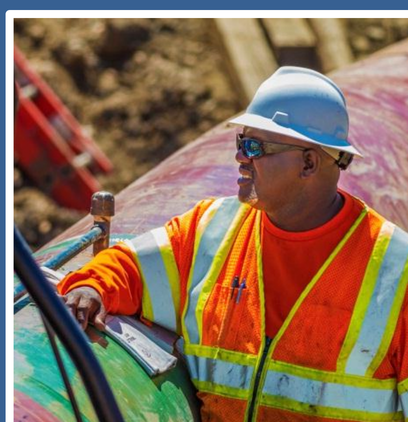
2016 CALIFORNIA GAS REPORT

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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2016 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The 2016 *California Gas Report* presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2035. 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, Southwest Gas Corporation, 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 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 on request from PG&E and SoCalGas/SDG&E. Write or email us at the address shown in the Reserve Your Subscription section at the end of this report.

2016 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

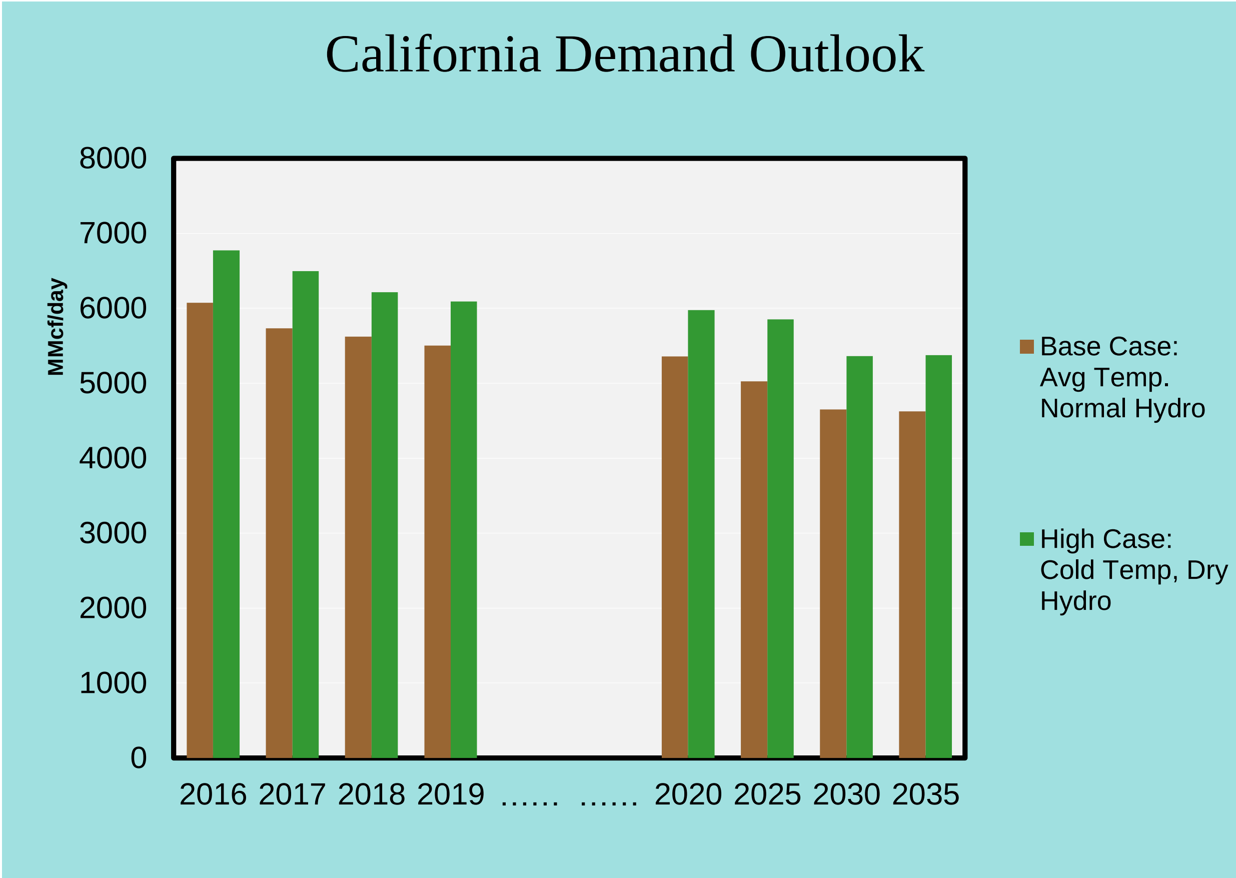
EXECUTIVE SUMMARY

DEMAND OUTLOOK

California natural gas demand, including volumes not served by utility systems, is expected to decrease at a rate of 1.4 percent per year from 2016 to 2035. The forecast decline is a combination of moderate growth in the Natural Gas Vehicle (NGV) market and across-the-board declines in all other market segments: residential, commercial, electric generation, and industrial markets.

Residential gas demand is expected to decrease at an annual average rate of 0.5 percent. Demand in the commercial and industrial markets are expected to decline at an annual rate of 0.24 percent. Aggressive energy efficiency programs 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 primary technology to meet the ever-growing demand for electric power. However, overall gas demand for electric generation is expected to decline at 1.3 percent per year for the next 20 years due to more efficient power plants, statewide efforts to minimize greenhouse gas (GHG) emissions through aggressive programs pursuing demand-side reductions, and the acquisition of preferred power generation resources that produce little or no carbon emissions.



The graph above summarizes statewide gas demand under a base case and 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 6,072 MMcf/d in 2016 decreasing to 4,626 MMcf/d by 2035, a decline of 1.35% per year.

In 2016, Northern California is projected to require an additional 2.3% of gas supply to meet demand for the high gas demand scenario, whereas southern California is projected to require an additional 4.0% of supply to meet demand under the high scenario condition. 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. 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 renewable power will meet 33% of the state's electric needs by 2020 and 50% by 2030 and beyond.

In 2015, the state enacted legislation intended to improve air quality, provide aggressive reductions in energy dependency and boost the employment of renewable power. The first legislation, the 2015 Clean Energy and Pollution Reduction Act, also known as Senate Bill (SB) 350, requires the amount of electricity generated and sold to retail customers per year from eligible renewable energy resources be increased to 50 percent by December 31, 2030. SB 350 establishes annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses by January 1, 2030.

Second, the Energy Efficiency Act (AB 802) provides aggressive state directives to increase the energy efficiency of existing buildings, requires that access to building performance data for nonresidential buildings be provided by energy utilities and encourages pay-for-performance incentive-based programs. This paradigm shift will allow California building owners a better and more effective way to access whole-building information and at the same time will help to address climate change, and deliver cost-effective savings for ratepayers.

Last, the Energy Efficiency Act (AB 793) is intended to promote and provide incentives to residential or small and medium-sized business utility customers that acquire energy management technology for use in their home or place of business. AB 793 requires energy utilities to develop a plan to educate residential customers and small and medium business customers about the incentive program.

The table on the following page provides estimates of 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

	2016	2017	2018	2019	2020	2025	2030	2035
California Energy Requirements by CPUC-Jurisdictional Utilities (CAISO) [1]								
Electricity Demand (GWh)	254,951	253,808	251,995	250,857	250,201	249,154	247,036	245,176
33% Renewables by 2020 & 50% Renewables by 2030								
Renewable Electric Generation (GWh/Yr) [2]	63,738	68,528	73,078	77,766	82,566	103,399	123,518	122,588
Increase over 2015 Level (GWh/Yr) [3]	3,998	8,789	13,339	18,026	22,827	43,659	63,779	62,849
Gas Savings over 2015 Level (Bcf/Yr) [4]	24	53	81	109	139	265	387	381
Electric Energy Efficieny Goals [5]								
Electricity Savings over 2015 Level (GWh/Yr)	3,562	6,976	10,092	12,749	15,110	23,645	33,832	44,604
Gas Savings over 2015 Level (Bcf/Yr) [4]	22	42	61	77	92	143	205	271
Energy Efficiency Goal for Natural Gas Programs [6]								
Gas Savings over 2015 Level (Bcf/Yr)	10	26	37	50	70	111	149	189
Total Gas Savings (Bcf/Yr) [7]	55	122	180	237	300	520	741	841

Notes:

(1) Electricity demand forecast from the California Energy Commission: http://www.energy.ca.gov/2015_energypolicy/documents/2016-01-27_load_serving_entity_and_Balancing_authority.php, Mid-Case LSE and Balancing Authority Forecast.xls, "form1.1c" tab. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is -0.151%.

(2) Assumes 33% renewables by the year 2020 and 50% renewables by 2030.

(3) Increase reflects only the impacts of equipment installed after December 31, 2015.

(4) Gas savings are estimated based on the following generic assumptions for California: gas-fired peaking plants are assumed to be the marginal source for 10% of the 8,760 hours in each year (24 x 365) and combined-cycle plants are marginal in another 75% of each year. Each MWh displaced from a peaking plant saves 10 MMBtu (10 Dth, or approximately 10,000 CF) of natural gas. Each MWh displaced from a combined-cycle plant saves 7 MMBtu (7 Dth, or approximately 7,000 CF) of natural gas. A conservation program that saves 1 MWh in every hour of a year saves about 55,000 MMBtu of natural gas (8,750 hours x 10% x 10 MMBtu, plus 8,760 hours x 75% x 7 MMBtu). Conservation programs that save MWh primarily during summer peak periods produce greater natural gas savings per MWh. Similar estimates apply to renewable electric generators.

(5) Data from the California Energy Commission: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03 ; "Committed Electricity Efficiency Conservations Savings by Planning Area and Sector", Mid CORRECTED, "STATEWIDEnonrescon-Mid Demand" tab. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is 1.661%.

(6) Data from the California Energy Commission: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03 ; Committed Gas Savings by PA-RF15.xlxs. From 2027-2035 the average growth rate was used from the last five years (2022-2026) which is 1.096%.

(7) Total gas savings are annual savings from equipment installed after December 31, 2015.

Future Gas System Impacts Resulting From Increased Renewable Generation, and Localized or Distributed-Generation Resources

Since electric utility-system operators must balance electrical demand with generation sources on a real-time basis, most system operators rely on "dispatchable" resources that can respond quickly to changes in demand. The challenge with renewable resources is that while they can provide energy, they are not always totally predictable nor are they often considered controllable resources.

In the future the increase in renewable generation in the state will reduce the total amount of natural gas usage, but it is also expected that the future increases in renewable electric generation will increase the daily and hourly load-forecast variance associated with operation of the natural gas-fueled electric generation system. California is currently on track to meet a 33% Renewable Portfolio Standard (RPS) by 2020. SB 350 further raised the RPS target to 50% by 2030. All this renewable energy will displace some of the natural gas currently being used to generate electricity in California, but the reduction will not be proportional to the amount of renewable generation energy due to the intermittent nature of this renewable generation. The intermittent nature of renewable generation is likely to cause the electric system to rely more heavily on natural gas-fired electric generation for providing the ancillary services (load following, ramping, and quick starts) needed to balance the electric system in the short term until other technologies can mature. Per the CPUC Storage Mandate Decision D.13-10-040, energy storage products would use the excess renewable energy to charge the battery or system during the time of low energy demand and would provide energy back into the grid during periods of high energy demand.

It is expected that solar and wind generating units will provide most of the new renewable electric generation in the years ahead with much of the smaller incremental renewable power coming from solar PV (photovoltaic) installations, because solar generation costs have declined rapidly in the past few years and solar has siting advantages, especially in urban areas. Due to this expansion of renewable resources, there may be an increased need for rapid-response, gas-fired generators that could be available to follow load fluctuations due to the intermittent nature of added renewables. Since gas-fired generation is the marginal resource in most hours, the amount of gas consumed for integrating more renewables will fluctuate hourly. The gas system will therefore need to be both robust and flexible to handle such fluctuations with minimal disturbance.

