	2799	2800	2863	2935	5
6	Total supplies Available(4)	2949	2949	2950	3013	3085	6
7	Pipeline Bypass(5)	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3316	3379	3451	8
	GAS SUPPLY TAKEN						
	California Source Gas						
9	PG&E Purchases(6)	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases(6)	228	251	288	321	332	12
13	Customer Transport	229	386	582	719	730	13
14	*Total U.S. Southwest Gas*	457	637	870	1040	1062	14
	Canadian Gas						
15	PG&E Purchases(6)	600	600	600	600	600	15
16	Customer Transport	1078	1083	1083	1084	1084	16
17	*Total Canadian Gas*	1678	1683	1683	1684	1684	17
	Supplemental						
18	PG&E Purchases(6)	0	0	0	0	0	18
19	Customer Transport	0	0	1	64	136	19
20	*Total Supplement*	0	0	1	64	136	20
21	Total out of state	2135	2320	2554	2788	2882	21
22	Subtotal (all pipeline)	2285	2470	2704	2938	3032	22
23	Storage Injection	175	174	174	174	174	23
24	Pipeline Bypass(5)	366	366	366	366	366	24
25	*Total Throughput*	2826	3010	3244	3478	3572	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2007-2022
MMCF/DAY
AVERAGE DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
	REQUIREMENTS FORECAST BY END USE [1]						
	CORE						
1	Residential	587	605	632	656	665	1
2	Commercial	245	251	261	270	273	2
3	NGV	4	5	6	7	8	3
4	Total Core	836	861	899	933	946	4
	NONCORE						
5	Industrial	451	449	443	435	432	5
6	SMUD Electric Generation	125	186	185	185	185	6
7	PG&E Electric Generation[2]	815	915	1113	1317	1400	7
8	EOR	0	0	0	0	0	8
9	NGV	2	2	2	2	2	9
10	Resale	11	12	12	12	12	10
11	Southwest Exchange Gas[3]	0	10	10	10	10	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1405	1575	1766	1962	2042	13
	SHRINKAGE						
14	Company use and Unaccounted for	34	36	40	43	44	14
15	TOTAL END USE SERVED BY UTILITY[4]	2275	2472	2705	2938	3032	15
16	Storage Injection (Includes Wild Goose)	175	174	174	174	174	16
17	Subtotal - including injection	2450	2646	2879	3112	3206	17
18	Pipeline Bypass	366	366	366	366	366	18
19	Total Requirements	2816	3012	3245	3478	3572	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.
(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
(3) The current SEGDA agreement with SoCal Gas expires in March 2008. After this time, PG&E provides gas to these Southwest Gas customers.
(4) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2002-2006
MMCF/DAY
LOW DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas(1)	1115	1115	1115	1115	1115	2
3	Canadian Gas(2)	1684	1684	1684	1684	1684	3
4	Supplemental(3)	0	0	0	0	0	4
5	*Total out of state gas*	2799	2799	2799	2799	2799	5
6	Total supplies Available(4)	2949	2949	2949	2949	2949	6
7	Pipeline Bypass(5)	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3315	3315	3315	8
	GAS SUPPLY TAKEN						
	California Source Gas						
9	PG&E Purchases(6)	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases(6)	117	121	127	135	142	12
13	Customer Transport	126	76	85	153	193	13
14	*Total U.S. Southwest Gas*	243	197	212	288	335	14
	Canadian Gas						
15	PG&E Purchases(6)	600	600	600	600	600	15
16	Customer Transport	1042	991	1000	1044	1055	16
17	*Total Canadian Gas*	1642	1591	1600	1644	1655	17
	Supplemental						
18	PG&E Purchases(6)	0	0	0	0	0	18
19	Customer Transport	0	0	0	0	0	19
20	*Total Supplement*	0	0	0	0	0	20
21	Total out of state	1885	1788	1812	1932	1990	21
22	Subtotal (all pipeline)	2035	1938	1962	2082	2140	22
23	Storage Injection	172	174	175	175	175	23
24	Pipeline Bypass(5)	366	366	366	366	366	24
25	*Total Throughput*	2573	2478	2503	2623	2681	25

NOTES:
(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.
(2) 175 MMcf/day assumed to southern California.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Supplies available through utility system.
(5) Bypass is defined in the Glossary.
(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2002-2006
MMCF/DAY
LOW DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
	REQUIREMENTS FORECAST BY END USE (1)						
	CORE						
1	Residential	507	509	513	518	524	1
2	Commercial	213	216	218	220	222	2
3	NGV	2	3	3	3	4	3
4	Total Core	722	728	734	741	750	4
	NONCORE						
5	Industrial	450	453	453	452	452	5
6	SMUD Electric Generation	65	67	54	88	124	6
7	PG&E Electric Generation(2)	746	640	669	747	761	7
8	EOR	0	0	0	0	0	8
9	NGV	1	2	2	2	2	9
10	Resale	10	11	11	11	11	10
11	Southwest Exchange Gas	0	0	0	0	0	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1273	1174	1190	1301	1351	13
	SHRINKAGE						
14	Company use and Unaccounted for	30	29	29	30	31	14
15	TOTAL END USE SERVED BY UTILITY(3)	2025	1931	1953	2072	2132	15
16	Storage Injection (Includes Wild Goose)	172	174	175	175	175	16
17	Subtotal - including injection	2197	2105	2128	2247	2307	17
18	Pipeline Bypass	366	366	366	366	366	18
19	Total Requirements	2563	2471	2494	2613	2673	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2007-2022
MMCF/DAY
LOW DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas(1)	1115	1115	1115	1115	1115	2
3	Canadian Gas(2)	1684	1684	1684	1684	1684	3
4	Supplemental(3)	0	0	1	34	77	4
5	*Total out of state gas*	2799	2799	2800	2833	2876	5
6	Total supplies Available(4)	2949	2949	2950	2983	3026	6
7	Pipeline Bypass(5)	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3316	3349	3392	8
	GAS SUPPLY TAKEN						
	California Source Gas						
9	PG&E Purchases(6)	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases(6)	149	170	206	235	246	12
13	Customer Transport	233	384	579	746	785	13
14	*Total U.S. Southwest Gas*	382	554	785	981	1031	14
	Canadian Gas						
15	PG&E Purchases(6)	600	600	600	600	600	15
16	Customer Transport	1072	1083	1083	1084	1084	16
17	*Total Canadian Gas*	1672	1683	1683	1684	1684	17
	Supplemental						
18	PG&E Purchases(6)	0	0	0	0	0	18
19	Customer Transport	0	0	1	34	77	19
20	*Total Supplement*	0	0	1	34	77	20
21	Total out of state	2054	2237	2469	2699	2792	21
22	Subtotal (all pipeline)	2204	2387	2619	2849	2942	22
23	Storage Injection	176	174	174	174	174	23
24	Pipeline Bypass(5)	366	366	366	366	366	24
25	*Total Throughput*	2746	2927	3159	3389	3482	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2007-2022
MMCF/DAY
LOW DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
	REQUIREMENTS FORECAST BY END USE (1)						
	CORE						
1	Residential	529	545	569	591	599	1
2	Commercial	224	230	241	249	252	2
3	NGV	4	5	6	7	8	3
4	Total Core	757	780	816	847	859	4
	NONCORE						
5	Industrial	451	449	443	435	432	5
6	SMUD Electric Generation	125	186	185	185	185	6
7	PG&E Electric Generation(2)	815	915	1113	1317	1400	7
8	EOR	0	0	0	0	0	8
9	NGV	2	2	2	2	2	9
10	Resale	11	12	12	12	12	10
11	Southwest Exchange Gas(3)	0	10	10	10	10	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1405	1575	1766	1962	2042	13
	SHRINKAGE						
14	Company use and Unaccounted for	32	33	37	40	42	14
15	TOTAL END USE SERVED BY UTILITY(4)	2194	2388	2619	2849	2943	15
16	Storage Injection (Includes Wild Goose)	176	174	174	174	174	16
17	Subtotal - including injection	2370	2562	2793	3023	3117	17
18	Pipeline Bypass	366	366	366	366	366	18
19	Total Requirements	2736	2928	3159	3389	3483	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.
(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.
(3) The current SEGDA agreement with SoCal Gas expires in March 2008. After this time, PG&E provides gas to these Southwest Gas customers.
(4) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2002-2006
MMCF/DAY
HIGH DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas(1)	1115	1115	1115	1115	1115	2
3	Canadian Gas(2)	1684	1684	1684	1684	1684	3
4	Supplemental(3)	0	0	0	0	0	4
5	*Total out of state gas*	2799	2799	2799	2799	2799	5
6	Total supplies Available(4)	2949	2949	2949	2949	2949	6
7	Pipeline Bypass(5)	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3315	3315	3315	3315	8
	GAS SUPPLY TAKEN						
	California Source Gas						
9	PG&E Purchases(6)	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases(6)	277	283	290	299	308	12
13	Customer Transport	222	296	223	329	416	13
14	*Total U.S. Southwest Gas*	499	579	513	628	724	14
	Canadian Gas						
15	PG&E Purchases(6)	600	600	600	600	600	15
16	Customer Transport	1081	1082	1080	1081	1083	16
17	*Total Canadian Gas*	1681	1682	1680	1681	1683	17
	Supplemental						
18	PG&E Purchases(6)	0	0	0	0	0	18
19	Customer Transport	0	0	0	0	0	19
20	*Total Supplement*	0	0	0	0	0	20
21	Total out of state	2180	2261	2193	2309	2407	21
22	Subtotal (all pipeline)	2330	2411	2343	2459	2557	22
23	Storage Injection	174	174	174	176	174	23
24	Pipeline Bypass(5)	366	366	366	366	366	24
25	*Total Throughput*	2870	2951	2883	3001	3097	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2002-2006
MMCF/DAY
HIGH DEMAND YEAR

LINE		2002	2003	2004	2005	2006	LINE
	REQUIREMENTS FORECAST BY END USE (1)						
	CORE						
1	Residential	627	630	635	641	648	1
2	Commercial	255	257	261	263	266	2
3	NGV	2	3	3	3	4	3
4	Total Core	884	890	899	907	918	4
5	Industrial	450	453	453	452	452	5
6	SMUD Electric Generation	69	74	60	97	137	6
7	PG&E Electric Generation(2)	765	941	882	943	990	7
8	EOR	0	0	0	0	0	8
9	NGV	1	2	2	2	2	9
10	Resale	10	11	11	11	11	10
11	Southwest Exchange Gas	0	0	0	0	0	11
12	California Exchange Gas	1	1	1	1	1	12
13	Subtotal Noncore	1296	1482	1409	1506	1593	13
14	Company use and Unaccounted for	35	36	35	36	37	14
15		2215	2408	2343	2449	2548	15
16	Storage Injection (Includes Wild Goose)	174	174	174	176	174	16
17	Subtotal - including injection	2389	2582	2517	2625	2722	17
18	Pipeline Bypass(4)	366	366	366	366	366	18
19	Total Requirements	2755	2948	2883	2991	3088	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

ANNUAL GAS SUPPLY
FORECAST YEARS 2007-2022
MMCF/DAY
HIGH DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
	GAS SUPPLY AVAILABLE						
1	**California Source Gas**	150	150	150	150	150	1
	Out of State Gas						
2	U.S. Southwest Gas(1)	1115	1115	1115	1115	1115	2
3	Canadian Gas(2)	1684	1684	1684	1684	1684	3
4	Supplemental(3)	0	40	157	370	468	4
5	*Total out of state gas*	2799	2839	2956	3169	3267	5
6	Total supplies Available(4)	2949	2989	3106	3319	3417	6
7	Pipeline Bypass(5)	366	366	366	366	366	7
8	*Total Including Bypass*	3315	3355	3472	3685	3783	8
	GAS SUPPLY TAKEN						
	California Source Gas						
9	PG&E Purchases(6)	0	0	0	0	0	9
10	Customer Transport	150	150	150	150	150	10
11	*Total California*	150	150	150	150	150	11
	Out of State Gas (via existing facilities)						
	U.S. Southwest Gas						
12	PG&E Purchases(6)	317	344	382	418	430	12
13	Customer Transport	467	600	681	677	667	13
14	*Total U.S. Southwest Gas*	784	944	1063	1095	1097	14
	Canadian Gas						
15	PG&E Purchases(6)	600	600	600	600	600	15
16	Customer Transport	1083	1084	1084	1084	1084	16
17	*Total Canadian Gas*	1683	1684	1684	1684	1684	17
	Supplemental						
18	PG&E Purchases(6)	0	0	0	0	0	18
19	Customer Transport	0	40	157	370	468	19
20	*Total Supplement*	0	40	157	370	468	20
21	Total out of state	2467	2668	2904	3149	3249	21
22	Subtotal (all pipeline)	2617	2818	3054	3299	3399	22
23	Storage Injection	175	174	179	174	174	23
24	Pipeline Bypass(5)	366	366	366	366	366	24
25	*Total Throughput*	3158	3358	3599	3839	3939	25

NOTES:

(1) This is based on the intrastate capacity of 1,115 MMcf/day and includes transport of customer-owned gas and purchases by PG&E and 25 MMcf/day to Southern California. The total capacity from the U. S. Southwest and the Rocky Mountain producing regions is higher than the intrastate capacity of 1,140 MMcf/day on PG&E's Baja Path.

(2) 175 MMcf/day assumed to southern California.

(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.

(4) Supplies available through utility system.

(5) Bypass is defined in the Glossary.

(6) Core portfolio only.

ANNUAL GAS REQUIREMENTS
FORECAST YEARS 2007-2022
MMCF/DAY
HIGH DEMAND YEAR

LINE		2007	2010	2015	2020	2022	LINE
	REQUIREMENTS FORECAST BY END USE (1)						
	CORE						
1	Residential	654	674	704	731	741	1
2	Commercial	268	275	283	293	296	2
3	NGV	4	5	6	7	8	3
4	Total Core	926	954	993	1031	1045	4
	NONCORE						
5	Industrial	451	449	443	435	432	5
6	SMUD Electric Generation	137	210	200	200	200	6
7	PG&E Electric Generation(2)	1039	1140	1349	1561	1648	7
8	EOR	0	0	0	0	0	8
9	NGV	2	2	2	2	2	9
10	Resale	11	12	12	12	12	10
11	Southwest Exchange Gas	0	10	10	10	10	11
12	California Exchange Gas(3)	1	1	1	1	1	12
13	Subtotal Noncore	1641	1824	2017	2221	2305	13
	SHRINKAGE						
14	Company use and Unaccounted for	38	40	44	47	49	14
15	TOTAL END USE SERVED BY UTILITY(4)	2605	2818	3054	3299	3399	15
16	Storage Injection (Includes Wild Goose)	175	174	179	174	174	16
17	Subtotal - including injection	2780	2992	3233	3473	3573	17
18	Pipeline Bypass(4)	366	366	366	366	366	18
19	Total Requirements	3146	3358	3599	3839	3939	19
20	System Curtailment	0	0	0	0	0	20

NOTES:

(1) Requirements forecast by end use includes on-system sales and transportation volumes only.

