CALIFORNIA GAS REPORT

2010

Prepared by the California Gas and Electric Utilities

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PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES

Southern California Gas Company
Pacific Gas and Electric Company
San Diego Gas & Electric Company
Southwest Gas Corporation
City of Long Beach Gas & Oil Department
Southern California Edison Company

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2010 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The 2010 California Gas Report presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2030. 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 details on the requirements and supplies of natural gas for Pacific Gas and Electric Company (PG&E), the Sacramento Municipal Utility District (SMUD), Wild Goose Storage, Inc. and Lodi Gas Storage LLC. The Southern California section shows similar detail for Southern California Gas Company (SoCalGas), the City of Long Beach Municipal Oil and Gas Department, and San Diego Gas and Electric Company.

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 by customer class. Separate sets of tables are presented for average and cold year temperature 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. This report should not be used by readers as a substitute for a full, detailed analysis of their own specific energy requirements.

A working committee, comprised of the representatives from each utility was responsible for compiling the report. The membership of this Committee is listed in the Respondents section at the end of this report.

Workpapers and next year's report are available upon request from PG&E and SoCalGas/SDG&E. Write, fax or email us at the address shown in the Reserve Your Subscription section at the end of this report.

2010 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

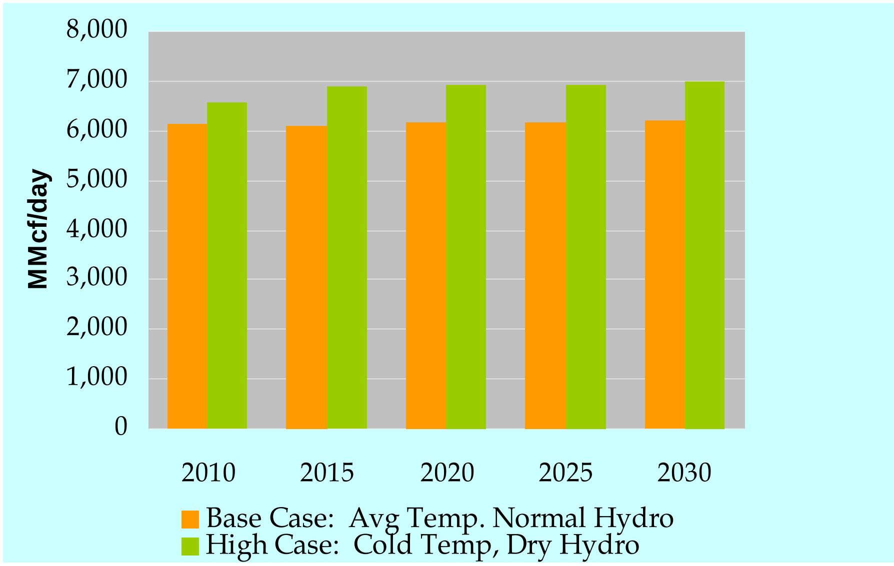
DEMAND OUTLOOK

California natural gas demand, including volumes not served by utility systems, is expected to grow at a modest rate of just 0.07 percent per year from 2010 to 2030. Forecast growth is a combination of moderate growth in the residential, core commercial, and electric generation markets, tempered by the declining demand in the noncore commercial and industrial markets.

Residential gas demand is expected to increase at an annual average rate of 0.05 percent. Demand in the core commercial market is expected to grow at an annual rate of only 0.22; whereas demand in the industrial noncore sector is estimated to decline by -0.58 percent annually as California continues its transition from a manufacturing-based to a service-based economy. Aggressive energy efficiency programs are expected to make a significant impact in managing growth in the residential, commercial and industrial markets.

For the purpose of load following as well as backstopping intermittent renewable resource generation, gas-fired generation will continue to be the technology of choice to meet the ever-growing demand for electric power. However, overall gas demand for electric generation is expected to grow at a modest 0.35% per year for the next 21 years due to more efficient power plants, statewide efforts to minimize greenhouse gas emissions through aggressive programs pursuing demand side reductions and the acquisition of preferred resources that produced little or no carbon emissions.

California Demand Forecast (MMcf/Day)



The graph above summarizes statewide demand under a base case scenario and a high case scenario. The base case refers to the expected gas demand for an average temperature year and normal hydroelectric power (hydro) year, and the high case refers to expected gas demand for a cold temperature year and dry hydro conditions. Under an average temperature condition and a normal hydro year, gas demand for the state is projected to average 6,128 MMcf/d in 2010 increasing to 6,223 MMcf/d by 2030, a cumulative growth of just 1.55 percent in the entire forecast period.

In 2010, Northern California is projected to require an additional 11.1% of gas supply to meet demand for the high gas demand scenario; whereas Southern California is projected to require an additional 3.5% of supply to meet the demand under the high scenario condition. This spread between the regions is expected. It can be explained on the basis that northern California is colder and tends to rely more heavily on hydroelectric power than Southern California. The weather scenario for each year is an independent event and each event has the same likelihood of occurring. The annual demand forecast for the base case and high case should therefore not be viewed as a combined event from year to year.

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 2000-2001 "energy crisis" in California was not limited to electricity. Gas prices at the Southern California border reached levels nearly ten times greater than had been experienced in previous history. California utilities are committed to helping their customers make the best possible choices regarding use of this increasingly valuable resource. Gas demand for electric power generation is expected to be moderated by CPUC-mandated goals for electric energy efficiency programs and renewable power. The base case forecasts in this report assume that the state will have 20% of its energy needs met with renewable power by 2012, and then additional renewable power is added to increase the renewable portion to 33% by 2020 and beyond.

The state's recently passed greenhouse gas (GHG) reduction law, AB 32, has set aggressive targets for the state to meet in order to reduce its overall GHG production. This law creates substantial uncertainty on the amount of natural gas that will be used in the outer years of the forecast. There is a high degree of uncertainty regarding what impact will occur in each sector as a result of the implementation of the measures to meet the GHG reduction goals.

The table on the following page approximates total gas savings based on the impact of renewables in addition to the impact of electric and gas energy efficiency goals on the CPUC-jurisdictional utilities. Gas savings from electric energy efficiency goals are based on a generic assumption of heat rate per megawatt hour of electricity produced at gas-fired peaking and combined-cycle power plants.

Impact of Renewable Generation and Energy Efficiency Programs on Gas Demand

	2009	2010	2015	2020	2025	2030
California Energy Requirements by CPUC-Jurisdictional Utilities (CAISO) (1)						
Electricity Demand (GWh)	192,004	192,406	205,115	217,710	231,080	245,272
20% Reneweables by 2012						
Renewable Electric Generation (GWh/Yr) (2)	28,432	32,040	41,023	43,542	46,216	49,054
Increase over 2005 Level (GWh/Yr) (3)	5,919	9,527	18,510	21,029	23,703	26,542
Gas Savings over 2005 Level (Bcf/Yr)	36	58	112	128	144	161
Electric Energy Efficieny Goals (5)						
Electricity Savings over 2005 Level (GWh/Yr)	10,781	13,057	22,804	22,380	21,910	22,230
Gas Savings over 2005 Level (Bcf/Yr) (4)	65	79	138	136	133	135
Energy Efficiency Goal for Natural Gas Programs (5)						
Gas Savings over 2005 Level (Bcf/Yr)	17	22	50	73	81	82
Total Gas Savings (Bcf/Yr) (6)	119	159	301	336	358	378

Note:

(1) See http://www.energy.ca.gov/2009publications/CEC-200-2009-012/index.html for the forecast report and tables.
Since the CEC's forecasts only go out 10 years, this forecast was extended by staff, as was done for the last CGR.

(2) Renewables goal from 2008 through 2011 is the sum of actual renewables in 2007 of 22,390 GWh from PG&E, SCE and SDG&E's RPS compliance filing dated August 2009 and March 2010 plus prorated volume of annual growth to meet 20% target in 2012. This goal differs from the individual utilities' renewables forecasts, which are based on more complex modeling assumptions. Renewables electric generation, as defined for the purpose of the 20% goal, excludes generation from large hydroelectric plants.

(3) Increase reflects only impacts of equipment installed after 12/31/2005.

(4) Electricity and natural gas savings goals per CPUC Decision, D.00-09-047, September 24, 2009. Table 2 pp. 45.

(5) Total gas savings are annual savings from equipment installed after 12/31/2005.

NATURAL GAS PROJECTS: PROPOSALS, COMPLETIONS, AND LIQUEFIED NATURAL GAS

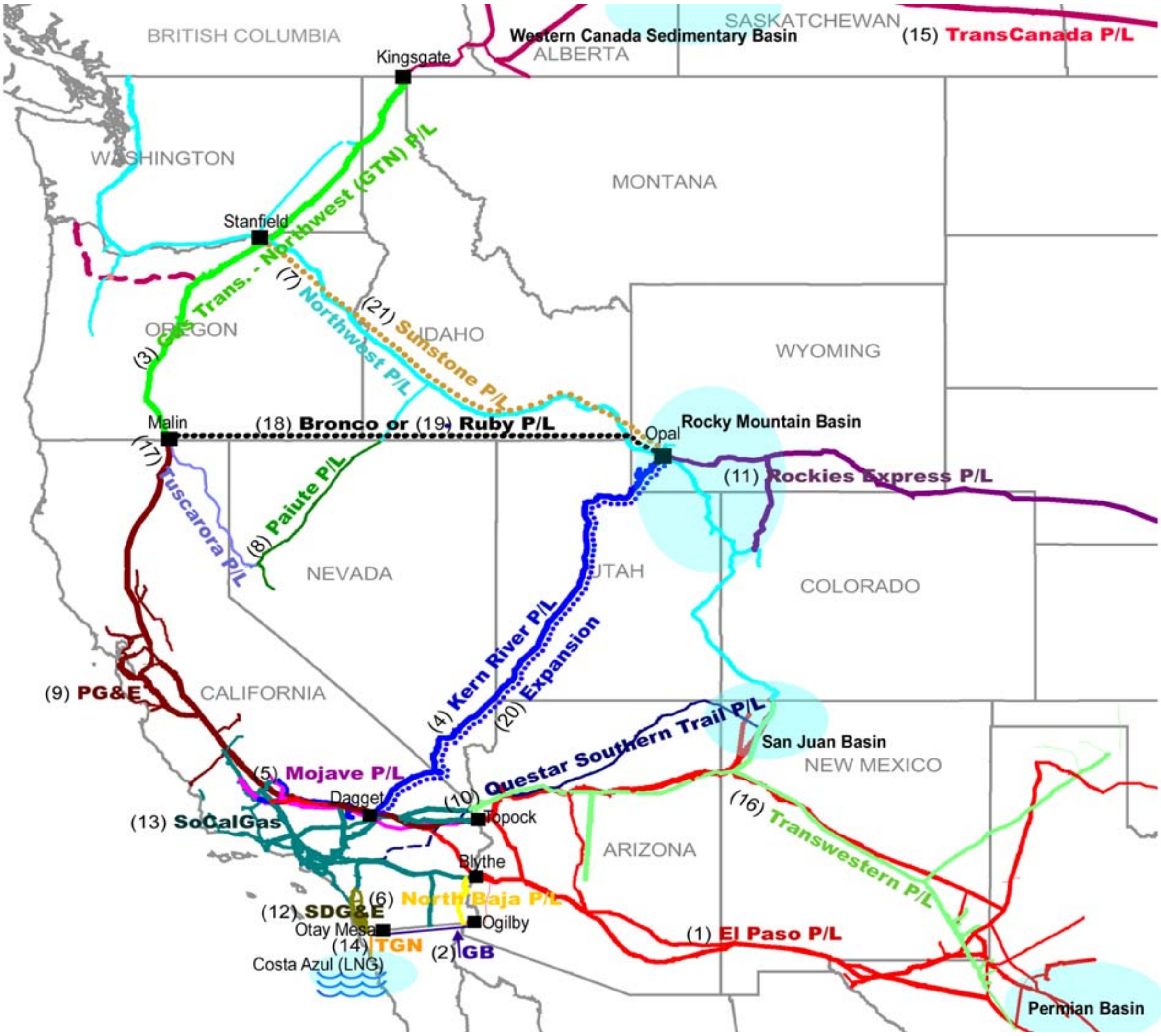
Over the past five years, California natural gas utilities, interstate pipelines, and in-state natural gas storage facilities have increased their delivery and receipt capacity to meet natural gas demand growth. In addition, more projects have been proposed and some are under construction. The California Energy Commission (Energy Commission) posts a list of natural gas projects on their website, which tracks both completed projects and ones that are being developed or in the proposal stage, along with proposed liquefied natural gas (LNG) projects. To review these project lists check the Energy Commission's website at http://www.energy.ca.gov/naturalgas/.

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. Since 2008, the Energia Costa Azul LNG (Liquefied Natural Gas) receiving terminal in Baja California was certified, and has provided yet another source of supply for California. This project has the potential to re-gasify 1 Bcf/d of LNG. The amount of supply delivered through that project will be based on a host of factors, including world supply availability in the Pacific basin. 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 for the California market. Interstate pipelines currently serving California include El Paso Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission-Northwest, Transwestern Pipeline Company, Questar Southern Trails Pipeline, Tuscarora Pipeline and the Bajanorte/North Baja Pipeline.

Western North American Natural Gas Pipelines



In Operation:

1. El Paso Natural Gas
2. Gasoducto Bajanorte (GB)
3. Gas Transmission Northwest (GTN)
4. Kern River Pipeline
5. Mojave Pipeline
6. North Baja Pipeline
7. Northwest Pipeline
8. Paiute Pipeline
9. Pacific Gas Electric Company
10. Questar Southern Trail Pipeline
11. Rockies Express (REX)
12. San Diego Gas &Electric Company
13. Southern California Gas Company
14. Transportadora de Gas Natural (TGN)
15. TransCanada Pipeline
16. Transwestern Pipeline
17. Tuscarora Pipeline

Proposed:

18. Bronco Pipeline
19. Ruby Pipeline
20. Kern River Expansion
21. Sunstone Pipeline delayed indefinitely

Liquefied Natural Gas (LNG)

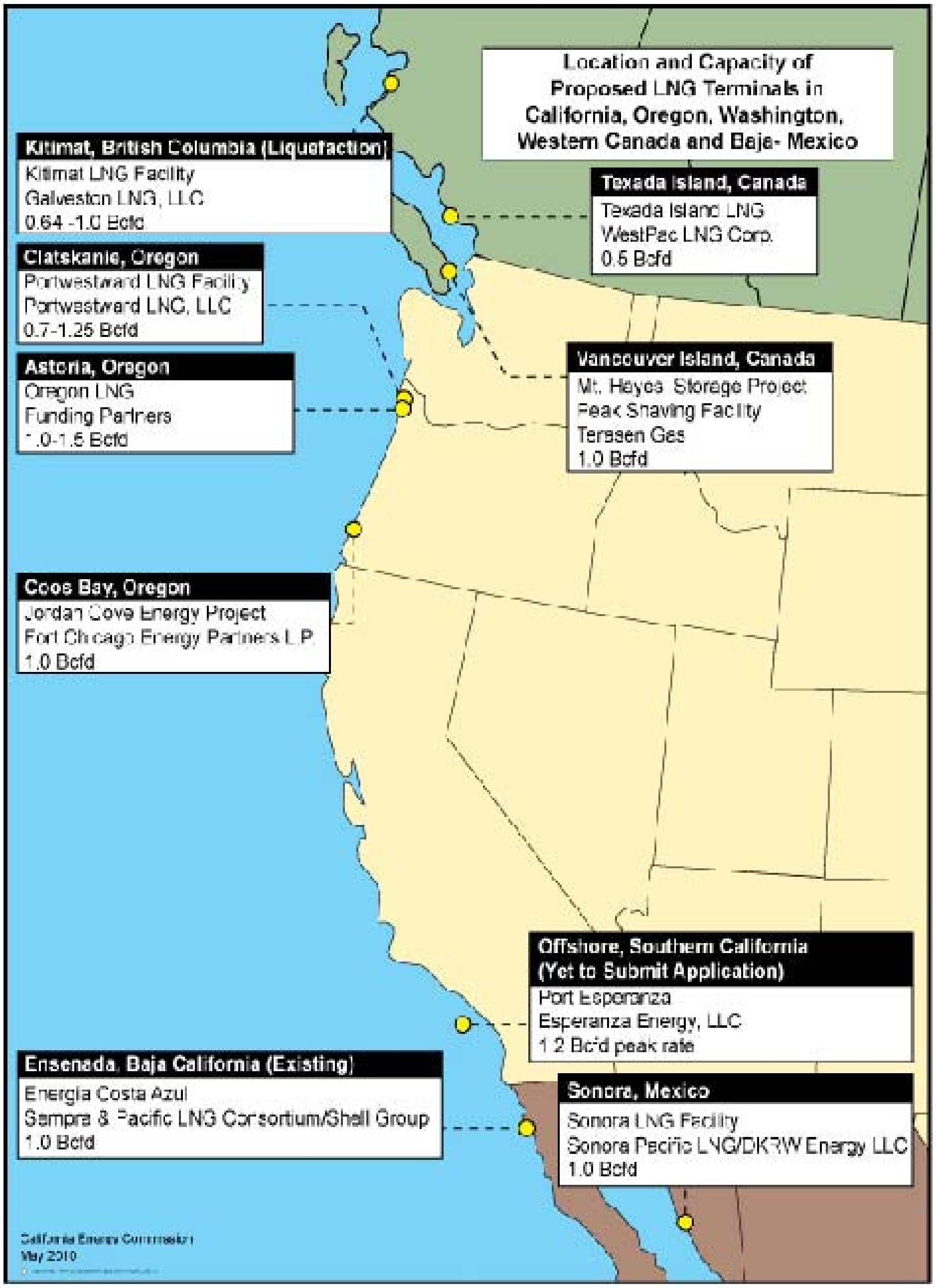
With the completion of the Costa Azul LNG terminal in Baja California, Mexico in May 2008, LNG is likely to increase significantly as a gas supply source to California in the years ahead.

The 1,000 MMcf/d Energia Costa Azul LNG Terminal located in Baja California, Mexico received its first cargo on April 18, 2008 followed by a second cargo on May 6, 2008. These initial cargos were used to complete performance testing of the new terminal and on May 15, 2008, the Costa Azul terminal declared itself ready for commercial operations. Costa Azul will provide the potential for LNG-derived natural gas supplies to be delivered to the SoCalGas system. There remains some uncertainty about the volume of LNG supplies that will be delivered to California from the Costa Azul terminal in the coming years, but it is likely that these supplies will begin to play a more significant role in serving demand in the Southern California area. The Costa Azul terminal also has the potential to expand its capabilities to 2,500 MMcf/d in the future.

In addition to the Costa Azul terminal in Mexico, a few other LNG terminal projects have been proposed on the West Coast that could ultimately result in additional LNG-derived supplies being delivered to California. The Jordan Cove LNG project in Coos Bay, Oregon will bring supplies directed to Malin on the California-Oregon border, which would provide benefits to the state without the need for additional infrastructure in California. One additional project, off the coast of Long Beach, has been proposed by Esperanza Energy, but they have yet to file a formal application with state and federal agencies. At this time, the Clearwater Port Project and the Oceanway Secure Energy Project are no longer viable LNG projects for California. It is too early at this point to estimate expected supplies that would be available from these facilities or when they may be available, however, it is possible that one or more of these projects could be on-line during the 2010-2030 forecast period presented in the *2010 California Gas Report*.

Attached is a map from the California Energy Commission highlighting all of the proposed LNG projects on the West Coast. At this point, aside from the Energia Costa Azul facility, each of these projects is still awaiting necessary government approvals in order to begin construction. Additional information on these projects is available at www.energy.ca.gov/naturalgas/.

Proposed West Coast LNG Terminals



May 2010
California Energy Commission
www.energy.ca.gov

STATEWIDE CONSOLIDATED SUMMARY TABLES

The consolidated summary tables on the following pages show the statewide aggregations of projected gas supplies and gas requirements (demand) from 2010 to 2030 for average temperature and normal hydro years and cold temperature and dry hydro years.

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 Gas and Oil Department, San Diego Gas & Electric Company, Southwest Gas Corporation, City of Vernon, Alpine Natural Gas, Island Energy, West Coast Gas, Inc, and the municipalities of Coalinga and Palo Alto.

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

STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
Average Temperature and Normal Hydro Year
MMcf/Day

	2010	2011	2015	2020	2025	2030
California's Supply Sources						
Utility						
California Sources	440	440	440	440	440	440
Out-of-State	4,504	4,396	4,442	4,480	4,440	4,467
Utility Total	4,944	4,836	4,882	4,920	4,880	4,907
Non-Utility Served Load (1)	1,403	1,392	1,418	1,441	1,459	1,477
Statewide Supply Sources Total	**6,348**	**6,228**	**6,300**	**6,361**	**6,339**	**6,384**
California's Requirements						
Utility						
Residential	1,193	1,184	1,177	1,190	1,196	1,205
Commercial	493	496	496	484	477	488
Natural Gas Vehicles	33	34	39	44	56	67
Industrial	810	801	780	745	713	705
Electric Generation (2)	1,856	1,800	1,866	1,927	1,928	1,927
Enhanced Oil Recovery Steaming	30	29	29	29	29	29
Wholesale/International+Exchange	230	230	233	237	242	247
Company Use and Unaccounted-for	85	81	83	84	84	84
Utility Total	4,729	4,655	4,703	4,741	4,726	4,753
Non-Utility						
Enhanced Oil Recovery Steaming	784	786	785	787	797	807
EOR Cogeneration/Industrial	164	164	163	166	168	170
Electric Generation	456	442	470	488	494	501
Non-Utility Served Load (1)	1,403	1,392	1,418	1,441	1,459	1,477
Statewide Requirements Total (3)	**6,133**	**6,047**	**6,121**	**6,182**	**6,185**	**6,230**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of Off System deliveries.

STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
Average Temperature and Normal Hydro Year
MMcf/Day

Utility	**2010**	**2011**	**2015**	**2020**	**2025**	**2030**
Northern California						
California Sources (1)	130	130	130	130	130	130
Out-of-State	2,233	2,152	2,207	2,317	2,291	2,310
Northern California Total	2,363	2,282	2,337	2,447	2,421	2,440
Southern California						
California Sources (2)	310	310	310	310	310	310
Out-of-State	2,272	2,245	2,235	2,163	2,148	2,157
Southern California Total	2,582	2,555	2,545	2,473	2,458	2,467
Utility Total	4,944	4,836	4,882	4,920	4,880	4,907
Non-Utility Served Load (3)	1,403	1,392	1,418	1,441	1,459	1,477
Statewide Supply Sources Total	**6,348**	**6,228**	**6,300**	**6,361**	**6,339**	**6,384**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).

STATEWIDE ANNUAL GAS REQUIREMENTS (1)
Average Temperature and Normal Hydro Year
MMcf/Day

	2010	2011	2015	2020	2025	2030
Utility						
Northern California						
Residential	560	559	559	567	572	579
Commercial - Core	225	228	236	236	235	241
Natural Gas Vehicles - Core	5	5	6	7	15	20
Natural Gas Vehicles - Noncore	1	1	2	2	1	1
Industrial - Noncore	449	443	437	426	415	415
Wholesale	10	10	10	10	10	10
SMUD Electric Generation	118	122	122	122	122	122
Electric Generation (2)	724	680	732	841	841	841
Exchange CA) (	1	1	1	1	1	1
Company Use and Unaccounted-for	55	51	53	55	55	55
Northern California Total (3)	2,148	2,101	2,158	2,268	2,267	2,286
Southern California						
Residential	633	625	618	623	624	626
Commercial - Core	215	216	216	214	215	219
Commercial Noncore -	53	51	44	35	27	28
Natural Gas Vehicles - Core	27	28	31	35	40	46
Industrial - Core	56	55	51	45	37	35
Industrial - Noncore	305	304	293	274	261	255
Wholesale	219	219	222	225	231	236
SDG&E+Vernon Electric Generation	232	211	210	193	190	188
Electric Generation (4)	781	787	802	771	774	775
Enhanced Oil Recovery Steaming	30	29	29	29	29	29
Company Use and Unaccounted-for	30	30	30	29	29	29
Southern California Total	2,582	2,555	2,545	2,473	2,458	2,467
Utility Total	4,729	4,655	4,703	4,741	4,726	4,753
Non-Utility Served Load (5)	1,403	1,392	1,418	1,441	1,459	1,477
Statewide Gas Requirements Total (6)	**6,133**	**6,047**	**6,121**	**6,182**	**6,185**	**6,230**

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants. Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).
(6) Does not include off-system deliveries.

STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
Cold Temperature and Dry Hydro Year
MMcf/Day

	2010	2011	2015	2020	2025	2030
California's Supply Sources						
Utility						
California Sources	440	440	440	440	440	440
Out-of-State	4,847	4,915	5,054	5,075	5,051	5,086
Utility Total	5,287	5,355	5,494	5,515	5,491	5,526
Non-Utility Served Load (1)	1,403	1,408	1,434	1,461	1,479	1,497
Statewide Supply Sources Total	**6,690**	**6,763**	**6,928**	**6,975**	**6,970**	**7,024**
California's Requirements						
Utility						
Residential	1,309	1,302	1,301	1,323	1,341	1,357
Commercial	520	524	528	518	514	527
Natural Gas Vehicles	33	34	38	43	56	67
Industrial	812	803	783	747	715	706
Electric Generation (2)	2,029	2,144	2,292	2,326	2,327	2,326
Enhanced Oil Recovery Steaming	30	29	29	29	29	29
Wholesale/International+Exchange	247	247	249	253	259	265
Company Use and Unaccounted-for	91	91	94	95	95	96
Utility Total	5,072	5,174	5,315	5,336	5,337	5,372
Non-Utility						
Enhanced Oil Recovery Steaming	784	786	785	787	797	807
EOR Cogeneration/Industrial	164	164	163	166	168	170
Electric Generation	456	458	486	508	514	520
Non-Utility Served Load (1)	1,403	1,408	1,434	1,461	1,479	1,497
Statewide Requirements Total (3)	**6,475**	**6,582**	**6,749**	**6,796**	**6,816**	**6,870**

Notes:

(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).

(2) Includes utility generation, wholesale generation, and cogeneration.

(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
Cold Temperature and Dry Hydro Year
MMcf/Day

Utility	**2010**	**2011**	**2015**	**2020**	**2025**	**2030**
Northern California						
California Sources (1)	130	130	130	130	130	130
Out-of-State	2,484	2,479	2,630	2,719	2,709	2,735
Northern California Total	2,614	2,609	2,760	2,849	2,839	2,865
Southern California						
California Sources (2)	310	310	310	310	310	310
Out-of-State	2,363	2,436	2,423	2,356	2,342	2,351
Southern California Total	2,673	2,746	2,733	2,666	2,652	2,661
Utility Total	5,287	5,355	5,494	5,515	5,491	5,526
Non-Utility Served Load (3)	1,403	1,408	1,434	1,461	1,479	1,497
Statewide Supply Sources Total	**6,690**	**6,763**	**6,928**	**6,975**	**6,970**	**7,024**

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).