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

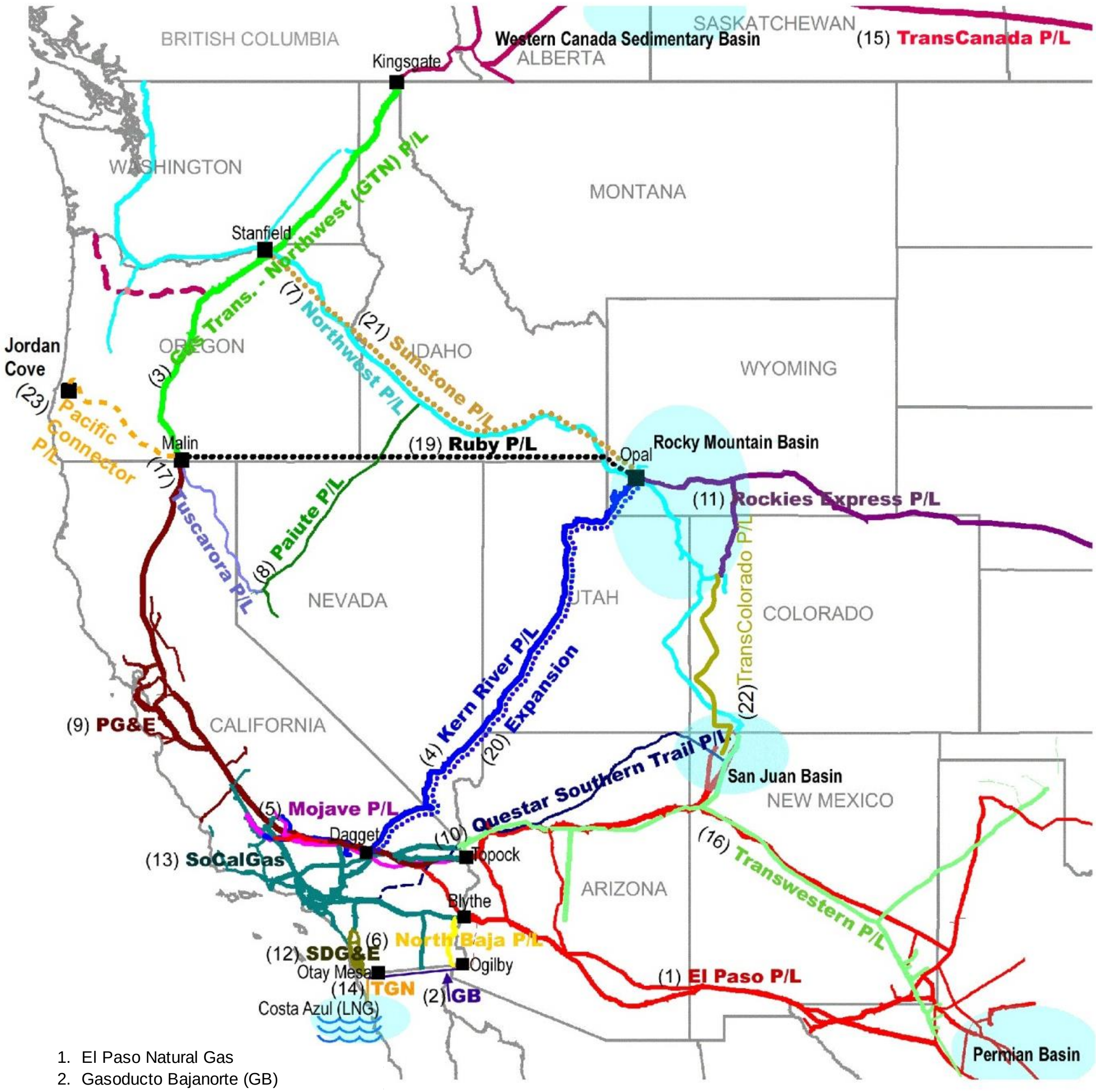
Over the past five years, California natural gas utilities, interstate pipelines, and in-state natural gas-storage facilities have increased their delivery and receipt capacity to meet natural gas demand growth. In addition, more projects have been proposed and some are under construction. The California Energy Commission (Energy Commission) posts a list of natural gas projects on its 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.energyalmanac.ca.gov/naturalgas/index.html.

Supply Outlook/Pipeline Capacity

California's existing gas supply portfolio is regionally diverse and includes supplies from California sources (onshore and offshore), Southwestern U.S. supply sources (the Permian, Anadarko, and San Juan basins), the Rocky Mountains, and Canada. The Ruby pipeline came online in 2010, bringing up to 1.5 Bcf/d of additional gas to California (via Malin) from the Rocky Mountains. The Energia Costa Azul LNG (Liquefied Natural Gas) receiving terminal in Baja California provides yet another source of supply for California. 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. In addition to Ruby, 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 Baja Norte/North Baja Pipeline.

Western North American Natural Gas Pipelines



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. Piute Pipeline
9. Pacific Gas & Electric Company
10. Questar Southern Trail Pipeline
11. Rockies Express
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
18. Unused
19. Ruby Pipeline
20. Kern River Expansion
21. Sunstone Pipeline
22. Transcolorado Pipeline
23. Pacific Connector Pipeline

Liquefied Natural Gas (LNG)

The abundance of shale gas has changed the paradigm for liquefied natural gas in the West. Until the latter part of the last decade, LNG was seen as being a potential source of imported gas for California, but that has now changed to a focus on exporting gas. There are two proposed new LNG facilities in the West Coast. Both are in Canada and are described in the table below. The Costa Azul terminal remains the only import terminal on the west coast; however, it remains under-utilized as a source of gas for California. It is uncertain whether all of the proposed and potential export terminals will be built, but their construction and operation may put upward pressure on gas prices in the West in the future.

Potential and Proposed North American West Coast LNG Terminals
As of May 19, 2016[1]

	Western Region LNG Terminals Existing and Proposed as of May 19, 2016				
1	Baja California, Mexico	Existing	Sempra-Energia Costa Azul	4.0 Bcf/d	Import Terminal
2	Kenai, AL	Existing	Conoco Phillips	0.2 Bcf/d	Export Terminal
3	P. Manzanillo, MX	Existing	KMS GNL de Manzanillo	0.5 Bcf/d	Import Terminal
4	Kitimat, BC	Approved	LNG Canada	3.23 Bcf/d	Export Terminal
5	Squarmish, BC	Approved	Woodfibre LNG Ltd	0.29 Bcf/d	Export Terminal

[1] Source: FERC List of Existing, Proposed, and Potential LNG Terminals (http://www.ferc.gov/industries/gas/indus-act/lng.asp, accessed 5/22/2016)

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 2016 to 2035 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 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

	2016	2017	2018	2019	2020
California's Supply Sources					
Utility					
California Sources	165	165	165	165	165
Out-of-State	5,060	4,798	4,758	4,711	4,668
Utility Total	5,225	4,963	4,924	4,876	4,833
Non-Utility Served Load (1)	1,132	1,056	985	910	813
Statewide Supply Sources Total	**6,358**	**6,020**	**5,909**	**5,787**	**5,645**
California's Requirements					
Utility					
Residential	1,181	1,181	1,175	1,167	1,155
Commercial	484	485	481	478	473
Natural Gas Vehicles	46	48	50	52	54
Industrial	964	950	943	937	932
Electric Generation (2)	1,897	1,648	1,623	1,590	1,566
Enhanced Oil Recovery Steaming	46	46	46	46	46
Wholesale/International+Exchange	241	245	246	246	247
Company Use and Unaccounted-for	79	75	74	73	73
Utility Total	4,939	4,677	4,638	4,590	4,547
Non-Utility					
Enhanced Oil Recovery Steaming	52	52	52	52	52
EOR Cogeneration/Industrial	103	103	103	103	103
Electric Generation	977	901	830	755	658
Non-Utility Served Load (1)	1,132	1,056	985	910	813
Statewide Requirements Total (3)	**6,072**	**5,734**	**5,623**	**5,501**	**5,360**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

(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 AND REQUIREMENTS
Average Temperature and Normal Hydro Year
MMcf/Day

	2021	2022	2025	2030	2035
California's Supply Sources					
Utility					
California Sources	165	165	165	165	165
Out-of-State	4,620	4,618	4,599	4,481	4,489
Utility Total	4,786	4,783	4,764	4,646	4,654
Non-Utility Served Load (1)	781	691	547	291	258
Statewide Supply Sources Total	**5,566**	**5,474**	**5,312**	**4,938**	**4,912**
California's Requirements					
Utility					
Residential	1,148	1,139	1,114	1,080	1,076
Commercial	470	465	454	440	443
Natural Gas Vehicles	57	59	66	77	85
Industrial	931	929	930	942	938
Electric Generation (2)	1,529	1,540	1,548	1,454	1,453
Enhanced Oil Recovery Steaming	46	46	46	46	46
Wholesale/International+Exchange	247	247	247	251	256
Company Use and Unaccounted-for	71	72	72	71	71
Utility Total	4,500	4,497	4,478	4,360	4,368
Non-Utility					
Enhanced Oil Recovery Steaming	52	52	52	52	52
EOR Cogeneration/Industrial	103	103	102	82	77
Electric Generation	626	536	393	157	129
Non-Utility Served Load (1)	781	691	547	291	258
Statewide Requirements Total (3)	**5,281**	**5,188**	**5,026**	**4,652**	**4,626**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

(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	**2016**	**2017**	**2018**	**2019**	**2020**
Northern California					
California Sources (1)	43	43	43	43	43
Out-of-State	2,501	2,271	2,274	2,252	2,232
Northern California Total	2,545	2,314	2,317	2,295	2,275
Southern California					
California Sources (2)	122	122	122	122	122
Out-of-State	2,559	2,527	2,485	2,459	2,436
Southern California Total	2,681	2,649	2,607	2,581	2,558
Utility Total	5,225	4,963	4,924	4,876	4,833
Non-Utility Served Load (3)	1,132	1,056	985	910	813
Statewide Supply Sources Total	**6,358**	**6,020**	**5,909**	**5,787**	**5,645**

Utility	**2021**	**2022**	**2025**	**2030**	**2035**
Northern California					
California Sources (1)	43	43	43	43	43
Out-of-State	2,216	2,236	2,265	2,229	2,229
Northern California Total	2,259	2,279	2,308	2,272	2,272
Southern California					
California Sources (2)	122	122	122	122	122
Out-of-State	2,404	2,382	2,334	2,252	2,260
Southern California Total	2,526	2,504	2,456	2,374	2,382
Utility Total	4,786	4,783	4,764	4,646	4,654
Non-Utility Served Load (3)	781	691	547	291	258
Statewide Supply Sources Total	**5,566**	**5,474**	**5,312**	**4,938**	**4,912**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

STATEWIDE ANNUAL GAS REQUIREMENTS [1]
Average Temperature and Normal Hydro Year
MMcf/Day

	2016	2017	2018	2019	2020
Utility					
Northern California					
Residential	528	528	525	520	514
Commercial - Core	222	222	222	222	222
Natural Gas Vehicles - Core	8	8	9	9	10
Natural Gas Vehicles - Noncore	1	1	1	1	1
Industrial - Noncore	537	527	521	518	516
Wholesale	10	10	10	10	9
SMUD Electric Generation	122	122	122	122	122
Electric Generation (2)	784	567	578	564	552
Exchange (California)	1	1	1	1	1
Company Use and Unaccounted-for	46	42	42	41	41
Northern California Total (3)	2,259	2,028	2,031	2,010	1,989
Southern California					
Residential	652	652	650	647	641
Commercial - Core	217	217	214	211	207
Commercial - Noncore	46	45	45	45	44
Natural Gas Vehicles - Core	37	38	40	42	43
Industrial - Core	56	57	56	55	55
Industrial - Noncore	371	367	366	363	361
Wholesale	231	234	235	236	236
SDG&E+Vernon Electric Generation	204	199	185	180	178
Electric Generation (4)	788	760	738	724	714
Enhanced Oil Recovery Steaming	46	46	46	46	46
Company Use and Unaccounted-for	33	33	32	32	32
Southern California Total	2,681	2,649	2,607	2,581	2,558
Utility Total	4,939	4,677	4,638	4,590	4,547
Non-Utility Served Load (5)	1,132	1,056	985	910	813
Statewide Gas Requirements Total (6)	**6,072**	**5,734**	**5,623**	**5,501**	**5,360**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

STATEWIDE ANNUAL GAS REQUIREMENTS [1]
Average Temperature and Normal Hydro Year
MMcf/Day

	2021	2022	2025	2030	2035
Utility					
Northern California					
Residential	510	505	494	478	478
Commercial - Core	222	223	224	225	225
Natural Gas Vehicles - Core	10	11	12	15	15
Natural Gas Vehicles - Noncore	1	1	1	1	1
Industrial - Noncore	520	523	535	564	564
Wholesale	9	9	9	9	9
SMUD Electric Generation	122	122	122	122	122
Electric Generation [2]	538	557	582	530	530
Exchange (California)	1	1	1	1	1
Company Use and Unaccounted-for	40	41	41	41	41
Northern California Total [3]	1,974	1,993	2,022	1,986	1,986
Southern California					
Residential	639	634	620	603	598
Commercial - Core	204	199	189	175	177
Commercial - Noncore	44	43	42	40	40
Natural Gas Vehicles - Core	45	47	52	61	69
Industrial - Core	54	53	50	44	42
Industrial - Noncore	358	353	345	333	332
Wholesale	237	237	237	241	246
SDG&E+Vernon Electric Generation	178	178	174	166	165
Electric Generation [4]	692	684	671	636	636
Enhanced Oil Recovery Steaming	46	46	46	46	46
Company Use and Unaccounted-for	31	31	31	30	30
Southern California Total	2,526	2,504	2,456	2,374	2,382
Utility Total	4,500	4,497	4,478	4,360	4,368
Non-Utility Served Load [5]	781	691	547	291	258
Statewide Gas Requirements Total [6]	**5,281**	**5,188**	**5,026**	**4,652**	**4,626**