(2) Electric Generation includes Non-EOR cogeneration, PG&E Utility Electric Generation, and other non-utility generation.

(3) The current SEGDA agreement with SoCal Gas expires in March 2008. After this time, PG&E provides gas to these Southwest Gas customers.

(4) Figures are net of pipeline bypass load losses to non-jurisdictional gas suppliers.

2002 California Gas Report

SOUTHERN CALIFORNIA

INTRODUCTION

Southern California Gas Company (SoCalGas) is the principal distributor of natural gas in southern California, providing retail and wholesale customers with procurement, transportation, exchange and storage services. SoCalGas is a gas-only utility and, in addition to serving the residential, commercial, and industrial markets, provides gas for enhanced oil recovery and electric generation in southern California. San Diego Gas & Electric (SDG&E), Southwest Gas Corporation, and the City of Long Beach Energy Department are SoCalGas' three wholesale utility customers. Gas service at wholesale is expected to begin to the City of Vernon during the forecast period.

This report covers a 20-year forecast period, from 2002 through 2022; only the consecutive years 2002 through 2006 and the point years 2007, 2010, 2015 and 2020, and 2022, however, are shown in the tabular data in the next sections. The forecast is subject to uncertainty, but represents best estimates for the future, based upon the most current information available.

The Southern California section of the 2002 California Gas Report (CGR) begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting gas demand in various market sectors. The outlook on gas supply availability, which continues to be favorable, is presented followed by a review of the peak day demand forecast. Summary tables and figures underlying the forecast are provided.

THE SOUTHERN CALIFORNIA ENVIRONMENT

Economics and Demographics

The gas demand projections are partly determined by the long-term economic outlook for the SoCalGas service territory. After suffering prolonged recession in the early-to-mid 1990's, southern California's economy enjoyed a recovery in the last years of the decade before slowing in 2001 and 2002. Even with the recent slowdown, area employment has grown every year since 1994. After strong 3.0% growth in 2000, the area's non-farm jobs grew by a more modest 1.8% in 2001—still much stronger than the anemic 0.4% growth in the United States as a whole. Non-farm employment in 2002 should grow 1.5% and pass 7.8 million. In 2001, local service-sector jobs saw 2.5% growth – slower than previous years, but much better than the 1.4% national growth rate. It is expected that local service jobs will grow by 2.1% in 2002. In manufacturing, local employment dropped by 0.9% in 2001 and is expected to drop a further 2.2% in 2002—less severe than annual drops of more than 4% across the US. However, southern California's manufacturing jobs still remain more than 20% below their 1988 peak of 1.26 million.

From 2001 through 2006, service-area non-farm jobs should see 2.1% average annual growth. Beyond 2006, SoCalGas expects the service area population's average age to gradually increase, part of a national demographic trend of aging "baby boomers". As the population ages and as more people retire, it is expected that employment will grow at slower rates. From 2006 through 2022, local non-farm job growth should average only about 0.7% per year—with annual growth gradually slowing from 1.5% in 2007 to 0.2% by 2022. Area manufacturing jobs should drop an average of about 0.4% per year from 2001 through 2022. Manufacturing's share of non-farm employment will fall from over 13% in 2001 to less than 10% by 2022. Service-sector jobs should average nearly 2% annual growth from 2001 through 2022 – gradually increasing their share from 32% in 2001 to 38% by 2022.

Due to growth in residents, we expect that SoCalGas' active meters will increase by an average of 1.25% per year from 2001 to 2022 – slightly slower than the recent 1.31% average annual growth seen from 1999 through 2001.

REGULATORY ENVIRONMENT

The past year witnessed numerous developments at both the California Public Utilities Commission (CPUC) and Federal Energy Regulatory Commission (FERC) designed to make the natural gas industry more responsive to the changing needs of the marketplace.

State Regulatory Matters

In December of 2001 the California Public Utilities Commission (CPUC) adopted a decision in the Gas Industry Restructuring (GIR) proceeding bringing substantial changes to SoCalGas' services. Once fully implemented, the GIR decision will introduce a new structure in transportation, storage and balancing services. The capacity provisions provide new unbundled service offerings for transportation, storage, and balancing, while setting the revenue requirement for transmission and storage on a embedded cost basis through August 2006. The GIR decision also creates firm tradable rights for SoCalGas' 3875 MMcf/day of firm backbone transmission capacity to be sold at an embedded cost-based reservation charge. After a set-aside for core customers, receipt point rights would be awarded through an open season that ensures customer access and prevents market concentration. The GIR decision results in a number of new options for customers, including: firm tradable backbone transmission rights, fully tradable unbundled storage rights, new storage services, and unbundled balancing options.

In April of 2001, SoCalGas participated in a workshop by the CPUC – Energy Division to assess the adequacy of natural gas infrastructure in California. The Energy Division followed the workshop with a report acknowledging that SoCalGas has sufficient capacity to meet expected demand levels. Rulemaking 01-03-023 was also initiated by the CPUC in 2001 to determine whether curtailment and diversion priorities should be altered to noncore natural gas customers in SoCalGas' service area. After a full presentation of the record in the proceeding, the CPUC acknowledged that there was no need for changes to noncore transportation priorities, since curtailments were not expected in SoCalGas' service areas within the next 12 months.

In addition, the Commission has before it a proposed decision that would consolidate the core gas supply portfolios, storage capacities, and related interstate pipeline capacities of SoCalGas and San Diego Gas & Electric (SDG&E). Under this proposed decision each utility would charge the same procurement rate to customers in each of their service territories.

Federal Regulatory Matters

During the past year SoCalGas has been actively participating in numerous FERC proceedings relative to interstate capacity serving California, including Docket No. RP00-336-002, reviewing the basis for assigning capacity and receipt point rights on the El Paso Natural Gas Company pipeline system. SoCalGas echoed support for the position of FERC staff that FT-1 full requirements service on El Paso's system must be limited consistent with contract demand service to ensure certainty and reliability for shippers on the El Paso system. The FERC staff proposal would also require that the level of contract demand assigned to FT-1 shippers should be the greater of the billing determinants or coincidental peak demand. Finally, SoCalGas supported the position that the El Paso system needs to be fully pathed from the receipt point meter to delivery points to further improve the reliability of the El Paso system and its deliveries to California.

These changes proposed for the El Paso system represent changes similar to those approved by the California Public Utilities Commission for the SoCalGas system in recent years. These changes to SoCalGas' system will increase the reliability and certainty of supply deliveries. FERC issued an order on May 31, 2002 affirming the positions of FERC staff and reallocating the capacity on the El Paso pipeline system. The FERC order also addresses El Paso standards with respect to the allocation of any new expansion capacity added to their pipeline system.

GAS DEMAND (REQUIREMENTS)

OVERVIEW

SoCalGas expects continued 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 noncore market.

The following table compares the composition of SoCalGas' throughput for recorded year 2001 and forecast year 2022.

Composition of SoCalGas Throughput – Bcf
(Average Temperature Year)

	2001	2022	Change
Residential	264	325	23%
Core Non-Residential	100	137	37%
Noncore C&I	146	119	-19%
EOR-Steaming	11	8	-28%
Electric Generation	459	314	-32%
Wholesale	171	173	1%
Other	26	32	24%
TOTAL	**1177**	**1109**	**-6%**

Notes:
1) "Core Non-Residential includes Natural Gas Vehicle (NGV) throughput.
2) "Other" includes international (Mexicali) throughput and Lost and Unaccounted for Gas (L&UAF) + Company-Use gas.

Residential, core non-residential, and wholesale requirements are expected to increase as southern California's economy continues through a gradual economic expansion. Requirements for Enhanced Oil Recovery (EOR) steaming operations, which have declined since the Kern/Mojave pipeline began offering direct service to California customers in 1992, are expected to continue to decline. The electric generation (EG) market is expected to decline dramatically from the unusually high level in 2001. EG sendout in 2001 was unusually high due to low availability of hydro-power, delays in the start-up of new generation projects and unusually low output from nuclear power plants. For the forecast period, more electric power generation is expected to take place outside SoCalGas' service territory, reducing gas demand for electric generation. The decline in wholesale demand is also explained by the electric power generation market impacts in SDG&E's service territory, more than offsetting any expected growth in other core and noncore wholesale markets.

MARKET SENSITIVITY

Temperature

Core demand forecasts are prepared for three design temperature conditions – average, cold, and hot – to quantify changes in space heating demand due to weather. Temperature variations can cause significant changes in winter gas demand due to space heating in the residential, core commercial and industrial markets. The largest demand variations due to temperature occur in the month of January. Degree-day differences between the three conditions are developed from a six-zone temperature monitoring procedure within SoCalGas' service territory. The cold and hot design temperature conditions are based on a statistical recurrence factor of 1-in-35 years.

Pipeline Bypass

The Kern/Mojave Pipeline began operating in California in 1992, leading to bypass of the local gas distribution systems. In 2001, 143 Bcf of gas load bypassed SoCalGas' distribution system. Bypass to the Kern/Mojave mainline is expected to grow gradually to 160 Bcf per year in 2008. The expiration of several major long-term EOR customer transportation contracts by 2009 is expected to lead to an increase of bypass to 183 Bcf per year by 2013. Beyond 2013, bypass load is anticipated to decline slowly as total gas usage in the EOR market declines.

Several new pipeline or expansion projects have been proposed to directly serve customers in southern California. The first project, Questar Southern Trails (Questar), has already received approval from FERC. Questar anticipates initiating service on its East Zone this year. Questar has continued to work with local agencies to finalize the environmental approvals necessary to convert the West Zone to natural gas transportation service. This report assumes the Questar pipeline, with a capacity up to 44 BCF/year, will begin service in the early part of the forecast period. Kern River has completed a 135 MMcf/d expansion and is undertaking another 900 MMcf/d expansion of their system. There have been other projects proposed, but they must still obtain commitments from customers before starting the formal regulatory approval process.

MARKET SECTORS

Residential

Residential demand adjusted for temperature decreased to 238.0 Bcf in 2001 from 255.5 Bcf in 2000. Unadjusted residential demand was 259.5 Bcf in 2001, 9% more than temperature adjusted demand primarily because of colder than normal weather conditions in southern California.

Active residential meters averaged 4.79 million in 2001, an increase of 59,500 (or 1.3%) from the 2000 average. In 2002, SoCalGas expects an increase of more than 53,000 active meters. From 2002 through 2022, active residential meters are expected to grow at an average annual rate of 1.3%, reaching 6.28 million by 2022.

Residential demand is projected to grow from 263.3 Bcf in 2002 to 325.0 Bcf in 2022, an increase of 3.1 Bcf per year. SoCalGas' DSM programs are projected to save about 1 Bcf per year in the residential sector through 2016 and to decline thereafter.

Commercial

On a temperature-adjusted basis, core commercial market demand in 2001 totaled 71.5 Bcf, down 1.4 Bcf from 2000. This decrease is largely the result of the temporary, but substantial, impact of the energy crisis that occurred during years 2000 and 2001 in California. Projected core commercial gas demand (for an average temperature year) is 74.5 Bcf for 2002. Most of this forecasted increase in load is due to the resumption of positive economic conditions in southern California along with energy prices that are more in-line with historical price levels before the energy crisis. The growth, although at a decreasing rate through 2006, averages 3.2%. After 2006, core commercial demand is forecast to increase about 0.6% per year, from 84.5 Bcf in 2006 to 92.5 Bcf in 2022. Over this time frame, growth in employment is positive, but at a declining rate, gas costs decline modestly and space heating efficiency improves steadily.

Noncore commercial demand is forecast to be 20.4 Bcf in 2002, a slight increase of about 0.4 Bcf from 2001 usage. After year 2002, noncore commercial demand is expected to decrease to 17.7 Bcf in 2005 due to the noncore to core customers migration as the result of the Commission's decision in the GIR proceeding. After 2005, the noncore commercial demand is expected to grow at 0.4% per year reaching 20.3 Bcf in 2022. The growth is primarily due to the increase in the commercial employment forecast.

Industrial

In 2001, temperature-adjusted core industrial demand was 20.5 Bcf, a decrease of 0.2 Bcf over 2000 deliveries. From 2002 through 2006, retail core industrial market deliveries (for an average temperature year) are projected to increase from 1.0 Bcf in 2002, at a decreasing rate, to about 27.5 Bcf in 2006. After 2006, core industrial demand is expected to decline by approximately 0.6% per year over the forecast period, dropping to 24.8 Bcf in 2022. This decline results from a combination of a slightly lower industrial employment forecast, higher marginal gas rates and increases in gas equipment energy-efficiencies.

Retail noncore industrial deliveries are forecast to be 67.9 Bcf in 2002 compared to 67.9 Bcf in 2001. The forecast demand is expected to decrease from 68.3 Bcf in 2002 to 59.2 Bcf in 2005. The decrease is primarily due to the reclassification of Vernon load to Wholesale service, and the expected noncore to core customer migration as the result of the Commission's decision in the GIR proceeding. After 2005, noncore industrial demand is forecast to decline gradually to 50.1 Bcf in 2022, due to the decrease in service area industrial employment forecast and higher forecast of natural gas price.

Refinery G30 demand is made up of gas consumption by petroleum refining customers, hydrogen producers and petroleum refined product transporters. Refinery G30 demand is forecast to decline 0.9% per year, from 58.7 Bcf in 2001 to 47.5 Bcf in 2020. This decrease is mainly due to refiners' using alternate fuels during summer months where natural gas prices are forecasted to be less competitive than the alternate fuel prices.

Migration of Commercial and Industrial Load: Noncore to Core

As a result of the Commission's recent GIR decision, some commercial and industrial demand under noncore (G-30) is expected to migrate to commercial and industrial demand under core (G-10) as existing noncore contracts expire. For calendar year 2002 through 2004 the accumulated transfer from noncore to core service is forecast to be 0.5 Bcf, 6.2 Bcf and 9.9 Bcf, respectively. For 2005, and each year thereafter, the forecast is 7.9 Bcf. These forecasts assume a November 1, 2002 implementation date for the new rules governing customers' use of intrastate pipeline and storage capacity on SoCalGas' system.