STATEWIDE ANNUAL GAS REQUIREMENTS (1)
Cold Temperature and Dry Hydro Year
MMcf/Day

	2010	2011	2015	2020	2025	2030
Utility						
Northern California						
Residential	615	617	625	641	658	671
Commercial - Core	240	244	254	256	259	267
Natural Gas Vehicles - Core	5	5	6	7	15	20
Natural Gas Vehicles - Noncore	1	1	1	1	1	1
Industrial - Noncore	450	444	438	427	416	415
Wholesale	12	12	12	12	12	12
SMUD Electric Generation	118	122	122	122	122	122
Electric Generation (2)	896	923	1,059	1,137	1,137	1,137
Exchange (CA)	1	1	1	1	1	1
Company Use and Unaccounted-for	60	59	62	64	64	65
Northern California Total (3)	2,399	2,428	2,581	2,670	2,685	2,711
Southern California						
Residential	693	685	676	682	683	686
Commercial - Core	226	228	228	225	226	231
Commercial - Noncore	55	53	46	36	29	29
Natural Gas Vehicles - Core	27	28	31	35	40	46
Industrial - Core	57	56	52	46	38	35
Industrial - Noncore	305	304	293	274	261	255
Wholesale	234	234	236	240	246	252
SDG&E+Vernon Electric Generation	233	226	228	203	201	198
Electric Generation (4)	781	873	882	864	867	868
Enhanced Oil Recovery Steaming	30	29	29	29	29	29
Company Use and Unaccounted-for	31	32	32	31	31	31
Southern California Total	2,673	2,746	2,733	2,666	2,652	2,661
Utility Total	5,072	5,174	5,315	5,336	5,337	5,372
Non-Utility Served Load (5)	1,403	1,408	1,434	1,461	1,479	1,497
Statewide Gas Requirements Total (6)	**6,475**	**6,582**	**6,749**	**6,796**	**6,816**	**6,870**

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas uses at Blythe and Elk Hills powerplants.
Source: CEC 2007 Natural Gas Market Assessment Report, Dec. 2007 (2008-2017 published in Table J-4).
(6) Does not include off-system deliveries.

STATEWIDE RECORDED 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 displayed in the following tables shows the composition of supplies from both out-of-state sources as well as California sources. The data are 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.

Recorded 2003 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)	57	575	245	23	26	5	6	938
Noncore Commercial/Industrial	63	68	64	53	139	14	11	411
EG (3)	121	130	122	101	267	27	21	789
EOR	7	7	6	5	14	1	1	42
Wholesale/Resale/International (4)	58	197	66	55	37	13	(49)	377
Total	306	976	503	238	483	61	(11)	2,557
Pacific Gas and Electric Company (5)								
Core	-	146	9	569	9	-	-	733
Noncore Commercial/Industrial/EG/Resale (3)	155	305	78	595	157	-	64	1,354
Total	155	451	87	1,164	166	-	64	2,087
Other Northern California								
Core (5)	-	-	-	-	-	-	11	11
Non-Utilities Served Load (6)								
Direct Sales/Bypass	451	-	-	-	600	86	-	1,137
TOTAL SUPPLIER	912	1,427	590	1,402	1,249	147	64	5,791

Notes:

(1) Includes storage activities. For PG&E, this includes volumes flowing over Kern River High Desert interconnect & Questar Southern Trails interconnect.
(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	3	43	14	49	12	0	13	135
Noncore Commercial/Industrial	0	136	45	1	0	0	0	183
Total	3	179	60	50	12	0	13	317

(5) Includes Southwest Gas Corp., Avista and Tuscarora data.
(6) Deliveries to end-users by non-CPUC jurisdictional pipelines.

Recorded 2004 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)	71	599	226	45	43	-	8	994
Noncore Commercial/Industrial	56	63	54	91	142	10	0	416
EG (3)	105	118	101	171	266	19	1	781
EOR	5	5	5	8	12	1	0	35
Wholesale/Resale/International (4)	57	158	134	52	48	10	(33)	427
Total	294	943	520	367	511	40	(23)	2,653
Pacific Gas and Electric Company (5)								
Core	-	158	65	578	18	-	-	819
Noncore Industrial/Wholesale/EG (3)	104	294	22	609	252	-	-	1,281
Total	104	452	87	1,187	270	-	-	2,100
Other Northern California								
Core (6)	-	-	-	-	-	-	11	11
Non-Utilities Served Load								
Direct Sales/Bypass	475	-	-	-	757	91	-	1,323
TOTAL SUPPLIER	873	1,395	607	1,554	1,538	131	(12)	6,087

Notes:

(1) Includes storage activities. For PG&E, this includes volumes flowing over Kern River High Desert interconnect & Questar Southern Trails interconnect.

(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 GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company								
Core	5	29	25	47	-	-	44	150
Noncore Commercial/Industrial	0	114	97	1	-	-	1	213
Total	5	144	122	47	-	-	45	363

(5) Kern River supplies include volumes on Kramer Junction Interconnect and Questar Southern Trails Interconnect.

(6) Includes Southwest Gas Corporation, Avista, and Tuscarora data

(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.

Recorded 2005 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)	60	600	208	18	106	-	(16)	976
Noncore Commercial/Industrial	56	43	59	52	172	7	16	404
EG (3)	94	71	99	87	287	11	26	676
EOR	5	4	5	4	14	1	1	34
Wholesale/Resale/International (4)	55	161	107	52	48	7	(35)	393
Total	270	878	478	213	627	25	(8)	2,483
Pacific Gas and Electric Company (5)								
Core	-	193	52	535	11	-	-	791
Noncore Industrial/Wholesale/EG (3)	117	306	55	592	151	-	-	1,221
Total	117	499	107	1,127	162	-	-	2,012
Other Northern California								
Core (6)	-	-	-	-	-	-	11	11
Non-Utilities Served Load (7)								
Direct Sales/Bypass	474	-	-	-	675	108	-	1,257
TOTAL SUPPLIER	861	1,377	585	1,340	1,464	133	3	5,763

Notes:

(1) Includes storage activities. For PG&E, this includes volumes flowing over Kern River High Desert interconnect & Questar Southern Trails interconnect.

(2) Includes NGV volumes, unaccouted-for and company use.

(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 GT-NW	Kern River	Mojave	Other (1)	Total
San Diego Gas & Electric Company								
Core	6	42	28	46	1	-	26	149
Noncore Commercial/Industrial	0	104	69	1	-	-	-	174
Total	6	146	97	47	1	-	26	323

(5) Kern River supplies include volumes on Kramer Junction Interconnect and Questar Southern Trails Interconnect.

(6) Includes Southwest Gas Corporation, Avista, and Tuscarora data

(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.

Recorded 2006 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN / PG&E	Kern River	Mojave (9)	Other (1)	Total
Southern California Gas Company								
Core 2) (	7	704	182	13	92	10	20	1,029
Noncore Commercial/Industrial	77	75	63	34	155	4	2	410
EG (3)	145	140	119	63	291	7	4	769
EOR	7	7	6	3	15	0	0	39
Wholesale/Resale/International (4)	7	227	88	43	18	3	8	394
Total	243	1,154	458	157	571	24	34	2,641
Pacific Gas and Electric Company (5)								
Core	0	202	60	571	5	0	0	838
Noncore Industrial/Wholesale/EG (6)	136	295	62	643	26	0	55	1,217
Total	136	497	122	1,214	31	0	55	2,055
Other Northern California								
Core (7)	0	0	0	0	0	0	12	12
Non-Utilities Served Load (8,9)								
Direct Sales/Bypass	469	21	0	0	820	23	0	1,333
TOTAL SUPPLIER	848	1,672	580	1,371	1,422	47	101	6,041

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes, unaccounted-for and company use.
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, & SDG&E, as shown.

	California Sources	El Paso	Trans western	GTN / PG&E	Kern River	Mojave (9)	Other (1)	Total
San Diego Gas & Electric Company								
Core	6	53	21	36	15	2	7	139
Noncore Commercial/Industrial	0	136	53	0	0	0	0	189
Total	6	189	73	36	15	2	7	328

Includes new procedure to allocate SDG&E volumes in 2006.

(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) Because many of Mojave's transport contracts expired in 2006, the pipeline's emphasis is now to transport natural gas from Daggett to Ehrenberg via El Paso's line 1903. As a result, its gas deliveries to points inside California have declined from previous years.

Recorded 2007 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	Total
Southern California Gas Company								
Core (2)	-4	746	220	8	44	1	3	1,018
Noncore Commercial/Industrial	71	56	77	42	146	3	9	405
EG (3)	150	118	161	89	306	7	19	849
EOR	7	5	7	4	14	0	1	39
Wholesale/Resale/International (4)	8	183	149	33	19	1	13	406
Total	232	1,108	615	176	529	12	45	2,717
Pacific Gas and Electric Company (5)								
Core	0	152	119	545	9	0	0	825
Noncore Industrial/Wholesale/EG (6)	128	388	91	700	42	0	52	1,401
Total	128	540	210	1,244	51	0	52	2,226
Other Northern California								
Core (7)	0	0	0	0	0	0	12	12
Non-Utilities Served Load (8,9)								
Direct Sales/Bypass	465	25	0	0	1,049	14	0	1,552
TOTAL SUPPLIER	825	1,673	825	1,420	1,629	26	109	6,507

Notes:
(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes, unaccounted-for and company use.
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, & SDG&E, as shown.

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	Total
San Diego Gas & Electric Company								
Core	6	50	41	26	15	1	10	149
Noncore Commercial/Industrial	0	96	77	0	0	0	0	173
Total	6	146	118	26	15	1	10	322

(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.
(10) Mojave's emphasis after 2006 is to transport natural gas from Daggett to Ehrenberg via El Paso's line 1903. In 2007, only 26 MMcf/d was delivered to California and 429 MMcf/d was transported to Arizona.

Recorded 2008 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	Total
Southern California Gas Company								
Core (2)	-39	730	228	14	84	1	-21	998
Noncore Commercial/Industrial	73	103	70	19	121	6	8	400
EG (3)	166	233	158	44	275	13	17	907
EOR	7	10	7	2	12	1	1	39
Wholesale/Resale/International (4)	1	192	198	11	21	0	-2	422
Total	209	1,268	661	90	514	21	3	2,766
Pacific Gas and Electric Company (5)								
Core	0	219	136	502	1	0	0	858
Noncore Industrial/Wholesale/EG (6)	135	433	131	623	23	0	43	1,387
Total	135	652	267	1,125	23	0	43	2,245
Other Northern California								
Core (7)	0	0	0	0	0	0	14	14
Non-Utilities Served Load (8,9)								
Direct Sales/Bypass	445	28	0	0	840	19	0	1,332
TOTAL SUPPLIER	789	1,948	928	1,215	1,377	40	60	6,357

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes, unaccounted-for and company use.
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, & SDG&E, as shown.

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	Total
San Diego Gas & Electric Company								
Core	1	73	38	9	17	0	-2	136
Noncore Commercial/Industrial	0	80	118	0	0	0	0	198
Total	1	152	157	9	17	0	-2	334

(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.
(10) Mojave's emphasis after 2006 is to transport natural gas from Daggett to Ehrenberg via El Paso's Line 1903. In 2008, Line 1903 transported 449 MMcf/d to Arizona.

Recorded 2009 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans w2estern	GTN	Kern River	Mojave (10)	Other (1)	Total
Southern California Gas Company								
Core + UAF (2)	98	590	187	20	69	0	19	983
Noncore Commercial/Industrial	35	123	48	31	135	9	5	386
EG (3)	73	259	101	65	284	20	10	811
EOR	3	11	4	3	12	1	0	35
Wholesale/Resale/International (4)	7	191	155	30	17	1	12	412
Total	216	1,174	495	148	518	30	46	2,627
Pacific Gas and Electric Company (5)								
Core	0	219	136	486	0	0	0	842
Noncore Industrial/Wholesale/EG (6)	135	358	175	623	46	0	0	1,337
Total	135	577	311	1,110	46	0	0	2,179
Other Northern California								
Core (7)	0	0	0	0	0	0	13	13
Non-Utilities Served Load (8,9)								
Direct Sales/Bypass	386	27	0	0	909	19	0	1,341
TOTAL SUPPLIER	737	1,778	806	1,258	1,473	49	59	6,160

Notes:
(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes NGV volumes
(3) EG includes UEG, COGEN, and EOR Cogen.
(4) Includes transportation to City of Long Beach, Southwest Gas, City of Vernon, DGN, & SDG&E, as shown.

	California Sources	El Paso	Trans w2estern	GTN	Kern River	Mojave (10)	Other (1)	Total
San Diego Gas & Electric Company								
Core	6	45	36	23	14	0	9	133
Noncore Commercial/Industrial	0.058	105	85	0	0	0	0	191
Total	6	150	122	23	14	0	9	324

(5) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(6) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(7) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(9) California production is preliminary.

STATEWIDE RECORDED HIGHEST SENDOUT

The table below summarizes the highest gas sendout days by the state in the summer and winter periods from the last five years. Daily gas sendout from Southern California Gas Company, Pacific Gas & Electric and from customers not served by these utilities were used to construct the following tables.

Estimated California Highest Winter Sendout (MMcf/d)

Estimated California Highest Winter Gas Sendout (MMcf/d)

Date	Year	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2005	01/13/2005	3,570	3,942	7,512	1,217	8,729
2006	12/19/2006	3,547	4,242	7,789	1,315	9,104
2007	01/15/2007	3,906	4,685	8,591	1,700	10,291
2008	12/17/2008	4,131	5,025	9,156	1,403	10,559
2009	12/08/2009	4,219	4,611	8,830	1,327	10,157

Estimated California Highest Summer Gas Sendout (MMcf/d)

Date	Year	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2005	07/21/2005	2,287	3,089	5,376	1,226	6,602
2006	07/24/2006	2,646	3,801	6,447	1,342	7,789
2007	08/29/2007	2,793	3,773	6,566	1,558	8,123
2008	09/04/2008	2,504	3,227	5,731	1,358	7,089
2009	09/02/2009	2,631	3,311	5,942	1,369	7,311

Notes:
(1) PG&E Piperanger.
(2) SoCalGas Envoy.
(3) Source: DOGGR, Monthly Oil and Gas Production and Injection Report, Lipmann Monthly Pipeline Reports. Nonutility Demand equals Kern/Mojave and California monthly average total flows less PG&E and SoCal Gas peak day supply from Kern/Mojave and California Production. Provided by the CEC.
(4) PG&E and SoCalGas gas sendouts are reported for the day on which the Utility Total sendout is the maximum for the respective season each year. Winter season months are Jan, Feb, Mar, Nov and Dec; while Summer season months are Apr, May, Jun, Jul, Aug and Sep.

2010 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

Pacific Gas and Electric Company (PG&E) provides natural gas procurement, transportation, and storage services to 4.1 million residential customers and over 225,000 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, some customers also utilize the PG&E system to meet their gas needs in southern California.

The northern California section of the report begins with an overview of the gas demand forecast followed by a discussion of the forecast methodology, economic conditions, and other factors affecting demand in various markets, including the regulatory environment. 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.

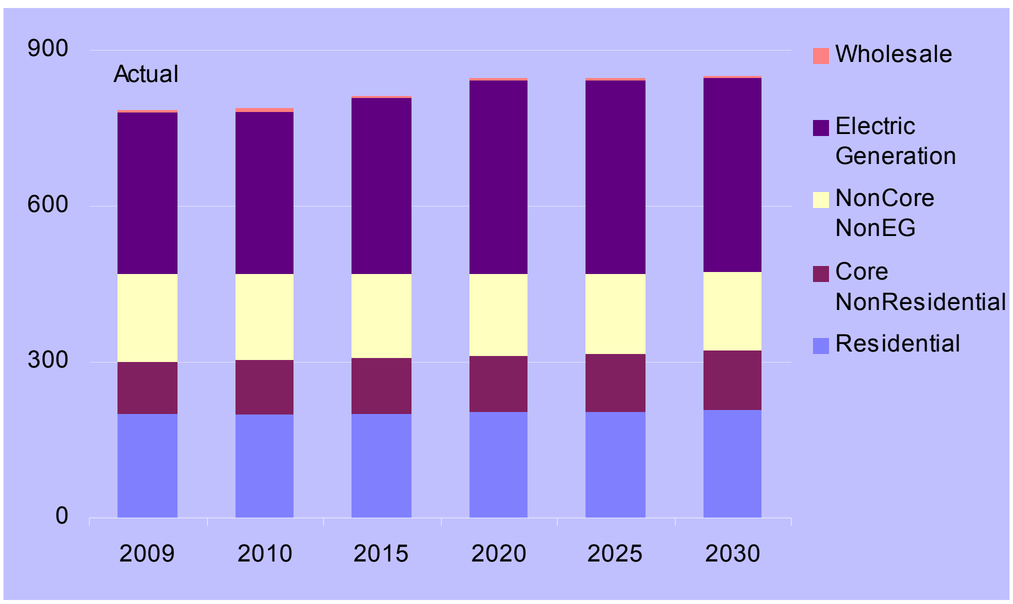
The forecast in this report covers the years 2010 through 2030. However, as a matter of convenience, the tabular data at the end of the section show only the years 2010 through 2014, and the years 2015, 2020, 2025, and 2030.

GAS DEMAND

OVERVIEW

PG&E's *2010 California Gas Report (CGR)* average year demand forecast projects total on-system demand growing at an annual average rate of 0.3 percent between 2010 and 2030. This overall growth rate is a combination of 0.3 percent annual growth in the core market and an annual increase of 0.3 percent in the noncore market. By comparison, the 2008 CGR estimated an annual average growth rate of 0.2 percent per year, based on growth of 0.5 percent per year for the core market and decline of 0.1 percent per year for the noncore market.

Composition of PG&E Requirements (Bcf)
Average Demand Year



The projected rate of growth of the core market has decreased from the *2008 California Gas Report* primarily due to increased emphasis on energy efficiency, slower growth in the customer base, and the incorporation of climate change into this forecast.

The forecast rate of growth of the noncore market has increased significantly due to planned additions of gas-fired power plants in northern California. While the amount of renewable energy generation is assumed to increase to 33% of retail sales by 2020 in this CGR, most of it is expected to be sited in southern California. In this CGR, total gas demand by electric generators and cogenerators in northern California for average hydrological conditions is estimated to increase at a rate of about 0.7 percent per year from 2010 through 2030. This total gas demand includes gas demand by SMUD's gas-fired power plants. It excludes gas delivered by nonutility pipelines to electric generators and cogenerators in PG&E's service area, such as deliveries by the Kern/Mojave pipelines to the La Paloma and Sunrise plants in central California. Increasing quantities of renewable energy generation are expected to increase the need for load following and ancillary services such as regulation. These ancillary services are likely to be provided by gas-fired power plants and increase gas demand. PG&E's 2010 CGR forecast, however, does not capture this increase. Recast, however, does not capture this increase.

FORECAST METHOD

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed from econometric models. Forecasts for other sectors (NGV, wholesale) are developed from market information. Forecasts of gas demand by power plants are based on modeling of the electricity market in the Western Electricity Coordinating Council using the MarketBuilder model. While variation in short-term gas use depends mainly on prevailing weather conditions, longer-term trends in gas demand are driven primarily by changes in customer usage patterns influenced by underlying economic, demographic, and technological changes; such as: growth in population and employment; changes in prevailing prices; growth in electricity demand and in electric generation by renewables; changes in the efficiency profiles of residential and commercial buildings and the appliances within them; and, the response to climate change.

MARKET SENSITIVITY

The average-year gas demand forecast presented here is a reasonable projection for an uncertain future. However, a point forecast 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 an alternative forecast of gas demand under assumed high demand conditions.

For the high-demand condition scenario, PG&E relied on a weather vintage approach. PG&E forecasts total gas demand, assuming the demographic conditions and infrastructure likely to exist in each forecast year, but with the weather conditions set to match conditions that have an approximately 1-in-35 likelihood of occurrence. PG&E used the weather conditions from November 1976 through October 1977, as this time period was extremely dry in both northern California and the Pacific Northwest. In addition, the winter of 1976-1977 was colder than normal.

Temperature Assumptions

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. In previous CGRs, PG&E's average demand forecast assumed that temperatures in the forecast period would be equivalent to the average of observed temperatures during the past twenty years. PG&E is now building into its forecast an assumption of climate change. The climate change scenario is developed from work done at the National Center for Atmospheric Research (Boulder, Colorado) and downscaled to the PG&E service area. Although the near term temperatures of this scenario differ little from long term averages, the years beyond 2015 begin to show the effects of a warming climate. For example, in 2015, total December/January heating degree days are only 2 percent below the 20 year average. By 2025, however, the impact is significant, with the difference at 10 percent.

Of course, actual temperatures in the forecast period will be higher or lower than those assumed in the climate change scenario and gas use will vary accordingly. PG&E's high demand forecast assumes that winter temperatures in the forecast horizon will be the same as those that prevailed during November 1976-October 1977.

Seasonal variations in temperature have relatively little effect on power plant gas demand and, consequently, PG&E's forecasts of power plant gas demand for average and high demand are both based on average temperatures. (Each summer typically contains a few heat waves with temperatures 10º or 15º Fahrenheit above normal, which lead to peak electricity demands and drive up power plant gas demand; however, on a seasonal basis, temperatures seldom deviate more than 2º Fahrenheit from average.)

Hydro Conditions

In contrast to temperature deviations, annual water runoff for hydroelectric plants has varied by 50% above and below the long-term annual average. The impact of dry conditions was demonstrated during the drought and electricity crisis in water year 2001 (October 2000 through September 2001). For the 2010 CGR's high-demand scenario, as noted above, PG&E used the 1977 drought, which was more severe in both northern California and the Pacific Northwest than the 2001 drought.

MARKET SECTORS

Residential

Households in the PG&E service area are forecast to grow 1.0 percent annually from 2010 to 2030. However, gas use per household has been dropping in recent years due to improvements in appliance and building-shell efficiencies and high gas prices. This decline accelerated sharply in 2001 when gas prices spiked, causing temperature-adjusted residential gas demand to plunge by more than 8 percent. After recovering somewhat in 2002 and 2003, temperature-adjusted gas use per household reverted to its long-term trend and, despite a slight uptick in 2009, has fallen on average 2 percent per year since 2004. Due to expected continuing upgrades in appliance and building efficiencies, as well as warming temperatures, PG&E forecasts residential demand to grow on average by 0.1 percent per year from 2010 to 2030, implying an average decrease in gas use per household of almost 0.9 percent per year.

Commercial

The number of commercial customers in the PG&E service area is projected to grow on average by less than 0.2 percent per year from 2010 to 2030. The 2000-2001 noncore to core migration wave has caused this class to be less temperature sensitive than it had previously been and has also tended to stunt overall growth in both customer base and gas use per customer. Gas use per commercial customer is projected to grow slightly over the forecast horizon. Over the next 20 years, sales for this sector are expected to grow 0.4 percent per year.

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 increasing gas prices, noncore to core migration and a manufacturing sector mired in a severe downturn. After a slight recovery in 2002, demand from this sector fell another 6 percent in 2003 and has remained fairly flat since that point in time due to high real natural gas prices and to continuing structural change in California's manufacturing sector. While the Industrial sector has the potential for high year to year variability, over the long term, industrial gas consumption is expected to slowly decline by about 0.4 percent annually over the next 20 years as northern California's economy continues its decades-long transformation from manufacturing and agriculture to services.

Electric Generation

This sector includes cogeneration and power plants. Forecasts for this sector are subject to greater uncertainty due to: retirement of existing power plants with once-through cooling;

the timing, location, and type of new generation, particularly renewable-energy facilities; construction of new electric transmission lines; and the impact of greenhouse gas legislation and regulations on both generation and load. Because of these uncertainties, the forecast is held constant at 2020 levels for 2025 and 2030.

PG&E forecasts gas demand for most cogenerators by assuming a continuation of past usage, with modifications for expected expansions or closures. Operations at most cogeneration plants are not strongly affected by prices in the wholesale electricity market because electricity is generated with some other product, usually steam, for an industrial process.

PG&E forecasts gas demand by power plants and market-sensitive cogenerators using the MarketBuilder model. MarketBuilder is an economic-equilibrium model that has been applied to various markets with geographically distributed supplies and demands, such as the North American natural gas market. PG&E uses MarketBuilder to model the electricity market in the Western Electricity Coordinating Council, which encompasses the electric systems from Denver to the Pacific coast and from northern Mexico to British Columbia and Alberta.

PG&E's forecast for 2010–2030 uses the base-case electricity demand forecast from the CEC's 2009 *Integrated Energy Policy Report.* The forecast assumes that renewable energy generation will provide 20% of the state's retail sales by 2014 and 33% by 2020. PG&E assumed that gas-fired plants that employ once-through cooling will retire by the compliance date in the State Water Resources Control Board's March 2010 draft policy on the use of coastal and estuarine waters for power plant cooling, replaced by new gas-fired plants with comparable capacities.

SMUD EG

The Sacramento Municipal Utility District (SMUD) is the sixth largest community owned municipal utility in the United States, and SMUD provides electric service to over 575,000 customers within the greater Sacramento area. SMUD operates three cogeneration plants, a gas-fired combined-cycle plant and a peaking turbine with a total capacity of approximately 1,000 MW. The peak gas load of these units is approximately 158 MMcf/d, and the average load is about 122 MMcf/d.

SMUD owns and operates a pipeline connecting the Cosumnes combined-cycle plant and the three cogeneration plants to PG&E's backbone system near Winters, California. SMUD owns an equity interest of approximately 3.6 percent in PG&E's Line 300 and approximately 4.2 percent in Line 401 representing about 87 MMcf/d of capacity.

Greenhouse Gas Legislation/AB 32

During the forecast horizon covered by this California Gas Report, there are many uncertainties that may significantly impact the future trajectory of natural gas demand. It is unclear at this time what the ultimate effect on natural gas demand will be from California's landmark California Global Warming Solutions Act of 2006 (Assembly Bill 32, or AB32). On the one hand, more aggressive energy efficiency programs and/or increased targets for renewable electricity supplies could significantly reduce the use of natural gas by residential and commercial customers and power plants. On the other hand, increased penetration of electric and natural gas vehicles could reduce gasoline use and overall GHG emissions, but increase consumption of natural gas.

PG&E will continue to minimize GHG emissions by aggressively pursuing both demand-side reductions and acquisition of preferred resources, which produce little or no carbon emissions.

FUTURE GAS SYSTEM IMPACTS RESULTING FROM INCREASED RENEWABLE ELECTRIC GENERATION

PG&E expects the future increase in renewable electric generation to increase the daily and hourly forecast error associated with natural gas fueled electric generation. The intermittent nature of some renewable generation (e.g., wind power) is likely to cause the electric system to rely more heavily on natural gas fired electric generation to provide load following and other ancillary services—at least in the short term.

PG&E expects that wind power units will provide a significant percentage of the renewable electric generation in the years ahead. However, PG&E also predicts an increased reliance on rapid ramp-up and ramp-down generation sources that are available to follow load, especially when the renewable source is intermittent—that is, the generation is not available in the capacity originally forecast (i.e., the wind stops blowing when it was expected or starts blowing when it was not expected).

The impact of wind generation resources added to the northern California generation resource mix is that the system is likely to experience increased volatility of gas demand for electric generation. The uncertainty in day-ahead gas demands is likely to cause increased gas system inventory fluctuations, especially during the summer months. The daily generation forecast error associated with new wind resource development will be relatively significant by 2011-2014, as a result of the 20 percent Renewable Portfolio Standard (RPS) goal. The June-September period is expected to experience a 14 percent increase over the existing daily forecast error for the same period.