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 consumption at Elk Hills powerplant. Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
Cold Temperature [4] and Dry Hydro Year
MMcf/Day

	2016	2017	2018	2019	2020
California's Supply Sources					
Utility					
California Sources	165	165	165	165	165
Out-of-State	5,224	5,042	5,013	4,963	4,918
Utility Total	5,390	5,207	5,178	5,128	5,083
Non-Utility Served Load [1]	1,670	1,577	1,323	1,250	1,181
Statewide Supply Sources Total	**7,060**	**6,784**	**6,501**	**6,378**	**6,264**
California's Requirements					
Utility					
Residential	1,273	1,273	1,269	1,262	1,253
Commercial	504	505	501	498	493
Natural Gas Vehicles	46	48	50	52	54
Industrial	966	953	945	939	934
Electric Generation [2]	1,927	1,756	1,740	1,704	1,676
Enhanced Oil Recovery Steaming	46	46	46	46	46
Wholesale/International+Exchange	259	263	264	265	265
Company Use and Unaccounted-for	82	77	77	76	75
Utility Total	5,104	4,921	4,893	4,842	4,797
Non-Utility					
Enhanced Oil Recovery Steaming	52	52	52	52	52
EOR Cogeneration/Industrial	103	103	103	103	103
Electric Generation	1,515	1,422	1,168	1,095	1,026
Non-Utility Served Load [1]	1,670	1,577	1,323	1,250	1,181
Statewide Requirements Total [3]	**6,774**	**6,498**	**6,215**	**6,092**	**5,978**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

(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.

(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
Cold Temperature (4) and Dry Hydro Year
MMcf/Day

	2021	2022	2025	2030	2035
California's Supply Sources					
Utility					
California Sources	165	165	165	165	165
Out-of-State	4,890	4,895	4,982	4,846	4,853
Utility Total	5,056	5,060	5,147	5,011	5,018
Non-Utility Served Load (1)	1,136	1,094	992	638	641
Statewide Supply Sources Total	**6,191**	**6,154**	**6,139**	**5,649**	**5,659**
California's Requirements					
Utility					
Residential	1,247	1,238	1,216	1,189	1,184
Commercial	490	486	475	461	465
Natural Gas Vehicles	57	59	66	77	85
Industrial	933	931	932	944	940
Electric Generation (2)	1,655	1,673	1,785	1,664	1,663
Enhanced Oil Recovery Steaming	46	46	46	46	46
Wholesale/International+Exchange	266	266	266	270	275
Company Use and Unaccounted-for	75	76	75	74	74
Utility Total	4,770	4,774	4,861	4,725	4,733
Non-Utility					
Enhanced Oil Recovery Steaming	52	52	52	52	52
EOR Cogeneration/Industrial	103	103	103	88	87
Electric Generation	981	939	837	498	501
Non-Utility Served Load (1)	1,136	1,094	992	638	641
Statewide Requirements Total (3)	**5,906**	**5,868**	**5,853**	**5,363**	**5,373**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(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.
(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
Cold Temperature (4) and Dry Hydro Year
MMcf/Day

Utility	**2016**	**2017**	**2018**	**2019**	**2020**
Northern California					
California Sources (1)	43	43	43	43	43
Out-of-State	2,560	2,336	2,342	2,322	2,306
Northern California Total	2,603	2,379	2,386	2,366	2,349
Southern California					
California Sources (2)	122	122	122	122	122
Out-of-State	2,665	2,706	2,671	2,640	2,612
Southern California Total	2,787	2,828	2,793	2,762	2,734
Utility Total	5,390	5,207	5,178	5,128	5,083
Non-Utility Served Load (3)	1,670	1,577	1,323	1,250	1,181
Statewide Supply Sources Total	**7,060**	**6,784**	**6,501**	**6,378**	**6,264**

Utility	**2021**	**2022**	**2025**	**2030**	**2035**
Northern California					
California Sources (1)	43	43	43	43	43
Out-of-State	2,292	2,316	2,455	2,420	2,420
Northern California Total	2,336	2,360	2,498	2,463	2,463
Southern California					
California Sources (2)	122	122	122	122	122
Out-of-State	2,598	2,579	2,527	2,426	2,433
Southern California Total	2,720	2,701	2,649	2,548	2,555
Utility Total	5,056	5,060	5,147	5,011	5,018
Non-Utility Served Load (3)	1,136	1,094	992	638	641
Statewide Supply Sources Total	**6,191**	**6,154**	**6,139**	**5,649**	**5,659**

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 consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

STATEWIDE ANNUAL GAS REQUIREMENTS (1)
Cold Temperature (7) and Dry Hydro Year
MMcf/Day

	2016	2017	2018	2019	2020
Utility					
Northern California					
Residential	550	550	548	544	541
Commercial - Core	227	228	228	228	228
Natural Gas Vehicles - Core	8	8	9	9	10
Natural Gas Vehicles - Noncore	1	1	1	1	1
Industrial - Noncore	538	527	522	519	517
Wholesale	10	10	10	10	10
SMUD Electric Generation	122	122	122	122	122
Electric Generation (2)	814	604	617	603	591
Exchange (California)	1	1	1	1	1
Company Use and Unaccounted-for	47	42	42	42	41
Northern California Total (3)	2,317	2,093	2,100	2,080	2,063
Southern California					
Residential	723	723	721	718	712
Commercial - Core	230	230	227	223	220
Commercial - Noncore	47	47	46	46	45
Natural Gas Vehicles - Core	37	38	40	42	43
Industrial - Core	57	58	58	57	56
Industrial - Noncore	371	367	366	363	361
Wholesale	248	252	253	254	254
SDG&E+Vernon Electric Generation	204	206	195	191	187
Electric Generation (4)	788	825	807	788	775
Enhanced Oil Recovery Steaming	46	46	46	46	46
Company Use and Unaccounted-for	35	35	35	34	34
Southern California Total	2,787	2,828	2,793	2,762	2,734
Utility Total	5,104	4,921	4,893	4,842	4,797
Non-Utility Served Load (5)	1,670	1,577	1,323	1,250	1,181
Statewide Gas Requirements Total (6)	**6,774**	**6,498**	**6,215**	**6,092**	**5,978**

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 consumption at Elk Hills powerplant. Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

STATEWIDE ANNUAL GAS REQUIREMENTS (1)
Cold Temperature (7) and Dry Hydro Year
MMcf/Day

	2021	2022	2025	2030	2035
Utility					
Northern California					
Residential	538	535	527	519	519
Commercial - Core	230	230	232	235	235
Natural Gas Vehicles - Core	10	11	12	15	15
Natural Gas Vehicles - Noncore	1	1	1	1	1
Industrial - Noncore	520	523	536	565	565
Wholesale	10	10	10	10	10
SMUD Electric Generation	122	122	122	122	122
Electric Generation (2)	577	599	728	668	668
Exchange (California)	1	1	1	1	1
Company Use and Unaccounted-for	41	42	42	42	42
Northern California Total (3)	2,050	2,074	2,212	2,177	2,177
Southern California					
Residential	709	703	689	671	666
Commercial - Core	216	211	200	185	188
Commercial - Noncore	45	44	43	41	42
Natural Gas Vehicles - Core	45	47	52	61	69
Industrial - Core	55	54	51	45	43
Industrial - Noncore	358	353	345	333	332
Wholesale	255	255	255	259	265
SDG&E+Vernon Electric Generation	189	189	186	178	177
Electric Generation (4)	768	763	748	696	697
Enhanced Oil Recovery Steaming	46	46	46	46	46
Company Use and Unaccounted-for	34	34	33	32	32
Southern California Total	2,720	2,701	2,649	2,548	2,555
Utility Total	4,770	4,774	4,861	4,725	4,733
Non-Utility Served Load (5)	1,136	1,094	992	638	641
Statewide Gas Requirements Total (6)	**5,906**	**5,868**	**5,853**	**5,363**	**5,373**

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 consumption at Elk Hills powerplant. Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

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 2011 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	RUBY	Total
Southern California Gas Company									
Core + UAF (2)	195	442	257	33	138	0	-25	0	1,040
Noncore Commercial/Industrial	-18	157	24	25	203	14	20	0	423
EG (3)	-31	270	41	44	349	25	34	0	726
EOR	-1	10	2	2	13	1	1	0	27
Wholesale/Resale/International (4)	30	116	97	21	124	0	9	0	407
Total	175	996	420	125	828	40	40	0	2,623
Pacific Gas and Electric Company (5)									
Core	0	166	120	501	6	0	0	37	831
Noncore Industrial/Wholesale/EG (6)	108	132	116	563	118	0	6	281	1,323
Total	108	298	236	1,064	124	0	6	318	2,154
Other Northern California									
Core (7)	24	0	0	0	0	0	13	37	74
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	391	12	0	0	1,045	23	0	0	1,471
TOTAL SUPPLIER	698	1,306	656	1,189	1,997	63	59	355	6,322

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 western	GTN	Kern River	Mojave (10)	Other (1)	RUBY	Total
San Diego Gas & Electric Company									
Core	25	59	34	4	19	0	-3	0	138
Noncore Commercial/Industrial	-1	32	42	12	79	0	10	0	174
Total	23	91	76	17	98	0	7	0	312
SouthWest Gas									
Core	24	0	0	0	0	0	13.00	0.000	37.00
Noncore Commercial/Industrial	2	0	0	0	0	0	0.17	0.000	2.17
Total	26	0	0	0	0	0	13.17	0.000	39.17

(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.

Recorded 2012 Statewide Sources and Disposition Summary

MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	-10	402	304	59	216	0	10	0	981
Noncore Commercial/Industrial	41	86	80	55	145	13	1	0	425
EG (3)	89	186	174	119	315	28	3	0	922
EOR	3	6	5	4	10	1	0	0	29
Wholesale/Resale/International (4)	25	143	116	47	151	0	6	0	477
Total	148	822	680	283	838	42	21	0	2,834
Pacific Gas and Electric Company (5)									
Core	0	165	90	352	19	0	0	183	809
Noncore Industrial/Wholesale/EG (6)	84	94	95	428	141	318	13	689	1,863
Total	84	259	185	781	161	318	13	872	2,672
Other Northern California									
Core (7)	11	0	0	0	0	0	12	0	23
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	394	0	0	0	815	36	0	0	1,245
TOTAL SUPPLIER	637	1,081	865	1,064	1,814	396	46	872	6,774

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 western	GTN	Kern River	Mojave (10)	Other (1)	Ruby	Total
San Diego Gas & Electric Company									
Core	-1.4	55	41	8	30	0	1.4	0	134
Noncore Commercial/Industrial	21	58	50	29	90	0	4	0	251
Total	20	113	91	37	120	0	5	0	385
SouthWest Gas									
Core	22	0	0	0	0	0	11.50	0	33.50
Noncore Commercial/Industrial	2	0	0	0	0	0	0.15	0	2.15
Total	24	0	0	0	0	0	11.65	0	35.65

(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.

Recorded 2013 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	18	361	265	67	230	0	56	0	997
Noncore Commercial/Industrial	37	163	117	25	77	10	-2	0	426
EG (3)	72	324	231	50	153	19	-4	0	845
EOR	3	13	10	2	6	1	0	0	35
Wholesale/Resale/International (4)	23	141	114	45	144	2	2	0	472
Total	153	1,003	737	189	611	32	51	0	2,775
Pacific Gas and Electric Company (5)									
Core	0	91	116	330	43	0	0	181	760
Noncore Industrial/Wholesale/EG (6)	57	88	92	429	130	0	45	599	1,440
Total	57	178	208	759	173	0	45	779	2,200
Other Northern California									
Core (7)	12	0	0	0	0	0	12	0	24
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	396	0	0	0	645	129	0	0	1,170
TOTAL SUPPLIER	618	1,181	945	948	1,429	161	109	779	6,169

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 western	GTN	Kern River	Mojave (10)	Other (1)	Ruby	Total
San Diego Gas & Electric Company									
Core	-1.4	56.2	42.5	8.2	30.1	1.8	0.0	0	137
Noncore Commercial/Industrial	19.8	55.0	47.6	26.9	83.4	0.0	1.4	0	234
Total	18	111	90	35	114	2	1	0	371
SouthWest Gas									
Core	22	0	0	0	0	0	12	0	33.5
Noncore Commercial/Industrial	2	0	0	0	0	0	0.15	0	2.2
Total	24	0	0	0	0	0	11.65	0	35.7

(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.