Commercial and Industrial Load Growth: Incentives for Electric Self-Generation

Capital cost incentives, funded by the State of California through AB970, that encourage installation of self-generation equipment, are expected to lead to additional gas demand for electric generation by commercial and industrial customers. Because the incentives of this program are limited to 1,000 kW, or less per customer, most of the additional load is expected to fall under core rather than noncore service for these applications. Further, the total funding provided by AB970 is limited and customers must make application, prior to year-end 2004, to receive incentives.

Since the program began late in 2001, the load growth we forecast is very uncertain. For core commercial and industrial, the accumulated gas demand is expected to be just under 0.5 Bcf for 2002; growing to 1.3 Bcf and 2.0 Bcf, for 2003 and 2004, respectively; and, by 2005, full saturation of the program's incentives yield a load of 2.6 to 2.7 Bcf for each year thereafter. For the noncore, significant load growth is expected to start in 2003 at just over 0.1 Bcf, then 0.2 Bcf in 2004 and reaching just under 0.3 Bcf in 2005 and for each year thereafter.

Electric Generation

The electric generation (EG) sector includes the following markets: noncore commercial/industrial cogeneration and self-generation, enhanced oil recovery (EOR)-related cogeneration, and non-cogeneration electric generation (EG), generally referred to as exempt wholesale generators (EWG) and municipal utility electric generators (UEG). It should be noted that the forecasts of EG-related load are subject to a higher degree of uncertainty associated with the continued operation of existing generation facilities, the construction of new generation facilities in the western United States, and regulatory and market decisions that impact the operation of existing QF facilities and other electric generation plants, including the construction of additional electric transmission transfer capacity.

Commercial/Industrial/Cogeneration <20MW

The commercial/industrial cogeneration segment is generally made up of customers generating less than 20 MW of power. All the cogeneration units in this segment are installed primarily to generate electricity for internal consumption rather than for the sale of power to electric utilities. In 2001, recorded gas deliveries to this market were 13 Bcf, a decrease of 2.5 Bcf from 2000. Commercial/industrial cogeneration demand is projected to be around 15 Bcf for the next 20 years.

Commercial/Industrial/ Cogeneration (>20 MW)

Commercial/industrial cogeneration greater than 20 MW gas demand is forecast to decline 45%, from 61 Bcf in 2002 to 34 Bcf in 2003. The forecast is based on a power market simulation for the period to 2015 and thus reflects the anticipated dispatch of these resources under the forecast market conditions, in addition to receiving contract capacity payments. In addition, some customers are expected to select alternate service providers. The forecast remains at 34 Bcf per year from 2003 to 2015. Gas use increases by 2.0% per year consistent with the general increase in electric sales during the period 2016 through 2022

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. Refinery-related cogeneration is forecast to decline 0.8% per year, from 14.5 Bcf in 2001 to 12.2 Bcf in 2020. This decrease is mainly due to the use of alternative fuels during summer months when gas prices are less competitive with alternate fuels.

EOR-Related Cogeneration

In 2001, recorded gas deliveries to the EOR-related cogeneration market were 14.7 Bcf, a decrease of 11.7 Bcf from 2000. This decrease was mainly due to the temporary decrease in operating time of several plants as a result of the economic impact of electric industry restructuring. In addition, there was increased bypass to the Kern River/Mojave Pipeline and increased usage of customers' own field gas. EOR-related cogeneration demand is expected to decrease to 13.0 Bcf in 2002 because of load displacement by new, more efficient, electric generation plants. Demand will remain at that level until 2008 when usage will start to drop due to the expiration of several EOR long-term gas transportation contracts. Demand is forecast to level off in 2010 at 5.1 Bcf and remain at that level for the remainder of the forecast period.

Non-Cogeneration Electric Generation (EG)

SoCalGas forecasts a decline in retail non-cogeneration EG gas requirements of 44%, from 164 Bcf in 2002 to 91 Bcf in 2003. The forecast decline in gas use is a result of new off-system generation projects, which displace current on-system generator operation. SoCalGas forecasts an increase in retail non-cogeneration EG gas requirements of 7% per year, from 91 Bcf in 2003 to 213 Bcf in 2015. The forecast for SoCalGas' EG customers through 2015 is based on a power market simulation. EG gas use increases by 2.0% per year consistent with the general increase in electric sales during the period 2016 through 2022.

SoCalGas' forecast includes the construction of approximately 40,000 MW from 2002 to 2007 of new resources' capacity. Of that total, 10,500 MW is currently in operation, 26,000 MW are under construction, and 3,500 MW are in advanced development. Thus the forecast assumes only 40,000 MW of the more than 119,000 MW of "announced" generation in the Western Electric Coordinating Council (WECC) to date are actually constructed during the forecast period. Throughout the entire planning period, SoCalGas assumes a minimum planning reserve margin of 15% throughout the WECC. For electric demand within California, SoCalGas used the California Energy Commission's end-use electric demand forecast for California described in their report titled "Electricity Outlook: 2002-2012" which was released in January 2002. For electric demand outside of California, the CGR working group utilized the electric demand forecast based on work done by the energy-consulting firm, PIRA, Inc.

SoCalGas performed two special hydro sensitivities for Year 2005. Due to the displacement of generation by off-system resources, the impact of significant hydro conditions had little impact on gas demand. A one-in-twenty dry hydro year increased demand by 23 Bcf for the Year 2005. A one-in-twenty wet year decreased demand by 11 Bcf for the Year 2005.

Enhanced Oil Recovery – Steam

Recorded deliveries to the EOR steaming market in 2001 were 10.7 Bcf, a decrease of 2.0 Bcf from 2000. This decrease was due to the high gas prices relative to the price of crude oil and to increased usage of customers' own field gas. SoCalGas' EOR steaming demand is expected to remain stable at 10.1 Bcf from 2002 until 2008 when SoCalGas' EOR long-term gas transportation contracts terminate in late 2008. From 2009 through the end of the forecast period, usage is expected to be approximately 7.4 Bcf. These figures include gas delivered to PG&E's EOR customers through interutility exchange. In 2001, 0.01 Bcf of gas was delivered to PG&E through such arrangements. No change in demand is expected in that market. The EOR-related cogeneration demand is discussed in the Electric Generation sector.

Crude oil prices are not expected to reach a level that would initiate any major expansion in EOR operations during the forecast period. As a result, EOR production is expected to gradually decline by approximately 1% per year. In addition, oil producers will rely increasingly on the interstate pipelines in California to supplant traditional supply sources, such as own source gas and SoCalGas' transportation system.

Mexicali

SoCalGas used the forecast prepared by Ecogas, Mexicali, for this report. Mexicali's use is expected to increase from 4.5 Bcf at an average rate of 3.4% per year to 9.4 Bcf in 2022. The forecast assumes industrial loads switch to alternate fuels whenever they are less expensive than natural gas. The forecast assumes that customers will no longer be able to burn fuel oil #6 by 2010 as a result of anticipated future environmental regulations.

Wholesale

The forecast of wholesale gas demand includes transportation to SDG&E, the City of Long Beach Energy Department (Long Beach), Southwest Gas Corporation (SWG), and the City of Vernon (Vernon).

The non-EG gas demand forecast for SDG&E is based on the long-term demand forecast prepared by SDG&E for this report. Under average temperature conditions, total non-EG requirements for SDG&E are expected to increase from 54 Bcf in 2002 at an average growth rate of 1.1% per year to 67 Bcf in 2020.

The forecast of the large EG loads were based on the power market simulation as noted in the Electric Generation chapter for "non-cogeneration EG" demand. EG-related load is subject to a higher degree of uncertainty associated with the continued operation of existing generation facilities and the construction of new facilities. SDG&E's cogeneration and non-cogeneration EG requirements are expected to decrease from 65 Bcf in 2002 to 32 Bcf in 2004. The decline in gas use is a result of new off-system generation, which displace current on-system generation and expectation that a customer will take service from an alternate service provider. SoCalGas forecasts an increase in SDG&E's cogeneration and non-cogeneration EG gas requirements of 7.0% per year, from 32 Bcf in 2004 to 73 Bcf in 2015. SDG&E EG gas use, excluding cogeneration, increased by 2.0% per year consistent with the general increase in electric sales during the period 2016 through 2022.

The cogeneration EG demand forecast is based on the long-term demand forecast prepared by SDG&E for this report. The same assumptions used for the retail non-cogeneration EG demand were used for the wholesale non-cogeneration EG demand.

SoCalGas performed two special hydro sensitivities for Year 2005. Due to the displacement of generation by off-system resources, the impact of significant hydro conditions had little impact on gas demand. A one-in-twenty dry hydro year increased SDG&E's EG demand by 2 Bcf for the Year 2005. A one-in-twenty wet year decreased SDG&E's EG demand by 3 Bcf for the Year 2005.

For the City of Long Beach, SoCalGas used the forecast prepared by Long Beach for this report. Long Beach's use is expected to decrease gradually from 11.9 Bcf at an average rate of -0.1% per year to 11.7 Bcf in 2022. Long Beach's local deliveries are expected to decrease from 3.9 Bcf to 3.6 Bcf in 2022. SoCalGas' transportation to Long Beach is expected to increase from 8.0 Bcf to 8.1 Bcf in 2019.

The demand forecast for SWG is based on a long-term demand forecast prepared by SWG. In 2002, SoCalGas will serve approximately 5.9 Bcf directly, with another 3.7 Bcf being served by PG&E under exchange arrangements with SoCalGas. The direct service load is expected to grow steadily by 1.5% per year throughout the forecast period from 5.9 Bcf in 2002 to approximately 7.9 Bcf in 2022.

The wholesale forecast assumes Vernon initiates municipal gas service to a portion of the existing SoCalGas retail customers within the City's jurisdiction. The forecasted throughput starts at 6 Bcf and grows to 9 Bcf by 2022. Included in this forecast are two customers currently served under SoCalGas' retail EG rate schedule. The throughput forecast for these customers through 2015 is based on a power market simulation.

Natural Gas Vehicles

In November 1995, the CPUC issued a decision regarding Low Emission Vehicle (LEV) programs which approved, among other things, continued ratepayer support for customer information, education and training. Although the decision eliminated ratepayer support for construction of new public access refueling stations and monetary incentives to purchase NGVs, the availability of public funds has allowed the NGV market to continue to grow. SoCalGas' customer information, education and training program facilitates this growth by providing valuable guidance to potential new NGV customers as well as those customers who plan to expand their NGV fleet.

At the end of 2001, 134 fueling stations served approximately 13,000 vehicles that consumed 4.3 Bcf of compressed natural gas (CNG) for the year. SoCalGas remains optimistic about the NGV market growth, forecasting an increase in demand to 12.8 Bcf in 2012 and 20.0 Bcf in 2022. Although SoCalGas has divested all of its fueling stations, which were located on customer property, we expect the forecasted growth will be adequately served by a growing CNG refueling station industry. The growth is being propelled by the private and public sectors, with customer support from SoCalGas' LEV program. The South Coast Air Quality Management District (SCAQMD), in the past two years has passed several fleet rules which required public fleets to purchase NGVs when replacing their fleets. The SCAQMD is also expected to propose rules, which will affect private fleets in the same way as they did the public fleets. These rules have added tremendously to the growth of the NGV industry. There is also legislation, which has already passed in the U.S. Senate, to give incentives to NGV fueling station owners for equipment and CNG fuel price, and to NGV owners to reduce the cost of NGVs by as much as 50 percent. As these programs become effective, the market is expected to grow at an even faster pace.

In 1992 most NGVs were after-market conversions. Today's light-duty NGV market is dominated by Original Equipment Manufacturer (OEM) vehicles. Light-duty NGV products are presently offered by Ford, GM, Honda, Daimler-Chrysler and Toyota. In the medium- and heavy-duty vehicle arena there are more than 35 available engine/vehicle products for transits, schools, refuse and street sweepers. Although repowering of medium and heavy-duty vehicles still exist, the market is dominated by new OEM vehicles.

Reduced vehicle emissions continue to be a major benefit of NGVs. With emissions that are a fraction of California's Ultra Low Emission Vehicle (ULEV) emissions standard, new Ford and Honda products are the cleanest vehicles of their type ever seen in the market. In the heavy-duty market, NGV low emissions have the potential to generate greater air quality improvements. In this arena, Cummins is certifying its new heavy duty natural gas engines to an optional 1.7 gram NOx and NMHC standard that is below the level currently required. With purchase incentives that could include emission reduction credits, tax credits and direct grants, SoCalGas expects that NGVs will continue to provide an attractive option for customers.

On July 1, 2000, Caltrans, DMV and the California Highway Patrol gave the environmentally minded commuters another opportunity to drive more NGVs. On that day California drivers of dedicated NGVs were legally able to use the carpool lanes regardless of number of passengers in their vehicle. This has helped to advance the use of NGVs and increased the use of CNG as a vehicle fuel. Cities like the City of Los Angeles have gone even further, and allowed drivers of NGVs to park at City meters without having to pay for parking. These types of programs have helped to advance the awareness of NGVs, and allow the industry to grow at its rapid pace.

Higher gasoline prices over the last two years have also spurred more interest in NGVs. This year, gasoline prices at the pump have increased to above $2.00 per gallon, while NGV fuel hovered at about $1.35 per gasoline gallon equivalent on the average. This type of cost advantage coupled with tax incentives is expected to encourage the use of more NGVs.

DEMAND-SIDE MANAGEMENT

The cumulative net DSM load impact forecast for selected years is provided in **Table 1**. The net load impact includes all DSM programs that SoCalGas forecasted to implement in the years 2001 and 2002. Savings and goals for these programs are based on SoCalGas' 2000 DSM application to the Commission, since the latest application (filed late 2001) has been subject to significant change. Savings are consistent with those filed in SoCalGas' Biennial Cost Allocation Proceeding (BCAP).

Conservation and energy efficiency activities encourage customers to install energy efficient equipment and weatherization measures and adopt energy saving practices that result in reduced gas usage for a comparable level of service. Conservation and energy efficiency load impacts are shown as positive numbers. The "total net load impact" is the natural gas throughput reduction resulting from SoCalGas' DSM programs.