ENERGY EFFICIENCY PROGRAMS

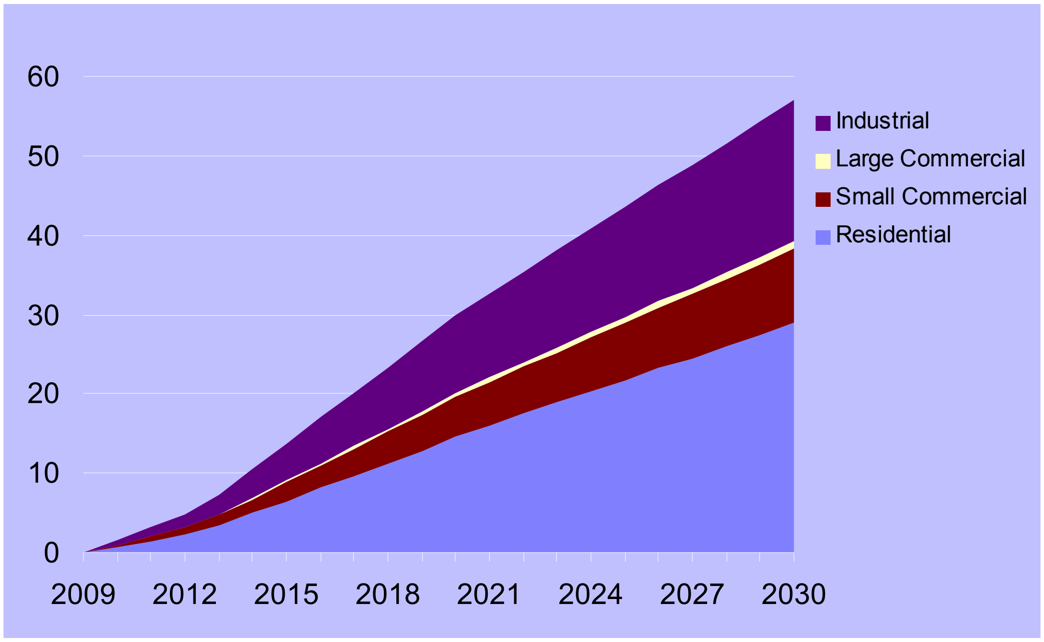
PG&E engages in a number of energy efficiency and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. PG&E administers over 85 distinct energy efficiency programs, including services that help customers evaluate their energy efficiency options and adopt recommended solutions, as well as simple equipment retrofit improvements, such as weatherization.

Conservation and energy efficiency load impacts are shown as positive numbers. The "total net load impact" is the natural gas throughput reduction resulting from the gas and electric Energy Efficiency programs.

The cumulative net energy efficiency load impact forecast for selected years is provided in the table below. The net load impact includes all Energy Efficiency programs that Pacific Gas and Electric Company (PG&E) has forecasted to implement in the years 2008 through 2030. Savings and goals for these programs are based on the program goals authorized by the Commission in D.04-09-060.

Details of PG&E's' 2006-2008 Energy Efficiency program portfolio are contained in PG&E's' Advice Letter 2704-G, 2786-E, which was submitted on February 17, 2006.

Energy Efficiency Cumulative Savings (Bcf)



GAS SUPPLY, CAPACITY AND STORAGE

OVERVIEW

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990's. 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.

GAS SUPPLY

California-Sourced Gas

Northern California-source gas supplies come primarily from gas fields in the Sacramento Valley. In 2009, PG&E's customers obtained on average 130 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, Southern Trails, and Transwestern pipeline systems.

PG&E's customers can purchase gas in the basins and transport it to California via interstate pipelines. Customers can also purchase gas 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 western Canada (British Columbia and Alberta) and transport it to California primarily through the Gas Transmission Northwest Pipeline. 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 Gas Transmission Northwest Pipeline interconnect at Stanfield, Oregon. In addition, the proposed Ruby Pipeline is expected to bring over 1 billion cubic feet per day of Rocky Mountain gas to Malin, Oregon beginning in 2011.

Storage

In addition to storage services offered by PG&E, Wild Goose Storage, Inc. and Lodi Gas Storage, LLC provide storage services from the Wild Goose and Lodi facilities, respectively. There are several proposed storage projects that have the potential to significantly expand the Northern California gas storage capacity in the 2010 to 2012 period.

INTERSTATE PIPELINE CAPACITY

As a result of pipeline expansion and new projects, California utilities and end-users benefit from 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, Gas Transmission Northwest, Southern Trails, 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

PG&E's Baja Path (Line 300) is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Southern Trails, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 1,060 MMcf/day.

Canada

PG&E's Redwood Path (Lines 400/401) is connected to Gas Transmission Northwest at Malin, Oregon. The Redwood Path has a firm capacity of 2,033 MMcf/day.

NEW GAS SUPPLIES AND INFRASTRUCTURE PROJECTS

PG&E anticipates that sufficient new 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 new supplies 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.

In the near term (2010-2015), new sources of gas supply to Northern California will be from the Rocky Mountain supply basin and Biogas. In addition, the growth of gas production in the Midcontinent shale plays (e.g., Barnett in northeast Texas) and the flow of Liquefied Natural Gas (LNG) supplies into the U.S. have had the effect of pushing larger volumes of San Juan and Permian supplies to California, as those southwest supplies are crowded out of markets to the east.

LNG Imports

Liquefied Natural Gas (LNG) imports will provide a new supply source whether directly connected to the PG&E system, or delivered across other systems to PG&E. The presence of LNG supplies in the West and Gulf Coast areas will increase supply and at a minimum make other supplies more available to western markets. Supplies of LNG can be expected to have a favorable impact on gas prices in that they, worst case, can be expected to dampen price increases, and best case, produce lower prices than currently exist.

The first LNG regasification project in the West is Sempra LNG's Costa Azul project, on Mexico's Baja Peninsula. Deliveries from the project began in May 2008, and future deliveries will likely move both directly into southern California as well as on to interstate pipelines that can access northern California. The facility also serves markets in Mexico. The initial capacity of this project is 1.0 Bcf/d and could be expanded in the future. Other projects along both the Mexican coast and the U.S. west coast are in various stages of preliminary development but have not received permits to begin construction. In general, it is likely that the recent success in developing relatively low cost domestic shale gas supplies will have some effect in limiting the number of these proposed LNG regasification facilities that actually come online.

Rocky Mountains

Another new source of gas supplies that could serve the northern California market would be from the Rocky Mountains, which is one of the natural gas supply areas in North America that is growing. El Paso Natural Gas has announced the 1.5 Bcf/d Ruby Pipeline project, which would connect the Rocky Mountain supply basin at Opal with Malin, Oregon. This project would provide a source of supply to offset declines of supply from the Western Canadian Sedimentary Basin in Canada. This project recently received its FERC certificate and is expected to be on-line in 2011.

There are other proposed projects that would bring supplies from the Rockies to California and the Pacific Northwest. Kern River, which completed a 145 MMcf/d expansion in April 2010, proposes another expansion of 266 MMcf/d to come online in 2011. In addition, Gas Transmission Northwest and Williams Company have proposed the Sunstone Pipeline Project, which would parallel Williams' existing Northwest Pipeline to Stanfield, where it would interconnect with the Gas Transmission Northwest Pipeline to flow gas to Malin. While the original timeline had this project online in 2011, the project sponsors are currently reevaluating the project, so its status is unclear.

Biogas

California is the nation's largest dairy producer, and also its largest energy consumer. The development of renewable energy sourced from California's vital agricultural sector holds significant promise for PG&E, its customers, and the environment. Energy from animal waste continues to be one of the most innovative ways PG&E is realizing its renewable energy goals.

PG&E has been accepting commercial-grade, renewable dairy manure biomethane into its transmission pipelines since 2007 and has been leading the industry in investigating other feedstocks, such as food waste, that can be similarly processed to produce biomethane for pipeline injection. Such cutting-edge initiatives will provide renewable energy to our customers, and produce important climate benefits by preventing methane from escaping to the atmosphere.

PG&E has been working with biogas project developers in various parts of its service territory and is looking forward to developing additional renewable biogas projects.

North American Supply Development Frontier Gas Supplies

The most promising development in the North American gas supply picture in the past several years has been the rapid development of various shale gas resources. While the initial developments were concentrated in the U.S. midcontinent, there are emerging plays in western Canada and in the eastern U.S. (Marcellus). These shale gas resources, combined with new approaches to drilling that involve hydraulic fracturing of the shale deposits to release gas, have both lowered the costs of extracting gas supplies and improved the prospects for renewed growth in North American gas supply. By contrast, many of the traditional, mature basins have been declining in output for a number of years.

On the longer term horizon, well beyond 2015, another potential source of new supply is gas produced near the Arctic Circle delivered through an Alaska Pipeline, or via a pipeline through Canada's McKenzie Delta in the Northwest Territory, or both. These pipelines could be capable of transporting several Bcf/d to Canadian and U.S. markets, including those in California. Neither pipeline has received final approval, and completion is likely to be about 10 years away.

Natural Gas Storage

There are also several new natural gas storage projects planned in northern California that could significantly expand total northern California gas storage capacity by 2012 or so. These projects are in addition to the recently completed Lodi Gas Storage expansion, which added 12 Bcf of working gas capacity at the end of 2008

PG&E is co-developing a natural gas storage project with Gill Ranch Storage, LLC. This project, located in the central San Joaquin Valley west of Fresno, would have about 20 Bcf of working gas along with about 650 MMcf/d of firm withdrawal. It would utilize depleted gas reservoirs in the Starkey formation. This storage project is expected to be operational in late 2010.

Wild Goose Storage, which currently has 29 Bcf of working gas capacity, filed for its Phase III expansion in April 2009. This expansion would add 21 Bcf of capacity and is proposed to go online in 2012.

The 8-Bcf Central Valley Storage project, which is being developed by the Nicor Companies, completed its application in 2009. A CPUC decision is expected in 2010, and the expected in-service date is 2012.

The 8-Bcf Sacramento Natural Gas Storage project is also in the development stage. This project would utilize the Florin Gas Field, which is a depleted natural gas reservoir in Sacramento. The project is currently in the permitting phase of development, with a draft Environmental Impact Report out for public comment. The project has experienced some delays through the permitting process, and the potential in-service date is unclear at this time.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

Gas Quality

Gas quality has received much attention over the last several years, largely due to the predicted increase in receipts of LNG. The compositional quality of LNG can be an issue as LNG can differ significantly from traditional North American sources. Equipment that burns natural gas can generally tolerate a range of gas quality but there are practical and safety limits that need to be considered by receiving pipelines and local distribution companies. PG&E has historically used the heating value of the gas, expressed as BTU, as an indicator of gas interchangeability (the ability to substitute gas of one chemical composition for gas of another, different chemical composition). However, based on recent testing, the Wobbe Number is a better indicator of gas quality. The Wobbe Number reflects not only the BTU content but the specific gravity of the gas as well. Specific gravity is an indicator of the relative proportion of heavier versus lighter hydrocarbons. In its testing, PG&E tentatively concluded that it could accept gas supplies with a Wobbe Number as high as 1,385.

FEDERAL REGULATORY MATTERS

PG&E actively participates in FERC ratemaking proceedings for interstate pipelines connected PG&E's system because these cases can impact the cost of gas delivered to our gas customers and the services provided. PG&E also participates in FERC proceedings of general interest to the extent they affect PG&E's operations and policies or natural gas market policies generally.

Ruby Pipeline

Ruby Pipeline LLC, of which El Paso Corporation is the parent, received approval from FERC on April 5, 2010 (Docket CP09-54) to construct the Ruby Pipeline from the Opal Hub in Wyoming to Malin, Oregon. The proposed pipeline, which is also awaiting various other federal, state and local permits, will run about 675 miles through Wyoming, Utah, Nevada and Oregon. It will initially be capable of transporting 1.5 Bcf/d. If the project proceeds as scheduled, construction will begin in the second quarter, 2010 and be in service by March 2011. The project is designed to bring additional supplies to Rocky Mountain gas to the Northwest and to California. PG&E holds 375 MMcf/d of capacity on Ruby, which is the first carbon neutral pipeline in the United States.

El Paso

El Paso and its shippers reached a settlement of many issues related to its 2008 rate case application (Docket RP08-426) for new rates and service changes effective January 1, 2009. The settlement is currently before FERC for approval and will result in a modest increase in rates. The few issues on which the parties could not reach settlement will be the subject of hearings before FERC with a decision expected by the end of 2010.

Kern River

Kern River completed a FERC authorized expansion in April 2010 that increased mainline capacity by approximately 145 MMcf/d to a total of 1.9 Bcf/d (Docket CP08- 429). This was accomplished primarily by adding compression. Kern is also pursuing another expansion, the Apex Expansion, that if approved by FERC (Docket CP10-14), will further expand mainline capacity by approximately 266 MMcf/d in 2011.

Transwestern

Transwestern completed its Phoenix Expansion Project in February 2009 which added 500 MMcf/d of new capacity to serve the Phoenix area (Docket CP06-459). The Phoenix lateral is a 42 inch pipe that moves gas from the Transwestern mainline south 260 miles to Phoenix. TW completed an associated expansion of one of its key supply lines, the San Juan Lateral, in 2008.

FERC Order 720 and 720 A

In the interest of market transparency and under authority granted by the Energy Policy Act of 2005, beginning July 1, 2010, FERC has ordered large non-interstate pipelines like PG&E to begin posting scheduled volume information for all receipt and delivery points, including at the individual customer level, equal to or greater than 15,000 MMBtu/d. The information must be posted once a day by 8 PM the day before flow day. PG&E anticipates posting scheduled volumes associated with the Timely Cycle, the market's primary nomination cycle, nominations for which are due at 9:30 AM the day before flow.

FERC Notice of Inquiry regarding Integration of Variable Energy Resources (Docket RM10-11)

FERC sought comments in April 2010 as to how to more effectively integrate renewable generation resources into the electric grid. While providing numerous comments from an electric perspective, PG&E also emphasized that electric system planners need to work closely with gas system planners to confirm that gas systems are sized appropriately and offer the necessary services to allow gas fired electric generation projects to respond to sudden changes in renewable project output.

Environmental Protection Agency Greenhouse Gas Reporting (Docket EPA HQ OAR 2009 0923)

On March 23, 2010, EPA released a proposed rule that will require natural gas distribution companies to report fugitive greenhouse gas emissions beginning in 2011. Reporting would be at the facility level for facilities that emit GHGs greater than or equal to 25,000 metric tons or CO2 equivalent per year. The proposed rule complements the reporting requirements rule issued by EPA in 2009 for other emission sources (Docket EPA-HQ-2008-0508). PG&E is already reporting certain GHG information to the California Air Resources Board. A final EPA rule regarding natural gas distribution companies is expected by the end of 2010.

ABNORMAL PEAK DAY DEMAND AND SUPPLY

APD DEMAND FORECAST

The Abnormal Peak Day (APD) forecast is a projection of demand under extremely adverse conditions. The design criterion for PG&E, as required under CPUC regulation, is a 1-in-90 year cold temperature event. This corresponds to a 27 degree Fahrenheit system-weighted mean temperature across the PG&E gas system.. PG&E core demand forecast corresponding to 27 degree F temperature is estimated to be approximately 3.1 Bcf/day. PG&E load forecast shown here excludes all noncore demand and, in particular, excludes all electric generation (EG) demand. PG&E estimates that total noncore demand during an APD event would be approximately 1.5 Bcf/day, with EG demand comprising between one-half to two-thirds of the total noncore demand.

The APD core forecast is developed using the observed relationship between historical daily weather and core usage data. This relationship is then used to forecast the core load under APD conditions.

APD SUPPLY REQUIREMENT FORECAST

For APD planning purposes, supplies will flow under Core Procurement's firm capacity, any as-available capacity, and capacity made available pursuant to supply diversion arrangements. Supplies could also be purchased from noncore suppliers. Flowing supplies may come from Canada, the U.S. Southwest, the Rocky Mountain Region, SoCalGas, and California. Also, a significant part of the APD demand will be met by storage withdrawals from PG&E's and independent storage providers' underground storage facilities located within Northern and Central California.

PG&E's Core Gas Supply Department is responsible for procuring adequate flowing supplies to approximately 90 percent of PG&E's core gas usage. Core aggregators provide procurement services for the balance of PG&E's core customers and have the same obligation as PG&E Core Gas Supply 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.

When Core supplies are insufficient to meet core demand, PG&E can, divert gas from the noncore, including gas-fired EG, to meet Core demand. High Diversion and Emergency

Flow Order noncompliance charges are expected to be sufficient to cause the noncore market to either reduce or cease its 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, curtail operations. The implication for the future is that under supply shortfall conditions such as an APD, a significant portion of 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 EG, on an APD would be approximately 1.5 Bcf/day. With the additions of the Wild Goose, Lodi, and Gill Ranch storage facilities, more noncore demand will be satisfied in the event of an APD. The availability of supply for any given high demand event, such as an APD, is dependent on a wide range of factors, including the availability of interstate flowing supplies and on system storage inventories.

Forecast of Core Gas Demand and Supply on an Abnormal Peak Day (APD)
MMcf/Day

	2010-11	2011-12	2012-13
APD Core Demand (1)	3,092	3,100	3,108
Firm Storage Withdrawal (2)	1,104	1,104	1,104
Required Flowing Supply (3)	1,988	1,996	2,004
Total APD Resources	3,092	3,100	3,108

Notes:

(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD core demand forecast is calculated for 27 degrees Fahrenheit system composite temperature, corresponding to 1-in-90 year cold temperature event. PG&E now uses a system composite temperature based on six weather sites. This results in a 27 degree APD temperature that is roughly equivalent to the 29 degree APD temperature used in earlier reports.

(2) Core Firm Storage Withdrawal capacity includes 49 MMcf/d contracted with an on-system independent storage provider.

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

The tables below provide peak day demand projections on PG&E's system for both winter (December month) and summer (August month) periods under PG&E's high-demand scenario.

Winter Peak Day Demand
(MMcf/Day)

Year	Core (1)	Non-Core Non-EG (2)	Electric Generation, including SMUD(3)	Total Demand
2010	2,846	424	999	4,269
2011	2,853	418	952	4,223
2012	2,861	417	1,046	4,324
2013	2,868	417	1,057	4,342
2014	2,875	416	1,129	4,420
2015	2,882	413	1,145	4,440

Notes:
(1) Core demand calculated for 30-degrees-Fahrenheit system-composite temperature, corresponding to 1-in-35-year cold-temperature event
(2) Average daily winter (December) demand
(3) Average daily winter (December) demand under 1-in-35 dry hydro conditions

Summer Peak Demand
(MMcf/Day)

Year	Core(4)	Non-Core Non-EG(4)	Electric Generation, including SMUD(5)	Total Demand
2010	416	570	1,326	2,312
2011	413	561	1,310	2,284
2012	418	559	1,339	2,316
2013	422	559	1,411	2,392
2014	425	560	1,490	2,475
2015	425	556	1,463	2,444

Notes:
(4) Average daily summer (August) demand
(5) Average daily summer (August) demand under 1-in-35 dry hydro conditions

2010 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA
TABULAR DATA

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 2005-2009
MMCF/DAY

LINE		2005	2006	2007	2008	2009	LINE
	GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS						
1	Core Purchases	0	0	0	0	0	1
2	Customer Gas Transport & Exchange	117	136	128	135	135	2
3	Total California Source Gas	117	136	128	135	135	3
	OUT-OF-STATE GAS						
	Core Net Purchases						
6	Rocky Mountain Gas	11	5	9	1	0	6
7	U.S. Southwest Gas	245	262	271	356	352	7
8	Canadian Gas	535	571	545	502	486	8
	Customer Gas Transport						
10	Rocky Mountain Gas	151	81	95	65	94	10
11	U.S. Southwest Gas	361	357	479	564	535	11
12	Canadian Gas	592	643	700	623	623	12
13	Total Out-of-State Gas	1,895	1,919	2,099	2,111	2,091	13
14	STORAGE WITHDRAWAL (2)	250	242	287	290	256	14
15	Total Gas Supply Taken	2,262	2,297	2,514	2,535	2,483	15
	GAS SENDOUT						
	CORE						
19	Residential	512	546	561	541	547	19
20	Commercial	233	233	233	237	217	20
21	NGV	4	4	4	5	5	21
22	Total Throughput-Core	749	783	798	783	769	22
	NONCORE						
24	Industrial	431	442	457	477	461	24
25	Electric Generation (1)	753	778	858	861	853	25
26	NGV	1	1	1	1	1	26
27	Total Throughput-Noncore	1185	1221	1316	1339	1315	27
28	WHOLESALE	10	10	10	10	10	28
29	Total Throughput	1944	2014	2125	2132	2094	29
30	CALIFORNIA EXCHANGE GAS	2	2	2	2	2	30
31	STORAGE INJECTION (2)	268	222	301	329	312	31
32	SHRINKAGE Company Use / Unaccounted for	48	60	86	72	76	32
33	Total Gas Send Out (3)	2,262	2,298	2,514	2,535	2,483	33
	CURTAILMENT / ALTERNATIVE FUEL BURNS (4)						
36	Residential, Commercial, Industrial	0	0	0	0	0	36
37	Utility Electric Generation	0	0	0	0	0	37
38	TOTAL CURTAILMENT	0	0	0	0	0	38

NOTES:

(1) Electric generation includes SMUD, cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by other pipelines.

(2) Includes both PG&E and third party storage

(3) Total gas send-out excludes off-system transportation; off-system deliveries are subtracted from supply total.

(4) 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 2010-2014
MMCF/DAY

AVERAGE DEMAND YEAR

LINE		2010	2011	2012	2013	2014	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path[(1)]	1060	1060	1060	1060	1060	2
3	Redwood Path[(2)]	2033	2033	2033	2033	2033	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.	39	39	41	41	41	3.a
4	**Supplemental[(3)]**	0	0	0	0	0	4
5	**Total Supplies Available**	3262	3262	3264	3264	3264	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	2233	2152	2156	2201	2226	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2363	2282	2286	2331	2356	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2363	2282	2286	2331	2356	11
REQUIREMENTS FORECAST BY END USE							
	CORE						
12	Residential[(4)]	560	559	562	563	561	12
13	Commercial	225	228	232	236	236	13
14	NGV	5	5	6	6	6	14
15	**Total Core**	790	792	800	805	804	15
	NONCORE						
16	Industrial	449	443	440	440	440	16
17	SMUD Electric Generation[(5)]	118	122	122	122	122	17
18	PG&E Electric Generation[(6)]	724	680	681	720	745	18
19	NGV	1	1	1	2	2	19
20	Wholesale	10	10	10	10	10	20
21	California Exchange Gas	1	1	1	1	1	21
22	**Total Noncore**	1303	1257	1256	1294	1320	22
23	**Off-System Deliveries[(7)]**	215	181	179	179	179	23
	Shrinkage						
24	Company use and Unaccounted for	55	51	52	53	53	24
25	**TOTAL END USE**	2363	2282	2286	2331	2356	25
26	System Curtailment	0	0	0	0	0	26

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to southern California.

ANNUAL GAS SUPPLY
FORECAST YEARS 2015-2030
MMCF/DAY

AVERAGE DEMAND YEAR

LINE		2015	2020	2025	2030	LINE
FIRM CAPACITY AVAILABLE						
1	**California Source Gas**	130	130	130	130	1
	Out of State Gas					
2	Baja ath(1) P	1060	1060	1060	1060	2
3	Redwood Path(2)	2033	2033	2033	2033	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.	41	41	41	41	3.a
4	**Supplemental(3)**	0	0	0	0	4
5	**Total Supplies Available**	3264	3264	3264	3264	5
GAS SUPPLY TAKEN						
6	**California Source Gas**	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	2207	2317	2291	2310	7
8	**Supplemental**	0	0	0	0	8
9	**Total Supply Taken**	2337	2447	2421	2440	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	10
11	**Total Throughput**	2337	2447	2421	2440	11
REQUIREMENTS FORECAST BY END USE						
	Core					
12	Residential(4)	559	567	572	579	12
13	Commercial	236	236	235	241	13
14	NGV	6	7	15	20	14
15	**Total Core**	801	810	822	840	15
	Noncore					
16	Industrial	437	426	415	415	16
17	SMUD Electric Generation(5)	122	122	122	122	17
18	PG&E Electric Generation(6)	732	841	841	841	18
19	NGV	2	2	1	1	19
20	Wholesale	10	10	10	10	20
21	California Exchange Gas	1	1	1	1	21
22	**Total Noncore**	1304	1403	1391	1391	22
23	**Off-System Deliveries(7)**	179	179	154	154	23
	Shrinkage					
24	Company use and Unaccounted for	53	55	55	55	24
25	**TOTAL END USE**	2337	2447	2421	2440	25
26	System Curtailment	0	0	0	0	26

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest Pipeline.
(3) May include interruptible supplies transported over existing facilities, displacement agreements, or modifications that expand existing facilities.
(4) Includes Southwest Gas direct service to its northern California service area.
(5) Forecast by SMUD.
(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(7) Deliveries to southern California.

ANNUAL GAS SUPPLY
FORECAST YEARS 2010-2014
MMCF/DAY

HIGH DEMAND YEAR

LINE		2010	2011	2012	2013	2014	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**	130	130	130	130	130	1
	Out of State Gas						
2	Baja Path(1)	1060	1060	1060	1060	1060	2
3	Redwood Path(2)	2033	2033	2033	2033	2033	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.	39	39	41	41	41	3.a
4	**Supplemental(3)**	0	0	0	0	0	4
5	**Total Supplies Available**	3262	3262	3264	3264	3264	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	130	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	2484	2479	2499	2576	2631	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2614	2609	2629	2706	2761	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2614	2609	2629	2706	2761	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential(4)	615	617	620	623	625	12
13	Commercial	240	244	249	253	254	13
14	NGV	5	5	6	6	6	14
15	**Total Core**	860	866	874	882	886	15
	Noncore						
16	Industrial	450	444	441	441	441	16
17	SMUD Electric Generation(5)	118	122	122	122	122	17
18	PG&E Electric Generation(6)	896	923	939	1,007	1,056	18
19	NGV	1	1	1	2	2	19
20	Wholesale	12	12	12	12	12	20
21	California Exchange Gas	1	1	1	1	1	21
22	**Total Noncore**	1478	1503	1516	1584	1634	22
23	**Off-System Deliveries(7)**	215	181	179	179	179	23
	Shrinkage						
24	Company use and Unaccounted for	60	59	59	61	62	24
25	**TOTAL END USE**	2614	2609	2629	2706	2761	25
26	System Curtailment	0	0	0	0	0	26

NOTES:

(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.

(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest Pipeline.

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

(4) Includes Southwest Gas direct service to its northern California service area.

(5) Forecast by SMUD.

(6) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.

(7) Deliveries to southern California.

ANNUAL GAS SUPPLY
FORECAST YEARS 2015-2030
MMCF/DAY

HIGH DEMAND YEAR

LINE		2015	2020	2025	2030	LINE
FIRM CAPACITY AVAILABLE						
1	**California Source Gas**	130	130	130	130	1
	Out of State Gas					
2	Baja Path(1)	1060	1060	1060	1060	2
3	Redwood Path(2)	2033	2033	2033	2033	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.	41	41	41	41	3.a
4	**Supplemental(3)**	0	0	0	0	4
5	**Total Supplies Available**	3264	3264	3264	3264	5
GAS SUPPLY TAKEN						
6	**California Source Gas**	130	130	130	130	6
7	**Out of State Gas (via existing facilities)**	2630	2719	2709	2735	7
8	**Supplemental**	0	0	0	0	8
9	**Total Supply Taken**	2760	2849	2839	2865	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	10
11	**Total Throughput**	2760	2849	2839	2865	11
REQUIREMENTS FORECAST BY END USE						
	Core					
12	Residential(4)	625	641	658	671	12
13	Commercial	254	256	259	267	13
14	NGV	6	7	15	20	14
15	**Total Core**	885	905	931	958	15
	Noncore					
16	Industrial	438	427	416	415	16
17	SMUD Electric Generation(5)	122	122	122	122	17
18	PG&E Electric Generation(6)	1,059	1,137	1137	1137	18
19	NGV	1	1	1	1	19
20	Wholesale	12	12	12	12	20
21	California Exchange Gas	1	1	1	1	21
22	**Total Noncore**	1633	1700	1689	1688	22
23	**Off-System Deliveries(7)**	179	179	154	154	23
	Shrinkage					
24	Company use and Unaccounted for	62	64	64	65	24
25	**TOTAL END USE**	2760	2849	2839	2865	25
26	System Curtailment	0	0	0	0	26

NOTES:
(1) PG&E's Baja Path receives gas from U. S. Southwest and Rocky Mountain producing regions via Kern River, Transwestern, El Paso and Southern Trails pipelines.
(2) PG&E's Redwood Path receives gas from Canadian and Rocky Mountain producing regions via Gas Transmission Northwest Pipeline.
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(7) Deliveries to southern California.