Recorded 2014 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	RUBY	Total
Southern California Gas Company									
Core + UAF (2)	35	426	182	61	226	0	-61	0	869
Noncore Commercial/Industrial	27	107	90	98	53	8	27	0	411
EG (3)	57	225	190	207	112	17	56	0	863
EOR	3	11	10	11	6	1	3	0	44
Wholesale/Resale/International (4)	20	122	99	39	125	2	2	0	410
Total	142	891	571	416	522	28	27	0	2397
Pacific Gas and Electric Company (5)									
Core	0	26	100	328	18	0	0	184	657
Noncore Industrial/Wholesale/EG (6)	49	237	161	428	64	0	57	642	1,638
Total	49	264	261	757	82	0	57	826	2,295
Other Northern California									
Core (7)	12	0	0	0	0	0	0	0	12
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	588	0	0	0	810	202	0	0	1,600
TOTAL SUPPLIER	791	1,155	832	1,173	1,414	230	84	826	6,492

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 western	GTN	Kern River	Mojave (10)	Other (1)	RUBY	Total
San Diego Gas & Electric Company									
Core	-1	48	36	7	26	2	0	0	117
Noncore Commercial/Industrial	17	48	41	23	73	0	1	0	204
Total	16	96	77	30	99	2	1	0	321
SouthWest Gas									
Core	20	0	0	0	0	0	11.10	0.000	20.00
Noncore Commercial/Industrial	2	0	0	0	0	0	0.40	0.000	2.00
Total	22	0	0	0	0	0	13.17	0.000	22.00

(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.

Recorded 2015 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	RUBY	Total
Southern California Gas Company									
Core + UAF (2)	-61	447	76	40	225	0	122	0	876
Noncore Commercial/Industrial	64	238	20	16	26	28	74	0	414
EG (3)	124	457	39	30	50	54	142	0	795
EOR	7	26	2	2	3	3	8	0	46
Wholesale/Resale/International (4)	-12	136	85	29	156	12	10	0	428
Total	122	1305	223	117	461	97	357	0	2559
Pacific Gas and Electric Company (5)									
Core	0	23	124	345	12	0	0	207	711
Noncore Industrial/Wholesale/EG (6)	37	216	145	798	81	0	56	551	1,884
Total	37	239	268	1,143	93	0	56	758	2,595
Other Northern California									
Core (7)	11	0	0	0	0	0	0	0	11
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	523	0	0	0	697	14	0	0	1,234
TOTAL SUPPLIER	693	1544	491	1260	1251	111	413	758	6399

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 western	GTN	Kern River	Mojave (10)	Other (1)	RUBY	Total
San Diego Gas & Electric Company									
Core	-8	68	16	7	26	0	7	0	116
Noncore Commercial/Industrial	-2	39	51	16	97	9	1	0	211
Total	-10	107	67	23	123	9	8	0	327
SouthWest Gas									
Core	21	0	0	0	0	0	11.10	0.000	37.00
Noncore Commercial/Industrial	2	0	0	0	0	0	0.40	0.000	2.17
Total	26	0	0	0	0	0	13.17	0.000	39.17

(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 sendout days by the state in the summer and winter periods from the last five years. Daily 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 Summer Sendout (MMcf/d (4))

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (3)	Non-Utility (3)	State Total
2011	04/08/2011	2,164	3,313	5,477	1,322	6,799
2012	08/13/2012	2,685	3,483	6,168	1,633	7,801
2013	07/01/2013	2,558	3,393	5,951	1,437	7,388
2014	09/16/2014	2,683	3,488	6,171	1,523	7,694
2015	09/10/2015	2,787	3,601	6,899	1,407	7,795

Estimated California Highest Winter Sendout (MMcf/d (4))

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (3)	Non-Utility (3)	State Total
2011	12/12/2011	2,842	4,152	6,994	1,501	8,495
2012	12/19/2012	3,628	4,294	7,922	1,501	9,423
2013	12/09/2013	4,850	4,881	9,731	1,426	11,157
2014	12/31/2014	3,429	4,325	7,754	1,465	9,219
2015	12/29/2015	3,626	4,036	7,865	1,311	8,973

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 sendouts are reported for the day on which the coincident 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, Sep and Oct.

2016 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

Pacific Gas and Electric Company (PG&E) provides natural gas procurement, transportation, and storage services to 4.2 million residential customers and over 229,000 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 (APD) demands and supply resources, as well as gas balances, are discussed at the end of this section.

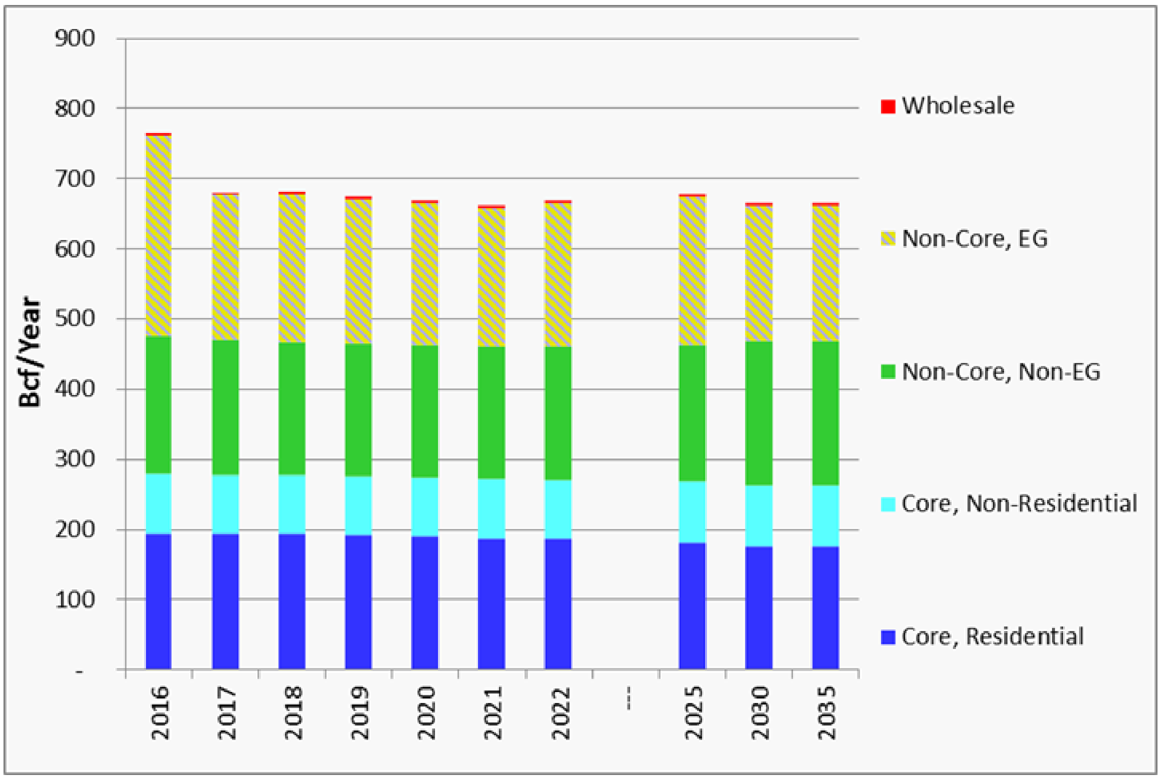
The forecast in this report covers the years 2016 through 2035. However, as a matter of convenience, the tabular data at the end of the section show only the years 2016 through 2022, and the years 2025, 2030, and 2035.

GAS DEMAND

OVERVIEW

PG&E's *2016 California Gas Report (CGR)* average-year demand forecast projects total on-system demand to decline at annual average rate of 0.6 percent between 2016 and 2035. This is due to the combination of a 0.3 percent annual decline in the core market and an annual decline of 0.9 percent in the noncore market. By comparison, the *2014 CGR* estimated an annual average growth rate of 0.1 percent per year, based on a 0.1 percent annual growth in the core market and a 0.1 percent annual growth in the noncore market.

Composition of PG&E Requirements (bcf)
Average-Year Demand



The projected rate of growth of the core market has decreased from the *2014 CGR* primarily due to increasing emphasis on Energy Efficiency (EE).

The forecast rate of growth of the noncore electric generation market has decreased due to higher levels of renewable generation to meet the 50 percent goal in 2030 and higher gas transmission rates for electric generators. In this CGR, total gas demand by electric generators and cogenerators in Northern California for average hydrological conditions is estimated to decrease at a rate of about 0.4 percent per year from 2017 through 2035 (the forecast assumes that new rates from PG&E's 2015 Gas Transmission and Storage (GT&S) Rate Case are effective in November 2016). This total gas demand 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. In addition, 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, thus, affecting gas demand to some extent. PG&E's 2016 CGR forecast, however, does not capture this impact.

FORECAST METHOD

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed using econometric models. Forecasts for other sectors (Natural Gas Vehicle (NGV), wholesale) are developed based on market information. Forecasts of gas demand by power plants are developed by modeling the electricity market in the Western Electricity Coordinating Council (WECC) using the MarketBuilder software. 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.

FORECAST SCENARIOS

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). 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 scenario, PG&E relied on a weather vintage approach by considering a year with cold temperatures and dry hydro conditions. Assuming the demographic conditions and infrastructure likely to exist in each forecast year, PG&E forecasts total gas demand with the weather conditions set to match the conditions that have an approximately 1-in-10 likelihood of occurrence. PG&E used an average of the forecasts with the weather conditions from November 2001 through October 2002 and November 2009 through October 2010, as the winters of 2001-2002 and 2009-2010 were colder than normal, and these time periods were average or dry in both Northern California and the Pacific Northwest. In addition to the weather assumptions, in the high-demand scenario PG&E assumed that Diablo Canyon Power Plan units retire at the end of their current licenses in 2024 and 2025.

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-year demand forecast assumed that temperatures in the forecast period would be equivalent to the average of observed temperatures during the past 20 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), downscaled to the PG&E service area. Although the near-term temperatures of this scenario differ little from long-term averages, the years beyond 2016 begin to show the effects of a warming climate. For example, in 2020, total December/January heating degree days are only 3 percent below the 20-year average. By 2035, however, the impact is more significant, with the difference at 7 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 2000-October 2001 and November 2009-October 2010.

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 10^{o} or 15^{o} 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 2^{o} Fahrenheit from average.)

Hydro Conditions

In contrast to temperature deviations, annual water runoff for hydroelectric plants has varied by 50 percent above and below the long-term annual average. The impact of dry conditions was demonstrated during the drought and electricity crisis in 2001 (October 2000 through September 2001). For the 2016 CGR's high-demand scenario, as noted above, PG&E used the 2001-2002 and 2009-2010 conditions.

Gas Price and Rate Assumptions

Inputs for gas prices and rate assumptions are important for forecasting gas demand; this is especially true for market sectors that are particularly price sensitive, such as industrial or electric generation. PG&E used the gas commodity price forecast described in detail in the Southern California section. The CPUC issued a final decision in PG&E's 2016 GT&S Rate Case on June 23, 2016, which significantly affects gas transmission and end use rates. Because of the uncertainty in the outcome of this case at the time the forecast was prepared, PG&E assumed rates based on its filed request would become effective in November 2016.

MARKET SECTORS

Residential

Households in the PG&E service area are forecast to grow 0.5 percent annually from 2016-2035. However, gas use per household has been dropping in recent years due to improvements in appliance and building-shell efficiencies. This decline accelerated sharply in 2001 when gas prices spiked, causing temperature-adjusted residential gas demand to 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 slight upticks in 2009 and 2010 due to cold winters, has fallen on average 1.6 percent per year since 2004. Total residential demand is expected to decrease despite household growth due to continuing upgrades in appliance and building efficiencies, as well as warming temperatures.

Commercial

The number of commercial customers in the PG&E service area is projected to grow on average by 0.4 percent per year from 2016-2035. 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 decline slightly over the forecast horizon due to continuing EE efforts as well as warmer temperatures. Over the next 20 years commercial sales are expected to grow at 0.1 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 but has seen slow growth in the recent past due to low natural gas prices and increased capacity at local refineries, though these effects have been tempered by the continuing structural change in California's manufacturing sector. PG&E observed historically high demand from the industrial sector in 2014 and 2015 due in part to refinery demand. While the industrial sector has the potential for high year-to-year variability, over the long-term, industrial gas consumption is expected to grow slowly at 0.2 percent annually over the next 20 years.