Savings reported are for measures installed under SoCalGas' DSM programs. Credit is only taken for measures that are installed as a result of SoCalGas' DSM programs, and only for the lifetimes of the measures installed. Measures with lifetimes less than the forecast planning period fall out of the forecast when their expected lifetime is reached. This means, for example, that a measure installed in 2000 with a lifetime of 10 years is only included in the forecast through 2009. Naturally occurring conservation that is not attributable to SoCalGas' DSM activities is not included in the DSM forecast.

Table 1. DSM Load Impact Forecast for Selected Years (MMcf)

Conservation "Hard"	**2002**	**2003**	**2004**	**2006**	**2011**	**2016**
Core Residential	670	1,005	1,341	1,341	1,346	986
Core Commercial	163	245	326	325	323	12
Core Industrial	347	520	694	694	694	672
SUBTOTAL	**1,180**	**1,770**	**2,360**	**2,359**	**2,362**	**1,669**
Conservation "Soft"						
Core Residential	93	140	140	47	0	0
Core Commercial	71	106	107	38	2	0
Core Industrial	142	213	213	71	0	0
SUBTOTAL	**306**	**458**	**459**	**155**	**2**	**0**
Net Load Impact						
Core Residential	763	1,145	1,480	1,387	1,346	986
Core Commercial	234	351	433	363	325	12
Core Industrial	489	733	906	764	694	672
TOTAL NET LOAD IMPACT	**1,486**	**2,228**	**2,819**	**2,515**	**2,365**	**1,669**

Notes:
1. DSM load impacts include 2001 program savings, but do not include pre-2001 program savings
2. "Hard" impacts include measures requiring a physical equipment modification or replacement
3. "Soft" impacts include energy management services type measures.
4. DSM impacts assume a heating value of 1015.35 Btu/cubic foot of natural gas.

CAPACITY, SOURCES, AND STORAGE

INTERSTATE PIPELINE CAPACITY

Southern California continues to operate in an environment of interstate pipeline capacity in excess of anticipated demand. Interstate pipeline delivery capability into southern California is over 4,000 MMcf/day, with approximately 3,230 MMcf/day available directly to SoCalGas customers (the remaining interstate capacity serves local distribution company bypass customers). These pipeline systems provide access to several large supply basins, located in: New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains and Western Canada. The interstate pipeline systems, along with local California gas supplies, deliver gas to most southern California customers through SoCalGas.

SoCalGas has firm receipt capacity at the following locations for its customers to access supply and interstate pipelines.

	Interstate and Local Volumes MMcf/day
Current Firm Capacity	
El Paso at Blythe	1,210
El Paso at Topock	540
North Needles (Transwestern, Questar Southern Trails)	800
Hector Road (Mojave)	50
Wheeler Ridge (PG&E, Kern/Mojave, CA Production)	765
Line 85 (CA Production)	190
North Coastal (CA Production)	120
Kramer Junction (Kern/Mojave)	200
Total Firm Supply Access	**3,875**

SoCalGas has added 335 MMcfd of receipt point capacity to its system within the last year and will add an additional 40 MMcfd by the end of summer 2002.

GAS SUPPLY SOURCES

Southern California receives gas supplies from several sedimentary basins in the western United States and Canada.

California Gas

Gas supply available to SoCalGas from California sources (state onshore plus state/federal offshore supplies) was about 400 MMcf/day in 2001.

Southwestern U.S. Gas

Traditional Southwestern U.S. sources of natural gas, especially from the San Juan Basin, will continue to supply most of southern California's natural gas demand. This gas is delivered via the El Paso Natural Gas Company and Transwestern Pipeline Company pipelines. The majority of San Juan basin gas is coalbed methane production, which has recently reached a plateau. Although the Unconventional Fuels Tax Credit (which expires in 2003) provides producers with an incentive to produce as much gas as possible from wells drilled before 1993, coalbed methane drilling is still profitable in the San Juan Basin and parts of Wyoming and Utah. The San Juan Basin's conventionally produced gas supplies have increased since 1991 and are expected to meet southern California's gas demand. Permian basin gas also provides an additional source of supply into California.

Rocky Mountain Gas

Rocky Mountain supply presents a viable alternative to traditional Southwestern U.S. gas sources for Southern California. This gas is delivered to southern California primarily on the Kern River Gas Transmission Company's pipeline, although there is also access through the San Juan Basin. While the majority of Rocky Mountain gas is conventional gas supplies, substantial gas supplies also qualify for the Unconventional Fuels Tax Credit through 2003 – mainly as tight formation gas and some as coal seam gas. In recent years, Rocky Mountain gas has increasingly flowed to Midwestern and Pacific Northwest Markets.

Canadian Gas

SoCalGas anticipates that the role of Canadian gas in meeting southern California's demand during the forecast period will decline. New pipeline capacity out of western Canada to the Midwest and eastern United States are likely to move Canadian gas away from California. Increased gas deliveries from the Permian Basin to California are expected to replace these supplies.

RETAIL CORE PEAK DAY DEMAND

SoCalGas plans and designs its system to provide continuous service to its core customers under an extreme peak day event. The extreme peak day design criteria is declined as in a 1-in-35 year event; this correlates to a system average temperature of 38 degrees Fahrenheit. Demand on an extreme peak day is met through a combination of withdrawals from underground storage facilities and flowing pipeline supplies. The following table summarizes the forecasted retail core demand and the supplies required to provide firm service on a peak day.

Retail Core Peak Day Demand and Supply Requirements (MMCF/day)

	2002	2005	2010	2015
Retail Core Demand	3,193	3,338	3,506	3,689
Firm Storage Withdrawal	1,935	1,935	2,032	2,139
Required Flowing Supplies	1,258	1,403	1,474	1,550

Notes:
Firm withdrawal requirements are held constant at 1,935 MMcf/d through year 2005 per the Comprehensive Settlement Agreement for GIR. Firm withdrawal and flowing supply requirements are shown to increase proportionally with demand growth beginning in 2006 and afterwards. Firm withdrawal plus firm pipeline supplies must be sufficient to meet peak day operating requirements. GIR may provide core customers with additional options to meet their peak requirements in the future.

2002 California Gas Report

SOUTHERN CALIFORNIA GAS COMPANY
TABULAR DATA

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 1997 TO 2001

Line	CAPACITY AVAILABLE		1997	1998	1999	2000	2001
1	California Source Gas						
	Out-of-State Gas						
2	California Offshore -POPCO / PIOC						
3	El Paso Natural Gas Co.						
4	Transwestern Pipeline Co.						
5	Kern / Mojave						
6	PGT / PG&E						
7	Other						
8	Total Out-of-State Gas						
9	TOTAL CAPACITY AVAILABLE						
	GAS SUPPLY TAKEN						
10	California Source Gas		236	250	271	386	388
	Out-of-State Gas						
11	Pacific Interstate Companies		263	277	111	0	0
12	Other Out-of-State		2,085	2,242	2,412	2,689	2,907
13	Total Out-of-State Gas		2,348	2,519	2,523	2,689	2,907
14	TOTAL SUPPLY TAKEN		2,584	2,769	2,794	3,075	3,295
15	Net Underground Storage Withdrawal		(8)	(79)	6	78	(70)
16	TOTAL THROUGHPUT (1)(2)		2,576	2,689	2,800	3,153	3,225
	ACTUAL DELIVERIES BY END-USE (3)						
17	Core	Residential	657	745	761	694	724
18		Commercial	175	190	197	199	205
19		Industrial	51	54	54	56	57
20		NGV	3	5	6	9	12
21		Subtotal	886	993	1,018	957	998
22	Noncore	Commercial	70	70	71	71	61
23		Industrial	365	370	377	392	338
24		EOR Steaming	41	29	25	33	29
25		Electric Generation	808	750	856	1,199	1,257
26		Subtotal	1,284	1,219	1,329	1,695	1,685
27	Wholesale	Residential	111	125	134	120	116
28		Com/Ind & Others	85	86	87	84	77
29		Electric Generation	182	206	181	231	276
30		Subtotal	378	417	402	435	469
31	International DGN		1	6	11	11	6
32	Co. Use & LUAF		27	55	40	55	66
33	SYSTEM TOTAL-THROUGHPUT (1)		2,576	2,689	2,800	3,153	3,225
	TRANSPORTATION AND EXCHANGE						
34	Core	All End Uses	40	38	42	42	26
35	Noncore	Commercial/Industrial	410	428	439	457	393
36		EOR Steaming	41	29	25	33	29
37		Electric Generation	806	749	855	1,197	1,255
38		Subtotal-Retail	1,297	1,244	1,361	1,729	1,703
39	Wholesale	All End Uses	378	417	402	435	469
40	International DGN		1	6	11	11	6
41	TOTAL TRANSPORTATION & EXCHANGE		1,676	1,667	1,774	2,175	2,178
	CURTAILMENT (RETAIL & WHOLESALE)						
42		Core	0	0	0	0	0
43		Noncore	0	0	0	0	0
44		TOTAL - Curtailment	0	0	0	0	0
45	REFUSAL		0	0	0	0	0

NOTES:

	1997	1998	1999	2000	2001
(1) Figures exclude pipeline bypass load losses due to interstate pipelines.	411	392	395	387	393
(2) Exclude own-source gas supply of procurement by Edison and City of Long Beach.	19	19	10	11	11

(3) Actual deliveries by end-use includes sales, transportation, and exchange volumes; exchange volumes in 2001 includes total delivery to PG&Es' customers.

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2002 THRU 2006

AVERAGE TEMPERATURE YEAR

LINE			2002	2003	2004	2005	2006	LINE
	FIRM CAPACITY AVAILABLE							
1	California Source Gas		510	510	510	510	510	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Total Out-of-State Gas		3,365	3,365	3,365	3,365	3,365	7
8	TOTAL CAPACITY AVAILABLE /1		3,875	3,875	3,875	3,875	3,875	8
	GAS SUPPLY TAKEN							
9	California Source Gas		510	510	510	510	510	9
10	Out-of-State		2,106	1,760	1,939	1,983	2,032	10
11	TOTAL SUPPLY TAKEN		2,616	2,270	2,449	2,493	2,542	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT 1/, 2/		2,616	2,270	2,449	2,493	2,542	13
	REQUIREMENTS FORECAST BY END-USE 3/							
14	CORE	Residential	721	728	731	738	743	14
15		Commercial	204	214	223	228	231	15
16		Industrial	57	67	74	75	75	16
17		NGV	14	17	19	21	23	17
18		Subtotal-CORE	996	1,026	1,047	1,062	1,072	18
19	NONCORE	Commercial	56	50	47	47	53	19
20		Industrial	356	339	325	314	305	20
21		EOR Steaming	28	28	28	28	28	21
22		Electric Generation (EG)	739	463	636	641	673	22
23		Subtotal-NONCORE	1,179	880	1,036	1,030	1,059	23
24	WHOLESALE	Core	172	174	175	177	179	24
25		Noncore Excl. EG	24	36	37	38	42	25
26		Electric Generation (EG)	178	94	91	121	123	26
27		Subtotal-WHOLESALE	374	304	303	336	344	27
28	INTERNATIONAL	DGN (Mexicali)	12	12	11	12	13	28
29		Co. Use & LUAF	55	48	52	53	54	29
30	SYSTEM TOTAL THROUGHPUT /1		2,616	2,270	2,449	2,493	2,542	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	23	23	23	24	24	31
32	NONCORE	Commercial/Industrial	408	387	372	361	358	32
33		EOR Steaming	28	28	28	28	28	33
34		Electric Generation (EG)	738	463	636	641	673	34
35		Subtotal-RETAIL	1,197	901	1,059	1,054	1,083	35
36	WHOLESALE	All End Uses	374	304	303	336	344	36
37	INTERNATIONAL	All End Uses	12	12	11	12	13	37
38	TOTAL TRANSPORTATION & EXCHANGE		1,583	1,217	1,373	1,402	1,440	38
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	39
40		Noncore	0	0	0	0	0	40
41		TOTAL - Curtailment	0	0	0	0	0	41

NOTES:

	2002	2003	2004	2005	2006
1/ Figures exclude pipeline bypass load losses of to non-jurisdictional gas suppliers.	403	470	475	479	485
2/ Excludes own-source gas supply of gas procurement by the City of Long Beach	11	11	11	11	11

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2007 THRU 2022

AVERAGE TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE		2007	2010	2015	2020	2022	LINE
1	California Source Gas		510	510	510	510	510	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Total Out-of-State Gas		3,365	3,365	3,365	3,365	3,365	7
8	TOTAL CAPACITY AVAILABLE /1		3,875	3,875	3,875	3,875	3,875	8
	GAS SUPPLY TAKEN							
9	California Source Gas		510	510	510	510	510	9
10	Out-of-State		2,092	2,174	2,296	2,458	2,527	10
11	TOTAL SUPPLY TAKEN		2,602	2,684	2,806	2,968	3,037	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT 1/, 2/		2,602	2,684	2,806	2,968	3,037	13
	REQUIREMENTS FORECAST BY END-USE 3/							
14	CORE	Residential	749	773	818	868	890	14
15		Commercial	234	240	247	253	253	15
16		Industrial	75	74	70	69	68	16
17		NGV	25	30	40	50	55	17
18		Subtotal-CORE	1,083	1,117	1,175	1,240	1,266	18
19	NONCORE	Commercial	53	54	55	56	56	19
20		Industrial	298	286	274	270	269	20
21		EOR Steaming	28	21	21	21	21	21
22		Electric Generation (EG)	723	780	762	830	861	22
23		Subtotal-NONCORE	1,102	1,141	1,112	1,177	1,207	23
24	WHOLESALE	Core	182	179	191	201	206	24
25		Noncore Excl. EG	42	42	42	42	42	25
26		Electric Generation (EG)	125	133	205	220	227	26
27		Subtotal-WHOLESALE	349	354	438	463	475	27
28	INTERNATIONAL	DGN (Mexicali)	13	15	22	25	25	28
29		Co. Use & LUAF	55	57	59	63	64	29
30	SYSTEM TOTAL THROUGHPUT /1		2,602	2,684	2,806	2,968	3,037	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	24	25	25	26	26	31
32	NONCORE	Commercial/Industrial	351	340	329	325	324	32
33		EOR Steaming	28	21	21	21	21	33
34		Electric Generation (EG)	723	780	762	830	861	34
35		Subtotal-RETAIL	1,126	1,166	1,137	1,202	1,232	35
36	WHOLESALE	All End Uses	349	354	438	463	475	36
37	INTERNATIONAL	All End Uses	13	15	22	25	25	37
38	TOTAL TRANSPORTATION & EXCHANGE		1,488	1,535	1,597	1,690	1,732	38
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	39
40		Noncore	0	0	0	0	0	40
41		TOTAL - Curtailment	0	0	0	0	0	41