2010 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

Southern California Gas Company (SoCalGas) is the principal distributor of natural gas in Southern California, providing retail and wholesale customers with transportation, exchange and storage services and also procurement services to most retail core customers. SoCalGas is a gas-only utility and, in addition to serving the residential, commercial, and industrial markets, provides gas for enhanced oil recovery (EOR) and electric generation (EG) customers in Southern California. San Diego Gas & Electric Company (SDG&E), Southwest Gas Corporation, the City of Long Beach Municipal Oil and Gas Department, and the City of Vernon are SoCalGas' four wholesale utility customers. SoCalGas also provides gas transportation service across its system to a border crossing point at the California-Mexico border at Mexicali to ECOGAS Mexico, S. de R.L. de C.V which is a wholesale international customer located in Mexico.

This report covers a 21-year natural gas demand and forecast period, from 2010 through 2030; only the consecutive years 2010 through 2014 and the point years 2015, 2020, 2025, and 2030 are shown in the tabular data in the next sections. These single point forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

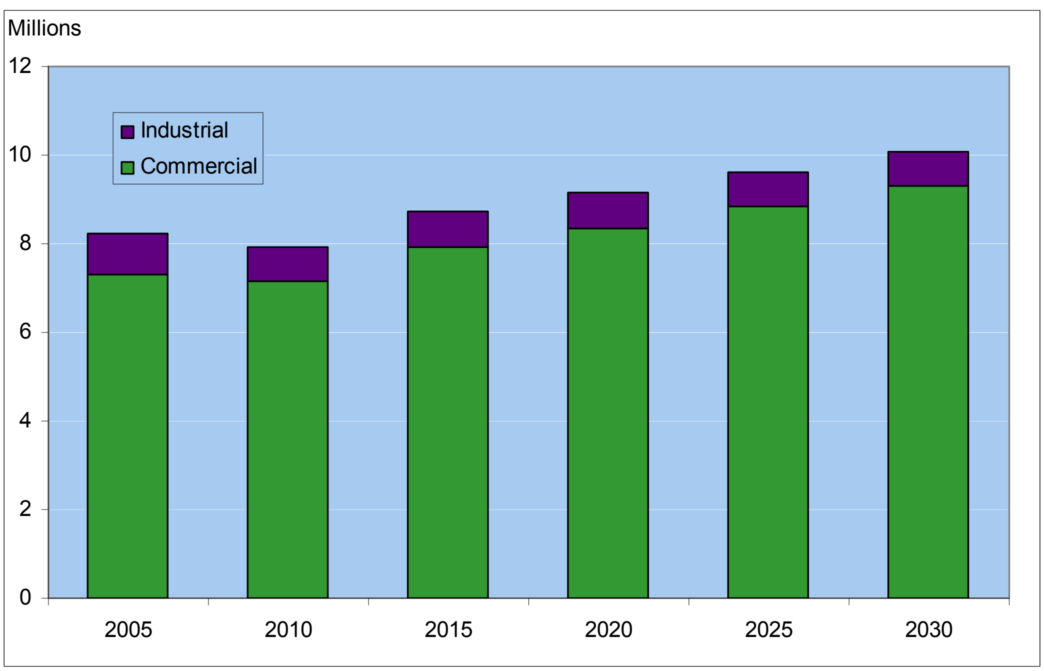
The Southern California section of the *2010 California Gas Report* (CGR) begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The natural gas price forecast methodology used to develop the gas demand forecast is discussed followed by a review of the peak day demand forecast. Summary tables and figures underlying the forecast are also provided.

THE SOUTHERN CALIFORNIA ENVIRONMENT

ECONOMICS AND DEMOGRAPHICS

The gas demand projections are in large part determined by the long-term economic outlook for the SoCalGas service territory. As of mid-2010, Southern California's economy seems to be bottoming out of its most severe slump since the 1930s. After peaking in 2007, area employment shrank by 1.6% in 2008, plummeted 4.0% in 2009, and is expected to drop a further 0.6% in 2010 before rising 2.1% in 2011. Overall area jobs are expected to average 1.6% annual growth from 2009 through 2014. Local industrial employment (manufacturing and mining) will grow a more modest 1.1% per year from 2009 to 2014. Commercial employment should grow about 1.7% per year during the same period. Government will be the weakest employment area, averaging only 0.3% growth to 2014 as politicians struggle to deal with huge government deficits. Services will enjoy the strongest employment increases during the same period, growing an average of 2.4% per year—led by 3.7% annual growth in professional and business services.

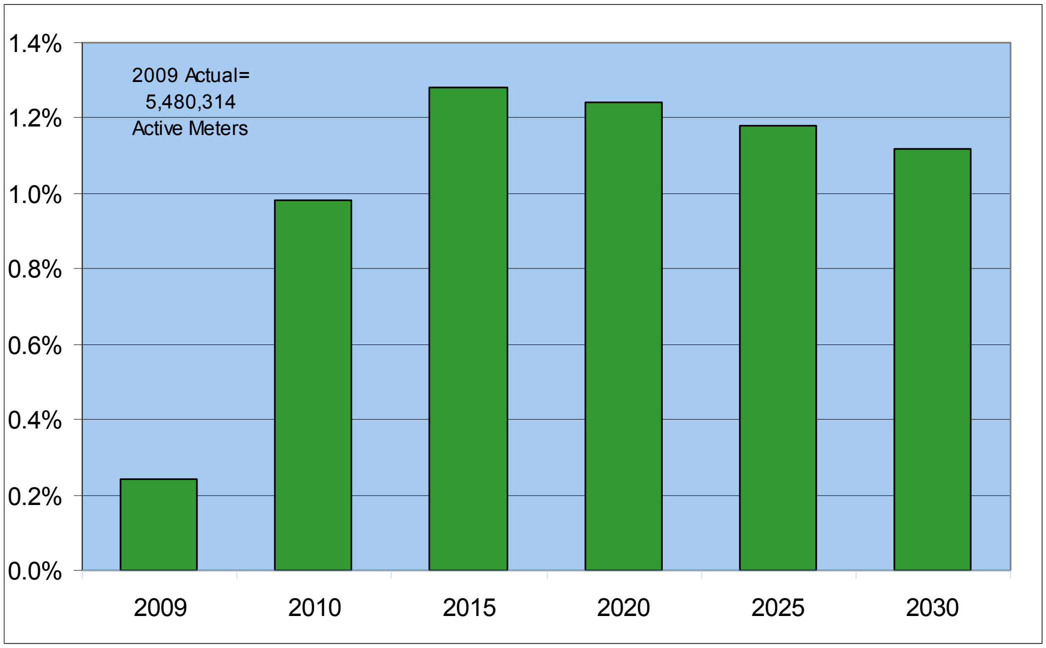
Southern California Employment (2005-2030)



In the longer term, service-area employment is expected to increase modestly as the area population's average age gradually increases--part of a national demographic trend of aging and retiring "baby boomers". From 2009 through 2030, total area job growth should average 1.1% per year. Area industrial jobs are forecasted to shrink an average of 0.2% per year through

2030; we expect the industrial share of total employment to fall from 9.3% in 2009 to 7.5% by 2030. Commercial jobs are expected to grow an average of 1.2% annually from 2009 through 2030.

SoCalGas Annual Meter Growth



Since 2007 SoCalGas' service area has been mired in a serious housing slump. Home building was depressed by a glut of existing-home short sales and foreclosures, tight credit conditions, and potential buyers' uncertainty in the job market. As a result, new gas meter hookups dropped drastically from nearly 85,000 in 2006 to under 32,000 in 2009. On the positive side: 1) with so little recent new construction, there is now little remaining unsold new-home inventory in southern California; 2) area home prices have dropped so steeply that they are now much more affordable relative to typical households' incomes; and 3) the area's population will still grow about 0.9% per year to 2030, boosted partly by continuing foreign immigration. So in coming years, as foreclosures clear and employment recovers, new housing and meter growth should rebound smartly. SoCalGas expects its active meters to increase an average of 1.2% annually from 2009 through 2030.

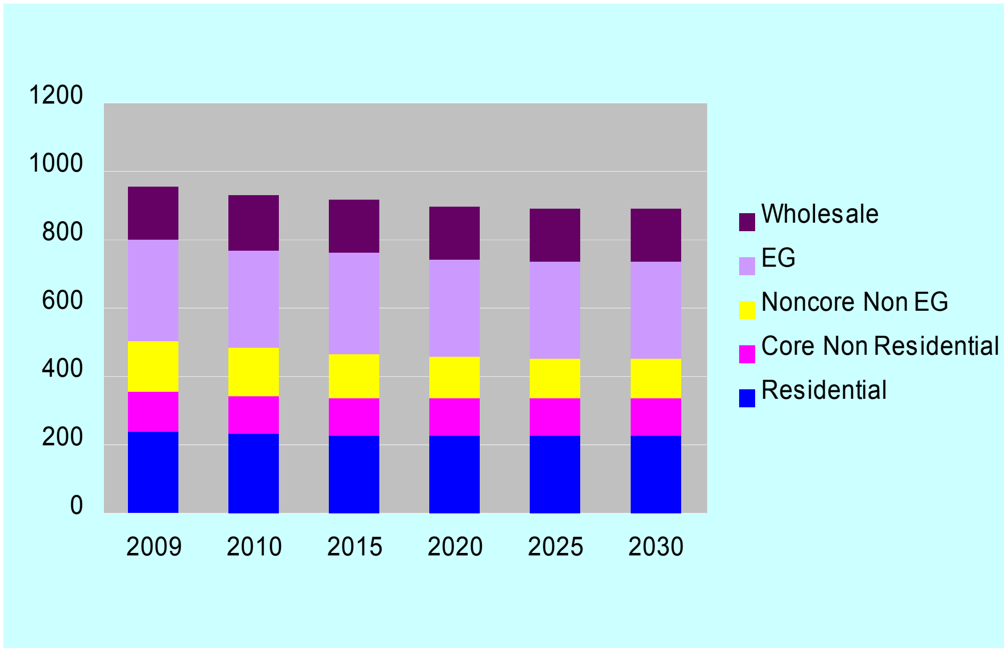
GAS DEMAND (REQUIREMENTS)

OVERVIEW

SoCalGas projects gas demand for all its market sectors to contract at an annual average rate of approximately 0.212% from 2010 to 2030. Demand is expected be virtually flat for the next 21 years due to modest economic growth, CPUC-mandated DSM goals and renewable electricity goals, decline in commercial and industrial demand, and continued increased use of non-utility pipeline systems by EOR customers and savings linked to advanced metering modules. By comparison, the *2008 California Gas Report* projected an annual growth rate of 0.02% from 2008 to 2030. The difference between the two forecasts is caused by the slump in the housing market for the next few years, a reduced employment forecast, a higher gas price projection, and aggressive energy efficiency savings goals.

The following chart shows the composition of SoCalGas' throughput for the recorded year 2009 (with weather-sensitive market segments adjusted to average year heating degree day assumptions) and for the 2010 to 2030 forecast period.

Composition of SoCalGas Requirements (Bcf)
Average Temperature and Normal Hydro Year (2009 – 2030)



Notes:

(1) Core non-residential includes core commercial, core industrial, gas air-conditioning, gas engine, natural gas vehicles.

(2) Non-core non-EG includes non-core commercial, non-core industrial, industrial refinery, and EOR-steaming

(3) Retail electric generation includes industrial and commercial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.

(4) Wholesale includes sales to the City of Long Beach, City of Vernon, SDG&E, Southwest Gas and Ecogas.

From 2010 to 2030, residential demand is expected to diminish due to the seesawing effect of declining use per meter offsetting new meter growth. The core, non-residential markets are expected to grow from 109 Bcf in 2010 to 110 Bcf by 2030. The change reflects an annual growth rate of 0.047% over the forecast period. The noncore, non-EG markets are expected to decline from 142 Bcf in 2010 to 114 Bcf by 2030. The annual rate of decline is approximately 1% due to very aggressive energy efficiency goals and associated programs. Utility gas demand for EOR steaming operations, which have declined since the FERC-regulated Kern/Mojave interstate pipeline began offering direct service to California customers in 1992, are expected to continue to decline as more utility service contracts expire. The non-core non-cogeneration load as a whole is expected to decline to 114 Bcf by 2030 from 150 Bcf in 2009. Lastly, gas demand in the electric generation (EG) market is also expected to continue dropping sharply due to the expected departure of several of SoCalGas' long-term EOR cogeneration customers. Non-cogeneration EG is expected to remain relatively flat due to the addition of more efficient power plants, the addition of new transmission lines, and renewable electricity goals. Total electric generation load, including cogeneration and non-cogeneration EG for a normal hydro year is expected to drop from 295 Bcf in 2009 to 283 Bcf in 2030, a cumulative decrease of 4.1%.

MARKET SENSITIVITY

Temperature

Core demand forecasts are prepared for two design temperature conditions – average and cold – 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 and core commercial and industrial markets. The largest demand variations due to temperature occur in the month of December. Heating Degree Day (HDD) differences between the two conditions are developed from a six-zone temperature monitoring procedure within SoCalGas' service territory. One HDD is when the average temperature for the day drops 1 degree below 65° Fahrenheit. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis, with a recurrence period of 35 years.

Hydro Condition

The non-cogen EG forecasts are prepared for two hydro conditions – average and dry. The dry hydro case refers to gas demand under a 1-in-10 hydro year.

MARKET SECTORS

Residential

Residential demand adjusted for temperature totaled 241 Bcf in 2009. The residential usage declined 2 Bcf from 2008 to 2009. Over the past three-year period, the residential, weather adjusted load has been declining approximately 0.82% per year on average.

The total residential customer count for SoCalGas consists of five residential segment types. These are single family, small and large multi-family customers, as well as master meter and sub-metered customers. The active meters for all residential customer classes were 5.28 million at the end of 2009. This amount reflects a 25,009 meter increase between 2008 and 2009 at year end. The overall observed 2008-2009 residential meter growth was 0.476%. Just two years before, the observed meter growth had been 53,326 new meters between 2006 and 2007, which amounts to an annual growth rate of 1.03%. The decrease in active meter growth reflects the overall state of the economy in Southern California.

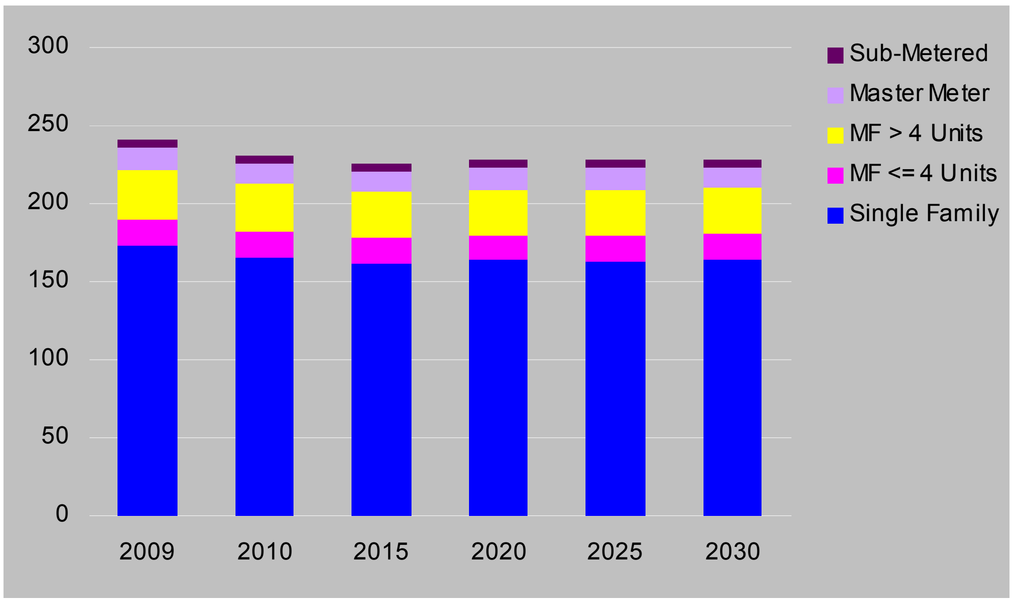
The *2008 California Gas Report* showed that, the single family and multi-family average annual use per meter totaled 515 therms and 312 therms, respectively. The *2010 California Gas Report*, shows the single family and multi family average annual use per meter have decreased to 493 and 303, respectively. The decline of approximately 3 to 4% per year in use per meter for all classes of residential customers is anticipated to continue due to the expected energy savings from tightened building and appliance standards and utility energy efficiency programs. By 2030, the single and multi-family average use per meter is forecasted to decline to 400 and 200 therms, respectively. This change reflects an approximate 23% overall decline in single family households' temperature-adjusted use per customer over 2010 to 2030, or alternatively, an average annual decline in use per customer of 1.09%. For multi–family households, the overall decline in use per customer is expected to be 34% over 2010 to 2030, or an average compound annual decline in use per customer of 2%. The expected decline in use per customer can further be explained by the deployment of the Advanced Metering system in the Southern California Area.

Mass deployment of SoCalGas' advanced metering modules (AMI) will begin in year 2011. SoCalGas plans to install approximately 6.0 million gas modules and replace almost 1.1 million AMI incremental gas meters by year end 2015. The deployment of SoCalGas AMI will not only provide substantial operating benefits but will also generate long term conservation benefits.

To summarize the forecast, the projected residential natural gas demand will be influenced primarily by modest residential meter growth, the forecasted declining use per customer, and the gradual attrition of sub-meter and master meter customers. The weather-adjusted residential demand forecast, on average, is expected to decline by 0.05% per year. In 2009, temperature adjusted residential demand was 241 Bcf. In 2010, the load is expected to be

231 Bcf. By the year 2030, residential demand is expected to decline to 229 Bcf. The 3 Bcf decrease over the period amounts to an annual average reduction in residential load of 0.12 Bcf per year. The graph below illustrates the projection

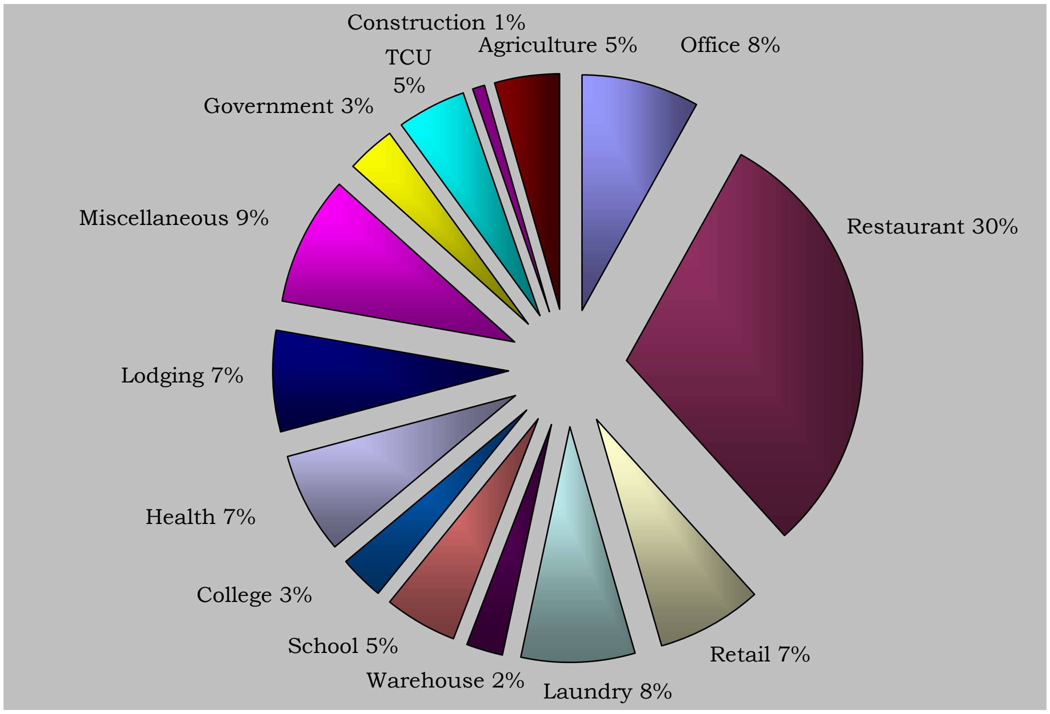
Annual Residential Demand Forecast (Bcf) (2009 – 2030)



Commercial

The commercial market consists of 14 business types identified by the customer's North American Industry Classification System (NAICS) codes. The restaurant business dominates this market with 30% of the usage in 2009.

Commercial Gas Demand by Business Types
Composition of Industry (2009)

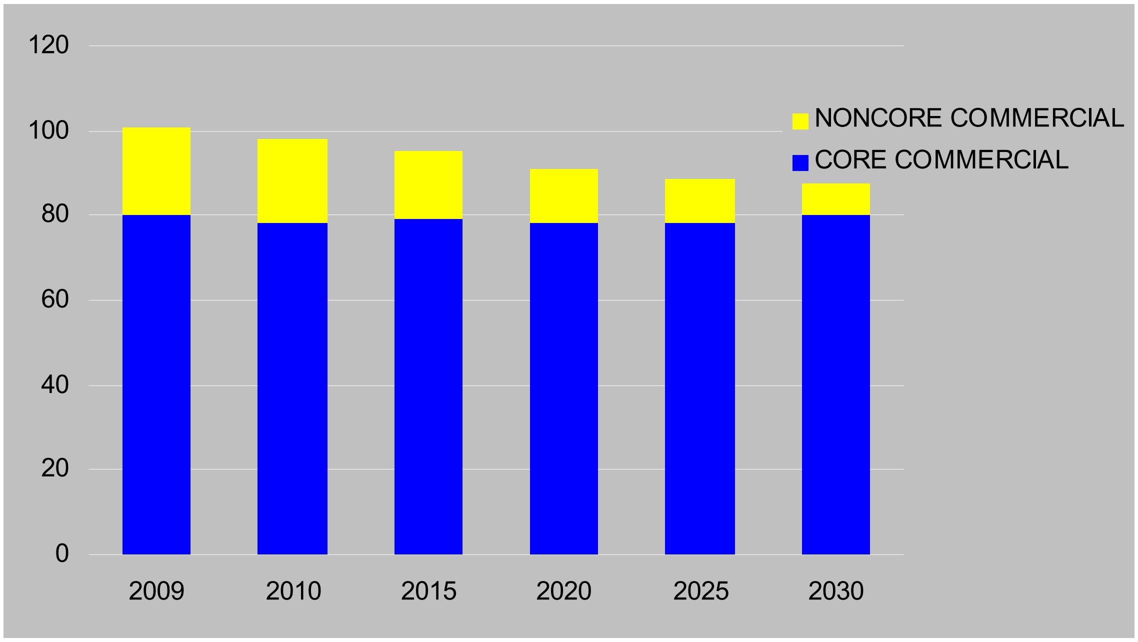


The core commercial market demand is expected to remain flat over the forecast period. On a temperature-adjusted basis, the core commercial market demand in 2009 totaled 80 Bcf. By the year 2030, the load is anticipated to be approximately 80 Bcf. The average annual growth rate from 2010 to 2030 is a mild .10%. The slow growth in gas usage is mainly the result of the impact of CPUC-authorized energy efficiency programs in this market.

Noncore commercial demand in 2009 was 21 Bcf. The non-core commercial market is expected to show substantial attrition by 2030, when the load is foreseen to total 10 Bcf. Aggressive CPUC-authorized energy efficiency programs targeted at this market is expected to depress the noncore load. Cost of compliance with environmental regulation and the state of the economy are two additional factors that explain the decreased noncore commercial load.

Annual Commercial Demand Forecast (Bcf)

Years 2009-2030

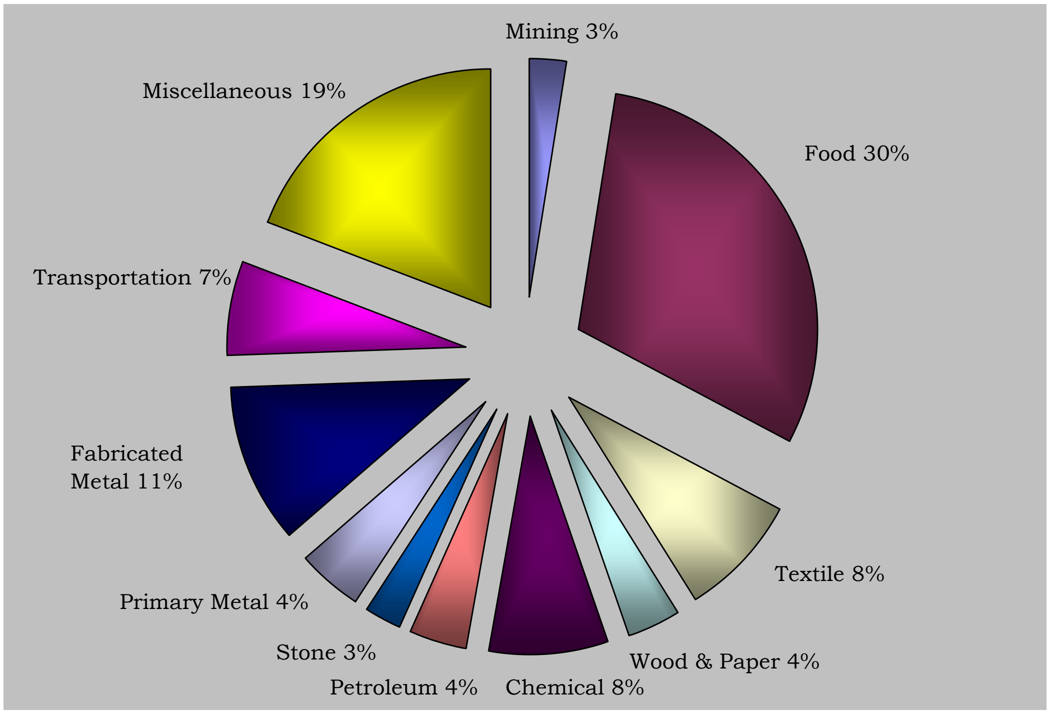


Industrial

Industrial gas demand in 2009 by business types served by California is shown below.

Non-Refinery Industrial Gas Demand by Business Types

Composition of Industrial Activity (2009)



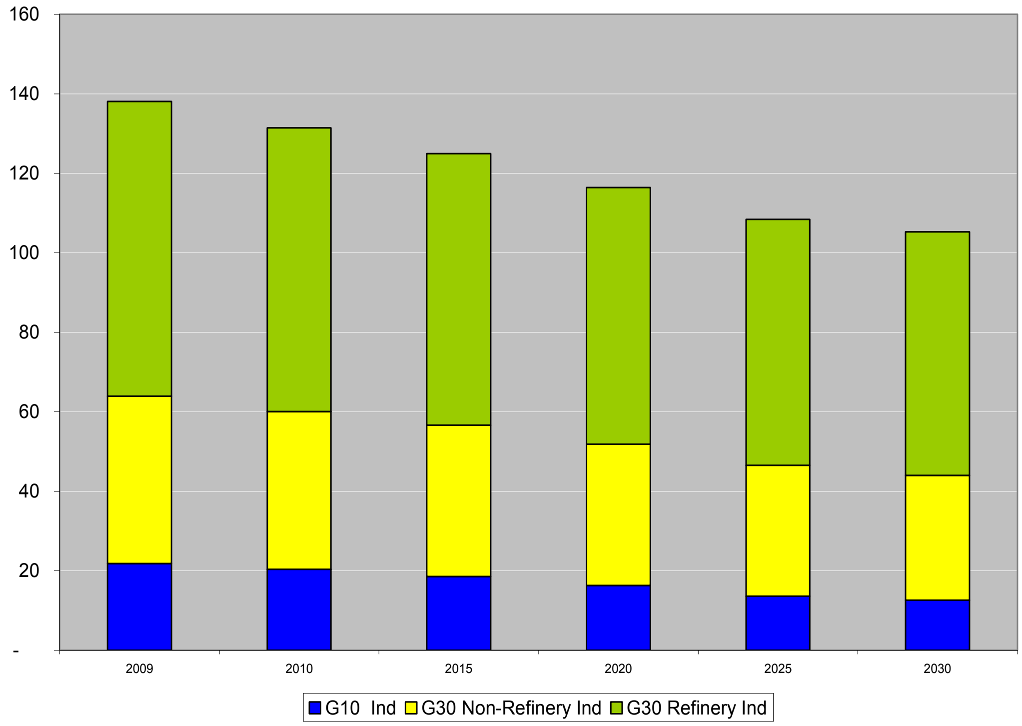
In 2009, temperature-adjusted core industrial demand was 218 Bcf which is 1.3 Bcf lower than 2008 deliveries. Core industrial market demand is projected to decrease by 2.4% per year from 20.3 Bcf in 2010 to 12.6 Bcf in 2030. This decrease in gas demand results from a combination of a slightly lower forecasted growth in industrial production, minor increases in marginal gas rates and the impact of savings from AMI project deployment starting in April 2010 and CPUC authorized energy efficiency program savings in this market.