Electric Generation

This sector includes cogeneration and power plants. Forecasts for this sector are subject to greater uncertainty due to the 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 (GHG) policies and regulations on both generation and load. Because of these uncertainties, the forecast is held constant at 2030 levels for 2035.

PG&E forecasts gas demand for most cogenerators by assuming a continuation of past usage, with modifications for expected expansions or closures. In this CGR, PG&E has assumed no additions of new onsite and export (demand- and supply-side) combined heat-and-power plants and retirement of existing plants when they are 40 years old. 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 software. MarketBuilder enables the creation of economic-equilibrium models of 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 WECC, which encompasses the electric systems from the Rocky Mountains to the Pacific coast and from northern Baja California to British Columbia and Alberta.

PG&E's forecast for 2016-2035 uses the mid-case electricity demand forecast from the California Energy Commission's (CEC) 2015 *Integrated Energy Policy Report.* The forecast assumes that renewable energy generation will provide 25 percent of the state's retail sales in 2016, 33 percent by 2020, 40 percent by 2024, and 50 percent by 2030. PG&E assumed that gas-fired plants that employ once-through cooling will retire by the compliance date set by the State Water Resources Control Board, with some replaced by new gas-fired plants.

Sacramento Municipal Utility District Electric Generation

The Sacramento Municipal Utility District (SMUD) is the sixth largest community owned municipal utility in the United States, and 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 megawatts. The peak gas load of these units is approximately 158 million cubic feet per day (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 for about 85 MMcf/d of capacity.

GREENHOUSE GAS LEGISLATION/ASSEMBLY BILL 32

During the forecast horizon covered by this CGR, 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 AB 32) and Clean Energy and Pollution Reduction Act of 2015 (Senate Bill 350, or SB 350). On the one hand, more aggressive EE 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 NGVs 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.

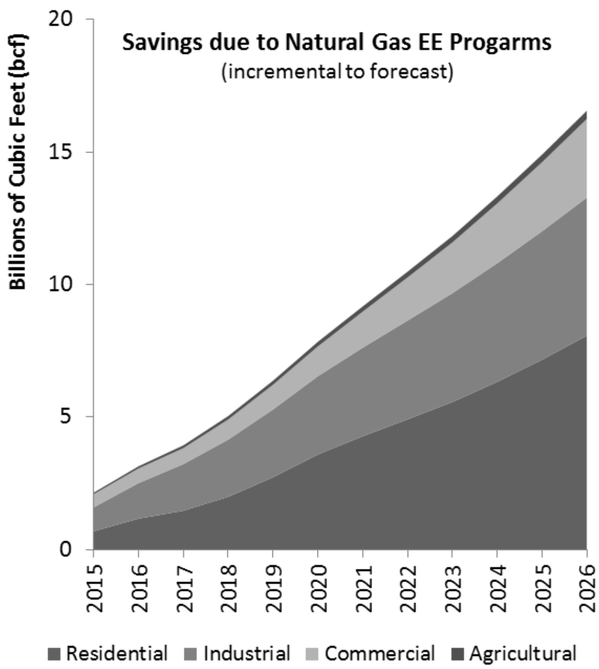
RENEWABLE ELECTRIC GENERATION

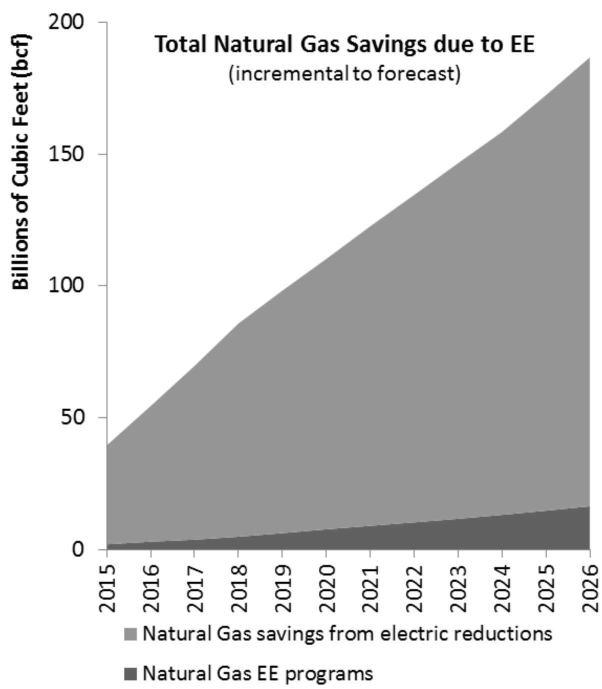
PG&E expects the growth of renewable electric generation due to higher renewable portfolios standards will result in a reduction in the demand for generation from natural gas-fueled resources. This overall reduction in demand may be accompanied by higher daily and hourly deviations between forecast and actual generation from natural gas-fueled electric resources. The intermittent nature of some renewable generation (e.g., wind or solar power) is likely to cause the electric system to rely more heavily on natural gas-fired electric generation to cover forecast deviations and intra-day and intra-hour variability of intermittent generation. This variability will, in turn, result in higher daily forecast errors for gas and increased fluctuations in gas-system inventory.

ENERGY EFFICIENCY PROGRAMS

PG&E engages in a number of EE and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from EE investments. Programs administered by PG&E include services that help customers evaluate their EE options and adopt recommended solutions, as well as simple equipment-retrofit improvements, such as rebates for new hot water heaters.

The forecast of cumulative natural gas savings due to PG&E's EE programs is provided in the figures below. Savings for these efforts are based on the report "California Energy Demand 2016-2026, Revised Electricity Forecast," CEC, January 2016, which contains an "Additional Achievable Energy Efficiency" section that previously had been published as a standalone report.





Conservation and EE savings include any interactive effects that may result from efficiency improvements of electric end uses; for instance, increased natural gas heating load that could result from efficiency improvements in lighting and appliances. These figures also include any reductions in natural gas demand for electric generation that may occur due to lower electric demand; see "Natural Gas savings from electric reductions" in the graph on the right above.

Details of PG&E's 2015 and 2016 Energy Efficiency Portfolio can be found in California Public Utilities Commission (CPUC or Commission) Decision (D.) 14-10-046, which authorized programs and budgets for 2015, and D.15-10-028, which authorized, among other things, extending these programs into 2016.

Impact of SB 350 on Energy Efficiency

SB 350, which was enacted in fall 2015, requires the CEC, in coordination with the CPUC and the local public utilities, to set EE targets that double the CEC's AAEE mid-case forecast, subject to what is cost-effective and feasible.[2] This legislation will undoubtedly impact levels of

[2] The bill text states: "On or before November 1, 2017, the commission, in collaboration with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The commission shall base the targets on a doubling of the mid case estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate, and the targets adopted by local publicly owned electric utilities pursuant to Section 9505 of the Public Utilities Code, extended to 2030 using an average annual

EE savings. There are, however, a number of uncertainties that led the investor-owned utilities (IOU) to defer incorporating estimates of additional savings until the 2018 CGR. These uncertainties include:

- The deadline for the CEC and CPUC to establish SB 350 targets is November 2017, 16 months after this CGR is filed. A lot of work will need to be done to set these targets.
- There are already state requirements for IOUs to pursue all cost-effective EE. Given that the doubling goal is subject to what is cost-effective and achievable, a significant increase in savings while still maintaining a cost-effective portfolio would require changes to programs and/or what is deemed to be cost-effective.
- IOU EE programs are still operating under avoided costs that were last updated in 2011 and 2012. An update to avoided costs is currently underway and is likely to decrease what is currently determined to be cost-effective, as gas prices have dropped and/or stayed lower than forecast in 2011 and 2012 and higher levels of renewables have pushed down energy and capacity values.
- In the CPUC's EE proceeding, an effort is underway to update EE goals to reflect SB 350 and AB 802 impacts. This update is not yet available and will be an important source for estimating SB 350 EE impacts. It is expected that these updated goals will be available for incorporation into the 2018 CGR.

For these reasons, PG&E used current levels of EE included in the 2015 Integrated Energy Policy Report in the forecast for this CGR. However, for context, the IOUs offer the following relative maximum impact of SB 350 on EE savings levels. Assuming cost-effectiveness challenges identified above can be resolved, a doubling of cumulative EE savings, based on the mid-case estimate of additional achievable EE savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, would result in approximately 600 million therms beyond current levels statewide by 2030. However, the reader is cautioned that this is based on a literal reading of the bill language and the CEC forecast identified in the bill, without consideration of the challenges mentioned above.

growth rate, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety."

GAS SUPPLY, CAPACITY, AND STORAGE

OVERVIEW

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990s. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity and storage 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 needs.

Overall, most of the gas supplies that serve PG&E customers are sourced from out of state with only a small portion originating in California. This mix is due to the increasing gas demand in California over the years and the limited amount of native California supply available.

GAS SUPPLY

California-Sourced Gas

Northern California-sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2015, PG&E's customers obtained on average 39 MMcf/d of California-sourced 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 producing basins and transport it to California via interstate pipelines. They can also purchase gas 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 gas from various suppliers in western Canada (British Columbia and Alberta) and transport it to California primarily through the Gas Transmission Northwest Pipeline. Likewise, they 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, the Ruby Pipeline and via the Gas Transmission Northwest Pipeline interconnect at Stanfield, Oregon. The Ruby Pipeline came online in July 2011 and brings up to 1.5 billion cubic feet per day (bcf/d) of Rocky Mountain gas to Malin, Oregon. With Ruby pipeline, the share of Canadian gas to PG&E's system has been reduced somewhat while the Redwood path from Malin to PG&E Citygate has run at a higher utilization rate.

Storage

In addition to storage services offered by PG&E, there are four other storage providers in Northern California—Wild Goose Storage, Inc., Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. As of 2015, these facilities had total working gas capacity of roughly 133 billion cubic feet and peak withdrawal capacity of 2.5 bcf/d.

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-on-pipeline competition. Interstate pipelines serving northern and central California include the El Paso, Mojave, Transwestern, Gas Transmission Northwest, Paiute Pipeline Company, Ruby, 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 1,016 MMcf/d.

Canada and Rocky Mountains

PG&E's Redwood Path (Lines 400/401) is connected to Gas Transmission Northwest and Ruby at Malin, Oregon. The Redwood Path has a firm capacity of 2,023 MMcf/d.

GAS SUPPLIES AND INFRASTRUCTURE PROJECTS

PG&E anticipates that sufficient 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.

The growth of gas production in the Midcontinent and eastern shale plays (e.g., Barnett in northeast Texas, Marcellus in Pennsylvania) have had the effect of pushing larger volumes of Canadian, Rockies, San Juan, and Permian supplies to California, as those supplies are crowded out of markets to the east.

Liquefied Natural Gas Imports/Exports

U.S. imports of liquefied natural gas (LNG) have been declining since 2008. The development of low-cost domestic shale gas supplies has largely eliminated the need for LNG imports and positioned the United States as a net exporter of LNG. Exports of LNG from the contiguous U.S. started in early 2016.

LNG contracts have traditionally been indexed to oil prices. The collapse of world oil prices in 2015, slowing growth of Asian economies, and the expansion of world LNG liquefaction capacity have increased the uncertainty around the economic viability of North American LNG liquefaction projects over the next several years.

There are numerous proposed projects to export LNG to world markets. Many of the projects are "brownfield," using existing U.S. import terminals to export LNG, but some are "greenfield." The "greenfield" LNG export projects targeting the Asian gas market are mostly on the west coasts of the U.S. and Canada.

The DOE granted conditional authorization to the Jordan Cove project in Oregon with non-FTA LNG export capacity of 0.8 bcf/d on March 24, 2014. On March 11, 2016, the FERC rejected the project and its related Pacific Connector pipeline. However, much more work lies ahead to resolve complex issues of commercial contracts, FERC and local approvals, financing, and new pipelines, before plans can succeed. On April 15, 2016, the Oregon LNG project was terminated due to local opposition.

The Jordan Cove LNG export project, which would be the first on the U.S. West Coast, is positioned to source gas from Canada and the U.S. Rockies; thus, it could directly compete for gas supplies available to Northern California.

North American Supply Development

The biggest development in the North American gas supply picture in the past several years has been the rapid development of various shale gas resources through horizontal drilling combined with hydraulic fracturing. While the initial developments were concentrated in the U.S. Midcontinent, the large Marcellus and Utica plays in the eastern U.S. have become the main source of supply growth, resulting in record U.S. gas production in 2015. While some of the traditional supply basins have shown modest declines in production, the Marcellus and Utica plays have grown from roughly 10 percent of U.S. production in 2012 to about 25 percent in 2015, with further growth expected in the next few years. Most industry forecasts now expect supply can increase to meet the most aggressive demand scenario in the future.