NOTES:	2007	2010	2015	2020	2022
1/ Figures exclude pipeline bypass load losses of to non-jurisdictional gas suppliers.	493	550	556	549	547
2/ Excludes own-source gas supply of gas procurement by the City of Long Beach	10	10	10	10	10

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2002 THRU 2006

COLD TEMPERATURE YEAR

LINE			2002	2003	2004	2005	2006	LINE
	FIRM CAPACITY AVAILABLE							
1	California Source Gas		510	510	510	510	510	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Total Out-of-State Gas		3,365	3,365	3,365	3,365	3,365	7
8	TOTAL CAPACITY AVAILABLE /1		3,875	3,875	3,875	3,875	3,875	8
	GAS SUPPLY TAKEN							
9	California Source Gas		510	510	510	510	510	9
10	Out-of-State		2,245	1,901	2,080	2,125	2,176	10
11	TOTAL SUPPLY TAKEN		2,755	2,411	2,590	2,635	2,686	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT 1/, 2/		2,755	2,411	2,590	2,635	2,686	13
	REQUIREMENTS FORECAST BY END-USE 3/							
14	CORE	Residential	825	832	836	844	850	14
15		Commercial	217	228	237	242	246	15
16		Industrial	59	69	76	77	77	16
17		NGV	14	17	19	21	23	17
18		Subtotal-CORE	1,115	1,146	1,168	1,184	1,196	18
19	NONCORE	Commercial	56	50	47	47	53	19
20		Industrial	356	339	325	314	305	20
21		EOR Steaming	28	28	28	28	28	21
22		Electric Generation (EG)	739	463	636	641	673	22
23		Subtotal-NONCORE	1,179	880	1,036	1,030	1,059	23
24	WHOLESALE	Core	189	192	192	194	196	24
25		Noncore Excl. EG	24	36	37	38	42	25
26		Electric Generation (EG)	178	94	91	121	123	26
27		Subtotal-WHOLESALE	391	322	320	353	361	27
28	INTERNATIONAL	DGN (Mexicali)	12	12	11	12	13	28
29		Co. Use & LUAF	58	51	55	56	57	29
30	SYSTEM TOTAL THROUGHPUT /1		2,755	2,411	2,590	2,635	2,686	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	25	25	25	25	26	31
32	NONCORE	Commercial/Industrial	408	387	372	361	358	32
33		EOR Steaming	28	28	28	28	28	33
34		Electric Generation (EG)	738	463	636	641	673	34
35		Subtotal-RETAIL	1,199	903	1,061	1,055	1,085	35
36	WHOLESALE	All End Uses	391	322	320	353	361	36
37	INTERNATIONAL	All End Uses	12	12	11	12	13	37
38	TOTAL TRANSPORTATION & EXCHANGE		1,602	1,237	1,392	1,420	1,459	38
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	39
40		Noncore	0	0	0	0	0	40
41		TOTAL - Curtailment	0	0	0	0	0	41

NOTES:	2002	2003	2004	2005	2006
1/ Figures exclude pipeline bypass load losses of to non-jurisdictional gas suppliers.	403	470	475	479	485
2/ Excludes own-source gas supply of gas procurement by the City of Long Beach	11	11	11	11	11

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2007 THRU 2022

COLD TEMPERATURE YEAR

LINE			2007	2010	2015	2020	2022	LINE
	FIRM CAPACITY AVAILABLE							
1	California Source Gas		510	510	510	510	510	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Total Out-of-State Gas		3,365	3,365	3,365	3,365	3,365	7
8	TOTAL CAPACITY AVAILABLE /1		3,875	3,875	3,875	3,875	3,875	8
	GAS SUPPLY TAKEN							
9	California Source Gas		510	510	510	510	510	9
10	Out-of-State		2,237	2,321	2,452	2,625	2,700	10
11	TOTAL SUPPLY TAKEN		2,747	2,831	2,962	3,135	3,210	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT 1/, 2/		2,747	2,831	2,962	3,135	3,210	13
	REQUIREMENTS FORECAST BY END-USE 3/							
14	CORE	Residential	857	885	936	994	1,020	14
15		Commercial	248	254	261	268	268	15
16		Industrial	77	75	72	70	70	16
17		NGV	25	30	40	50	55	17
18		Subtotal-CORE	1,207	1,244	1,309	1,382	1,413	18
19	NONCORE	Commercial	53	54	55	56	56	19
20		Industrial	298	286	274	270	269	20
21		EOR Steaming	28	21	21	21	21	21
22		Electric Generation (EG)	723	780	762	830	861	22
23		Subtotal-NONCORE	1,102	1,141	1,112	1,177	1,207	23
24	WHOLESALE	Core	199	196	209	222	227	24
25		Noncore Excl. EG	43	42	42	43	43	25
26		Electric Generation (EG)	125	133	205	220	227	26
27		Subtotal-WHOLESALE	367	371	456	485	497	27
28	INTERNATIONAL	DGN (Mexicali)	13	15	22	25	25	28
29		Co. Use & LUAF	58	60	63	66	68	29
30	SYSTEM TOTAL THROUGHPUT /1		2,747	2,831	2,962	3,135	3,210	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	26	27	27	28	28	31
32	NONCORE	Commercial/Industrial	351	340	329	325	324	32
33		EOR Steaming	28	21	21	21	21	33
34		Electric Generation (EG)	723	780	762	830	861	34
35		Subtotal-RETAIL	1,128	1,168	1,139	1,204	1,234	35
36	WHOLESALE	All End Uses	367	371	456	485	497	36
37	INTERNATIONAL	All End Uses	13	15	22	25	25	37
38	TOTAL TRANSPORTATION & EXCHANGE		1,508	1,554	1,617	1,714	1,756	38
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	39
40		Noncore	0	0	0	0	0	40
41		TOTAL - Curtailment	0	0	0	0	0	41

NOTES:

	2007	2010	2015	2020	2022
1/ Figures exclude pipeline bypass load losses of to non-jurisdictional gas suppliers.	493	550	556	549	547
2/ Excludes own-source gas supply of gas procurement by the City of Long Beach	10	10	10	10	10

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2002 THRU 2006

HOT TEMPERATURE YEAR

LINE	FIRM CAPACITY AVAILABLE		2002	2003	2004	2005	2006	LINE
1	California Source Gas		510	510	510	510	510	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Total Out-of-State Gas		3,365	3,365	3,365	3,365	3,365	7
8	TOTAL CAPACITY AVAILABLE /1		3,875	3,875	3,875	3,875	3,875	8
	GAS SUPPLY TAKEN							
9	California Source Gas		510	510	510	510	510	9
10	Out-of-State		1,974	1,626	1,804	1,844	1,893	10
11	TOTAL SUPPLY TAKEN		2,484	2,136	2,314	2,354	2,403	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT 1/, 2/		2,484	2,136	2,314	2,354	2,403	13
	REQUIREMENTS FORECAST BY END-USE 3/							
14	CORE	Residential	618	623	626	631	635	14
15		Commercial	191	201	209	214	217	15
16		Industrial	56	66	73	73	74	16
17		NGV	14	17	19	21	23	17
18		Subtotal-CORE	879	907	927	939	949	18
19	NONCORE	Commercial	56	50	47	47	53	19
20		Industrial	356	339	325	314	305	20
21		EOR Steaming	28	28	28	28	28	21
22		Electric Generation (EG)	739	463	636	641	673	22
23		Subtotal-NONCORE	1,179	880	1,036	1,030	1,059	23
24	WHOLESALE	Core	159	162	163	164	166	24
25		Noncore Excl. EG	24	36	37	38	42	25
26		Electric Generation (EG)	178	94	91	121	123	26
27		Subtotal-WHOLESALE	361	292	291	323	331	27
28	INTERNATIONAL	DGN (Mexicali)	12	12	11	12	13	28
29		Co. Use & LUAF	53	45	49	50	51	29
30	SYSTEM TOTAL THROUGHPUT /1		2,484	2,136	2,314	2,354	2,403	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	21	21	21	22	22	31
32	NONCORE	Commercial/Industrial	408	387	372	361	358	32
33		EOR Steaming	28	28	28	28	28	33
34		Electric Generation (EG)	738	463	636	641	673	34
35		Subtotal-RETAIL	1,195	899	1,057	1,052	1,081	35
36	WHOLESALE	All End Uses	361	292	291	323	331	36
37	INTERNATIONAL	All End Uses	12	12	11	12	13	37
38	TOTAL TRANSPORTATION & EXCHANGE		1,568	1,203	1,359	1,387	1,425	38
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	39
40		Noncore	0	0	0	0	0	40
41		TOTAL - Curtailment	0	0	0	0	0	41

NOTES:

	2002	2003	2004	2005	2006
1/ Figures exclude pipeline bypass load losses of to non-jurisdictional gas suppliers.	403	470	475	479	485
2/ Excludes own-source gas supply of gas procurement by the City of Long Beach	11	11	11	11	11

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2007 THRU 2022

HOT TEMPERATURE YEAR

LINE			2007	2010	2015	2020	2022	LINE
	FIRM CAPACITY AVAILABLE							
1	California Source Gas		510	510	510	510	510	1
	Out-of-State Gas							
2	Mojave (Hector Road)		50	50	50	50	50	2
3	El Paso Natural Gas Co. (Blythe)		1,210	1,210	1,210	1,210	1,210	3
4	El Paso Natural Gas Co. (Topock)		540	540	540	540	540	4
5	Transwestern Pipeline Co. (No. Needles)		800	800	800	800	800	5
6	Kern-Mojave, PG&E, Oxy (Wheeler Ridge)		765	765	765	765	765	6
7	Total Out-of-State Gas		3,365	3,365	3,365	3,365	3,365	7
8	TOTAL CAPACITY AVAILABLE /1		3,875	3,875	3,875	3,875	3,875	8
	GAS SUPPLY TAKEN							
9	California Source Gas		510	510	510	510	510	9
10	Out-of-State		1,952	2,030	2,144	2,296	2,363	10
11	TOTAL SUPPLY TAKEN		2,462	2,540	2,654	2,806	2,873	11
12	Net Underground Storage Withdrawal		0	0	0	0	0	12
13	TOTAL THROUGHPUT 1/, 2/		2,462	2,540	2,654	2,806	2,873	13
	REQUIREMENTS FORECAST BY END-USE 3/							
14	CORE	Residential	641	661	699	742	761	14
15		Commercial	220	226	232	238	238	15
16		Industrial	73	72	69	67	66	16
17		NGV	25	30	40	50	55	17
18		Subtotal-CORE	959	989	1,040	1,097	1,120	18
19	NONCORE	Commercial	53	54	55	56	56	19
20		Industrial	298	286	274	270	269	20
21		EOR Steaming	28	21	21	21	21	21
22		Electric Generation (EG)	723	780	762	830	861	22
23		Subtotal-NONCORE	1,102	1,141	1,112	1,177	1,207	23
24	WHOLESALE	Core	169	166	177	186	191	24
25		Noncore Excl. EG	42	42	42	42	42	25
26		Electric Generation (EG)	125	133	205	220	227	26
27		Subtotal-WHOLESALE	336	341	424	448	460	27
28	INTERNATIONAL	DGN (Mexicali)	13	15	22	25	25	28
29		Co. Use & LUAF	52	54	56	59	61	29
30	SYSTEM TOTAL THROUGHPUT /1		2,462	2,540	2,654	2,806	2,873	30
	TRANSPORTATION AND EXCHANGE							
31	CORE	All End Uses	22	23	23	24	24	31
32	NONCORE	Commercial/Industrial	351	340	329	325	324	32
33		EOR Steaming	28	21	21	21	21	33
34		Electric Generation (EG)	723	780	762	830	861	34
35		Subtotal-RETAIL	1,124	1,164	1,135	1,200	1,230	35
36	WHOLESALE	All End Uses	336	341	424	448	460	36
37	INTERNATIONAL	All End Uses	13	15	22	25	25	37
38	TOTAL TRANSPORTATION & EXCHANGE		1,473	1,520	1,581	1,673	1,715	38
	CURTAILMENT (RETAIL & WHOLESALE)							
39		Core	0	0	0	0	0	39
40		Noncore	0	0	0	0	0	40
41		TOTAL - Curtailment	0	0	0	0	0	41

NOTES:

	2007	2010	2015	2020	2022
1/ Figures exclude pipeline bypass load losses of to non-jurisdictional gas suppliers.	493	550	556	549	547
2/ Excludes own-source gas supply of gas procurement by the City of Long Beach	10	10	10	10	10

3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.

2002 California Gas Report

CITY OF LONG BEACH
GAS AND ELECTRIC DEPARTMENT

CITY OF LONG BEACH ENERGY DEPARTMENT

The annual gas supply and requirements for the Long Beach Energy Department (Long Beach) are shown on the following tables for the years 1997 through 2001 and the estimated years 2002 through 2022. Long Beach prepared all forecasted requirements.

Serving approximately 149,000 customers, Long Beach is the largest California municipal gas utility and the fifth largest municipal gas utility in the United States. Long Beach's service territory includes the cities of Long Beach and Signal Hill, and sections of surrounding communities including Lakewood, Bellflower, Compton, Seal Beach, Paramount, and Los Alamitos. Long Beach's customer load profile is 50 percent residential and 50 percent commercial/industrial.

As a municipal utility, Long Beach's rates and policies are established by the City Council, which acts as the regulatory authority. The City Charter requires the gas utility to establish its rates comparable to the rates charged by surrounding gas utilities for similar types of service.

Long Beach receives approximately one third of its gas supply directly into its pipeline system from local production fields that are located within Long Beach's service territory, as well as offshore. The other two thirds of Long Beach's gas supply is purchased at the California border, primarily from the Southwestern United States. Long Beach, as a wholesale customer, receives intrastate transmission service for this gas from SoCalGas.

The City of Long Beach and Long Beach Energy has embarked on a renewable energy partnership with Siemens Solar Industries to promote alternative energy sources that are friendly to the environment. As part of the partnership, Long Beach Energy offered a free program to train electricians in the installation of the new Siemens Solar earthsafe™ solar electric system. Long Beach Energy is preparing a citywide advertising campaign with materials Siemens developed that inform residents about the way solar electric systems work and the benefits of stabilizing energy costs.