Overall, the retail non-core industrial (non-refinery) gas demand has shown persistent signs of weakness since 2006 due to competitive economic pressure to relocate out-of-state or to exit the line of business altogether. After 2007, the economic recession has lead to further reductions in gas demand from this market segment. Furthermore, beginning in 2007, industrial demand dropped annually by 6%, 19%, and 11% from the 2006 level.

Gas demand for the retail non-core industrial market as a whole is expected to decline at a rate of 1.4% annually, from an actual of 42 Bcf in 2009 to a projected demand of 31 Bcf by 2030. The reduced demand is primarily due to the departure of customers within the City of Vernon to wholesale service by the City of Vernon, the Commission-authorized energy efficiency programs designed to reduce gas demand, the expected slowdown of economic activity mostly in the mining, textile and petroleum sectors, and lastly the gradual decline in energy intensity among all sectors. By 2030, the energy efficiency programs-induced demand reductions and the transition for wholesale service by the City of Vernon are expected to reduce non-core industrial load by 4.24 Bcf and 0.8 Bcf, respectively.

Annual Industrial Demand Forecast (Bcf)

Years 2009 - 2030



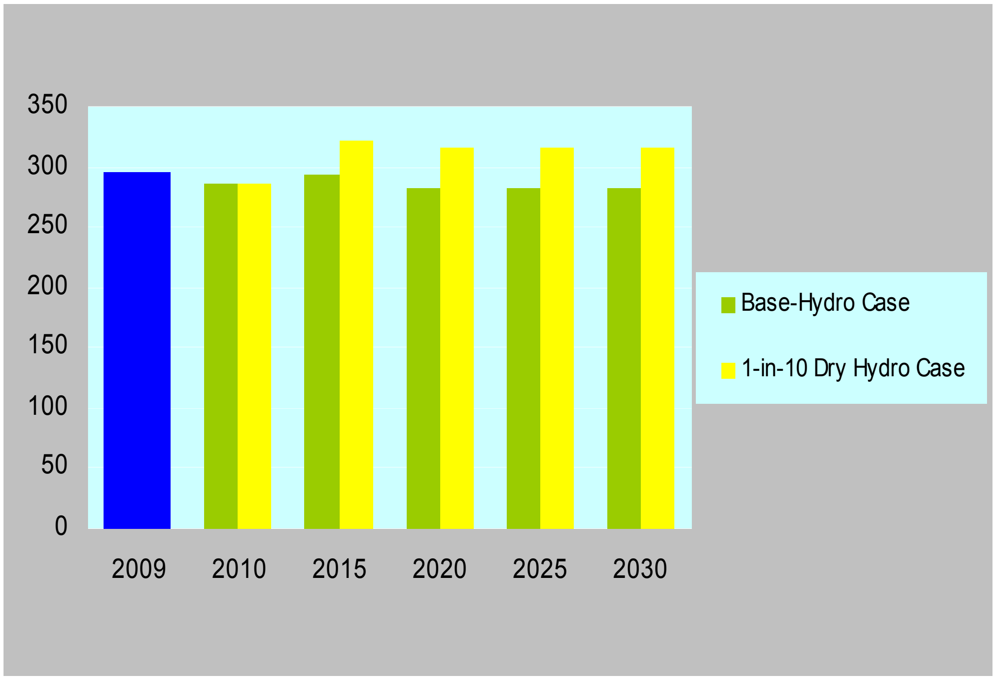
Refinery industrial demand is comprised of gas consumption by petroleum refining customers, hydrogen producers and petroleum refined product transporters. Refinery industrial gas demand is forecast to decline 0.7% per year, from 71 Bcf in 2009 to 61 Bcf in 2030. The majority of the decrease is due to the estimated savings from both Commission-authorized energy efficiency programs.

Electric Generation

This sector includes the following markets: all commercial/industrial cogeneration; EOR-related cogeneration; and, non-cogeneration electric generation. It should be noted that the forecast of electric generation (EG)-related load are subject to a higher degree of uncertainty due to the following: the continued operation of existing generation facilities and the potential shutdown of units from the state's new once-through-cooling (OTC) regulation; the timing and location of new generation facilities in the rest of California and the western United States; the regulatory and market decisions that impact the operation of existing cogeneration facilities; the location, timing and construction of new renewable resources; the construction of additional electric transmission lines, and future greenhouse gas (GHG) regulations. The forecast is based on a power market simulation for the period 2010 to 2020 and thus reflects the anticipated dispatch of all of the EG resources in the SoCalGas service territory under base electricity demand and both the average and the low hydroelectric availability market conditions. The base case assumes that 33% of the state's energy needs are met with renewable power by 2020 and additional renewable power is added after 2020 to maintain the 33% level.

Due to the large uncertainty in the timing and type of generation plants that would be added after 2020, the EG forecast is held constant at 2020 levels for 2025 and 2030. In this time frame there is the potential for new lower GHG generation sources being developed and built in a large enough quantity to create downward pressure on the demand for natural gas after 2020, however, electrification of other sectors such as transportation could create upward pressure.

SoCalGas Service Area Total Electric Generation Forecast (Bcf)



Industrial/Commercial/Cogeneration <20MW

The commercial/industrial cogeneration market segment is generally comprised of customers with generating capacity of less than 20 megawatts (MW) of electric power. Most of the cogeneration units in this segment are installed primarily to generate electricity for internal customer consumption rather than for the sale of power to electric utilities. In 2008, recorded gas deliveries to this market were 19 Bcf. By 2009, the small cogeneration load totals 20 Bcf, which represents a 5.3% increase over the 2008 level. Overall, cogeneration demand is projected to grow from 22 Bcf in 2010 to 26 Bcf by the year 2030. From 2010 through 2030, small cogeneration load is anticipated to grow at an annual average rate of 0.88%.

Industrial/Commercial Cogeneration >20 MW

For commercial/industrial cogeneration customers greater than 20 MW, gas demand is forecast to remain relatively constant increasing from 51 Bcf in 2010 to 52 Bcf in 2020. Although there is uncertainty in this sector as contracts come up for renewal, this forecast assumes that the existing businesses and these facilities will continue to be cost–effective and thus will continue to operate at historical levels. This may change in the future which could therefore have a significant impact on the forecast. Furthermore, this sector could also be impacted by GHG regulations.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. Refinery-related cogeneration is forecast to decline 0.4% per year, from 18.3 Bcf in 2010 to 16.8 Bcf in 2030, mainly due to projected fuel switching in the summer months.

Refinery-Industrial Demand

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, hydrogen producers and petroleum refined product transporters. Refinery industrial gas demand is forecast to decline 0.7% per year, from 71 Bcf in 2010 to 61 Bcf in 2030. The majority of the decrease is due to the estimated savings from Commission-authorized energy efficiency programs. The reduction of refinery gas demand also reflects the effect of refiners' using alternate fuels such as butane during summer months when their cost of natural gas is forecasted to be less competitive than the cost of these alternate fuels.

Enhanced Oil Recovery-Related Cogeneration

In 2009, recorded gas deliveries to the EOR-related cogeneration market were 7.4 Bcf, a decrease of 13.2 Bcf from 2008 due to the expiration of the long-term EOR transportation contracts with SoCalGas. EOR-related cogeneration demand is forecast to level off in 2010 at 3.7 Bcf and remain at that level for the remainder of the forecast period.

Non-Cogeneration Electric Generation

For the non-cogeneration EG market, gas demand is forecast to slightly decrease from 192 Bcf in 2010 to 187 Bcf in 2020. This forecast is the result of several factors. The addition of more efficient power plants, the addition of new electric transmission lines, and growth of renewable resources in Southern California are the major drivers.

SoCalGas' forecast includes 5,500 MW of new thermal generating resources, both combined cycles and peaking units in its service area by the end of 2020. However, 8,600 MW of older plants were retired as a result of direct replacement. There is a fair amount of uncertainty as to the future mix of plants between now and 2020 as the owners of the existing plants that use OTC look to make decisions regarding modifications, shutdown or repower to comply with the recently passed regulation. For electricity demand within California, SoCalGas used the California Energy Commission's (CEC) California Energy Demand Staff Adopted Forecast for

2010 to 2020. (http://www.energy.ca.gov/2009publications/CEC-200-2009-012/CEC-200-2009-012-CMF.PDF). For electric end-use demand outside of California, SoCalGas used Ventyx's electric demand forecast. Throughout the entire planning period that was modeled, SoCalGas assumes that market participants will construct additional generation resources such that the Western Electricity Coordinating Council maintains a minimum planning reserve margin of 15%.

Starting in 2010, renewable electricity generation was ramped up to meet 33% of the state's total electric energy distributed in 2020. The renewable-sourced energy generation in 2020 was estimated by taking 33% of the forecasted load from the CEC's California Energy Demand 2010-2020, Staff Adopted Forecast. Current forecast showed that close to 70% of the incremental renewable power needed to meet the 33% target will be located in Southern California. This is putting more downward pressure on EG gas demand.

Due to the large uncertainty in the timing and type of generation plants that would be added after 2020, the EG forecast is held constant at 2020 levels for 2025 and 2030. SoCalGas performed a dry hydro sensitivity gas demand forecast. A 1-in-10 dry hydro year is expected to raise gas demand by 30 Bcf, on average, over the forecast period.

Uncertainties in achieving renewables' goals and electric demand will affect the gas demand forecast for electricity generation. For sensitivity analyses of EG gas demand and the renewables goal, SoCalGas uses the average Southern California natural gas plant heat rate of 8,300 Btu/KWh and a factor of 1.0273 MMBtu/MCF to convert energy to volumetric units of gas. SoCalGas expects that for each additional 1000 GWh of electric demand, gas demand would grow by 8 Bcf, assuming all the growth comes from Southern California gas-fired power plants. If the percentage of renewable energy increases by 1% in Southern California (approximately 1,500 GWh), EG gas demand would decrease by 12 Bcf, assuming all the decrease comes from Southern California gas-fired power plants.

Enhanced Oil Recovery – Steam

Recorded deliveries to the EOR steaming market in 2009 were 12.6 Bcf, a decrease of 1.8 Bcf from 2008 demand due to the termination of SoCalGas' last long-term EOR gas transportation contracts. SoCalGas' EOR steaming demand is expected to further decrease to 10.7 Bcf in 2010 as EOR customers increase their use of interstate pipelines to supply their gas demand. From 2011 through the end of the forecast period, usage is expected to be approximately 10.4 Bcf. These figures include gas delivered to PG&E's EOR customers through inter-utility exchange. In 2009, less than 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 section.

Crude oil prices are forecast to remain high over the forecast period which may result in some expansion of California EOR operations in some fields. However, this expansion is forecast to be offset by declining oil production in other fields as the fields are depleted. For gas supplies, oil producers will rely increasingly on interstate pipelines in California to supplant traditional supply sources, such as own source gas and SoCalGas' transportation system.

Wholesale and International

SoCalGas provides wholesale transportation service SDG&E, the City of Long Beach Electric and Gas Department (Long Beach), Southwest Gas Corporation (SWG), and the City of Vernon (Vernon) and Ecogas. The wholesale load is expected to decrease from 164.8 Bcf in 2010 to 156.8 Bcf in 2030.

San Diego Gas & Electric

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 0.6% per year from 132 Bcf in 2010 to 117 Bcf in 2030. Refer to SDG&E's section for more information.

City of Long Beach

The wholesale load forecast is based on forecast information provided by the City of Long Beach. Long Beach's gas use is expected to remain fairly constant from 9.7 Bcf in 2010 to 9.8 Bcf by 2030. Long Beach's local deliveries are expected to decline from about 1.2 Bcf in 2010 to 0.6 Bcf in 2030. SoCalGas' transportation to Long Beach is expected to increase gradually from 8.0 Bcf in 2010 to 8.7 Bcf by 2030. Refer to City of Long Beach Municipal Gas & Oil Department for more information.

Southwest Gas

The demand forecast for Southwest Gas is based on a long-term demand forecast prepared by Southwest Gas. In 2010, SoCalGas expects to serve approximately 6.7 Bcf directly, with another 3.0 Bcf being served by PG&E under exchange arrangements with SoCalGas. The total load is expected to grow from 9.7 Bcf in 2010 to approximately 14.8 Bcf in 2030.

City of Vernon

The City of Vernon initiated municipal gas service to its electric power plant within the city's jurisdiction in June, 2005. Since 2005 there has also been a gradual increase of Commercial/Industrial gas demand as customers within the city boundaries have interconnected with Vernon's municipal gas system. The forecasted throughput starts at 9 Bcf in 2010 and increases to 10 Bcf by 2014, after which the demand remains relatively flat through 2030. Vernon's commercial and industrial load is based on recorded historical usage for commercial and industrial customers already served by Vernon plus the customers that are expected to request retail service from Vernon. The throughput forecast for Vernon's municipal EG customers is based on a power market simulation.

Ecogas Mexico, S. De R.L. De C.V (Ecogas)

SoCalGas used the forecast prepared by Ecogas, Mexicali, for this report. Mexicali's use is expected to gradually increase from approximately 6 Bcf/year in 2010 to 6.4 Bcf/year by 2030.

Natural Gas Vehicles (NGV)

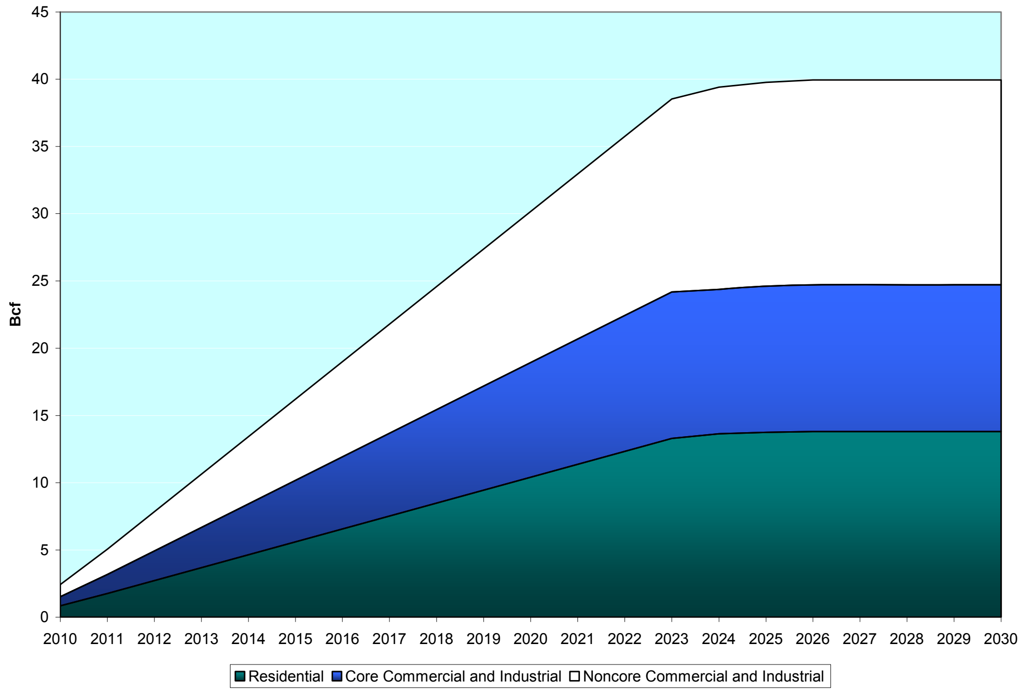
The NGV market is forecast to continue to grow due to federal, state and local incentives and regulations related to the purchase and operation of alternate fuel vehicles coupled with rapidly increasing cost of petroleum (gasoline and diesel). At the end of 2009, there were 254 compressed natural gas (CNG) fueling stations delivering 9.5 Bcf of natural gas during the year. SoCalGas remains optimistic about the NGV market's growth, forecasting an increase in demand from 9.5 Bcf in 2009 to 11.2 Bcf in 2015 and 16.8 Bcf in 2030. The growth is being propelled by the private and public sectors, with customer support from SoCalGas' Clean Transportation program.

ENERGY EFFICIENCY PROGRAMS

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 while still maintaining 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 the Energy Efficiency programs.

The cumulative net Energy Efficiency load impact forecast for selected years is shown in the graph below. The net load impact includes all Energy Efficiency programs that SoCalGas and SDG&E have forecasted to be implemented beginning in year 2010 and occurring through year 2026. Savings and goals for these programs are based on the program goals authorized by the Commission in D.04-09-060.

Annual Energy Efficiency Cumulative Savings Goal (Bcf)



Savings reported are for measures installed under SoCalGas' Energy Efficiency programs. Credit is only taken for measures that are installed as a result of SoCalGas' Energy Efficiency programs, and only for the measure lives of the measures installed. Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. This means, for example, that a measure installed in 2005 with a lifetime of 10 years is only included in the forecast through 2014. Naturally occurring conservation that is not attributable to SoCalGas' Energy Efficiency activities is not included in the Energy Efficiency forecast.

Details of SoCalGas' 2010-2012 Energy Efficiency program portfolio are contained in SoCalGas' A.08-07-022 which was submitted on July 2, 2009 and became effective January 1, 2010. The full application is available at the following site:

http://www.socalgas.com/regulatory/A0807022.shtmlNotes:

(1) "Hard" impacts include measures requiring a physical equipment modification or replacement.
(2) SoCalGas does not include "soft" impacts, e.g., energy management services type measures.
(3) The assumed average measure life is 15 years.

GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

Southern California Gas and San Diego Gas & Electric receive gas supplies from several sedimentary basins in the western United States and Canada including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountain, Western Canada, and local California supplies. Recorded 2005 through 2009 receipts from gas supply sources can be found in the Sources and Disposition tables in the Executive Summary.

California Gas

Gas supply available to SoCalGas from California sources was 160 MMcf/day in 2009.

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 San Juan Basin's conventionally produced gas supplies have peaked in 1999 and has been declining at an annual rate of 1.4%. The Permian Basin's 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 to Rockies gas through pipelines interconnected to the San Juan Basin. Production from the Rocky Mountain region in 2009 has doubled since 2000 due to the successful applications of new technology to drill for coal-bed methane 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 U.S. Midwest and eastern United States are likely to move Canadian gas away from California. Increased gas deliveries from the Rockies and Permian Basin to California are expected to replace these supplies.

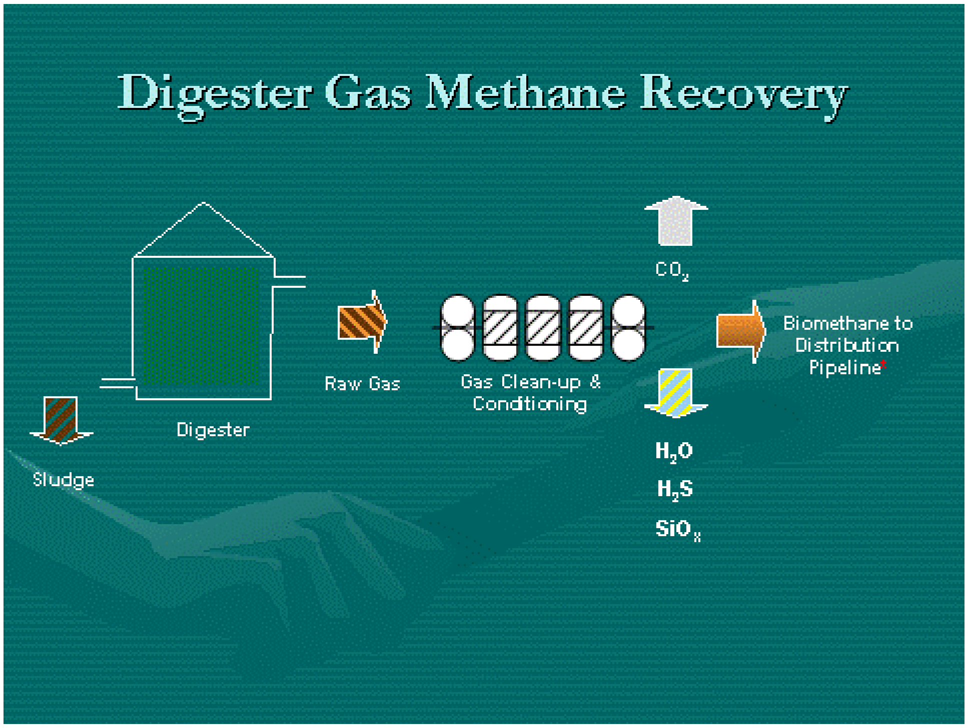
Biogas

AB 32, the Global Warming Solutions Act of 2006, established statewide Greenhouse Gas (GHG) emissions caps to reduce GHG emissions: to year 2000 levels by 2010; to 1990 levels by 2020; and, to 80 percent below 1990 levels by 2050. SDG&E and SoCalGas are working collaboratively with customers and research centers to demonstrate various technologies to achieve these renewable GHG emissions reduction goals by treating biogas produced by digesters from sewage, animal waste and other biomaterials. SoCalGas/SDG&E are researching ways to turn biogas into biomethane that can be safely injected into the utilities' distribution and transmission systems.

Biogas is gas that is produced from the breakdown of organic material under conditions with low to no availability of oxygen. Biogas is produced in processes including, but not limited to, anaerobic digestion, anaerobic decomposition, and thermo-chemical decomposition under sub stoichiometric conditions. These processes are applied to biodegradable biomass materials, such as manure, sewage, municipal solid waste, green waste, and from energy crops, to produce landfill gas, digester gas, and other forms of biogas. Biomethane is biogas that has been upgraded or otherwise conditioned to meet CPUC natural gas specifications and is suitable for injection into natural gas distribution pipeline systems operated by public and private utilities.

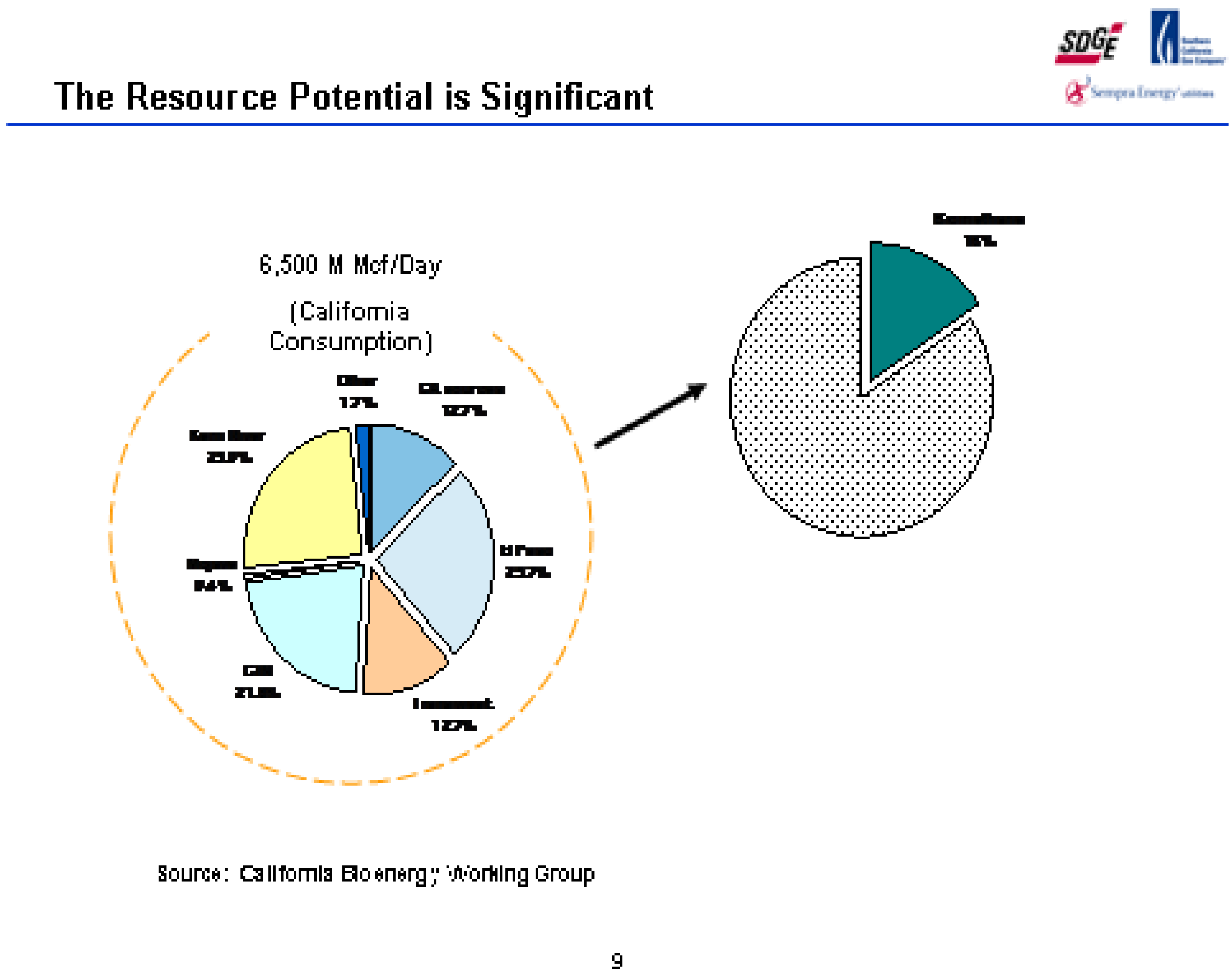
One of the biggest potential sources of biogas is the sewage treatment facilities in Southern California. According to the U.S. EPA, the wastewater treatment industry uses the equivalent of 56 billion kWh of electricity per year, or about 3% of total U.S. consumption. In addition, the industry is responsible for emitting 26.7 million tons of CO_2 equivalent methane every year. The biogas released from anaerobic digestion contains between 60% and 95% methane that can be captured and used for electricity and heat generation. Substituting clean-burning, renewable biogas for electricity for fossil fuels will reduce CO_2 emissions associated with burning those fuels.

SDG&E and SoCalGas are working with the city of Escondido to test the upgrading treatment of the biogas produced at the HARRFF Waste Treatment Plant in order to meet pipeline quality SoCal Gas Rule 30 standards. Eventually there are plans to inject the treated pipeline quality biomethane into the SDG&E/SoCalGas distribution system. The city of Escondito's HARRFF Waste Treatment Plant produces 150,000 cubic feet of biogas each day that is currently flared with no beneficial use. This biogas treatment research collaboration brings SDG&E/SoCalGas and Escondido together to demonstrate technology that will enable greater access to a new source of renewable energy. Once the treatment technology has been tested and found safe, SDG&E/SoCalGas will seek out viable biogas producing facilities to increase the use of biogas in Southern California. The following diagram shows the basic biogas treatment process that is being evaluated at Escondito.



The development of this green technology will result in the reduction of GHG emissions and reduce our carbon footprint. In addition, it will turn currently flared biogas into beneficial use of digester gas that can be used at HARRF for heating the digesters resulting in future cost savings and city revenues.