GAS STORAGE

Northern California is served by several gas storage facilities in addition to the long-standing PG&E fields at McDonald Island, Pleasant Creek, and Los Medanos. Other storage providers include Gill Ranch Storage, LLC (the 20 bcf facility was co-developed with PG&E, which owns 25 percent of the capacity), Wild Goose Storage, Inc., Lodi Gas Storage, LLC, and Central Valley Storage, LLC.

The abundant storage capacity in the Northern California market has had the effect of creating additional liquidity in the market both in Northern California and in other parts of the West. The extent to which Northern California storage helped supply the larger western market could be seen during much of the winter of 2013-2014; increased storage withdrawals allowed pipeline supplies to meet demand outside of California.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

Gas Quality

Gas quality has received much less attention since 2010 due to the abundance of domestic gas supply, which has diminished interest in LNG imports, as described in the previous section. Hence, the challenges associated with integrating LNG and traditional North American sources, each typically with different quality characteristics, do not require immediate resolution.

Pipeline Safety

Since 2011, the CPUC and the state legislature have adopted a series of regulations and bills that reinforce the setting of public and employee safety as the top priority for the state's gas utilities. In particular, SB 705 mandated for the first time that gas operators develop and implement safety plans that are consistent with the best practices in the gas industry.

On December 29, 2015, PG&E filed its 2015 update to the Gas Safety Plan with the CPUC. The Gas Safety Plan update demonstrates PG&E's commitment to implement processes and procedures to achieve its vision to becoming the safest and most reliable natural gas utility in the nation. One of the plan highlights is the Gas Safety Excellence framework, which guides how PG&E operates, conducts, and manages all parts of its business by putting safety and people at the heart of everything it does; investing in the reliability and integrity of its gas system; and, by continuously improving the effectiveness and affordability of its processes.

Additionally, PG&E submits semi-annual GT&S, and Gas Distribution Pipeline Safety Reports. These reports are designed to provide the CPUC and other interested stakeholders with insight into the amount of safety and reliability-related work PG&E has completed over the course of the reporting period.

See below for a selection of 2015 highlights further demonstrating PG&E's commitment to gas safety:

- **American Petroleum Institute Recommended Practice (API RP 1173)**: PG&E is the first company in the U.S. to meet the rigor of a new industry gold standard for pipeline safety and safety culture.

- **PAS-55 and ISO 55001**: Successfully maintained PAS 55-1 and ISO 55001 certifications for asset management with two separate, third-party assessments.

- **Cast Iron Pipe Removal**: Culminating in a multi-decade program to improve system safety, PG&E completed removal of all known cast iron pipe from its system.

- **Community Pipeline Safety Initiative**: A multi-year program designed to enhance safety by improving access to pipeline right-of-way. 2015 goals included clearing 380 miles of trees and brush and 90 miles of structures located too close to gas pipelines and which pose an emergency access or safety concern.

Storage Safety

On January 16, 2016, California Governor Jerry Brown ordered that injections into Southern California Gas Company's (SoCalGas) Aliso Canyon storage field remain suspended until a "comprehensive review, utilizing independent experts, of the safety of the storage wells" is completed. The reduced working storage capacity on the SoCalGas system would tend to increase the volatility in southern California natural gas prices. Greater price volatility in Southern California would likely cause greater fluctuations in flows on PG&E's system (particularly the Baja path), on the interconnects between PG&E's and SoCalGas' systems, and into and out of Northern California storage fields. Greater fluctuations in flows could lead to increased use of PG&E's storage for balancing and more frequent operational flow orders.

On March 1, 2016, SoCalGas and San Diego Gas & Electric Company submitted a joint motion to the CPUC proposing temporary daily balancing while the Aliso Canyon field is out of service. The impacts above could be even greater if the real-time dispatch of SoCalGas fired generators is constrained by their day-ahead dispatch to minimize balancing penalties, resulting in northern California gas-fired generators being used to meet real-time load variations.

Emergency regulations implemented by the Division of Oil, Gas, and Geothermal Resources on February 5, 2015 should have no potential impact in meeting peak demands in summer and winter. Scheduling of inspections, maintenance, repairs and monitoring under the emergency regulations could potentially result in short duration outages.

The Division of Oil, Gas, and Geothermal Resources will promulgate new regulations to replace the emergency regulations and various legislation introduced on storage safety.

Core Gas Aggregation Program

As of early 2016, Core Transport Agents (CTA) serve approximately 19 percent of PG&E's core gas demand. PG&E completed implementing the CTA Settlement Agreement, part of the Gas Accord V Settlement Agreement, in 2015. The CTA Settlement Agreement modified the practice by which PG&E offers a share of its pipeline and storage capacity holdings to CTAs to serve core customers. In April 2015, the CTAs began taking full cost responsibility for all rejected firm pipeline capacity and rejected firm storage inventory capacity. In October 2015, the Commission issued D.15-10-050, which established a new interstate pipeline capacity planning range for PG&E's core gas customers, and affirmed that PG&E

should acquire interstate pipeline capacity for both PG&E's bundled core customers and for those core customers served by CTAs.

FEDERAL REGULATORY MATTERS

PG&E actively participates in FERC ratemaking proceedings for interstate pipelines connected to PG&E's system, because these cases can impact the cost of gas delivered to PG&E's 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.

El Paso Natural Gas Company, L.L.C. (El Paso)

El Paso filed a general rate case application in the FERC Docket No. RP10-1398, for revised rates and terms and conditions effective April 1, 2011. Several issues raised in rehearing requests and exceptions to FERC's decisions are currently under review by the U.S. Court of Appeals.

Kern River Gas Transmission (Kern River)

There are currently no significant regulatory issues.

Ruby Pipeline, L.L.C. (Ruby)

There are currently no significant regulatory issues.

Transwestern Pipeline Company, L.L.C. (Transwestern)

On October 15, 2015, FERC approved a rate case settlement between Transwestern and shippers. Under the settlement, Transwestern may not file a new general Section 4 rate case before October 1, 2019, unless it files to implement a surcharge in compliance with FERC's policy statement providing for the modernization of natural gas facilities. Transwestern and shippers, including PG&E, are working to resolve non-rate issues, including the adoption of a maximum heating value of the gas received and delivered.

Gas Transmission Northwest (GTN) and Canadian Pipelines

On June 30, 2015, FERC approved a rate settlement between Gas Transmission Northwest and its customers. The agreement is effective January 1, 2016 through December 31, 2019, and results in a rate decrease for California customers.

PG&E participates in Canadian regulatory matters pertaining to its pipeline capacity subscriptions on TransCanada's NOVA Gas Transmission Limited (NGTL) and Foothills Pipelines Limited Company (Foothills). NGTL and Foothills transport PG&E's Canadian-sourced gas from Alberta and British Columbia, delivering the supplies to GTN at the Canadian-U.S. Border, for ultimate delivery to California.

On April 7, 2016, Canada's National Energy Board (NEB) approved a settlement agreement on NGTL's 2016-17 revenue requirements. Foothills received approval for separate rate changes effective in 2015 and 2016, respectively. The resulting transportation rate changes on both pipelines are nominal.

FERC Gas-Electric Coordination Actions (AD12-12 & EL14-22)

Since 2012, FERC commissioners have raised questions about whether there is sufficient coordination and harmonization between gas and electric systems regarding reliability. Concerns have arisen for several reasons: extreme weather events that can affect both the gas and electric grids; expectations of significant increases in gas-fired electric generation nationwide (less so in PG&E's service territory since a significant number of gas-fired generators already exist); and the expanding prevalence of renewable generation portfolio requirements and the resulting need for non-renewable fuel sources, like natural gas, to support the grid when renewable generation is unavailable or reduced.

In spring 2012, FERC held multiple technical conferences and requested comments from gas and electric industry stakeholders regarding any impediments to closer coordination/communication. After multiple meetings and comment periods, on March 20, 2014, FERC issued a Notice of Proposed Rulemaking (NOPR) proposing to move the start of the Gas Day from the current 9 a.m. to 4 a.m. (Central Time) and change the natural gas intraday scheduling practice. The NOPR provided the gas and electricity industry the opportunity to work through the North American Energy Standards Board (NAESB) to reach consensus on modification of the proposed gas day and nomination schedule by September 29, 2014, and requested comments on the NOPR by November 28, 2014.

PG&E actively participated in the NAESB process and led a coalition that supported retention of the existing Gas Day and adoption of the NAESB consensus scheduling cycle changes. On April 16, 2015, FERC issued Order 809 in which FERC adopted the NAESB endorsed modified scheduling cycles. FERC elected to retain the existing Gas Day.

In general, PG&E's position is that gas-electric coordination should be viewed on a regional basis due to the numerous differences in infrastructure and electric markets across the country. PG&E also believes that a high degree of coordination already exists in California between gas system operators and the (electric) California Independent System Operator (CAISO).

Also on March 20, 2014, FERC requested that Independent System Operators/Regional Transmission Operators (ISO/RTO) investigate electric scheduling practices. FERC did not dictate any specific language changes; instead it required each ISO/RTO, to make a filing 90 days after the gas-day revised final order is published containing either (1) proposed tariff changes to adjust the electric scheduling; or (2) show why such changes are not necessary. The

CAISO proposed that its electric scheduling timelines remain unchanged. FERC accepted the CAISO's recommendation.

OTHER REGULATORY MATTERS

Gas Exports

The U.S. Department of Energy (DOE) evaluates the impact of LNG projects proposing to export LNG to countries without a Free Trade Agreement (FTA) with the U.S. and grants approval only if the project is deemed in the public interest. As of February 2016, the DOE had approved 16 non-FTA LNG export applications with a total export capacity of 15.7 bcf/d.

The U.S. Federal Energy Regulatory Commission (FERC), on the other hand, is focused on evaluating the environmental impacts of proposed LNG projects, and is responsible for authorizing the siting and construction of LNG facilities. As of January 2016, FERC had approved for construction 12.8 bcf/d of LNG export capacity, all but 2.2 bcf/d of which was under construction. As of March 2016, only the first train of Sabine Pass Liquefaction, LLC, has completed construction.

With low domestic natural gas prices compared to world markets, the United States is positioned to become a net exporter of natural gas by 2020. Mexico, accounting for approximately 60 percent of total U.S. gas exports, became the largest importer of U.S. natural gas in 2015. The U.S. natural gas exports to Mexico have grown in recent years from 0.9 bcf/d in 2010 to 2.9 bcf/d in 2015, and are projected to reach 5.0 bcf/d by 2020. Declining gas production and increasing gas demand for power generation and industrial use in Mexico are main drivers of this export growth. Completion of several gas pipeline capacity-expansion projects on both sides of the U.S.-Mexico border have resulted in 7 bcf/d of export capacity as of 2015.More pipeline projects are under way to help meet Mexico's growing demand for U.S. gas. When completed, these pipelines will significantly increase the total U.S.-to-Mexico pipeline-export capacity.

Greenhouse Gas (GHG) Reporting and Cap-and-Trade Obligations

In 2015, PG&E Gas Operations reported to the Environmental Protection Agency (EPA) GHG emissions in accordance with 40 Code of Federal Regulations Part 98 in three primary categories: GHG emissions in 2015 resulting from combustion at seven compressor stations, where the annual emissions exceed 25,000 metric tons of CO_2 equivalent ($mtCO_2e$); the GHG emissions resulting from combustion of all customers except customers consuming more than 460 MMcf; and certain vented and fugitive emissions from the seven compressor stations and natural gas distribution system.

In 2015, PG&E Gas Operations reported to the California Air Resources Board (CARB) GHG emissions approximately 44 million $mtCO_2e$ in three primary categories: GHG emissions resulting from combustion at seven compressor stations and one underground gas storage facility, where the annual emissions exceed 10,000 $mtCO_2e$; the GHG emissions resulting from combustion of delivered gas to all customers; and vented and fugitive emissions from seven compressor stations, one underground gas storage facility and the natural gas distribution system.

The seven compressor stations subject to the CARB mandatory reporting are still subject to the CARB Cap-and-Trade Program. On January 1, 2015, natural gas suppliers became subject to the Cap-and-Trade Program and now have a compliance obligation for GHG emissions from the natural gas use of their small customers (i.e., those customers who are not covered directly under CARB's Cap-and-Trade program). In 2014, CARB estimated that PG&E's responsibility for compliance obligations of GHG emissions as a natural gas supplier were approximately 16.4 million mtCO_2e for 2015. CARB will issue the final 2015 compliance obligations of GHG emissions as a natural gas supplier in October 2016.