2002 California Gas Report

CITY OF LONG BEACH ENERGY DEPARTMENT - TABULAR DATA

CITY OF LONG BEACH - ENERGY DEPARTMENT

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 1997 THRU 2001

LINE	GAS SUPPLY AVAILABLE	1997	1998	1999	2000	2001	LINE
	California Source Gas						
1	Regular Purchases						1
2	Received for Exchange/Transport						2
3	Total California Source Gas						3
4	Purchases from Other Utilities						4
	Out-of-State Gas						
5	Pacific Interstate Companies						5
6	Additional Core Supplies						6
7	Incremental Supplies						7
8	Out-of-State Transport						8
9	Total Out-of-State Gas						9
10	Subtotal						10
11	Underground Storage Withdrawal						11
12	GAS SUPPLY AVAILABLE						12
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	11	11	10	11	11	13
14	Received for Exchange/Transport	0	0	0	0	0	14
15	Total California Source Gas	11	11	10	11	11	15
16	Purchases from Other Utilities	0	0	0	0	0	16
	Out-of-State Gas						
17	Pacific Interstate Companies	0	0	0	0	0	17
18	Additional Core Supplies	0	0	0	0	0	18
19	Incremental Supplies	21	25	27	24	21	19
20	Out-of-State Transport	0	0	0	0	0	20
21	Total Out-of-State Gas	21	25	27	24	21	21
22	Subtotal	32	36	37	35	32	22
23	Underground Storage Withdrawal	0	0	0	0	0	23
24	TOTAL Gas Supply Taken & Transported	32	36	37	35	32	24

CITY OF LONG BEACH - ENERGY DEPARTMENT

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 1997 THRU 2001

LINE	ACTUAL DELIVERIES BY END-USE		1997	1998	1999	2000	2001	LINE
1	CORE	Residential	16	18	18	17	17	1
2	CORE/NONCORE	Commercial	7	7	7	7	7	2
3	CORE/NONCORE	Industrial	9	10	10	9	7	3
4		Subtotal	31	35	36	33	31	4
5	NON CORE	Non-EOR Cogeneration	0	0	0	0	0	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	0	0	0	0	0	7
8		Subtotal	0	0	0	0	0	8
9	WHOLESALE	Residential	0	0	0	0	0	9
10		Com. & Ind., others	0	0	0	0	0	10
11		Electric Utilities	0	0	0	0	0	11
12		Subtotal-WHOLESALE	0	0	0	0	0	12
13		Co. Use & LUAF	0	1	0	1	1	13
14		Subtotal-END USE	31	36	36	35	32	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL-THROUGHPUT		31	36	36	35	32	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	N/A	N/A	N/A	N/A	N/A	18
19		Non-EOR Cogeneration	N/A	N/A	N/A	N/A	N/A	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	21	25	27	24	21	22
23	WHOLESALE	All-End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		21	25	27	24	21	24
	ACTUAL CURTAILMENT							
25		Residential	0	0	0	0	0	25
26		Commercial/Industrial	0	0	0	0	0	26
27		Non-EOR Cogeneration	0	0	0	0	0	27
28		EOR Cogen. & Steaming	0	0	0	0	0	28
29		Electric Utilites	0	0	0	0	0	29
30		Wholesale	0	0	0	0	0	30
31		TOTAL- Curtailment	0	0	0	0	0	31
32	REFUSAL		0	0	0	0	0	32

NOTE: Actual deliveries by end-use includes sales, transportation, and exchange volumes, but excludes actual curtailments.

CITY OF LONG BEACH - ENERGY DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY

ESTIMATED YEARS 2002 THRU 2006

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2002	2003	2004	2005	2006	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		11	11	11	11	11	4
5	Out-of-State Gas		22	22	22	22	24	5
6	TOTAL SUPPLY TAKEN		33	32	32	32	35	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		33	32	32	32	35	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	17	17	17	17	17	9
10		Commercial	5	5	5	5	5	10
11		NGV	0	0	0	0	0	11
12		Subtotal-CORE	22	22	22	22	23	12
13	NONCORE	Industrial	9	8	8	8	8	13
14		Non-EOR Cogeneration	1	1	1	1	1	14
15		EOR	0	0	0	0	0	15
16		Utility Electric Generation	0	0	0	0	0	16
17		NGV	0	0	0	0	0	17
18		Subtotal-NONCORE	9	9	9	9	9	18
19		Co. Use & LUAF	0	0	0	0	0	19
20	SYSTEM TOTAL THROUGHPUT (1)		32	31	31	31	32	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	13	13	13	13	16	22
23	NONCORE	Industrial	9	8	8	8	8	23
24		Non-EOR Cogeneration	1	1	1	1	1	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	9	9	9	9	9	27
28	TOTAL TRANSPORTATION		23	22	22	23	25	28

(1) Requirement forecast by end-use includes sales and transportation volumes.

CITY OF LONG BEACH - ENERGY DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY

ESTIMATED YEARS 2007 THRU 2022

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2007	2010	2015	2020	2022	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		10	10	10	10	10	4
5	Out-of-State Gas		22	22	22	22	22	5
6	TOTAL SUPPLY TAKEN		32	32	32	32	32	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		32	32	32	32	32	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	17	17	17	17	17	9
10		Commercial	5	5	5	5	5	10
11		NGV	0	0	0	0	0	11
12		Subtotal-CORE	23	23	23	23	23	12
13	NONCORE	Industrial	8	8	8	8	8	13
14		Non-EOR Cogeneration	1	1	1	1	1	14
15		EOR	0	0	0	0	0	15
16		Utility Electric Generation	0	0	0	0	0	16
17		NGV	0	0	0	0	0	17
18		Subtotal-NONCORE	9	9	9	9	9	18
19		Co. Use & LUAF	0	0	0	0	0	19
20	SYSTEM TOTAL THROUGHPUT (1)		32	32	32	32	32	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	13	14	14	14	14	22
23	NONCORE	Industrial	8	8	8	8	8	23
24		Non-EOR Cogeneration	1	1	1	1	1	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	9	9	9	9	9	27
28	TOTAL TRANSPORTATION		23	23	23	23	23	28

(1) Requirement forecast by end-use includes sales and transportation volumes.

2002 California Gas Report

SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO
GAS & ELECTRIC COMPANY

San Diego Gas & Electric Company (SDG&E), a Sempra Energy company, is a combined gas and electric distribution utility serving more than three million people in San Diego and southern Orange counties. SDG&E delivers natural gas to over 770,000 customers in San Diego County, including the power plants and turbines previously owned and operated by the company. Total gas sales and transportation through SDG&E's system for 2001 was approximately 156 billion cubic feet (Bcf), which is an average of over 425 million cubic feet per day (MMcf/day). These 2001 deliveries corresponded to the increase in gas usage by power generators.

GAS DEMAND

This projection of natural gas requirements reflects the forecast and planning assumptions from the Biennial Cost Allocation Proceeding (BCAP) filing of March 2002. The outlook for gas sales and transportation demand excluding cogeneration and electric generation (EG) is projected to increase by 10% between 2002 and 2010. Compared to the last long-term forecast in the *2000 California Gas Report*, this is 3% lower than the anticipated growth over the same period, resulting from higher gas supply costs impacting gas customer usage. Assumptions for SDG&E's gas transport requirements for cogeneration and EG are included as part of the wholesale market sector description for Southern California.

SDG&E projects core and noncore sales and transportation customer gas consumption and peak demand for its service territory, with the exception of gas requirements for the fossil fuel power plants. Customer gas usage forecasts are derived from models that integrate demographic assumptions, economics, energy prices, conservation, marketing programs, building and appliance standards, weather, and other factors. These forecasting models use econometric techniques and end-use forecasting methodologies.

The projection for compressed natural gas vehicle (NGV) requirements assumes moderate growth due to federal, state and local incentives for the purchase of school and transit buses. The Metropolitan Transit Development Board expects to add a significant number of new NGV buses, going from 290 to at least 600 vehicles over the next four to five years. The planned addition of several new refueling sites with public access will offset a reduction to the local public fueling infrastructure resulting from the closure of several retail stations. There are now a total of 21 NGV stations currently serving about 2,500 NGVs in San Diego County.

GAS SUPPLY

Approval of Application 01-01-021 allows SDG&E and the Southern California Gas Company (SoCalGas) to consolidate their gas supply portfolios and related interstate pipeline and storage capacities under common management. The resulting gas supply mix will be less weighted toward spot market purchases at the California border for SDG&E customers than in the past. Gas procurement for the consolidated portfolio will continue to be subject to a performance-based incentive mechanism that allows for the reasonableness of gas purchases to be judged against a market benchmark.

SDG&E has two long-term contracts with El Paso Natural Gas Company for total of 13.6 MMcf/day of firm transportation capacity and for 52.5 MMcf/day on the PGT/PG&E (1993 Expansion) pipeline system from Canada. Underground storage inventory rights for SDG&E's core gas customers totaling 4,500,000 Decatherms (Dth) are specified in the current one-year natural gas service contract with SoCalGas. In accordance with the Gas Industry Restructuring (GIR) Decision 01-12-018, SDG&E may elect to obtain an amount of storage inventory proportional to SoCalGas for core reliability and balancing service in 2003.

There is expected to be sufficient supply deliverability to SDG&E's gas system from the SoCalGas pipeline system and storage facilities. Gas delivery is made primarily through the Moreno-to-San Diego transmission pipeline.

PEAK DAY DEMAND AND DELIVERABILITY

SDG&E's design peak day gas demand consists of projected requirements for its core market of residential and small commercial customers, as well as a limited amount of retail noncore gas requirements. The peak day is expected to occur during the winter season due to demand for gas space heating. SDG&E plans to meet its design peak day gas demand from a combination of flowing gas supplies and withdrawing gas storage inventory.

SDG&E's gas transmission system is designed to provide a 100 percent level of service to all core customers under design peak day conditions. Because this design peak day is expected to occur only once every 35 years, the remaining capacity during non-peak conditions is available to serve noncore customers. During periods of cold weather or extremely high electric generation demand, however, it may not always be possible to maintain a 100% level of service to all noncore customers under the current system design criteria.

The following table shows SDG&E's core gas demand forecast for the 1-in-35-year design peak day for the winter periods. This assumes that supplies from storage withdrawal are at SDG&E's maximum allowable rate under the terms of the current SoCalGas service contract and are used before out-of-state flowing gas supply purchases for the peak day core requirements. SDG&E supplies from storage withdrawal after the current storage contract expires are assumed to be proportional to storage withdrawal rights determined in the GIR decision for SoCalGas. Any reduction in firm storage inventory withdrawal will result in an increased requirement for out-of-state flowing gas supplies.

SAN DIEGO GAS & ELECTRIC COMPANY
Design Peak Day Forecast
for Core Demand and Supplies
(MMCF/DAY)

	2002-03	2003-04	2004-05
PEAK DAY DEMAND:	415	414	414
AVAILABLE SUPPLY			
Storage Withdrawal	225	281	281
Out-of-State Supply	190	133	133
TOTAL CORE SUPPLY:	415	414	414

2002 California Gas Report

SAN DIEGO GAS & ELECTRIC COMPANY TABULAR DATA

Annual Gas Supply and Requirements
Recorded Years 1997-2001
MMCF/Day

GAS SUPPLY AVAILABLE	1997	1998	1999	2000	2001
California Source Gas					
Regular Purchases					
Received for Exchange/Transport					
Total California Source Gas					
Purchases from Other Utilities					
Out-of-State Gas					
Pacific Interstate Companies					
Additional Core Supplies					
Supplemental Supplies-Utility					
Out-of-State Transport-Others					
Total Out-of-State Gas					
GAS SUPPLY AVAILABLE					
Underground Storage Withdrawl					

Gas Supply Taken	1997	1998	1999	2000	2001
California Source Gas					
Regular Purchases	26	34	18	10	10
Received for Exchange/Transport	0	0	0	0	0
Total California Source Gas	26	34	18	10	10
Purchases from Other Utilities	0	0	0	0	0
Out-of-State Gas					
Pacific Interstate Companies	0	0	0	0	0
Additional Core Supplies	0	0	0	0	0
Supplemental Supplies-Utility	253	279	200	145	130
Out-of-State Transport-Others	49	51	131	233	284
Total Out-of-State Gas	302	330	331	378	414
TOTAL Gas Supply Taken & Transported	329	364	349	388	424

Annual Gas Supply and Requirements
Recorded Years 1997-2001
MMCF/Day

Actual Deliveries by End-Use		1997	1998	1999	2000	2001
CORE	Residential	86	96	104	92	93
	Commercial	35	37	41	40	46
	Industrial	0	0	0	0	0
Subtotal -	*CORE*	120	134	144	132	139
NONCORE	Commercial	0	0	0	0	0
	Industrial	29	26	22	21	12
	Non-EOR Cogen/EG	44	47	128	228	276
	Electric Utilities	134	157	51	0	0
Subtotal -	*NONCORE*	207	229	201	250	288
WHOLESALE	All End Uses	0	0	0	0	0
Subtotal -	*Co Use & LUAF*	1	1	4	7	-2
SYSTEM TOTAL THROUGHPUT		329	364	349	388	424
Actual Transport & Exchange						
CORE	Residential	1	0	0	0	0
	Commercial	3	4	5	5	6
NONCORE	Industrial	8	8	6	5	6
	Non-EOR Cogen/EG	37	39	120	222	272
	Electric Utilities	0	0	0	0	0
Subtotal -	*RETAIL*	49	51	131	233	284
WHOLESALE	All End Uses	0	0	0	0	0
TOTAL TRANSPORT & EXCHANGE		49	51	131	233	284
Storage						
	Storage Injection	19	18	15	17	12
	Storage Withdrawal	23	9	27	20	7
Actual Curtailment						
	Residential	0	0	0	0	0
	Com/Indl & Cogen	0	0	0	0	0
	Electric Utilities	0	0	0	1	3
TOTAL CURTAILMENT		0	0	0	1	3
REFUSAL		1	0	0	0	0

ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes

Annual Gas Supply and Requirements
Forecast Years 2002-2006
MMCF/Day
Average Temperature Year

GAS SUPPLY AVAILABLE	2002	2003	2004	2005	2006
California Source Gas					
Regular Purchases	0	0	0	0	0
Received for Exchange/Transport	0	0	0	0	0
Total California Source Gas	0	0	0	0	0
Purchases from Other Utilities	0	0	0	0	0
Out-of-State Gas					
Pacific Interstate Companies	0	0	0	0	0
Additional Core Supplies	0	0	0	0	0
Incremental Supplies (Utility)	139	140	139	140	141
Out-of-State Transport (for others)	208	108	122	135	194
Total Out-of-State Gas	347	248	261	275	335
GAS SUPPLY AVAILABLE	347	248	261	275	335
Underground Storage Withdrawal	14	14	14	14	14