As shown in the graph below, the resource potential for biomethane production is significant at about 1 BCF/day but high treatment costs and the limited number of potential projects that are large enough to be economic, reduce the potential for biomethane production significantly. SoCalGas/SDG&E have identified 4 to 8 potential projects of a size large enough to make biogas treatment economic.



Liquefied Natural Gas (LNG)

With the completion of the Costa Azul LNG terminal in Baja California, Mexico in May 2008, LNG is expected to be an important supply source to California. As for the other gasification facilities currently under the planning and permitting stage, it is uncertain as to how many other re-gasification facilities will actually be built and where they will be located on the West Coast of North America.

INTERSTATE PIPELINE CAPACITY

Interstate pipeline delivery capability into SoCalGas and SDG&E on any given day is theoretically is over 6,515 MMcf/day based on the Federal Energy Regulatory Commission (FERC) Certificate Capacity or SoCalGas estimated physical capacity of upstream pipelines. These pipeline systems provide access to several large supply basins, located in: New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains, Western Canada, and LNG.

Upstream Capacity to Southern California

Pipeline	Upstream Capacity (MMcf/d)
El Paso at Blythe	1,210
El Paso at Topock	540
Transwestern at Needles	1,150
PG&E at Kern River	650 (1)
Southern Trails at Needles	80
Kern/Mojave at Wheeler Ridge	885
Kern at Kramer Junction	550
Occidental at Wheeler Ridge	150
California Production	310
TGN at Otay Mesa	400
North Baja at Blythe	600
Total Potential Supplies	6,725

(1) Estimate of physical capacity.

FIRM RECEIPT CAPACITY

SoCalGas/SDG&E currently has firm receipts capacity at the following locations for its core customers to access supply from interstate pipelines.

SoCalGas/SDG&E Current Firm Receipt Capacity

Transmission Zone	Total Transmission Zone Firm Access (MMcf/d)	Specific Point of Access (1) (Limitations)(2) (MMcf/d)
Southern	1,210	EPN Ehrenberg (1,200) TGN Otay Mesa (400) NBP Blythe (600)
Northern	1,590	EPN Topock (540) TW North Needles (800) QST North Needles (120) KR Kramer Junction (550)
Wheeler Ridge	765	KR/MP Wheeler Ridge (765) PG&E Kern River Station (520) OEHI Gosford (150)
Line 85	160	California Supply
Coastal	150	California Supply
Other	N/A	California Supply
Total	3,875	

(1) Pipelines

EPN: El Paso Natural Gas Pipeline
TGN: Transportadora de Gas Natural de Baja California
NBP: North Baja Pipeline
TW: Transwestern Pipeline
MP: Mojave Pipeline
QST: Questar Southern Trails Pipeline
KR: Kern River Pipeline
PG&E: Pacific Gas and Electric
OEHI: Occidental of Elk Hills

(2) Transmission Zone Contract Limitations:

Southern Zone:

- In total EPN Ehrenberg and NBP Blythe cannot exceed 1,210 MMcfd.
- In total EPN Ehrenberg, NBP Blythe and TGN Otay Mesa cannot exceed 1,210 MMcfd.

Northern Zone:

- In total TW at Topock and EPN at Topock cannot exceed 540 MMcfd.
- In total TW at North Needles and QST at North Needles cannot exceed 800 MMcfd.
- In total TW at North Needles, TW Topock, EPN Topock, QST North Needles and KR Kramer Junction cannot exceed 1,590 MMcfd.

Wheeler Ridge Zone:

- In total PG&E at Kern River Station and OEHI at Gosford cannot exceed 520 MMcfd.
- In total PG&E Kern River Station, OEHI Gosford, and KR/MP Wheeler Ridge cannot exceed 765 MMcfd.

In 2007 SoCalGas purchased a 45-mile segment of pipeline from Questar which allows for pressure betterment in the City of Twentynine Palms area. The pipeline also provides additional capacity that allows SoCalGas to continue to maintain full delivery into the area under peak load conditions.

STORAGE

Underground storage of natural gas plays a vital role in balancing the region's energy supply and demand. SoCalGas owns and operates four underground storage facilities located at Aliso Canyon, Honor Rancho, Goleta and Playa Del Rey. These facilities play a vital role in balancing the region's energy supply and demand.

Of SoCalGas' total 133.1 billion cubic feet (Bcf) of storage capacity, 80 Bcf is allocated to our Core residential, small industrial and commercial customers. About 4 Bcf of space is used for system balancing. The remaining capacity is available to other customers.

REGULATORY ENVIRONMENT

State Regulatory Matters

Firm Access Rights and Off System Delivery

D.04-09-022 ordered SoCalGas to file a separate application to address its proposal for firm rights. In A.04-12-004, SoCalGas again put forth its proposal for firm rights on the SoCalGas system and also to integrate the two gas transmission systems on an economic basis. The Commission subsequently bifurcated A.04-12-004 into two phases; Phase 1 would address system integration issues with regard to the SoCalGas and SDG&E systems and Phase 2 would address the firm access rights and off-system delivery issues.

SoCalGas' system integration proposal sought to combine the transmission-related costs of SDG&E and SoCalGas so that customers of each utility share in the transmission costs of both utilities. These integrated transmission rates would allow customers of SDG&E and SoCalGas to obtain gas at that rate from any existing or new receipt point on the SDG&E and SoCalGas systems. In April 2006, the Commission issued D.06-04-033 approving SoCalGas and SDG&E's system integration proposals.

The second phase of A.04-12-004 was initiated following the Commission's issuance of D.06-04-033 to address firm rights and off system deliveries. The Commission issued a decision in Phase II. The decision addresses the issues concerning a system of firm access rights for SDG&E and SoCalGas. Other issues addressed were SDG&E and SoCalGas proposals for an off-system delivery service to PG&E Company and for a gas pooling service, and whether SoCalGas peaking rate tariff should be retained.

SoCalGas filed application A.08-06-006 in June 2008 to expand the existing Off-System delivery authority to all receipt points. SoCalGas requested approval to: provide interruptible and firm off-system services at all receipt points; charge a discountable interruptible off-system delivery rate; charge a firm off-system delivery rate that fully recovers the costs of new facilities plus a discountable interruptible off-system delivery; roll0in the firm off-system facility costs into those of the overall transmission system if appropriate, and resolve shipper imbalances. A decision is expected in 2010.

SoCalGas filed application A.010-03-028 in March 2009 t assess how the Firm Access Rights (FAR) system is working and whether any changes or modifications are needed ("FAR update"). SoCalGas requested: minor changes to the open season process; change of the "FAR" name to the more appropriate and descriptive "Backbone Transportation Service," increase firm capacity at the Kramer Junction receipt point by 50 MMcfd to 550 MMcfd, authorization of a fully-unbundled cost-based rate design and in-kind treatment of transmission fuel.

BIENNIAL COST ALLOCATION PROCEEDING (BCAP)

SoCalGas and SDG&E filed their BCAP, A.08-02-001 in February 2008. The application updated throughput forecasts, cost, allocation, and rates by customer class, in addition to addressing issues deferred from prior proceedings. The BCAP was subsequently bifurcated into two phases. Phase I dealt with core storage capacity allocation, the allocation of revenues between shareholders and customers of the unbundled Transactions Based Storage program and cost ceilings on inventory, injection, and withdrawal services. Phase II addressed the customer demand forecasts, Unaccounted For Gas (AF) allocation by customer class, cost allocation of base margin and non-margin costs by customer class, and a new Transmission Level Service closing the regulatory gap between CPUC and FERC related pipeline systems.

In July 2008, parties agreed to a settlement of the Phase One issues. A motion to adopt the Phase One Settlement Agreement was filed and the Commission granted the motion and adopted the terms of the Phase One Settlement Agreement in D.08-012-020. The six-year agreement allows SoCalGas to invest in certain storage replacement and expansion projects that ultimately will add 145 MMcfd of storage injection capacity and 7 Bcf of inventory capacity. The agreement also provides that the revenues from the unbundled storage and system operator hub services programs be shared between ratepayers and shareholders on a graduated basis.

With respect to Phase Two, a joint motion to adopt a Settlement Agreement of the Phase Two issues was filed on June 2, 2009. The Settlement Agreement proposed to allocate the revenue requirement associated with SoCalGas and SDG&E's gas transmission, and distribution systems and storage operations based on the Utilities' gas demand forecasts. D.09-011-006 granted the joint motion to adopt the Settlement Agreement, with a few modifications. SoCalGas and SDG&E's new BCAP rates went into effect on February 1, 2010. The BCAP rates will continue through 2012.

FEDERAL REGULATORY MATTERS

SoCalGas participates in FERC proceedings relative to interstate capacity serving California because these cases can affect the cost of gas delivered to customers. SoCalGas holds contracts for interstate transportation capacity on El Paso, Kern River, GTN and Transwestern pipelines.

El Paso Rate Case: El Paso filed an uncontested settlement agreement on March 11, 2010. The settlement covers cost of service, cost allocation and rate design issues; and carves out four issues for hearing. The four issues are: all issues concerning Article 11.2a and b of the 1996 Settlement; El Paso's proposed 250% load factor rates for short term firm and interruptible service; Line 1903 purchase price; and El Paso's 60% equity/40% dept capital structure. These issues have been the subject of evidentiary hearings beginning on May 18, 2010. El Paso's postage stamp fuel rate was retained; however, any party to the Settlement has the right to file a complaint alleging that El Paso's fuel rate is unjust and unreasonable. The Settlement rates will save SoCalGas and SDG&E approximately $15 million per year as compared to the filed rates.

Kern River filed its rate case in November 2004. In this highly contentious case, the rate design, particularly Kern's levelized methodology, and return on equity (ROE) are two of the most controversial issues. In a recent opinion issued on April 17, 2008, the FERC approved Kern's levelized rate design methodology and re-opened the case to only consider the inclusion of Master Limited Partnerships in the proxy group used for determining Kern's ROE. A decision on this aspect of the case is expected by year end 2008. Concomitantly, BP Energy and Calpine Corporation, who oppose the FERC's rulings in this case, have submitted the FERC rulings for review in the U.S. Circuit Court of Appeals.

On December 17, 2009, the FERC commission issued its final order on the parameters used to develop new billing rates for existing gas contracts transporting natural gas supplies on this pipeline. Kern has filed, and the FERC has provisional accepted, the new billing rates effective April 1, 2010. There is an outstanding ancillary issue dealing with the development of "step-down" rates that would apply to transportation services following the expiration of existing gas contract service terms. The FERC is scheduled to issue an initial decision on the ancillary issue by April 22, 2011. The Kern River pipeline system delivers natural gas supplies from gas basins located in the Rocky Mountains in Wyoming to deliver points in Southern California, located south of Las Vegas, Nevada.

Transwestern filed a rate case on September 29, 2006. Key issues in this case were the proposed fuel and reservation rate increases and gas quality standards. Shippers filed a settlement agreement on February 1, 2007 that resolved all issues except for gas quality standards for Wobbe and BTU content. FERC approved the uncontested settlement on June 26, 2007. On February 29, 2008, Transwestern submitted a request to FERC to withdraw its revised tariff sheets proposing Wobbe and BTU quality specifications and defer the issue to the next rate case. This request was accepted by FERC on April 14, 2008. The Settlement has a 5 year term.

Transwestern Pipeline has a settlement on its transportation rates through the end of 2010. Transwestern may file as early as April 2010 for a revision in its rates. The Transwestern pipeline system delivers natural gas supplies from gas fields located in southwestern Colorado and western Texas to the border between Arizona and Southern California near Needles, California.

Gas Transmission Northwest (GTN) Corporation has a settlement on its transportation rates through the end of 2011. GTN transports natural gas supplies from the Canadian/U.S. border in British Columbia to the Oregon/California border near Malin, Oregon.

Another proceeding of note is the North Baja Pipeline (NBP expansion. On February 7, 2006, TransCanada filed an application for a two-phase expansion of its North Baja Pipeline. The project proposed to import up to 2.7 Bcf/day of Liquefied Natural Gas (LNG) supply from terminals in Baja California. The project links to a corresponding expansion of the Gasoducto Bajanorte line in Mexico. North Baja connects with the SoCalGas' system at the Blythe Meter Station site. Phase I of the project went into service April 2008; the anticipated in-service date for Phase II is June 2010.

GREENHOUSE GAS ISSUES

National Policy

National greenhouse gas (GHG) policy is currently under development. In general, the programs will all be designed to reduce national GHG emissions, and the electric utility sector will bear much of the reduction requirements.

Restriction on New Conventional Coal Generation

Many bills would prohibit new coal-fired generation unless it includes carbon sequestration. Since carbon sequestration technology is not yet proven, in the near term, new generation will likely be dependent upon natural gas. Even absent a prohibition on coal generation without sequestration, the prospect of future carbon regulation can be expected to stifle coal investments, at least until the specific form of that regulation is known. Therefore, as California's electricity demand increases, California as well as the rest of the country will likely become more dependent upon new natural gas generation to meet needs that cannot be met through renewable resources. This increase in national demand for natural gas, combined with future anticipated reductions in available North American natural gas supplies, may tighten supplies to California.

Reduction in GHG Emissions from the Electric Sector

Many national legislative proposals would establish a national cap on GHG emissions that declines over time. Since existing conventional coal power plants have higher emissions than their natural gas-fired counterparts, there will be pressure to reduce the use of these older coal plants and increase the construction and use of natural gas-fired and renewable plants. Absent corresponding decreases in national demand for natural gas-fired generation (through enhanced energy efficiency requirements and other measures such as a national RPS) this will increase national demand for natural gas.

Under a GHG cap and trade program, GHG emission allowances could be allocated on a fuel-neutral basis based upon MW output. This maximizes incentives for high emitters to reduce their emissions while properly recognizing prior actions that have reduced GHG emissions. It also maximizes the incentives for zero emitting resources to enter the market, because they would have the opportunity to sell allowances when they enter as a result of their extremely low emission profile. In short, such a structure maximizes incentives to use the most efficient and lowest GHG emitting electric generation technologies.

Motor Vehicle Emissions Reductions

National GHG policy-makers realize that motor vehicles are one of the largest sources of GHG emissions, and one of the potential solutions is the substitution of natural gas and electricity for the current diesel and gasoline energy sources. This transition to cleaner fuels will also increase the demand for both natural gas and natural gas-generated electricity. Some legislative proposals under consider reducing the use of all fossil fuels, without recognizing the fact that natural gas use may need to actually increase, at least in the near term, to meet the needs of a cleaner national transportation fleet.

California Policy

California is in the process of implementing a broad portfolio of policies and regulations aimed at reducing greenhouse gas (GHG) emissions. This process is a collaborative effort underway at the California Public Utilities Commission (CPUC), the California Energy Commission (CEC) and the California Air Resources Board (ARB). ARB however is statutorily empowered with rendering the final decision on the GHG regulatory framework and compliance. Policies under consideration include both programmatic measures and market-based mechanisms to reduce GHG emissions.

Emission Performance Standard

On January 25, 2007, the CPUC adopted an interim GHG Emission Performance Standard (EPS) pursuant to SB 1368. This is a facility-based emission standard requiring that all new long-term commitments for base-load generation to serve California consumers be built with power plants that have emissions no greater than a combined cycle gas turbine plant- 1,100 pounds of CO2 (carbon dioxide) per megawatt-hour. New long-term contracts covered under the EPS standard include new plant investments, new or renewal contracts with a team of five years or more or major investments by the utility in its existing base-load power plants. These emission-based standards may be revisited once an emission cap is operational in California pursuant to AB 32.

The EPS effectively eliminates the ability for California LSEs to procure electricity from coal resources, thereby increasing the need for new renewable generation and natural gas-fired generation resources (for baseload generation and to address the reliability needs associated with increased reliance on intermittent renewable generation resources).

Low Carbon Fuel Standards

On January 18, 2007, Governor Schwarzenegger signed an Executive Order establishing the low carbon fuel standard (LCFS). LCFS requires a 10 percent carbon intensity reduction by 2020 in the transportation sector. It is recognized that 40 percent of California's GHG emissions are attributable to the transportation sector and 96 percent of the state's transportation needs require petroleum-based fuels. The LCFS requires fuel providers to ensure that the mix of fuel they sell into the California market meets, on average, a declining standard for GHG emissions measured in CO_2 equivalent gram per unit of fuel energy sold. As stated above, the transition to cleaner fuels will increase the demand for both natural gas and natural gas-generated electricity in order to meet the needs of a cleaner state transportation fleet, which will increasingly utilize electricity and natural gas in the future.

CPUC/CEC Interim Recommendations on Point Of Regulation

On March 13, the CPUC approved interim recommendations to the Air Resources Board on a number of policies and requirements for GHG emissions reductions from the electricity and natural gas sectors. These recommendations, which resulted in collaboration and joint decisions by the CPUC and CEC, may be adopted as part of the ARB scoping plan for its further work in implementing AB 32, which requires that statewide GHG emissions be reduced to 1990 levels by 2020. The CPUC and CEC recommend that ARB adopt a mix of direct mandatory/regulatory requirements and a cap-and-trade system (C&T) for the energy sectors, but also recommends that the natural gas sector not be included in a cap and trade system at this time. It was recommended that for now reductions in the natural gas sector should come exclusively from mandatory measures (primarily energy efficiency programs).

The referenced "natural gas sector" in the interim decision, does not include sources likely to be directly regulated by the ARB's large point sources using natural gas and electricity generation fueled by natural gas. Specifically, the "natural gas sector" would exclude all natural gas used for electric generation including all natural gas used by cogeneration facilities (including the thermal use of the co-generator). The "natural gas sector" would also exclude all utility deliveries to wholesale customers to avoid double counting. For distribution operations of utilities, it would include only the natural gas combustion not covered directly by ARB as large point sources and fugitive emissions associated with the distribution and transmission systems. For interstate pipelines, it would include the combustion of all customers served directly by the interstate pipeline that are not large point sources, all interstate pipeline natural gas combustion in the state of California not covered as large point sources, and all fugitive emissions within the state of California. The natural gas consumption and fugitive emissions of independent natural gas storage facilities would be included if they are not covered directly by ARB as large point sources. All stationary combustion sources emitting >25,000 MT CO_2/year would be regulated by ARB as large point sources.

It has not been determined if residential and small industrial natural gas customers will be included in a Cap & Trade program. Although a programmatic approach to reducing emissions from remaining emitters in this sector plus the development of offsets in this sector could be used for compliance in the capped sector. Allowing firms in this sector to be a source of offsets effectively provides incentives for these smaller customers to find low GHG reductions and connects this sector with the capped sector. Natural gas combustion in utility operations, interstate pipelines, and independent storage producers may be excluded in a C&T system. These kinds of emissions are not easily subject to measurement or verification. Fugitive emissions, including from pipelines, storage facilities, and compressor stations are not easily subject to accurate measurement or verification and are therefore better addressed through programs aimed at best practices in managing leaks and other methane emissions. Natural gas used as a feedstock may also be excluded from the natural gas sector.

Programmatic Emission Reduction Measures

The CEC, CPUC and ARB are considering a variety of non market-based measures to reduce GHG emissions. Some of these programs include, the California Energy Efficiency Green Building Standards, which include both residential and commercial new and retrofit, the Green State Buildings Executive Order, CPUC's adopted goal of "zero net energy" for all new residential construction by 2020 and a similar goal for commercial buildings by 2030, potential Combined Heat and Power and distributed Generation portfolio standards or feed-in tariffs, and increasing the renewable portfolio standard to 33%. Energy Efficiency and renewables are considered fundamental to emission reduction in the electric sector. As a result, integration of additional renewables will require quick-start peaking capacity for firming and shaping of intermittent power, which in the foreseeable future will be gas-fired Combustion Turbines.

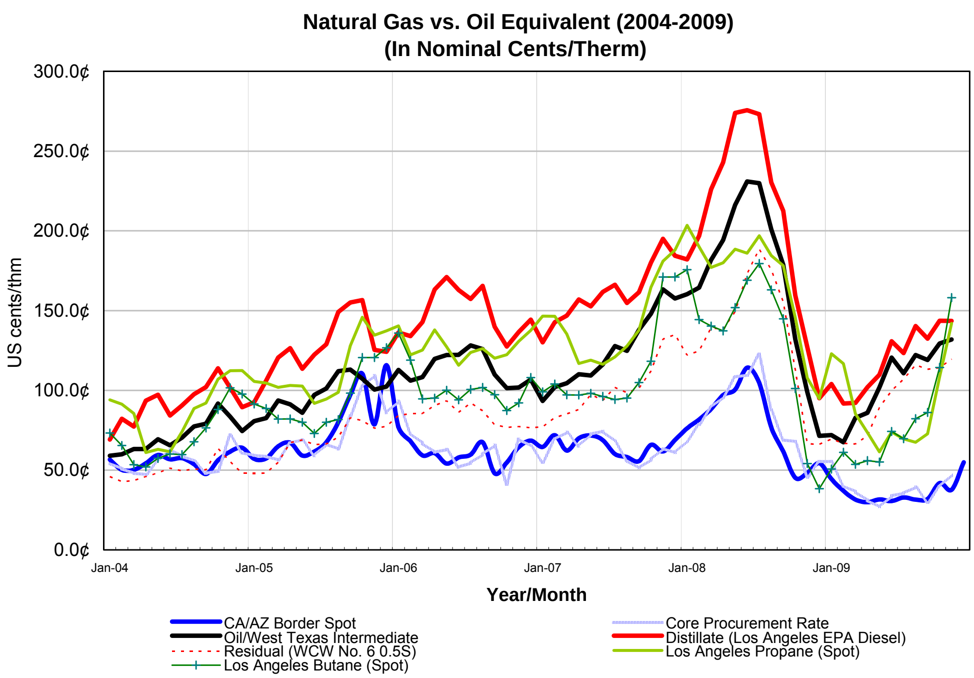
A decision adopting final CPUC and CEC recommendations to the ARB, which would include treatment of the natural gas sector under AB 32, was scheduled for September 2008. The CPUC and CEC's recommendations are limited to the electricity and natural gas sectors. The first indication on policy direction by ARB, which will describe the regulatory framework in which California will reduce GHG emission levels to 1990 by 2020, including whether a multi-sector C&T system will be implemented, the sectors to be included in the C&T system, and the emission cap for each sector was not be available until ARB released their final Scoping Plan. ARB adopted its final Scoping Plan in December 2009. The final Scoping Plan was to be adopted and in effect by early 2010. By 2012 GHG reduction measures are enforceable. The Scoping Plan will be updated by ARB every five years.

GAS PRICE FORECAST

MARKET CONDITION

Natural gas prices during the 2010 CGR period are forecast to increase due to a combination of oil price increases and strong growth in natural gas consumption, particularly in the electric generation sector. The price of natural gas is still trading at a discount to crude oil and oil-derived products as shown in the chart below but over the longer term oil and gas prices should start to converge.

Current North American production from conventional supplies has been declining, particularly at the Western Canadian Sedimentary Basin and offshore production in the Gulf of Mexico. However, with advanced technology in horizontal drilling, proven reserves from unconventional resources have been soaring due to the unlocking of trapped gas from shale, tight sands and coal bed methane in the Mid Continent, Rockies and eastern U.S. The new technology is successful at finding trapped gas that was not economical before but is now economic due to technological breakthroughs that have reduced development costs substantially. The aggressive expansion in the production of shale gas in the Mid Continent, eastern U.S. and Canada and continuing growing production of coal bed methane in the Rockies is expected to relieve some of the price pressure in the next few years although reductions in conventional sources offset that increase to some degree.



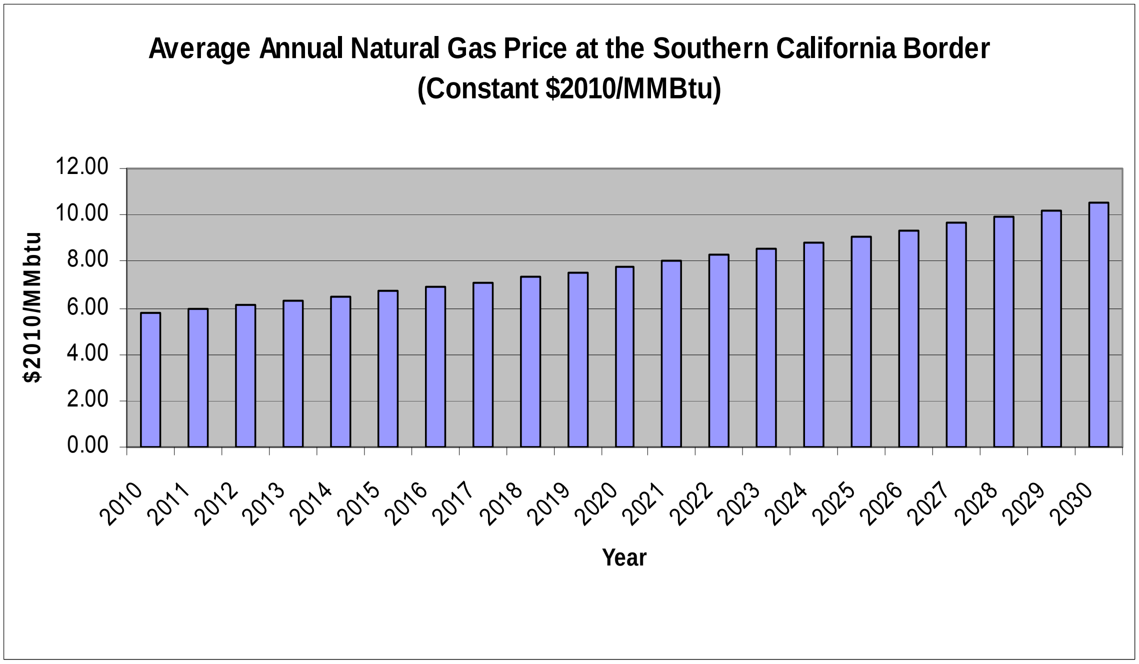
With world-wide LNG prices still higher than the current price at Henry Hub, LNG imports in the short-term are expected to be limited with only a minor impact on domestic supply or price. LNG however is expected to moderate winter gas price increases as LNG will be withdrawn from storage during peak demand periods. LNG has started to be delivered into the U.S. Southwest from the Energia Costa Azul LNG receiving terminal in Baja California, Mexico, in limited quantities. In the long-run, more LNG will be available when the new generation of liquefaction trains are reliably operated; although world-wide demand will most likely dictate the amount of LNG supplies delivered to North America.

Therefore, industry experts now forecast that gas prices can be expected to be more plentiful and less volatile during the forecast period. Increased shale gas production and increased LNG liquefaction supplies combined with the worldwide economic slowdown are expected to moderate prices in the medium term. However, increasing demand for clean natural gas for electric power generation, Natural Gas Vehicles fuel, and substitution of gas for coal in electric power production to meet Greenhouse Gas reduction goals will continue to put some upward pressure on prices.

DEVELOPMENT OF THE FORECAST

The base 2010 CGR Gas Price Forecast (2010 CGR GPF) used to develop the gas demand forecasts was prepared using the average of NYMEX natural gas futures prices in March 2010 and the long-term forecasts from 2010 to 2030 of the California Energy Commission (CEC), the Energy Information Administration (EIA) and private sources that relied on fundamentals-based models. Natural gas prices are expected to average out at $5.75/MMbtu in 2010 and increase by about three percent per year through 2030.

It is important to recognize that natural gas prices have recently been much more volatile than in the past, and no price forecast can be expected to account for all uncertainties. SoCalGas and the participants of the *2010 CGR* do not warrant the accuracy of the gas price projection. In no event shall SoCalGas or the participants of the *2010 CGR* be liable for the use or reliant of the natural gas price forecast.


Average Annual Natural Gas Price at the Southern California Border
(Constant $2010/MMBtu)
$2010/MMbtu
12.00
10.00
8.00
6.00
4.00
2.00
0.00
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Year

PEAK DAY DEMAND AND DELIVERABILITY

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio. SoCalGas and SDG&E plan and design their systems to provide continuous service to their core customers under an extreme peak day event. The extreme peak day design criteria is defined as a 1-in-35 likelihood event for each utility's service area. This criteria correlates to a system average temperature of 38.8 degrees Fahrenheit for SoCalGas' service area and 41.8 degrees Fahrenheit for SDG&E's service area.