In 2014, Rulemaking (R.) 15-01-008 was initiated by the Commission to carry out the intent of SB 1371 (Statutes 2014, Chapter 525).1 SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipelines consistent with Public Utilities Code Section 961 (d), § 192.703 (c) of Subpart M of Title 49 of the CFR, the Commission's General Order 112-F, and the state's goal of reducing GHG emissions. As part of this rulemaking, natural gas utilities are required to annually report methane emissions from intentional and unintentional releases and their leak management practices. On June 17, 2016, PG&E filed the 2015 Annual Report and reported 3.25 billion cubic feet (Bcf) of methane emissions from intentional and unintentional releases. Currently, these emissions are not subject to the CARB Cap-and-Trade Program.

California State Senate Bill 350

On October 7, 2015, Governor Brown signed into law SB 350 which among others requires that commencing in 2017 the Commission adopt a process for each Load Serving Entity (LSE) to file and periodically update an Integrated Resource Plan (IRP) to ensure that LSEs:

- Meet the GHG emissions reduction targets established by the State Air Resources Board, in coordination with the Commission and the Energy Commission, for the electricity sector and each load-serving entity that reflect the electricity sector's percentage in achieving the economy-wide GHG emissions reductions of 40 percent from 1990 levels by 2030;
- Procure at least 50 percent eligible renewable energy resources by December 31, 2030;
- Enable each electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates;
- Minimize impacts on ratepayers' bills;
- Ensure system and local reliability;

- Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities;
- Enhance distribution systems and demand-side energy management; and
- Minimize localized air pollutants and other GHG emissions, with early priority on disadvantaged communities.

On February 11, 2016, the Commission opened R.16-02-007 with the primary purpose of implementing the Commission's requirement to adopt an IRP process.

ABNORMAL PEAK DAY DEMAND AND SUPPLY

APD DEMAND FORECAST

The APD forecast is a projection of demand under extreme weather conditions. PG&E uses a 1-in-90-year cold-temperature event as the design criterion. This criterion corresponds to a 27 degree Fahrenheit system-weighted mean temperature across the PG&E gas system. The PG&E core demand forecast corresponding to a 27 degree Fahrenheit temperature is estimated to be approximately 3.2 bcf/d. The 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 2.5 bcf/d, 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 production. 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 serve approximately 78 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 south 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 the PG&E system and others.

If core supplies are insufficient to meet core demand, PG&E can divert gas from noncore customers, including EG customers, to meet it. PG&E's tariffs contain diversion and Emergency Flow Order (EFO) noncompliance charges that are designed to cause the noncore market to either reduce or cease its use of gas, if required. Since little, if any, alternate fuel-burn capability exists today, supply diversions from the noncore would necessitate those noncore customers to 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 2.5 bcf/d. With the Wild Goose, Lodi, Gill Ranch, and Central Valley Gas 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 storage inventories.

Forecast of Core Gas Demand and Supply on an APD
(Million Cubic Feet Per Day)

	2016-17	2017-18	2018-19
APD Core Demand(1)	3,199	3,208	3,211
Firm Storage Withdrawal(2)	1,076	1,076	1,076
Required Flowing Supply(3)	2,123	2,132	2,135
Total APD Resources	3,199	3,208	3,211

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 uses a system-composite temperature based on six weather sites.
(2) Core Firm Storage Withdrawal capacity includes 98 MMcf/day 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 month (December) and summer month (August) periods under PG&E's high-demand scenario.

Winter Peak Day Demand
(Million Cubic Feet per Day)

Year	Core(1)	Noncore Non-EG(2)	EG, including SMUD(3)	Total Demand
2016	2,645	542	929	4,117
2017	2,653	531	987	4,167
2018	2,655	526	1,012	4,194
2019	2,647	524	978	4,152
2020	2,640	521	942	4,112
2021	2,636	536	904	4,075

Notes:
(1) Core demand calculated for 34-degrees-Fahrenheit system-composite temperature, corresponding to 1-in-10-year cold-temperature event.
(2) Average daily winter (December) demand.
(3) Average daily winter (December) demand under 1-in-10 cold-and-dry conditions.

Summer Peak Day Demand
(Million Cubic Feet per Day)

Year	Core(4)	Noncore Non-EG(4)	EG, including SMUD(5)	Total Demand
2016	379	667	1,506	2,554
2017	372	654	1,144	2,167
2018	365	648	1,197	2,210
2019	362	645	1,167	2,177
2020	360	644	1,199	2,210
2021	358	646	1,173	2,187

Notes:
(4) Average daily summer (August) demand.
(5) Average daily summer (August) demand under 1-in-10 cold-and-dry conditions.

2016 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA
TABULAR DATA

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 2011-2015
MMCF/DAY

LINE		2011	2012	2013	2014	2015	LINE
	GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS						
1	Core Purchases	0	0	0	0	0	1
2	Customer Gas Transport & Exchange	108	84	57	49	37	2
3	Total California Source Gas	108	84	57	49	37	3
	OUT-OF-STATE GAS						
	Core Net Purchases						
6	Rocky Mountain Gas	44	203	223	202	219	6
7	U.S. Southwest Gas	286	255	207	126	147	7
8	Canadian Gas	501	353	330	328	345	8
	Customer Gas Transport						
10	Rocky Mountain Gas	417	846	774	763	689	10
11	U.S. Southwest Gas	248	190	180	398	360	11
12	Canadian Gas	563	483	432	428	798	12
13	Total Out-of-State Gas	2,059	2,330	2,146	2,247	2,558	13
14	STORAGE WITHDRAWAL(2)	346	259	395	344	238	14
15	Total Gas Supply Taken	2,513	2,673	2,598	2,640	2,833	15
	GAS SENDOUT						
	CORE						
19	Residential	577	537	538	437	450	19
20	Commercial	244	229	229	207	209	20
21	NGV	5	6	6	7	8	21
22	Total Throughput-Core	826	771	774	651	667	22
	NONCORE						
24	Industrial	497	518	519	533	534	24
25	Electric Generation (1)	724	939	987	990	1,025	25
26	NGV	1	1	1	1	1	26
27	Total Throughput-Noncore	1,222	1,458	1,507	1,524	1,560	27
28	WHOLESALE	10	9	10	8	8	28
29	Total Throughput	2,058	2,239	2,291	2,183	2,235	29
30	OFF-SYSTEM DELIVERIES(4)					251	30
31	CALIFORNIA EXCHANGE GAS	1	2	2	0	0	31
32	STORAGE INJECTION(2)	405	344	267	425	291	32
33	SHRINKAGE Company Use / Unaccounted for	49	88	39	32	56	33
34	Total Gas Send Out	2,513	2,673	2,598	2,640	2,833	34
	TRANSPORTATION & EXCHANGE						
38	CORE — ALL END USES	118	130	152	144	142	38
39	NONCORE — INDUSTRIAL	497	518	519	533	534	39
40	ELECTRIC GENERATION	724	939	987	990	1025	40
41	SUBTOTAL/RETAIL	1,339	1,587	1,658	1,666	1,701	41
43	WHOLESALE/INTERNATIONAL	10	9	10	8	8	43
45	TOTAL TRANSPORTATION AND EXCHANGE	1,349	1,596	1,668	1,674	1,709	45
	CURTAILMENT/ALTERNATIVE FUEL BURNS						
48	Residential, Commercial, Industrial	0	0	0	0	0	48
49	Utility Electric Generation	0	0	0	0	0	49
50	TOTAL CURTAILMENT	0	0	0	0	0	50

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) 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.

(4) For years 2011 through 2014, Total gas send-out excludes off-system transportation; off-system deliveries are subtracted from supply total.

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY

AVERAGE DEMAND YEAR

LINE			2016	2017	2018	2019	2020	LINE
FIRM CAPACITY AVAILABLE								
1	**California Source Gas**		43	43	43	43	43	1
	Out of State Gas							
2	Baja Path[1]		1,016	1,016	1,016	1,016	1,016	2
3	Redwood Path[2]		2,023	2,023	2,023	2,023	2,023	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.		41	41	41	41	41	3.a
4	**Supplemental[3]**		0	0	0	0	0	4
5	**Total Supplies Available**		3,123	3,123	3,123	3,123	3,123	5
GAS SUPPLY TAKEN								
6	**California Source Gas**		43	43	43	43	43	6
7	**Out of State Gas (via existing facilities)**		2,501	2,271	2,274	2,252	2,232	7
8	**Supplemental**		0	0	0	0	0	8
9	**Total Supply Taken**		2,545	2,314	2,317	2,295	2,275	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	0	10
11	**Total Throughput**		2,545	2,314	2,317	2,295	2,275	11
REQUIREMENTS FORECAST BY END USE								
	Core							
12	Residential[4]		528	528	525	520	514	12
13	Commercial		222	222	222	222	222	13
14	NGV		8	8	9	9	10	14
15	**Total Core**		758	759	756	752	746	15
	Noncore							
16	Industrial		537	527	521	518	516	16
17	SMUD Electric Generation[5]		122	122	122	122	122	17
18	PG&E Electric Generation[6]		784	567	578	564	552	18
19	NGV		1	1	1	1	1	19
20	Wholesale		10	10	10	10	9	20
21	California Exchange Gas		1	1	1	1	1	21
22	**Total Noncore**		1,455	1,227	1,233	1,216	1,202	22
23	**Off-System Deliveries[7]**		286	286	286	286	286	23
	Shrinkage							
24	Company use and Unaccounted for		46	42	42	41	41	24
25	**TOTAL END USE**		2,545	2,314	2,317	2,295	2,275	25
	TRANSPORTATION & EXCHANGE							
26	CORE	ALL END USES	153	153	152	152	151	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	537	527	521	518	516	27
28		ELECTRIC GENERATION	906	689	700	686	674	28
29		SUBTOTAL/RETAIL	1,596	1,368	1,374	1,357	1,342	29
30		WHOLESALE/INTERNATIONAL	10	10	10	10	9	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,605	1,378	1,383	1,366	1,352	31
32	System Curtailment		0	0	0	0	0	32

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 TransCanada Gas Transmission Northwest pipeline and Ruby 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
MMCF/DAY

AVERAGE DEMAND YEAR

LINE			2021	2022	2025	2030	2035	LINE
FIRM CAPACITY AVAILABLE								
1	**California Source Gas**		43	43	43	43	43	1
	Out of State Gas							
2	Baja Path[(1)]		1,016	1,016	1,016	1,016	1,016	2
3	Redwood Path[(2)]		2,023	2,023	2,023	2,023	2,023	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.		41	41	41	41	41	3.a
4	**Supplemental[(3)]**		0	0	0	0	0	4
5	**Total Supplies Available**		3,123	3,123	3,123	3,123	3,123	5
GAS SUPPLY TAKEN								
6	**California Source Gas**		43	43	43	43	43	6
7	**Out of State Gas (via existing facilities)**		2,216	2,236	2,265	2,229	2,229	7
8	**Supplemental**		0	0	0	0	0	8
9	**Total Supply Taken**		2,259	2,279	2,308	2,272	2,272	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	1	10
11	**Total Throughput**		2,259	2,279	2,308	2,272	2,273	11
REQUIREMENTS FORECAST BY END USE								
	Core							
12	Residential[(4)]		510	505	494	478	478	12
13	Commercial		222	223	224	225	225	13
14	NGV		10	11	12	15	15	14
15	**Total Core**		742	739	730	718	718	15
	Noncore							
16	Industrial		520	523	535	564	564	16
17	SMUD Electric Generation[(5)]		122	122	122	122	122	17
18	PG&E Electric Generation[(6)]		538	557	582	530	530	18
19	NGV		1	1	1	1	1	19
20	Wholesale		9	9	9	9	9	20
21	California Exchange Gas		1	1	1	1	1	21
22	**Total Noncore**		1,191	1,213	1,251	1,228	1,228	22
23	**Off-System Deliveries[(7)]**		286	286	286	286	286	23
	Shrinkage							
24	Company use and Unaccounted for		40	41	41	41	41	24
25	**TOTAL END USE**		2,259	2,279	2,308	2,272	2,272	25
	TRANSPORTATION & EXCHANGE							
26	CORE	ALL END USES	151	151	150	149	149	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	520	523	535	564	564	27
28		ELECTRIC GENERATION	660	679	704	652	652	28
29		SUBTOTAL/RETAIL	1,330	1,352	1,389	1,365	1,365	29
30		WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,340	1,362	1,398	1,374	1,374	31
32	System Curtailment		0	0	0	0	0	32

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 TransCanada Gas Transmission Northwest pipeline and Ruby 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
MMCF/DAY

HIGH DEMAND YEAR (1 in 10 Cold Year)