GAS SUPPLY TAKEN	2002	2003	2004	2005	2006
California Source Gas					
Regular Purchases	0	0	0	0	0
Received for Exchange/Transport	0	0	0	0	0
Total California Source Gas	0	0	0	0	0
Purchases from Other Utilities	0	0	0	0	0
Out-of-State Gas					
Pacific Interstate Companies	0	0	0	0	0
Additional Core Supplies	0	0	0	0	0
Incremental Supplies (Utility)	139	140	139	140	141
Out-of-State Transport (for others)	208	108	122	135	194
Total Out-of-State Gas	347	248	261	275	335
TOTAL Gas Supply Taken & Transported	347	248	261	275	335
Underground Storage Withdrawal	14	14	14	14	14

Annual Gas Supply and Requirements
Forecast Years 2002-2006
MMCF/Day

Average Temperature Year

Requirements Forecast by End-Use		2002	2003	2004	2005	2006
CORE	Residential	90	90	89	90	90
	Commercial	48	49	49	50	50
	NGV	2	2	2	2	2
	Industrial	0	6	6	6	6
Subtotal -	*CORE*	140	147	146	147	148
NONCORE	Commercial	0	0	0	0	0
	Industrial	9	6	6	6	6
	Electric Generation	179	88	86	116	117
Subtotal -	*NONCORE*	188	94	93	122	123
WHOLESALE	All End Uses	0	0	0	0	0
	Co Use & LUAF	3	2	2	2	2
SYSTEM TOTAL - THROUGHPUT		331	243	241	271	274
	Storage Injection	14	14	14	14	14
Transportation & Exchange						
CORE	All End Uses	9	9	9	10	10
NONCORE	Commercial/Industrial	6	6	6	6	6
	Electric Generation	176	88	86	116	117
Subtotal -	*RETAIL*	192	103	102	131	133
WHOLESALE	All End Uses	0	0	0	0	0
TOTAL TRANSPORT & EXCHANGE		192	103	102	131	133
CURTAILMENT (Retail & Wholesale)						
	Core	0	0	0	0	0
	Com/Ind	0	0	0	0	0
	Electric Generation	0	0	0	0	0
Total -	*CURTAILMENT*	0	0	0	0	0
REFUSAL		0	0	0	0	0

NOTE:
Requirement forecast by end-use includes sales, transportation, and exchange volumes.

ADDITIONAL NOTES:
SDG&E end-use sales service to noncore customers is eliminated per GIR D.01-12-018, and SDG&E noncore requirements are included here with the SDG&E core requirements forecast from 2003. As projected with this forecast, SDG&E has an option per GIR D.01-12-018 to obtain core reliability and balancing storage service for proportional core usage with SoCalGas. The heating value (MMBtu/Mcf) used for this forecast is from the 2003 BCAP filing assumptions.

Annual Gas Supply And Requirements
Forecast years 2007-2022
MMCF/Day
Average Temperature Year

GAS SUPPLY AVAILABLE	2007	2010	2015	2020	2022
California Source Gas					
Regular Purchases	0	0	0	0	0
Received for Exchange/Transport	0	0	0	0	0
Total California Source Gas	0	0	0	0	0
Purchases from Other Utilities	0	0	0	0	0
Out-of-State Gas					
Pacific Interstate Companies	0	0	0	0	0
Additional Core Supplies	0	0	0	0	0
Incremental Supplies (Utility)	143	150	160	170	175
Out-of-State Transport (for others)	218	249	269	290	299
Total Out-of-State Gas	361	400	429	460	474
GAS SUPPLY AVAILABLE	361	400	429	460	474
Underground Storage Withdrawal	14	14	14	14	14

GAS SUPPLY TAKEN					
California Source Gas					
Regular Purchases	0	0	0	0	0
Received for Exchange/Transport	0	0	0	0	0
Total California Source Gas	0	0	0	0	0
Purchases from Other Utilities	0	0	0	0	0
Out-of-State Gas					
Pacific Interstate Companies	0	0	0	0	0
Additional Core Supplies	0	0	0	0	0
Incremental Supplies (Utility)	143	150	160	170	175
Out-of-State Transport (for others)	218	249	269	290	299
Total Out-of-State Gas	361	400	429	460	474
TOTAL Gas Supply Taken & Transported	361	400	429	460	474
Underground Storage Withdrawal	14	14	14	14	14

Annual Gas Supply and Requirements
Forecast Years 2007-2022
MMCF/Day

Average Temperature Year

Requirements Forecast by End-Use		2007	2010	2015	2020	2022
CORE	Residential	92	97	106	114	119
	Commercial	51	53	54	55	55
	NGV	2	2	2	2	2
	Industrial	6	6	6	6	6
Subtotal -	*CORE*	151	158	168	178	182
NONCORE	Commercial	0	0	0	0	0
	Industrial	6	6	6	7	7
	Electric Generation	119	126	199	215	221
Subtotal -	*NONCORE*	125	132	206	221	228
WHOLESALE	All End Uses	0	0	0	0	0
	Co Use & LUAF	2	2	3	3	3
SYSTEM TOTAL - THROUGHPUT		278	293	376	402	413
	Storage Injection	14	14	14	14	14
Transportation & Exchange						
CORE	All End Uses	10	10	10	11	10
NONCORE	Commercial/Industrial	6	6	6	7	7
	Electric Generation	119	126	199	215	221
Subtotal -	*RETAIL*	135	142	216	232	239
WHOLESALE	All End Uses	0	0	0	0	0
TOTAL TRANSPORT & EXCHANGE		135	142	216	232	239
CURTAILMENT (Retail & Wholesale)						
	Core	0	0	0	0	0
	Com/Ind	0	0	0	0	0
	Electric Generation	0	0	0	0	0
Total -	*CURTAILMENT*	0	0	0	0	0
REFUSAL		0	0	0	0	0

NOTE:
Requirement forecast by end-use includes sales, transportation and exchange volumes.

ADDITIONAL NOTES:
SDG&E end-use sales service to noncore customers is eliminated per GIR D>01-12-018, and SDG&E noncore requirements are included here with the SDG&E core requirements forecast from 2003. As projected with this forecast, SDG&E has an option per GIR D.01-12-018 to obtain core reliability and balancing storage service for proportional core usage with SoCalGas. The heating value (MMBtu/Mcf) used for this forecast is from the 2003 BCAP filing assumptions.

2002 California Gas Report

LOS ANGELES DEPARTMENT OF WATER AND POWER

LOS ANGELES DEPARTMENT OF WATER AND POWER

The Los Angeles Department of Water and Power (LADWP), the nation's largest municipally owned utility, supplies water and electricity to approximately 3.8 million residents of the nation's second largest city. Throughout the last three decades, the LADWP has diversified its generation resources in order to spread the risk of fuel supply over a diverse array of generation facilities both inside and outside the Los Angeles basin. Recognizing the need to minimize the impact of electric generation on basin air quality, LADWP gradually achieved the goal of 100-percent gas utilization. Currently, the LADWP basin gas generation facilities provide approximately 20 percent of annual generation needs, burning 57.2 Bcf in calendar year 2001.

Within the last 6 years, LADWP has seen a gas usage range from a high of 68.1 Bcf to a low consumption of 19.7 Bcf. The abundance of coal-fired generation and other economy energy purchase options have combined to limit basin gas-fired generation. Oil burning has been relegated to the status of emergency backup, unused in the last 13 years.

LADWP's natural gas demand forecast is presented in the following tables for 2002 through 2022 and was developed in March 2002. It was based on the preliminary Fuel and Purchased Power Budget for native load only. The forecast assumes no energy is obtained from outside purchases, Renewable Energy, Distributed Generation, DSM, or any LADWP programs. Normal weather conditions, growth in the economy, and LADWP's increasing electric sales are also factored in. The LADWP projects an increase of electricity sales due to lower electric rates and growth in the economy as California continues to recover from recession.

LADWP holds firm capacity rights on three interstate pipelines, the value of which has increased with the passage of time. This capacity also provides LADWP with flexibility in establishing its supply portfolio and provides a measure of security.

The LADWP is undergoing a significant corporate restructuring to achieve the necessary competitiveness to survive in a deregulated environment. Current plans call for significant debt reduction by 2003, enhanced services for existing customers, and flexibility to negotiate rates for large commercial/industrial customers.

Since LADWP is entitled to approximately 27 percent of the electric transmission into California, it intends to remain active in governmental and regulatory proceedings affecting both gas and electric issues.

2002 California Gas Report

LOS ANGELES DEPARTMENT OF WATER AND POWER – TABULAR DATA

Los Angeles Department of Water and Power

ANNUAL GAS SUPPLY AND SENDOUT
RECORDED YEARS 1997-2001
MMCF/DAY

LINE	GAS SUPPLY AVAILABLE	1997	1998	1999	2000	2001	LINE
1	California Source Gas						1
	Out-of-State Gas						
2	California Offshore - POPCO/PIOC						2
3	El Paso Natural Gas Co.						3
4	Transwestern Pipeline Co.						4
5	Kern /Mojave						5
6	PGT/PG&E						6
7	Other						7
8	TOTAL Out-of-State Gas						8
9	Subtotal						9
10	Underground Storage Withdrawal						10
11	TOTAL GAS SUPPLY AVAILABLE						11
	GAS SUPPLY TAKEN						
12	California Source Gas	0	0	0	0	0	12
	Out-of-State Gas						
13	Pacific Interstate Companies	0	0	0	0	0	13
14	Other Out-of-State	54	82	148	185	157	14
15	Total Out-of-State Gas	54	82	148	185	157	15
16	Subtotal	54	82	148	185	157	
17	.Underground Storage Withdrawal	0	0	0	0	0	17
18	TOTAL GAS SUPPLY TAKEN	54	82	148	185	157	18

Los Angeles Department of Water and Power

ANNUAL GAS SUPPLY AND SENDOUT
RECORDED YEARS 1997-2001
MMCF/DAY

LINE	ACTUAL DELIVERIES BY END-USE		1997	1998	1999	2000	2001	LINE
1	CORE	Residential	0	0	0	0	0	1
2	CORE/NONCORE	Commercial	0	0	0	0	0	2
3	CORE/NONCORE	Industrial	0	0	0	0	0	3
4		Subtotal	0	0	0	0	0	4
5	NONCORE	Non-EOR Cogeneration	0	0	0	0	0	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	53	82	148	185	157	7
8		Subtotal	53	82	148	185	157	8
9	WHOLESALE	Residential	0	0	0	0	0	9
10		Com. & Ind., others	0	0	0	0	0	10
11		Electric Utilities	0	0	0	0	0	11
12		Subtotal WHOLESALE	0	0	0	0	0	12
13		Co. Use & LUAF	0	0	0	0	0	13
14		Subtotal-END USE	53	82	148	185	157	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL THROUGHPUT		53	82	148	185	157	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17	CORE	All End Uses	0	0	0	0	0	17
18	NONCORE	Commercial/Industrial	0	0	0	0	0	18
19		Non-EOR Cogeneration	0	0	0	0	0	19
20		EOR Cogen. & Steaming	0	0	0	0	0	20
21		Electric Utilities	53	82	148	185	157	21
22		Subtotal-RETAIL	53	82	148	185	157	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		53	82	148	185	157	24
	CURTAILMENT (RETAIL & WHOLESALE)							
25		Core	0	0	0	0	0	25
26		Noncore	0	0	0	0	0	26
27		TOTAL-Curtailment	0	0	0	0	0	27
28	REFUSAL		0	0	0	0	0	28

Los Angeles Department of Water and Power

ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2002 THRU 2006
MMCF/DAY
AVERAGE TEMPERATURE YEAR

LINE	GAS SUPPLY AVAILABLE		2002	2003	2004	2005	2006	LINE
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2		California Offshore - POPCO/PIOC	0	0	0	0	0	2
3		El Paso Natural Gas Co.	36	36	36	36	36	3
4		Transwestern Pipeline Co.	0	0	0	0	0	4
5		Kern /Mojave	158	196	196	196	196	5
6		PGT/PG&E	0	0	0	0	0	6
7		Other	0	0	0	0	0	7
8	TOTAL Out-of-State Gas		194	232	232	232	232	8
9		Subtotal	194	232	232	232	232	9
10	Underground Storage Withdrawal		0	0	0	0	0	10
11	TOTAL GAS SUPPLY AVAILABLE		194	232	232	232	232	11
	GAS SUPPLY TAKEN							
12	California Source Gas		0	0	0	0	0	12
	Out-of-State Gas							
13		Pacific Interstate Companies	0	0	0	0	0	13
14		Other Out-of-State	198	211	185	170	179	14
15	Total Out-of-State Gas		198	211	185	170	179	15
16		Subtotal	198	211	185	170	179	
17	.Underground Storage Withdrawal		0	0	0	0	0	17
18	TOTAL GAS SUPPLY TAKEN		198	211	185	170	179	18
LINE	**REQUIREMENTS FORECAST BY END-USE**							
1	CORE	Residential	0	0	0	0	0	1
2	CORE/NONCORE	Commercial	0	0	0	0	0	2
3	CORE/NONCORE	Industrial	0	0	0	0	0	3
4		Subtotal	0	0	0	0	0	4
5	NONCORE	Non-EOR Cogeneration	0	0	0	0	0	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	198	211	185	170	179	7
8		Subtotal	198	211	185	170	179	8
9	WHOLESALE	Residential	0	0	0	0	0	9
10		Com. & Ind., others	0	0	0	0	0	10
11		Electric Utilities	0	0	0	0	0	11
12		Subtotal WHOLESALE	0	0	0	0	0	12
13		Co. Use & LUAF	0	0	0	0	0	13
14		Subtotal-END USE	198	211	185	170	179	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL THROUGHPUT		198	211	185	170	179	16
	TRANSPORTATION AND EXCHANGE							
17	CORE	All End Uses	0	0	0	0	0	17
18	NONCORE	Commercial/Industrial	0	0	0	0	0	18
19		Non-EOR Cogeneration	0	0	0	0	0	19
20		EOR Cogen. & Steaming	0	0	0	0	0	20
21		Electric Utilities	198	211	185	170	179	21
22		Subtotal-RETAIL	198	211	185	170	179	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		198	211	185	170	179	24
	CURTAILMENT (RETAIL & WHOLESALE)							
25		Core	0	0	0	0	0	25
26		Noncore	0	0	0	0	0	26
27		TOTAL-Curtailment	0	0	0	0	0	27
28	REFUSAL		0	0	0	0	0	28