Demand on an extreme peak day is met through a combination of withdrawals from underground storage facilities and flowing pipeline supplies. The firm storage withdrawal amount of 2,225 MMCF/day is the value SoCalGas and SDG&E are approved to hold (per CPUC D.08-12-020 on Dec. 4, 2008 at p. 12) to serve the combined core portfolio of SoCalGas' and SDG&E's retail core customers. Firm withdrawal plus firm pipeline supplies must be sufficient to meet peak day operating requirements. The following table provides an illustration of how storage and flowing supplies can meet the growth in forecasted retail core peak day demand for a summer peak and a winter peak.

Retail Core Peak Day Demand and Supply Requirements
(MMcf/Day)

Year	SoCalGas Retail Core Demand (1)	SDG&E Retail Core Demand (2)	Total Demand	Firm Storage Withdrawal (3)	Required Flowing Supply
2010	2,996	376	3,372	2,225	1,147
2011	2,970	372	3,341	2,225	1,116
2012	2,969	371	3,340	2,225	1,115
2013	2,949	370	3,319	2,225	1,094
2014	2,940	369	3,308	2,225	1,083
2015	2,938	368	3,307	2,225	1,082
2016	2,941	368	3,309	2,225	1,084

Notes:
(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-35 peak temperature cold day SDG&E core sales and transportation.
(3) This amount approved by the CPUC for SoCalGas and SDG&E to serve the combined core portfolio of SoCalGas' and SDG&E's retail core customers in CPUC D.08-12-020 on 12/4/2008 at p. 12..

The tables below provide system-wide peak day demand projections on SoCalGas' system for both winter (December month) and summer (August month) periods.

Winter Peak Day Demand
(MMcf/Day)

Year	Core (1)	Noncore NonEG (2)	Electric Generation (3)	Total Demand
2010	2,996	916	1,137	5,049
2011	2,970	914	1,098	4,981
2012	2,969	908	1,103	4,980
2013	2,949	907	1,119	4,975
2014	2,940	907	1,104	4,950
2015	2,938	907	1,128	4,973
2016	2,941	904	1,134	4,978

Notes:
(1) 1-in-35 peak temperature cold day SoCalGas core.
(2) 1-in-10 peak temperature cold day for Hdd-sensitive load. Includes SoCalGas non-core and wholesale non-EG.
(3) UEG/EWG Base Hydro + all other EG.

Summer Peak Day Demand
(MMcf/Day)

Year	Core (1)	Noncore NonEG (2)	Electric Generation (3)	Total Demand
2010	594	538	1,732	2,863
2011	590	536	1,733	2,859
2012	590	529	1,893	3,012
2013	588	526	1,763	2,876
2014	586	523	1,885	2,994
2015	585	520	1,836	2,941
2016	586	514	1,807	2,907

Notes:
(1) Average daily summer (August) demand SoCalGas core.
(2) Average daily summer (August) demand. (Includes SoCalGas retail and wholesale load).
(3) Peak day summer
(4) (August) load under 1-in-10 dry hydro condition

2010 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY
TABULAR DATA

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2005 TO 2009

Line			2005	2006	2007	2008	2009	Line
	GAS SUPPLY TAKEN							
1	California Source Gas		274	242	232	209	216	1
	Out-of-State Gas							
2	Pacific Interstate Companies		-	-	-	-	-	2
3	Other Out-of-State		2,220	2,386	2,462	2,585	2,397	3
4	Total Out-of-State Gas		2,220	2,386	2,462	2,585	2,397	4
5	TOTAL SUPPLY TAKEN		2,494	2,628	2,694	2,794	2,613	5
6	Net Underground Storage Withdrawal		(11)	13	23	(28)	8	6
7	TOTAL THROUGHPUT (1)(2)		2,483	2,641	2,717	2,766	2,621	7
	DELIVERIES BY END-USE (3)							
8	Core	Residential	660	678	673	659	645	8
9		Commercial	211	215	224	211	210	9
10		Industrial	65	65	65	64	59	10
11		NGV	20	21	23	25	26	11
12		Subtotal	956	979	985	959	940	12
13	Noncore	Commercial	60	63	60	59	56	13
14		Industrial	344	347	345	341	324	14
15		EOR Steaming	34	39	39	39	35	15
16		Electric Generation	676	769	849	907	811	16
17		Subtotal	1,114	1,218	1,293	1,346	1,226	17
18	Wholesale/International		393	394	406	422	412	18
19	Co. Use & LUAF		20	50	33	39	43	19
20	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,483	2,641	2,717	2,766	2,621	20
	TRANSPORTATION AND EXCHANGE							
21	Core	All End Uses	7	11	14	17	20	21
22	Noncore	Commercial/Industrial	404	410	405	400	380	22
23		EOR Steaming	34	39	39	39	35	23
24		Electric Generation	676	769	849	907	811	24
25		Subtotal-Retail	1,121	1,229	1,307	1,363	1,246	25
26	Wholesale/International		393	394	406	422	412	26
27	TOTAL TRANSPORTATION & EXCHANGE		1,514	1,623	1,713	1,785	1,658	27
	CURTAILMENT (RETAIL & WHOLESALE)							
28		Core						28
29		Noncore						29
30		TOTAL - Curtailment						30
31	REFUSAL							31
32		Dth/Mcf	1.0276	1.0302	1.0305	1.0300	1.0273	32

NOTES:

	2005	2006	2007	2008	2009
(1) Exclude own-source gas supply of procurement by Edison and City of Long Beach.	2	1	4	4	2

(2) Deliveries by end-use includes sales, transportation, and exchange volumes.
(3) Data includes effect of prior period adjustments.

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2010 THRU 2014

AVERAGE TEMPERATURE YEAR

LINE			2010	2011	2012	2013	2014	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		160	160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,590	1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	7
	GAS SUPPLY TAKEN							
8	California Source Gas		310	310	310	310	310	8
9	Out-of-State		2,272	2,245	2,243	2,235	2,230	9
10	TOTAL SUPPLY TAKEN		2,582	2,555	2,553	2,545	2,540	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 4/		2,582	2,555	2,553	2,545	2,540	12
	REQUIREMENTS FORECAST BY END-USE 5/							
13	CORE 6/	Residential	633	625	623	619	617	13
14		Commercial	215	216	216	217	217	14
15		Industrial	56	55	54	53	52	15
16		NGV	27	28	28	29	30	16
17		Subtotal-CORE	931	924	922	919	916	17
18	NONCORE	Commercial	53	51	50	48	46	18
19		Industrial	305	304	297	295	294	19
20		EOR Steaming	30	29	29	29	29	20
21		Electric Generation (EG)	781	787	799	795	795	21
22		Subtotal-NONCORE	1,169	1,171	1,175	1,167	1,164	22
23	WHOLESALE &	Core	176	176	175	176	176	23
24	INTERNATIONAL	Noncore Excl. EG	43	43	44	45	45	24
25		Electric Generation (EG)	232	211	207	208	209	25
26		Subtotal-WHOLESALE & INTL.	451	430	427	429	430	26
27		Co. Use & LUAF	30	30	30	30	30	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,582	2,555	2,553	2,545	2,540	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	20	20	20	20	20	29
30	NONCORE	Commercial/Industrial	358	355	347	342	340	30
31		EOR Steaming	30	29	29	29	29	31
32		Electric Generation (EG)	781	787	799	795	795	32
33		Subtotal-RETAIL	1,190	1,191	1,195	1,187	1,184	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	451	430	427	429	430	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,641	1,621	1,621	1,616	1,614	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)

	2010	2011	2012	2013	2014
4/ Excludes own-source gas supply f o gas procurement by the City of Long Beach	4	3	3	3	3
5/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.					
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	935	928	926	923	921

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2015 THRU 2030

AVERAGE TEMPERATURE YEAR

LINE			2015	2020	2025	2030	LINE
	CAPACITY AVAILABLE						
1	California Line 85 Zone (California Producers)		160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	2
	Out-of-State Gas		0	0	0	0	
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) [1/]		765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) [2/]		1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) [3/]		1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	7
	GAS SUPPLY TAKEN						
8	California Source Gas		310	310	310	310	8
9	Out-of-State		2,235	2,163	2,148	2,157	9
10	TOTAL SUPPLY TAKEN		2,545	2,473	2,458	2,467	10
11	Net Underground Storage Withdrawal		0	0	0	0	11
12	TOTAL THROUGHPUT [4/]		2,545	2,473	2,458	2,467	12
	REQUIREMENTS FORECAST BY END-USE [5/]						
13	CORE [6/]	Residential	618	623	624	626	13
14		Commercial	216	214	215	219	14
15		Industrial	51	45	37	35	15
16		NGV	31	35	40	46	16
17		Subtotal-CORE	916	916	917	927	17
18	NONCORE	Commercial	44	35	27	28	18
19		Industrial	293	274	261	255	19
20		EOR Steaming	29	29	29	29	20
21		Electric Generation (EG)	802	771	774	775	21
22		Subtotal-NONCORE	1,168	1,110	1,091	1,087	22
23	WHOLESALE &	Core	176	179	184	189	23
24	INTERNATIONAL	Noncore Excl. EG	45	46	47	48	24
25		Electric Generation (EG)	210	193	190	188	25
26		Subtotal-WHOLESALE & INTL.	432	418	421	424	26
27		Co. Use & LUAF	30	29	29	29	27
28	SYSTEM TOTAL THROUGHPUT [4/]		2,545	2,473	2,458	2,467	28
	TRANSPORTATION AND EXCHANGE						
29	CORE	All End Uses	20	20	20	20	29
30	NONCORE	Commercial/Industrial	337	309	288	283	30
31		EOR Steaming	29	29	29	29	31
32		Electric Generation (EG)	802	771	774	775	32
33		Subtotal-RETAIL	1,188	1,129	1,111	1,107	33
	WHOLESALE &						
34	INTERNATIONAL	All End Uses	432	418	421	424	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,620	1,547	1,532	1,531	35
	CURTAILMENT (RETAIL & WHOLESALE)						
36		Core	0	0	0	0	36
37		Noncore	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)

	2015	2020	2025	2030
4/ Excludes own-source gas supply f o gas procurement by the City of Long Beach	3	3	2	2

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

	2015	2020	2025	2030
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	920	921	922	932

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2010 THRU 2014

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2010	2011	2012	2013	2014	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		160	160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,590	1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	7
	GAS SUPPLY TAKEN							
8	California Source Gas		310	160	160	160	160	8
9	Out-of-State		2,363	2,586	2,581	2,576	2,568	9
10	TOTAL SUPPLY TAKEN		2,673	2,746	2,741	2,736	2,728	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 4/		2,673	2,746	2,741	2,736	2,728	12
	REQUIREMENTS FORECAST BY END-USE 5/							
13	CORE 6/	Residential	693	685	683	678	676	13
14		Commercial	226	228	228	229	228	14
15		Industrial	57	56	55	54	53	15
16		NGV	27	28	28	29	30	16
17		Subtotal-CORE	1,004	996	994	991	988	17
18	NONCORE	Commercial	55	53	51	49	47	18
19		Industrial	305	304	297	295	294	19
20		EOR Steaming	30	29	29	29	29	20
21		Electric Generation (EG)	781	873	882	883	879	21
22		Subtotal-NONCORE	1,171	1,258	1,260	1,256	1,249	22
23	WHOLESALE &	Core	191	190	190	191	191	23
24	INTERNATIONAL	Noncore Excl. EG	43	43	44	45	45	24
25		Electric Generation (EG)	233	226	222	222	223	25
26		Subtotal-WHOLESALE & INTL.	467	460	456	458	459	26
27		Co. Use & LUAF	31	32	32	32	32	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,673	2,746	2,741	2,736	2,728	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	21	21	21	21	21	29
30	NONCORE	Commercial/Industrial	360	356	348	344	341	30
31		EOR Steaming	30	29	29	29	29	31
32		Electric Generation (EG)	781	873	882	883	879	32
33		Subtotal-RETAIL	1,192	1,280	1,281	1,277	1,271	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	467	460	456	458	459	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,660	1,739	1,737	1,735	1,729	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)

	2010	2011	2012	2013	2014
4/ Excludes own-source gas supply of gas procurement by the City of Long Beach	4	3	3	3	3

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

	2010	2011	2012	2013	2014
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	1,009	1,001	999	996	993

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2015 THRU 2030

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2015	2020	2025	2030	LINE
	CAPACITY AVAILABLE						
1	California Line 85 Zone (California Producers)		160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	2
	Out-of-State Gas		0	0	0	0	
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) [1/]		765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) [2/]		1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST,KR) [3/]		1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,725	3,725	3,725	3,725	7
	GAS SUPPLY TAKEN						
8	California Source Gas		310	310	310	310	8
9	Out-of-State		2,423	2,356	2,342	2,351	9
10	TOTAL SUPPLY TAKEN		2,733	2,666	2,652	2,661	10
11	Net Underground Storage Withdrawal		0	0	0	0	11
12	TOTAL THROUGHPUT [4/]		2,733	2,666	2,652	2,661	12
	REQUIREMENTS FORECAST BY END-USE [5/]						
13	CORE [6/]	Residential	676	682	683	686	13
14		Commercial	228	225	226	231	14
15		Industrial	52	46	38	35	15
16		NGV	31	35	40	46	16
17		Subtotal-CORE	987	988	988	999	17
18	NONCORE	Commercial	46	36	29	29	18
19		Industrial	293	274	261	255	19
20		EOR Steaming	29	29	29	29	20
21		Electric Generation (EG)	882	864	867	868	21
22		Subtotal-NONCORE	1,250	1,204	1,185	1,181	22
23	WHOLESALE &	Core	191	194	200	205	23
24	INTERNATIONAL	Noncore Excl. EG	45	46	47	48	24
25		Electric Generation (EG)	228	203	201	198	25
26		Subtotal-WHOLESALE & INTL.	465	444	447	451	26
27		Co. Use & LUAF	32	31	31	31	27
28	SYSTEM TOTAL THROUGHPUT [4/]		2,733	2,666	2,652	2,661	28
	TRANSPORTATION AND EXCHANGE						
29	CORE	All End Uses	21	21	21	21	29
30	NONCORE	Commercial/Industrial	338	311	289	284	30
31		EOR Steaming	29	29	29	29	31
32		Electric Generation (EG)	882	864	867	868	32
33		Subtotal-RETAIL	1,271	1,224	1,206	1,202	33
34	WHOLESALE & INTERNATIONAL	All End Uses	465	444	447	451	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,736	1,668	1,654	1,653	35
	CURTAILMENT (RETAIL & WHOLESALE)						
36		Core	0	0	0	0	36
37		Noncore	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	38

NOTES:

1/ Wheeler Ridge Zone: KR & MP at Wheeler Ridge, PG&E at Kern Stn., OEHI at Gosford)
2/ Southern Zone (EPN at Ehrenberg, TGN at Otay Mesa, NBP at Blythe)
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.)

	2015	2020	2025	2030
4/ Excludes own-source gas supply for gas procurement by the City of Long Beach	3	3	2	2

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

	2015	2020	2025	2030
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	992	993	994	1,004

2010 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT

CITY OF LONG BEACH MUNICIPAL GAS & OIL DEPARTMENT

The annual gas supply and requirements for the Long Beach Gas & Oil Department (Long Beach) are shown on the following tables for the years 2005 through 2030. Long Beach prepared all forecast requirements with SoCalGas assisting in the preparation of the core demand forecast.

Serving approximately 145,000 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 55 percent residential and 45 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 a small amount 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. Currently, Long Beach receives approximately 15% of its gas supply from local production. The majority of Long Beach supplies are 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.

2010 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT
TABULAR DATA

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2005 THRU 2009

LINE	GAS SUPPLY AVAILABLE	2005	2006	2007	2008	2009	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	4	1	4	4	2	13
14	Received for Exchange/Transport	0	0	0	0	0	14
15	Total California Source Gas	4	1	4	4	2	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	29	30	26	23	23	19
20	Out-of-State Transport	0	0	0	0	0	20
21	Total Out-of-State Gas	29	30	26	23	23	21
22	Subtotal	33	31	31	27	25	22
23	Underground Storage Withdrawal	0	0	0	0	0	23
24	TOTAL Gas Supply Taken & Transported	33	31	31	27	25	24

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2005 THRU 2009

LINE	ACTUAL DELIVERIES BY END-USE		2005	2006	2007	2008	2009	LINE
1	CORE	Residential	16	15	15	14	14	1
2	CORE/NONCORE	Commercial	7	7	7	7	6	2
3	CORE/NONCORE	Industrial	7	7	7	5	4	3
4		Subtotal	30	28	29	26	24	4
5	NON CORE	Non-EOR Cogeneration	3	1.2	1	1	0.4	5
6		EOR Cogen. & Steaming	0	0	0	0	0	6
7		Electric Utilities	0	0	0	0	0	7
8		Subtotal	3	1.2	1	1	0.4	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	0.9	0.1	0.7	0.5	13
14		Subtotal-END USE	33	31	30	27	25	14
15		Storage Injection	0	0	0	0	0	15
16	SYSTEM TOTAL-THROUGHPUT		33	31	30	27	25	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	29	30	26	23	23	22
23	WHOLESALE	All End Uses	0	0	0	0	0	23
24	TOTAL TRANSPORTATION & EXCHANGE		29	30	26	23	23	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 - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY

ESTIMATED YEARS 2010 THRU 2014

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2010	2011	2012	2013	2014	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		4	3	3	3	3	4
5	Out-of-State Gas		23	23	23	24	23	5
6	TOTAL SUPPLY TAKEN		27	26	26	26	26	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		27	26	26	26	26	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	14	14	14	14	14	9
10		Commercial	5	5	5	5	5	10
11		NGV	0.1	0.1	0.1	0.1	0.1	11
12		Subtotal-CORE	20	20	20	20	20	12
13	NONCORE	Industrial	5	5	5	5	5	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	7	6	6	6	6	18
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	0.3	19
20	SYSTEM TOTAL THROUGHPUT (1)		26	26	26	26	26	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	18	18	18	18	18	22
23	NONCORE	Industrial	5	5	5	5	5	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	7	6	6	6	6	27
28	TOTAL TRANSPORTATION		24	24	24	24	24	28

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

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2015 THRU 2030

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2015	2017	2020	2025	2030	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		3	2	2	2	2	4
5	Out-of-State Gas		24	24	24	25	25	5
6	TOTAL SUPPLY TAKEN		27	26	26	27	27	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		27	26	26	27	27	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	14	14	15	15	15	9
10		Commercial	5	5	5	5	5	10
11		NGV	0.1	0.1	0.1	0.1	0.1	11
12		Subtotal-CORE	20	20	20	20	20	12
13	NONCORE	Industrial	5	5	5	5	5	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	6	6	6	6	6	18
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	0.3	19
20	SYSTEM TOTAL THROUGHPUT (1)		26	26	26	26	27	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	18	19	19	19	20	22
23	NONCORE	Industrial	5	5	5	5	5	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	6	6	6	6	6	27
28	TOTAL TRANSPORTATION		25	25	25	26	26	28

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

2010 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

San Diego Gas & Electric Company (SDG&E) is a combined gas and electric distribution utility serving more than three million people in San Diego and the southern portions of Orange counties. SDG&E delivers natural gas to over 845,000 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 2009 were approximately 125 billion cubic feet (Bcf), which is an average of over 324 million cubic feet per day (MMcf/day).

The Gas Supply, Capacity, and Storage section for SDG&E has been moved to SoCalGas' due to the integration of gas procurement and system integration functions into one combined SDG&E/SoCalGas system per D. 07-12-019 (natural gas operations and service offerings) and D. 06-12-031 (system integration.)

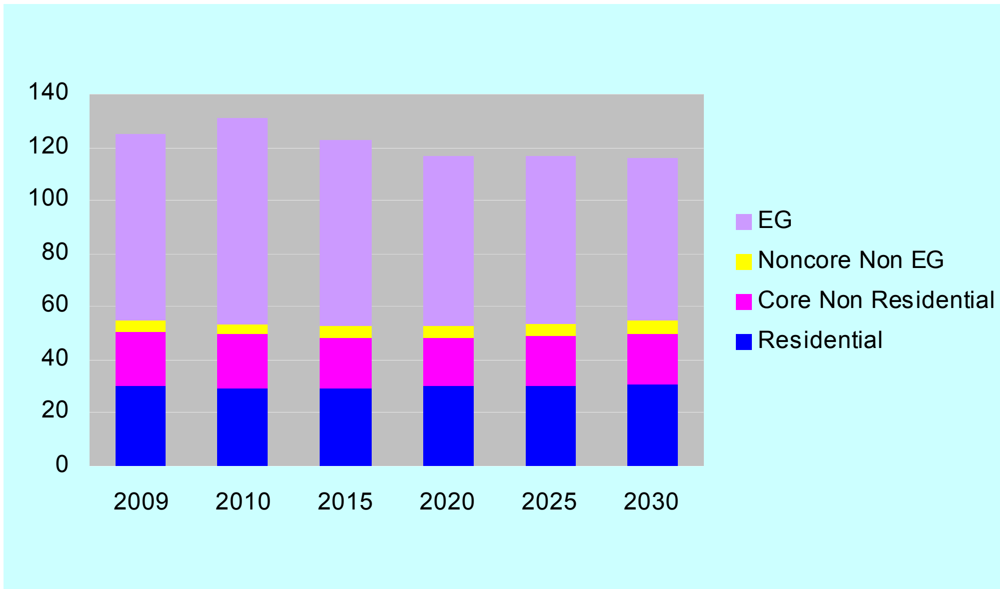
GAS DEMAND

OVERVIEW

SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above.

This projection of natural gas requirements, excluding electric generation (EG) demand, is derived from models that integrate demographic assumptions, economic growth, energy prices, energy efficiency programs, customer information programs, building and appliance standards, weather and other factors. Non-EG gas demand is projected to remain flat between 2009 and 2030. The total load, including EG, is expected to decline from a total of 125 Bcf in 2009 to 116 Bcf by 2030. Assumptions for SDG&E's gas transport requirements for EG are included as part of the wholesale market sector description for Southern California Gas Company.

Composition of SDG&E Gas Throughput (Bcf)
Average Temperature and Normal Hydro Year



MARKET SECTORS

Residential

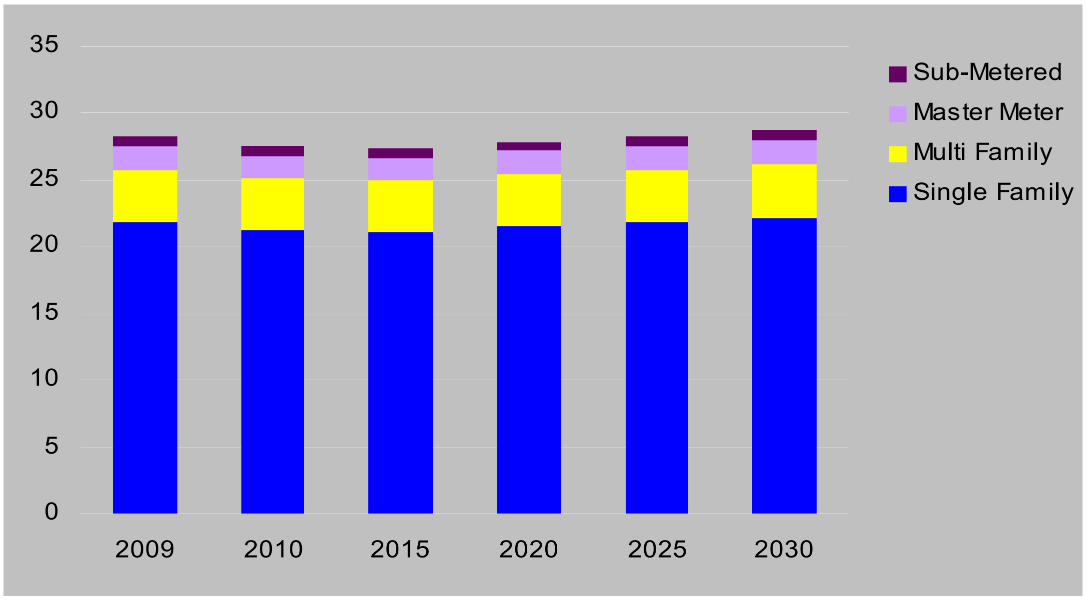
The total residential customer count for SDG&E consists of four residential segment types. These are single family and multi-family customers, as well as master meter and sub-metered customers. The active meters for all residential customer classes averaged 842,442 in 2009. This total reflects a 4,205 meter increase relative to the 2008 total. The overall observed 2008-2009 residential meter growth was 0.5%.

Residential demand adjusted for average temperature conditions totaled 28 Bcf in 2009. By the year 2030, the residential demand is expected to reach 29 Bcf. The change reflects a 3.5% growth rate over the 2009-2030 period.

Use per meter for all classes of residential customers is anticipated to decline due to the expected energy savings from tightened building and appliance standards and CPUC-authorized energy efficiency programs. In 2008, the weather normalized residential use per customer was 389 therms. In 2009, the weather normalized residential use per customer fell to 377.5 therms, or by 2.96%.

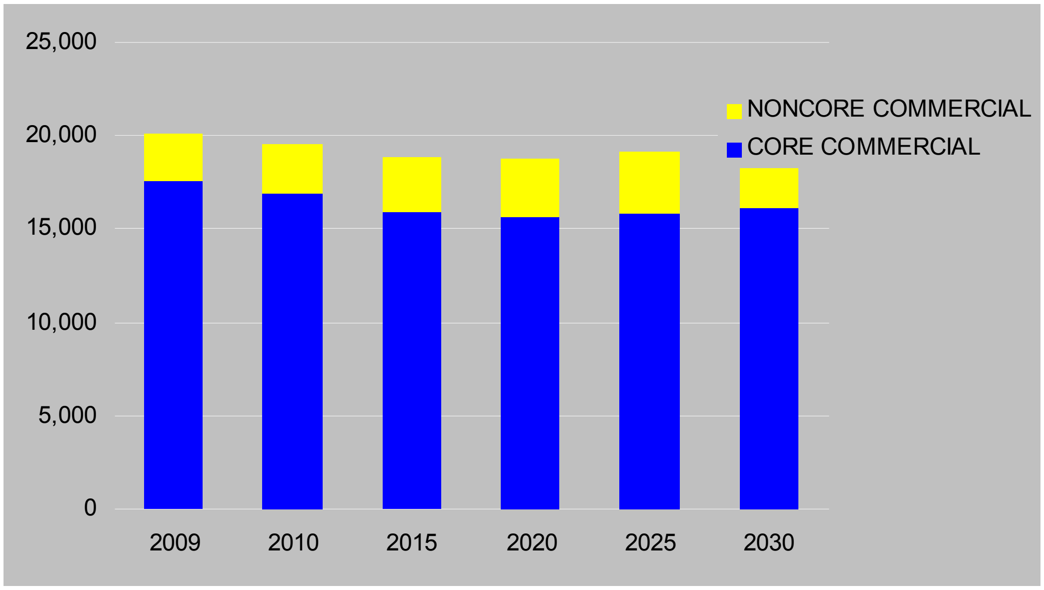
The projected residential natural gas demand will be influenced primarily by residential meter growth moderated by the forecasted declining use per customer due to energy efficiency improvements in the building shell design, appliance efficiency and CPUC-authorized EE programs plus the additional efficiency gains associated from advanced metering.