Los Angeles Department of Water and Power
ANNUAL GAS SUPPLY AND REQUIREMENTS
FORECAST YEARS 2007-2022
MMCF/DAY
AVERAGE TEMPERATURE YEAR

LINE	GAS SUPPLY AVAILABLE		2007	2010	2015	2020	2022	LINE
1	California Source Gas		0	0	0	0	0	1
	Out-of-State Gas							
2		California Offshore - POPCO/PIOC	0	0	0	0	0	2
3		El Paso Natural Gas Co.	0	0	0	0	0	3
4		Transwestern Pipeline Co.	0	0	0	0	0	4
5		Kern /Mojave	0	0	0	0	0	5
6		PGT/PG&E	0	0	0	0	0	6
7		Other	0	0	0	0	0	7
8	TOTAL Out-of-State Gas		0	0	0	0	0	8
9		Subtotal	0	0	0	0	0	9
10	Underground Storage Withdrawal		0	0	0	0	0	10
11	TOTAL GAS SUPPLY AVAILABLE		0	0	0	0	0	11
	GAS SUPPLY TAKEN							
12	California Source Gas		0	0	0	0	0	12
	Out-of-State Gas							
13		Pacific Interstate Companies	0	0	0	0	0	13
14		Other Out-of-State	187	215	239	262	279	14
15	Total Out-of-State Gas		187	215	239	262	279	15
16		Subtotal	187	215	239	262	279	
17	.Underground Storage Withdrawal		0	0	0	0	0	17
18	TOTAL GAS SUPPLY TAKEN		187	215	239	262	279	18

LINE	REQUIREMENTS FORECAST BY END-USE		2007	2010	2015	2020	2022	LINE
1	CORE	Residential	0	0	0	0	0	1
2	CORE/NONCORE	Commercial	0	0	0	0	0	2
3	CORE/NONCORE	Industrial	0	0	0	0	0	3
4		Subtotal	0	0	0	0	0	4
5	NONCORE	Non-EOR Cogeneration	0	0	0	0	0	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	187	215	239	262	279	7
8		Subtotal	187	215	239	262	279	8
9	WHOLESALE	Residential	0	0	0	0	0	9
10		Com. & Ind., others	0	0	0	0	0	10
11		Electric Utilities	0	0	0	0	0	11
12		Subtotal WHOLESALE	0	0	0	0	0	12
13		Co. Use & LUAF	0	0	0	0	0	13
14		Subtotal-END USE	187	215	239	262	279	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL THROUGHPUT		187	215	239	262	279	16
	TRANSPORTATION AND EXCHANGE							
17	CORE	All End Uses	0	0	0	0	0	17
18	NONCORE	Commercial/Industrial	0	0	0	0	0	18
19		Non-EOR Cogeneration	0	0	0	0	0	19
20		EOR Cogen. & Steaming	0	0	0	0	0	20
21		Electric Utilities	187	215	239	262	279	21
22		Subtotal-RETAIL	187	215	239	262	279	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		187	215	239	262	279	24
	CURTAILMENT (RETAIL & WHOLESALE)							
25		Core	0	0	0	0	0	25
26		Noncore	0	0	0	0	0	26
27		TOTAL-Curtailment	0	0	0	0	0	27
28	REFUSAL		0	0	0	0	0	28

2002 California Gas Report

GLOSSARY

AVERAGE DAY (Operational Definition)

Annual gas sales or requirements assuming average temperature year conditions divided by 365 days.

AVERAGE TEMPERATURE YEAR

Long-term average recorded temperature.

BCF

Billion cubic feet of gas.

BTU (British Thermal Unit)

Unit of measurement equal to the amount of heat energy required to raise the temperature of one pound of water one degree Fahrenheit. This unit is commonly used to measure the quantity of heat available from complete combustion of natural gas.

BYPASS

Most situations in which a customer is directly served by an interstate or intrastate pipeline without utilizing existing local distribution company facilities; however, in some cases direct delivery of gas is not considered bypass, e.g., a portion of California production. See Non-Utility Deliveries.

CALIFORNIA-SOURCE GAS

1. Regular Purchases – All gas received or forecast from California producers, excluding exchange volumes. Also referred to as Local Deliveries.
2. Received for Exchange/Transport – All gas received or forecast from California producers for exchange, payback, or transport.

CNG (Compressed Natural Gas)

Fuel for natural gas vehicles, typically natural gas compressed to 3000 pounds per square inch.

COGENERATION

Simultaneous production of electricity and thermal energy from the same fuel source. Also used to designate a separate class of gas customers.

COLD TEMPERATURE YEAR

Cold design-temperature conditions based on long-term recorded weather data.

COMMERCIAL (SoCalGas & SDG&E)

Category of gas customers whose establishments consist of services, manufacturing nondurable goods, dwellings not classified as residential, and farming (agricultural).

COMMERCIAL (PG&E)

Non-residential gas customers not engaged in electric generation, enhanced oil recovery, or gas resale activities with usage less than 20,800 therms per month.

COMPANY USE

Gas used by utilities for operational purposes, such as fuel for line compression and injection into storage.

CORE AGGREGATOR

Individuals or entities arranging natural gas commodity procurement activities on behalf of core customers. Also, sometimes known as an Energy Service Provider (ESP), a Core Transport Agent (CTA), or a Retail Service Provider (RSP).

CORE CUSTOMERS (SoCalGas & SDG&E)

All residential customers; all commercial and industrial customers with average usage less than 20,800 therms per month who typically cannot fuel switch. Also, those commercial and industrial customers (whose average usage is more than 20,800 therms per year) who elect to remain a core customer receiving bundled gas service from the LDC.

CORE CUSTOMERS (PG&E)

All customers with average usage less than 20,800 therms per month.

CORE SUBSCRIPTION

Noncore customers who elect to use the LDC as a procurement agent to meet their commodity gas requirements.

CPUC

California Public Utilities Commission

CUBIC FOOT OF GAS

Volume of natural gas which, at a temperature of 60 F and an absolute pressure of 14.73 pounds per square inch, occupies one cubic foot.

CURTAILMENT

Temporary suspension, partial or complete, of gas deliveries to a customer or customers.

EG

Electric Generation (including cogeneration) by a utility, customer, or independent power producer.

ENERGY SERVICE PROVIDER (ESP)

Individuals or entities engaged in providing retail energy services on behalf of customers. ESP's may provide commodity procurement, but could also provide other services, e.g., metering and billing.

ENHANCED OIL RECOVERY (EOR)

Injection of steam into oil-holding geologic zones to increase ability to extract oil by lowering its viscosity. Also used to designate a special category of gas customers.

EXCHANGE

Delivery of Gas by one party to another and the delivery of an equivalent quantity by the second party to the first. Such transactions usually involve different points of delivery and may or may not be concurrent.

EXEMPT WHOLESALE GENERATORS (EWG)

A category of customers consuming gas for the purpose of generating electric power.

FERC

Federal Energy Regulatory Commission.

GAS ACCORD

The Gas Accord is a multi-party settlement agreement, which restructured PG&E's gas transportation and storage services. The settlement was filed with the CPUC in August 1996, approved by the CPUC in August 1997 (D.97-08-055) and implemented by PG&E in March 1998. Most of the provisions of the Gas Accord have a term ending December 31, 2002.

Key features of the Gas Accord include the following: unbundling of PG&E's gas transmission service and a portion of its storage service; placing PG&E at risk for transmission service and a portion of its storage service; placing PG&E at risk for transmission and storage costs and revenues; establishing firm, tradable transmission and storage rights; establishing known transmission and storage rates for the term of the Gas Accord; reducing PG&E's role in core gas procurement; and resolving outstanding gas reasonableness and other gas regulatory matters.

GAS SENDOUT

That portion of the available gas supply that is delivered to gas customers for consumption, plus shrinkage.

HEATING DEGREE DAY(S)

A Measure of how much below a standard reference temperature (SoCalGas and SDG&E: 65F; PG&E 60F) actual temperatures have been. A basis for computing how much electricity and gas are needed for space heating purposes.

HOT TEMPERATURE YEAR

Hot design-temperature conditions, based on long-term recorded weather data.

INDUSTRIAL (SoCalGas & SDG&E)

Category of gas customers who are engaged in mining and in manufacturing durable goods.

INDUSTRIAL (PG&E)

Non-residential customers not engaged in electric generation, enhanced oil recovery, or gas resale activities using more than 20,800 therms per month.

LDC

Local electric and/or natural gas distribution company.

LNG (Liquefied Natural Gas)

Natural gas in its liquid state.

MMBTU

Million British Thermal Units.

MMCF

Million cubic feet of gas

MMCF/DAY

Million cubic feet of gas per day.

NGV (Natural Gas Vehicle)

Vehicle that uses CNG or LNG as its source of fuel for its internal combustion engine.

NONCORE CUSTOMERS

Commercial and industrial customers whose average usage exceeds 20,800 therms per month, including qualifying cogeneration and solar electric projects. Noncore customers assume gas procurement responsibilities and receive gas transportation service from the utility under firm or interruptible intrastate transmission arrangements.

NON-UTILITY DELIVERIES

The volume of gas delivered directly to customers by an interstate or intrastate pipeline or other independent source instead of the local distribution company.

OFF-SYSTEM SALES

Gas sales to customers outside the utility's service area.

OUT-OF-STATE GAS

Gas from sources outside the state of California.

PRIORITY OF SERVICE (SoCalGas & SDG&E)

In the event of a curtailment situation, utilities curtail gas usage to customers based on the following end-use priorities:

NONCORE SERVICE

Firm Service – All noncore customers served through firm intrastate transmission service, including core subscription service.

Interruptible – All noncore customers served through interruptible intrastate transmission service, including inter-utility deliveries.

PRIORITY OF SERVICE (PG&E)

In the event of a curtailment situation, PG&E curtails gas usage to customers based on the following end-use priorities:

Core Residential
Non-residential Core
Noncore using firm backbone service (including UEG)
Noncore using as-available backbone service (including UEG)
Market Center Services

PSIA

Pounds per square inch absolute. Equal to gauge pressure plus local atmospheric pressure.

PURCHASES FROM OTHER UTILITIES

Gas purchased from other utilities in California.

REQUIREMENTS

Total potential demand for gas, including that served by transportation, assuming the availability of unlimited supplies at reasonable cost.

RESALE

Gas customers who are either another utility or a municipal entity that, in turn, resells gas to end-use customers.

RESIDENTIAL

A category of gas customers whose dwellings are single-family units, multi-family units, mobile homes or other similar living facilities.

SHORT-TERM SUPPLIES

Gas purchased usually involving 30-day, short-term contract or spot gas supplies.

SPOT PURCHASES

Short-term purchases of gas typically not under contract and generally categorized as surplus or best efforts.

STORAGE BANKING

The direct use of local distribution company gas storage facilities by customers or other entities to store self-procured commodity gas supplies.

STORAGE INJECTION

Volume of natural gas injected into underground storage facilities.

STORAGE WITHDRAWAL

Volume of natural gas taken from underground storage facilities.

SUPPLEMENTAL SUPPLIES

A utility's best estimate for additional gas supplies that may be realized, from unspecified sources, during the forecast period.

SYSTEM CAPACITY or NORMAL SYSTEM CAPACITY
(*Operational Definition*)

The physical limitation of the system (pipelines and storage) to deliver or flow gas to end-users.

SYSTEM UTILIZATION or NOMINAL SYSTEM CAPACITY
(*Operational Definition*)

The use of system capacity or nominal system capacity at less then 100 percent utilization.

TAKE-OR-PAY

A term used to describe a contract agreement to pay for a product (natural gas) whether or not the product is delivered.

TARIFF

All rate schedules, sample forms, rentals, charges, and rules approved by regulatory agencies for used by the utility.

Tcf

Trillion cubic feet of gas.

THERM

A unit of energy measurement, nominally 100,000 BTUs.

TOTAL GAS SUPPLY AVAILABLE

Total quantity of gas estimated to be available to meet gas requirements.

TOTAL GAS SUPPLY TAKEN

Total quantity of gas taken from all sources to meet gas requirements.

TOTAL THROUGHPUT

Total gas volumes passing through the system including sales, company use, storage, transportation and exchange.

TRANSPORTATION GAS

Non-utility-owned gas transported for another party under contractual agreement.

UEG

Utility electric generation.

UNACCOUNTED FOR

Gas received into the system but unaccounted for due to measurement, temperature, pressure, or accounting discrepancies.

UNBUNDLING

The separation of natural gas utility services into its separate service components such as gas procurement, transportation, and storage with distinct rates for each service.

WACOG

Weighted average cost of gas.

WHOLESALE

A category of customer, either a utility or municipal entity, that resells gas.

2002 California Gas Report

RESPONDENTS

RESPONDENTS

The following utilities have been designated by the California Public Utilities Commission as respondents in the preparation of the California Gas Report:

- **Pacific Gas and Electric Company**
- **San Diego Gas & Electric Company**
- **Southern California Gas Company**

The following utilities, in addition to Wild Goose Storage, Inc., cooperated in the preparation of the report:

- **City of Long Beach Energy Department**
- **City of Los Angeles Department of Water and Power**
- **Sacramento Municipal Utilities District**
- **Southwest Gas Corporation**

Two statewide committees have been formed by the respondents and cooperating utilities to prepare this report. The following individuals served on these committees this year:

GENERAL COMMITTEE

Mike Katz	Pacific Gas and Electric Company
Thomas J. Armstrong	Southwest Gas Corporation
William L. Reed	Sempra Energy Utilities*
Lee Schavrien	Sempra Energy Utilities*

*Sempra Energy Utilities represents: Southern California Gas Company and San Diego Gas & Electric Company

WORKING COMMITTEE

Gregory Healy (Chairperson)	Sempra Energy Utilities*
Ginger Shugart	City of Long Beach Energy Department
Gino Beltran	Los Angeles Department of Water and Power
Carl Funke	San Diego Gas & Electric Company
Edward Gieseking	Southwest Gas Corporation
Don Petersen	Pacific Gas and Electric Company
Jasmin Ansar	Pacific Gas and Electric Company
Barry Brunelle	Sacramento Municipal Utilities District

OBSERVERS

Esther Montgomery	California Public Utilities Commission, Office of Ratepayer Advocates
Todd Peterson	California Energy Commission
William Wood	California Energy Commission

*Sempra Energy Utilities represents: Southern California Gas Company and San Diego Gas & Electric Company.

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