SDG&E Residential Demand Forecast (Bcf) (2009-2030)



Commercial

SDG&E Commercial Demand Forecast (MMcf)



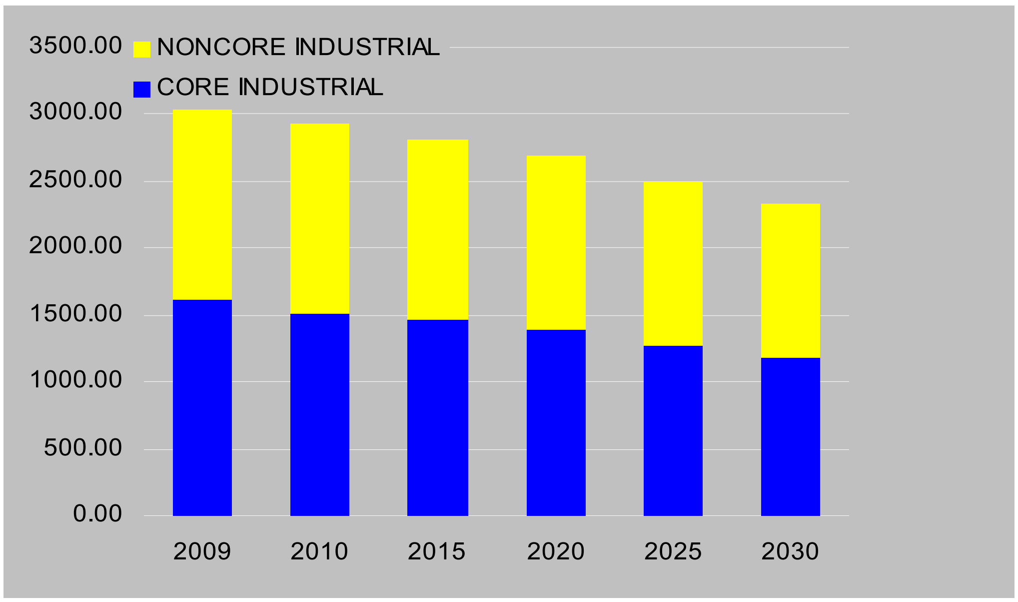
On a temperature-adjusted basis, the core commercial market demand in 2009 totaled 17.6 Bcf. By the year 2030, the SDGE core commercial load is expected to decline to 16.1 Bcf, a reduction of approximately 1.5 Bcf. This change reflects an annual average reduction in commercial load by approximately -0.4%. The annual load reduction that is anticipated over the forecast period can be attributed to CPUC-mandated energy efficiency programs. The effect of the CPUC-authorized energy efficiency programs is expected to reduce core commercial gas demand.

SDG&E's non-core commercial load in 2009 was 2.5 Bcf. Over the forecast period, gas demand in this market is projected show healthy growth mostly driven by increased economic activity and employment. Non-core commercial load is projected to grow to 3.6 Bcf by 2030, or an average annual increase of nearly 2%.

Industrial

In 2009, temperature-adjusted core industrial demand was 1.6 Bcf. The core industrial market demand is projected to decrease at an average rate of 1% per year from 1.6 Bcf in 2009 to 1.2 Bcf in 2030. This result is due to slightly lower forecasted growth in industrial production, the impact of CPUC-authorized energy-efficiency programs savings in the industrial sector, and further energy savings associated with the Advanced Metering Program (AMI).

SDG&E Industrial Demand Forecast (MMcf)

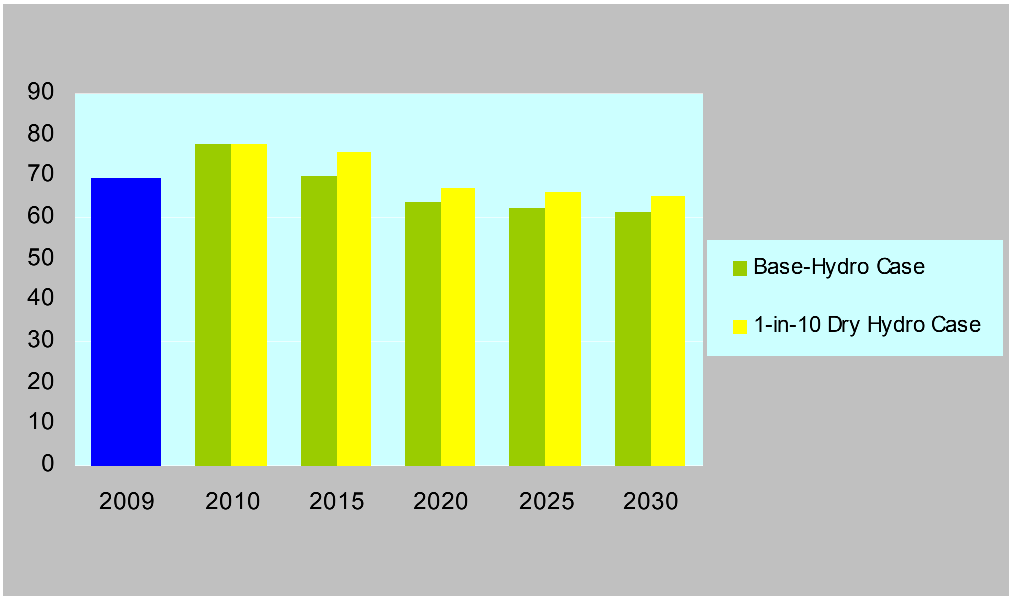


Non-core industrial load in 2009 was 1.6 Bcf and is expected to decline at an average rate of -1.5% per year to 1.16 Bcf by 2030. CPUC-mandated energy efficiency programs more than offset any modest gains from industrial economic growth. Energy efficiency savings are expected to reduce noncore industrial load by 0.022 Bcf per year, accounting for the entire expected drop in demand from 2009 to 2030.

Electric Generation

Total EG, including cogeneration and non-cogeneration EG, is expected to decrease at an annual average rate of 0.56 percent from 70 Bcf in 2009 to 62 Bcf in 2030. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.

SDG&E Service Area Total Electric Generation Forecast (Bcf)



Cogeneration

Small EG load from self-generation totaled 23.6 Bcf in 2009. Small EG load in 2030 is expected to be nearly the same as in 2009. This long-term outlook for no growth is lower than the 0.5% annual growth previously forecasted in the 2008 California Gas Report. The reduction in growth is due to an updated slower-growth outlook for the SDG&E area's industrial employment.

Non-Cogeneration Electric Generation

The forecast of the large EG loads in SDG&E's service area is based on the power market simulation as noted in the SoCalGas' Electric Generation chapter for "Non-Cogeneration EG" demand. This forecast includes approximately 750 MW of new thermal peaking generating resources in its service area by the end of 2020. However, approximately 1,400 MW of the existing plants were retired during the same time period. EG demand is forecasted to decrease from 48 Bcf in 2010 to 39 Bcf in 2020 due to the addition of a new electric transmission in 2012 and 33% state-wide renewables by 2020. The EG forecast is held constant at 2020 levels for 2025 and 2030 as previously explained.

SDG&E performed a 1-in-10 year dry hydro sensitivity forecast. Due to the displacement of the hydro generation by other off-system resources, the impact of significant hydro conditions had less impact on SDG&E's EG gas demand. A dry hydro year, increased SDG&E's EG demand on average for the forecast period by 5 Bcf per year. For additional information on EG assumption, such as renewable generation, greenhouse gas and sensitivity to electric demand and renewables goal, refer to the Non-Cogeneration Electric Generation in the SoCalGas Electric Generation chapter.

Natural Gas Vehicles (NGV)

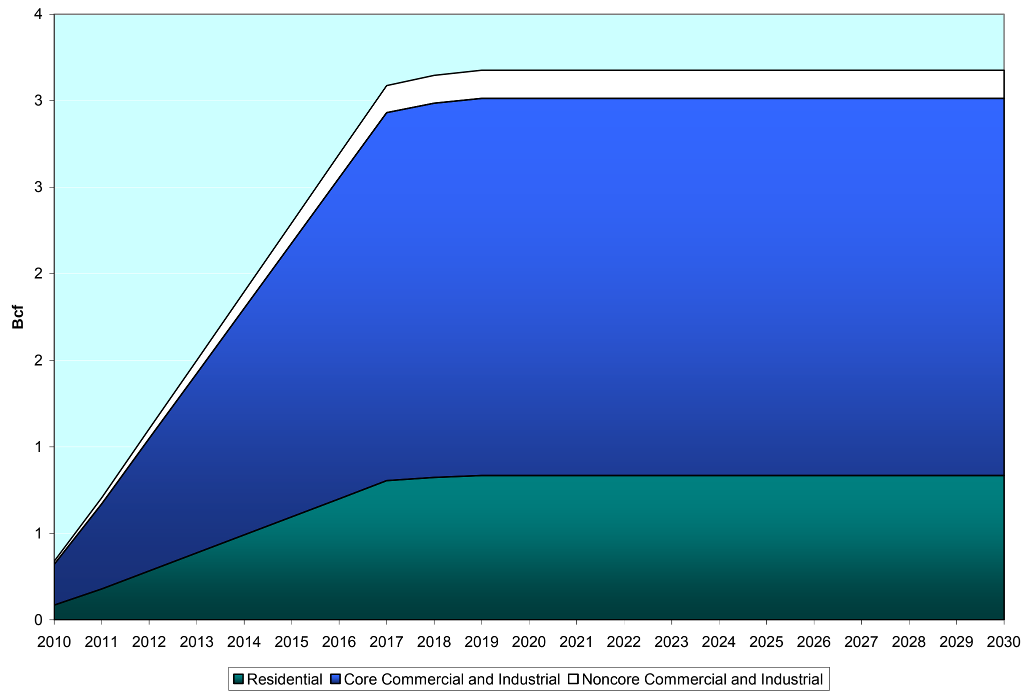
The NGV market is forecast to continue to grow due to federal, state and local incentives and regulations related to the purchase and operation of alternate fuel vehicles coupled with rapidly increasing cost of petroleum (gasoline and diesel). At the end of 2009, there were 28 compressed natural gas (CNG) fueling stations delivering 1.01 Bcf of natural gas during the year. SDG&E expects the NGV market to continue to experience slow growth, since transit fleets account for most of the demand and are very close to fleet saturation levels.

ENERGY EFFICIENCY PROGRAMS

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 while still maintaining 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 the Energy Efficiency programs.

The cumulative net Energy Efficiency load impact forecast for selected years is provided in the graph in the next page. The net load impact includes all Energy Efficiency programs that SDG&E has forecasted to implement starting from the years 2010 through 2026. Savings and goals for these programs are based on the program goals authorized by the Commission in D.09-09-047.

Energy Efficiency Cumulative Savings Goal (Bcf)



Savings reported are for measures installed under SDG&E's Energy Efficiency programs. Credit is only taken for measures that are installed as a result of SDG&E's Energy Efficiency programs, and only for the measure lives of the measures installed. Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. This means, for example, that a measure installed in 2005 with a lifetime of 10 years is only included in the forecast through 2014. Naturally occurring conservation that is not attributable to SDG&E's Energy Efficiency activities is not included in the Energy Efficiency forecast.

Details of SDG&E's 2010-2012 Energy Efficiency program portfolio are contained in SDG&E's A.08-07-022 which was submitted on July 2, 2009 and became effective January 1, 2010. The full application is available at the following site: http://www.sdge.com/regulatory/A08-07-023.shtml

Notes:
(1) "Hard" impacts include measures requiring a physical equipment modification or replacement.
(2) SDG&E does not include "soft" impacts, e.g., energy management services type measures.
(3) The assumed average measure life is 10 years.

GAS SUPPLY

Beginning April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined SoCalGas/SDG&E portfolio per Decision 07-12-019 December 6, 2007. Refer to the Gas Supply, Capacity and Storage section in the Southern California area for more information.

PEAK DAY DEMAND

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio with a total firm storage withdrawal capacity designed to serve the utilities' combined retail core peak-day gas demand. Please see the corresponding discussion of "Peak Day Demand and Deliverability" under the SoCalGas portion of this report for an illustration of how storage and flowing supplies can meet the growth in forecasted load for the combined (SoCalGas plus SDG&E) retail core peak day demand.

2010 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY
TABULAR DATA

ANNUAL GAS SUPPLY TAKEN (MMCF/DAY)
RECORDED YEARS 2002-2009

LINE		2005	2006	2007	2008	2009
	CAPACITY AVAILABLE					
1	**California Sources**					
	Out of State gas					
2	California Offshore (POPCO/PIOC)					
3	El Paso Natural Gas Company					
4	Transwestern Pipeline company					
5	Kern River/Mojave Pipeline Company					
6	TransCanada GTN/PG&E					
7	Other					
8	**TOTAL Output of State**					
9	Underground storage withdrawal					
10	**TOTAL Gas Supply available**					

LINE	Gas Supply Taken	2005	2006	2007	2008	2009
	California Source Gas					
11	Regular Purchases	6	6	6	10	0
12	Received for Exchange/Transport	0	0	0	0	0
13	**Total California Source Gas**	6	6	6	10	0
14	**Purchases from Other Utilities**	0	0	0	0	0
	Out-of-State Gas					
15	Pacific Interstate Companies	0	0	0	0	0
16	Additional Core Supplies	0	0	0	0	0
17	Supplemental Supplies-Utility	143	131	140	119	125
18	Out-of-State Transport-Others	174	191	176	204	199
19	**Total Out-of-State Gas**	317	322	316	323	324
20	**TOTAL Gas Supply Taken & Transported**	323	328	322	334	324

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND SENDOUT (MMCF/DAY)
RECORDED YEARS 2005-2009

LINE			2005	2006	2007	2008	2009
	Actual Deliveries by End-Use						
1	**CORE**	Residential	86	86	89	86	82
2		Commercial	48	48	49	49	48
3		Industrial	0	0	0	0	0
4	*Subtotal -*	*CORE*	134	133	138	135	130
5	**NONCORE**	Commercial	0	0	0	0	0
6		Industrial	10	12	9	12	11
7		Non-EOR Cogen/EG	163	131	101	119	115
8		Electric Utilities	0	47	63	68	64
9	*Subtotal -*	*NONCORE*	174	189	173	199	191
10	**WHOLESALE**	All End Uses	0	0	0	0	0
11	*Subtotal -*	*Co Use & LUAF*	15	5	11	2	3
12	**SYSTEM TOTAL THROUGHPUT**		323	328	322	336	324
	Actual Transport & Exchange						
13	**CORE**	Residential	0	0	0	0	0
14		Commercial	2	3	4	6	8
15	**NONCORE**	Industrial	9	11	9	12	11
16		Non-EOR Cogen/EG	162	130	100	119	115
17		Electric Utilities	0	47	63	68	64
18	*Subtotal -*	*RETAIL*	174	191	176	205	199
19	**WHOLESALE**	All End Uses	0	0	0	0	0
20	**TOTAL TRANSPORT & EXCHANGE**		174	191	176	205	199
	Storage						
21		*Storage Injection*	12	13	15	15	0
22		*Storage Withdrawal*	21	8	15	15	0
	Actual Curtailment						
23		Residential	0	0	0	0	0
24		Com/Indl & Cogen	0	0	0	0	0
25		Electric Generation	0	0	0	0	0
26	**TOTAL CURTAILMENT**		0	0	0	0	0
27	**REFUSAL**		0	0	0	0	0
	ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes						
		MMbtu/Mcf:	1.015	1.017	1.022	1.023	1.020

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2010 THRU 2014

AVERAGE TEMPERATURE YEAR

LINE			2010	2011	2012	2013	2014	LINE
	CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas 1/		607	607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	607	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		364	341	339	339	339	5
6	TOTAL SUPPLY TAKEN		364	341	339	339	339	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		364	341	339	339	339	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	81	80	80	80	80	9
10		Commercial	46	45	45	45	44	10
11		Industrial	4	4	4	4	4	11
12		NGV	4	4	4	4	4	12
13		Subtotal-CORE	135	133	133	133	132	13
14	NONCORE	Commercial	7	7	8	8	8	14
15		Industrial	4	4	4	4	4	15
16		Electric Generation (EG)	213	192	189	189	190	16
17		Subtotal-NONCORE	224	203	201	201	202	17
18		Co. Use & LUAF	5	5	5	5	5	18
19	SYSTEM TOTAL THROUGHPUT		364	341	339	339	339	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	9	9	9	9	9	20
21	NONCORE	Commercial/Industrial	11	11	11	12	12	21
22		Electric Generation (EG)	213	192	189	189	190	22
23	TOTAL TRANSPORTATION & EXCHANG		233	212	209	210	211	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:
1/ Capacity to receive gas from the Southern Zone of SoCalGas is an annual value based on weighting winter and non-winter season values: 607 = (630 winter) x (151/365) + (590 non-winter) x (214/365).
2/ For 2010 and after, assume capacity at same levels.
3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 128 126 126 126 125

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2015 THRU 2030

AVERAGE TEMPERATURE YEAR

LINE			2015	2020	2025	2030	LINE
	CAPACITY AVAILABLE 1/ & 2/						
1	California Source Gas		0	0	0	0	1
2	Southern Zone of SoCalGas 1/		607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	3
	GAS SUPPLY TAKEN						
4	California Source Gas		0	0	0	0	4
5	Out-of-State		342	324	321	323	5
6	TOTAL SUPPLY TAKEN		342	324	321	323	6
7	Net Underground Storage Withdrawal		0	0	0	0	7
8	TOTAL THROUGHPUT		342	324	321	323	8
	REQUIREMENTS FORECAST BY END-USE 3/						
9	CORE 4/	Residential	81	82	83	85	9
10		Commercial	44	43	43	44	10
11		Industrial	4	4	3	3	11
12		NGV	4	4	4	5	12
13		Subtotal-CORE	133	133	133	137	13
14	NONCORE	Commercial	8	9	9	10	14
15		Industrial	4	4	3	3	15
16		Electric Generation (EG)	192	174	172	169	16
17		Subtotal-NONCORE	204	187	184	182	17
18		Co. Use & LUAF	5	4	4	4	18
19	SYSTEM TOTAL THROUGHPUT		342	324	321	323	19
	TRANSPORTATION AND EXCHANGE						
20	CORE	All End Uses	9	9	9	9	20
21	NONCORE	Commercial/Industrial	12	12	13	13	21
22		Electric Generation (EG)	192	174	172	169	22
23	TOTAL TRANSPORTATION & EXCHANG		213	195	194	191	23
	CURTAILMENT						
24		Core	0	0	0	0	24
25		Noncore	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	26

NOTES:

1/ Capacity to receive gas from the Southern Zone of SoCalGas is an annual value based on weighting winter and non-winter season values: 607 = (630 winter) x (151/365) + (590 non-winter) x (214/365).

2/ For 2010 and after, assume capacity at same levels.

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

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:

	2015	2020	2025	2030
transportation (CAT) in MDth/d:	126	126	126	131

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2010 THRU 2014

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2010	2011	2012	2013	2014	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		607	607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	607	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Out-of-State		377	368	364	364	364	5
6	TOTAL SUPPLY TAKEN		377	368	364	364	364	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		377	368	364	364	364	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	90	89	89	89	89	9
10		Commercial	50	49	48	48	47	10
11		Industrial	4	4	4	4	4	11
12		NGV	4	4	4	4	4	12
13		Subtotal-CORE	148	146	145	145	144	13
14	NONCORE	Commercial	7	7	8	8	8	14
15		Industrial	4	4	4	4	4	15
16		Electric Generation (EG)	213	206	202	202	203	16
17		Subtotal-NONCORE	224	217	214	214	215	17
18		Co. Use & LUAF	5	5	5	5	5	18
19	SYSTEM TOTAL THROUGHPUT		377	368	364	364	364	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	10	10	10	10	9	20
21	NONCORE	Commercial/Industrial	11	11	11	12	12	21
22		Electric Generation (EG)	213	206	202	202	203	22
23	TOTAL TRANSPORTATION & EXCHANG		234	227	223	224	224	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:
1/ Capacity to receive gas from the Southern Zone of SoCalGas is an annual value based on weighting winter an non-winter season values: 607 = (630 winter) x (151/365) + (590 non-winter) x (214/365).
2/ For 2010 and after, assume capacity at same levels.
3/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:

	2010	2011	2012	2013	2014
transportation (CAT) in MDth/d:	141	139	138	138	138

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2015 THRU 2030

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

LINE			2015	2020	2025	2030	LINE
	CAPACITY AVAILABLE 1/ & 2/						
1	California Source Gas		0	0	0	0	1
2	Southern Zone of SoCalGas 1/		607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	3
	GAS SUPPLY TAKEN						
4	California Source Gas		0	0	0	0	4
5	Out-of-State		369	345	344	345	5
6	TOTAL SUPPLY TAKEN		369	345	344	345	6
7	Net Underground Storage Withdrawal		0	0	0	0	7
8	TOTAL THROUGHPUT		369	345	344	345	8
	REQUIREMENTS FORECAST BY END-USE 3/						
9	CORE 4/	Residential	89	90	92	93	9
10		Commercial	47	46	46	47	10
11		Industrial	4	4	4	3	11
12		NGV	4	4	4	5	12
13		Subtotal-CORE	144	144	146	148	13
14	NONCORE	Commercial	8	9	9	10	14
15		Industrial	4	4	3	3	15
16		Electric Generation (EG)	208	183	181	179	16
17		Subtotal-NONCORE	220	196	193	192	17
18		Co. Use & LUAF	5	5	5	5	18
19	SYSTEM TOTAL THROUGHPUT		369	345	344	345	19
	TRANSPORTATION AND EXCHANGE						
20	CORE	All End Uses	9	9	10	10	20
21	NONCORE	Commercial/Industrial	12	12	13	13	21
22		Electric Generation (EG)	208	183	181	179	22
23	TOTAL TRANSPORTATION & EXCHANG		229	204	204	202	23
	CURTAILMENT						
24		Core	0	0	0	0	24
25		Noncore	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	26

NOTES:

1/ Capacity to receive gas from the Southern Zone of SoCalGas is an annual value based on weighting winter and non-winter season values: 607 = (630 winter) x (151/365) + (590 non-winter) x (214/365).

2/ For 2010 and after, assume capacity at same levels.

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

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:

	2015	2020	2025	2030
transportation (CAT) in MDth/d:	138	138	139	141

2010 CALIFORNIA GAS REPORT

GLOSSARY

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.

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.

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.

CEC
California Energy Commission.

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.

Conversion Factor (Natural Gas)

- 1 CF (Cubic Feet) = Approx. 1,000 BTUs
- 1 CCF = 100 CF = Approximately 1 Therm
- 1 Therm = 100,000 BTUs = Approximately 100 CF = 0.1 MCF
- 10 Therms = 1 Dth (dekatherm) = Approximately 1 MCF
- 1 MCF = 1,000 CF = Approximately 10 Therms = 1 MMBTU
- 1 MMCF = 1 million cubic feet = Approximately 1 MDth (1 thousand dekatherm)
- 1 BCF = 1 billion CF = Approximately 1 million MMBTU

Conversion Factor (Petroleum Products)

Approximate heat content of petroleum products (Million BTU per Barrel)

- Crude Oil 5.800
- Residual Fuel Oil 6.287
- Distillate Fuel Oil 5.825
- Petroleum Coke 6.024
- Butane 4.360
- Propane 3.836
- Pentane Plus 4.620
- Motor Gasoline 5.253

Conversion Factor (LNG)

Approximate LNG liquid conversion factor for one therm (High-Heat Value)

- Pounds 4.2020
- Gallons 1.1660
- Cubic Feet 0.1570
- Barrels 0.0280
- Cubic Meters 0.0044
- Metric Tonnes 0.0019

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 Customer (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^{o} 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.

Futures (Gas)

Unit of natural gas futures contract trades in units of 10,000 million British thermal units (MMBtu) at the New York Mercantile Exchange (NYMEX). The price is based on delivery at Henry Hub in Louisiana.

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. In D.03-12-061, the CPUC ordered the Gas Accord structure to continue for 2004 and 2005.

Key features of the Gas Accord structure 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; and establishing transmission and storage rates.

Gas Sendout

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

GHG

Greenhouse gases are the gases present in the atmosphere which reduce the loss of heat into space and therefore contribute to global temperatures through the greenhouse effect. The most the most abundant greenhouse gases are, in order of relative abundance are water vapor, carbon dioxide, methane, nitrous oxide, ozone and CFCs.

Heating Degree Day (HDD)

A heating degree day is accumulated for every degree Fahrenheit the daily average temperature is below a standard reference temperature (SoCalGas and SDG&E: 65ºF; PG&E 60ºF). A basis for computing how much electricity and gas are needed for space heating purposes. For example, for a 50ºF average temperature day, SoCalGas and SDG&E would accumulate 15 HDD, and PG&E would accumulate 10 HDD.

Heating Value

Number of BTU's liberated by the complete combustion at constant pressure of one cubic foot of natural gas at a base temperature of sixty degrees Fahrenheit (60°F) and a pressure base of fourteen and seventy-three hundredths (14.73) psia, with air at the same temperature and pressure as the natural gas, after the products of combustion are cooled to the initial temperature of natural gas, and after the water vapor of the combustion is condensed to the liquid state. The heating value of the natural gas shall be corrected for the water vapor content of the natural gas being delivered except that, if such content is seven (7) pounds or less per one million cubic feet, the natural gas shall be considered dry.

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 that has been super cooled to -260° F (-162° C) and condensed into a liquid that takes up 600 times less space than in its gaseous state.

Load Following

A utility's practice of adding additional generation to available energy supplies to meet moment-to-moment demand in the distribution system served by the utility, and for keeping generating facilities informed of load requirements to insure that generators are producing neither too little nor too much energy to supply the utilities customers.

MMBTU

Million British Thermal Units. One MMBTU is equals to 10 therms or one dekatherm.

MCF

The volume of natural gas which occupies 1,000 cubic feet when such gas is at a temperature of 60º Fahrenheit and at a standard pressure of approximately 15 pounds per square inch.

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 Served Load

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:

1. Firm Service – All noncore customers served through firm intrastate transmission service, including core subscription service.
2. 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:

1. Core Residential
2. Non-residential Core
3. Noncore using firm backbone service (including UEG)
4. Noncore using as-available backbone service (including UEG)
5. Market Center Services

PSIA

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

Purchase 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.

Wobbe

The Wobbe number of a fuel gas is found by dividing the high heating value of the gas in BTU per standard cubic feet (scf) by the square root of a specific gravity with respect to air. The higher a gases' Wobbe number, the greater the heating value of the quality of gas that will flow through a hole of a given size in a given amount of time.

2010 CALIFORNIA GAS REPORT

RESPONDENTS

RESPONDENTS

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

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

The following utilities also cooperated in the preparation of the report.

- City of Long Beach Municipal Gas and Oil Department
- Sacramento Municipal Utilities District
- Southern California Edison Company
- Southwest Gas Corporation
- ECOGAS Mexico, S. de R.L. de C.V

A statewide committee have been formed by the respondents and cooperating utilities to prepare this report. The following individuals served on this committee.

Working Committee

- Herbert Emmrich(Chairperson) – SoCalGas/SDG&E
- Rose-Marie Payan-SoCalGas/SDG&E
- Robert Anderson – SoCalGas/SDG&E
- Jeff Huang – SoCalGas /SDG&E
- Glen Holland – SDG&E
- Edwina Sai-PG&E
- Eric Hsu-PG&E
- Mark Minick - SCE
- David Sanchez- City of Long Beach Gas and Oil
- Lynn Marshall - CEC
- Ruben Tavares - CEC
- Angela Tanghetti – CEC
- William Wood – CEC

Observers

- Richard Myers– CPUC Energy Division
- Ruben Tavares– CEC
- Paul Deaver- CEC
- Angela Tanghetti- CEC

RESERVE YOUR SUBSCRIPTION

2011 CALIFORNIA GAS REPORT – SUPPLEMENT

Southern California Gas Company
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or

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Email: Herb Emmrich
HEmmrich@semprautilities.com

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Also, please visit our website at: www.socalgas.com
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RESERVE YOUR SUBSCRIPTION

2011 CALIFORNIA GAS REPORT – SUPPLEMENT

Pacific Gas and Electric Company
2011 CGR Reservation Form
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ExY3@pge.com

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