LINE			2016	2017	2018	2019	2020	LINE
FIRM CAPACITY AVAILABLE								
1	**California Source Gas**		43	43	43	43	43	1
	Out of State Gas							
2	Baja Path(1)		1,016	1,016	1,016	1,016	1,016	2
3	Redwood Path(2)		2,023	2,023	2,023	2,023	2,023	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.		41	41	41	41	41	3.a
4	**Supplemental(3)**		0	0	0	0	0	4
5	**Total Supplies Available**		3,123	3,123	3,123	3,123	3,123	5
GAS SUPPLY TAKEN								
6	**California Source Gas**		43	43	43	43	43	6
7	**Out of State Gas (via existing facilities)**		2,560	2,336	2,342	2,322	2,306	7
8	**Supplemental**		0	0	0	0	0	8
9	**Total Supply Taken**		2,603	2,379	2,386	2,366	2,349	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	0	10
11	**Total Throughput**		2,603	2,379	2,386	2,366	2,349	11
REQUIREMENTS FORECAST BY END USE								
	Core							
12	Residential(4)		550	550	548	544	541	12
13	Commercial		227	228	228	228	228	13
14	NGV		8	8	9	9	10	14
15	**Total Core**		785	786	785	782	779	15
	Noncore							
16	Industrial		538	527	522	519	517	16
17	SMUD Electric Generation(5)		122	122	122	122	122	17
18	PG&E Electric Generation(6)		814	604	617	603	591	18
19	NGV		1	1	1	1	1	19
20	Wholesale		10	10	10	10	10	20
21	California Exchange Gas		1	1	1	1	1	21
22	**Total Noncore**		1,486	1,265	1,273	1,256	1,243	22
23	**Off-System Deliveries(7)**		286	286	286	286	286	23
	Shrinkage							
24	Company use and Unaccounted for		47	42	42	42	41	24
25	**TOTAL END USE**		2,603	2,379	2,386	2,366	2,349	25
	TRANSPORTATION & EXCHANGE							
26	CORE	ALL END USES	158	158	158	157	157	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	538	527	522	519	517	27
28		ELECTRIC GENERATION	936	726	739	725	713	28
29		SUBTOTAL/RETAIL	1,631	1,411	1,418	1,401	1,388	29
30		WHOLESALE/INTERNATIONAL	10	10	10	10	10	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,641	1,421	1,428	1,411	1,398	31
32	System Curtailment		0	0	0	0	0	32

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 TransCanada Gas Transmission Northwest pipeline and Ruby 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
MMCF/DAY

HIGH DEMAND YEAR (1 in 10 Cold Year)

LINE			2021	2022	2025	2030	2035	LINE
FIRM CAPACITY AVAILABLE								
1	**California Source Gas**		43	43	43	43	43	1
	Out of State Gas							
2	Baja Path[1]		1,016	1,016	1,016	1,016	1,016	2
3	Redwood Path[2]		2,023	2,023	2,023	2,023	2,023	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.		41	41	41	41	41	3.a
4	**Supplemental[3]**		0	0	0	0	0	4
5	**Total Supplies Available**		3,123	3,123	3,123	3,123	3,123	5
GAS SUPPLY TAKEN								
6	**California Source Gas**		43	43	43	43	43	6
7	**Out of State Gas (via existing facilities)**		2,292	2,316	2,455	2,420	2,420	7
8	**Supplemental**		0	0	0	0	0	8
9	**Total Supply Taken**		2,336	2,360	2,498	2,463	2,463	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	0	10
11	**Total Throughput**		2,336	2,360	2,498	2,463	2,463	11
REQUIREMENTS FORECAST BY END USE								
	Core							
12	Residential[4]		538	535	527	519	519	12
13	Commercial		230	230	232	235	235	13
14	NGV		10	11	12	15	15	14
15	**Total Core**		778	776	772	769	769	15
	Noncore							
16	Industrial		520	523	536	565	565	16
17	SMUD Electric Generation[5]		122	122	122	122	122	17
18	PG&E Electric Generation[6]		577	599	728	668	668	18
19	NGV		1	1	1	1	1	19
20	Wholesale		10	10	10	10	10	20
21	California Exchange Gas		1	1	1	1	1	21
22	**Total Noncore**		1,231	1,256	1,398	1,367	1,367	22
23	**Off-System Deliveries[7]**		286	286	286	286	286	23
	Shrinkage							
24	Company use and Unaccounted for		41	42	42	42	42	24
25	**TOTAL END USE**		2,336	2,360	2,498	2,463	2,463	25
	TRANSPORTATION & EXCHANGE							
26	CORE	ALL END USES	157	157	157	157	157	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	520	523	536	565	565	27
28		ELECTRIC GENERATION	699	721	850	790	790	28
29		SUBTOTAL/RETAIL	1,376	1,401	1,543	1,512	1,512	29
30		WHOLESALE/INTERNATIONAL	10	10	10	10	10	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,386	1,411	1,553	1,522	1,522	31
32	System Curtailment		0	0	0	0	0	33

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 TransCanada Gas Transmission Northwest pipeline and Ruby 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.

2016 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 services across its service territory 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.

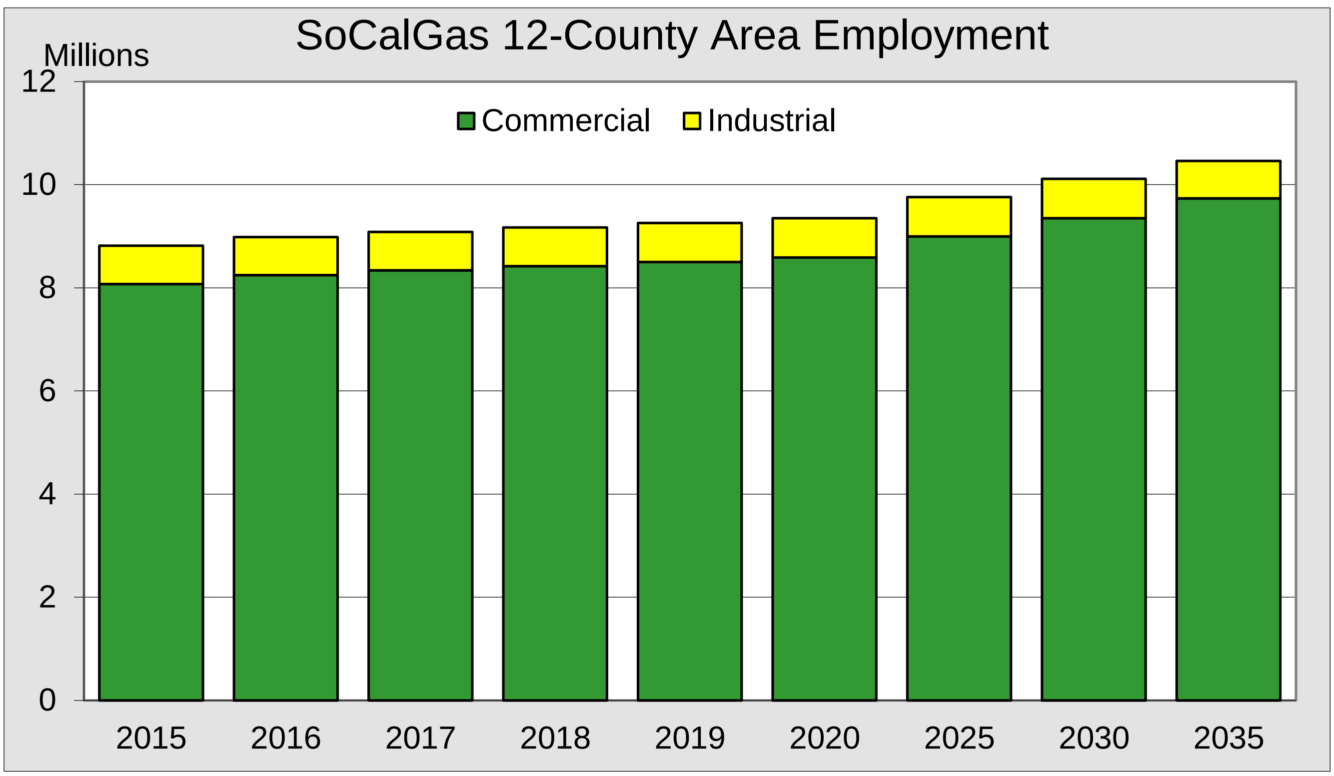
This report covers a 20-year demand and forecast period, from 2016 through 2035; only the consecutive years 2016 through 2022 and the point years 2025, 2030, and 2035 are shown in the tabular data in the next sections. These single point forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

The Southern California section of the *2016 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.

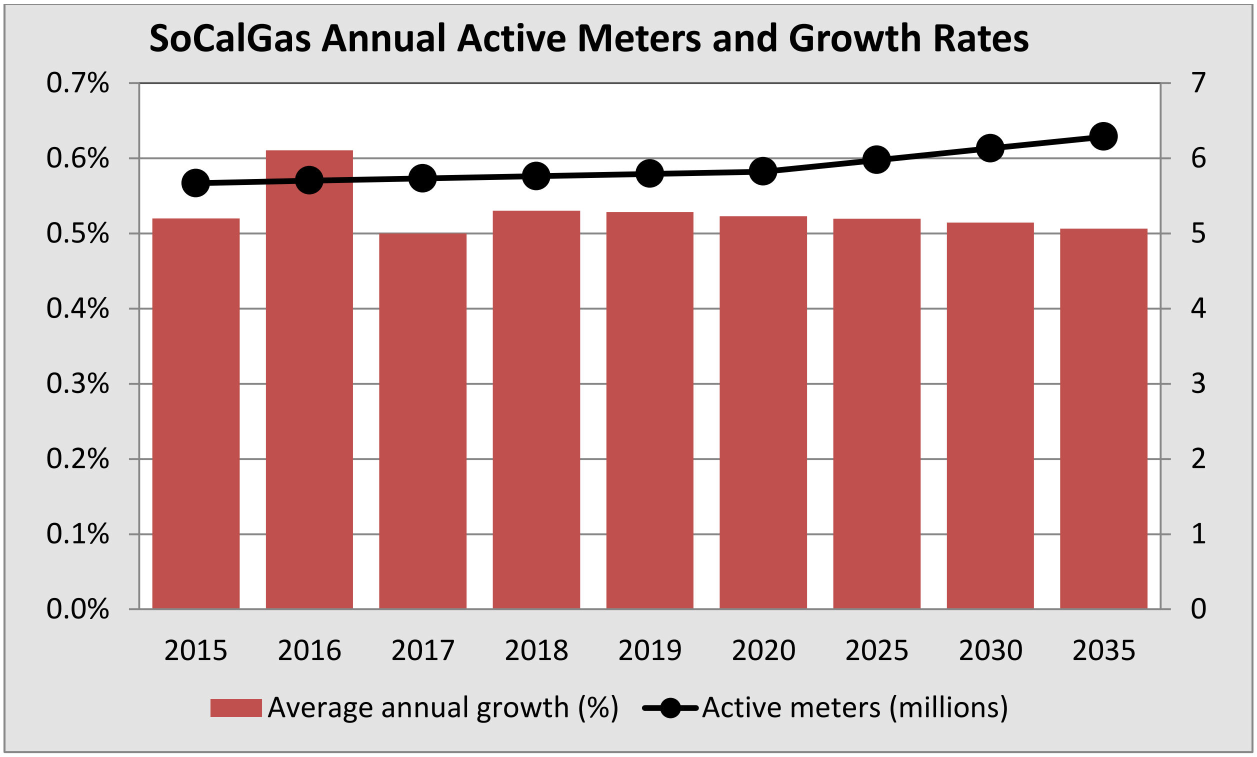
THE SOUTHERN CALIFORNIA ENVIRONMENT

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-2016, Southern California's economy appears to be heading into slower growth after largely recovering from the previous multi-year slump. Overall area jobs are expected to average moderate 1.0% annual growth from 2016 through 2020. During the same period, local manufacturing and mining industrial employment should grow a more modest 0.7% per year, with commercial jobs growing just over 1% annually. Construction jobs should continue their comeback, averaging over 4% annual growth from 2016 through 2020. Other sectors with expected strong growth in the same period include professional and business services (jobs growing 2.3% per year) and health and social services (1.7% per year).



Longer term, SoCalGas' service-area employment is expected to increase only modestly as the area population's average age gradually increases--part of a national demographic trend of aging and retiring "baby boomers". From 2016 through 2035, total area job growth should average 0.8% per year. Area industrial jobs are forecasted to shrink an average of 0.1% per year through 2035; we expect the industrial share of total employment to fall from 8.2% in 2016 to 6.9% by 2035. Commercial jobs are expected to grow an average of 0.9% annually from 2016 through 2035.



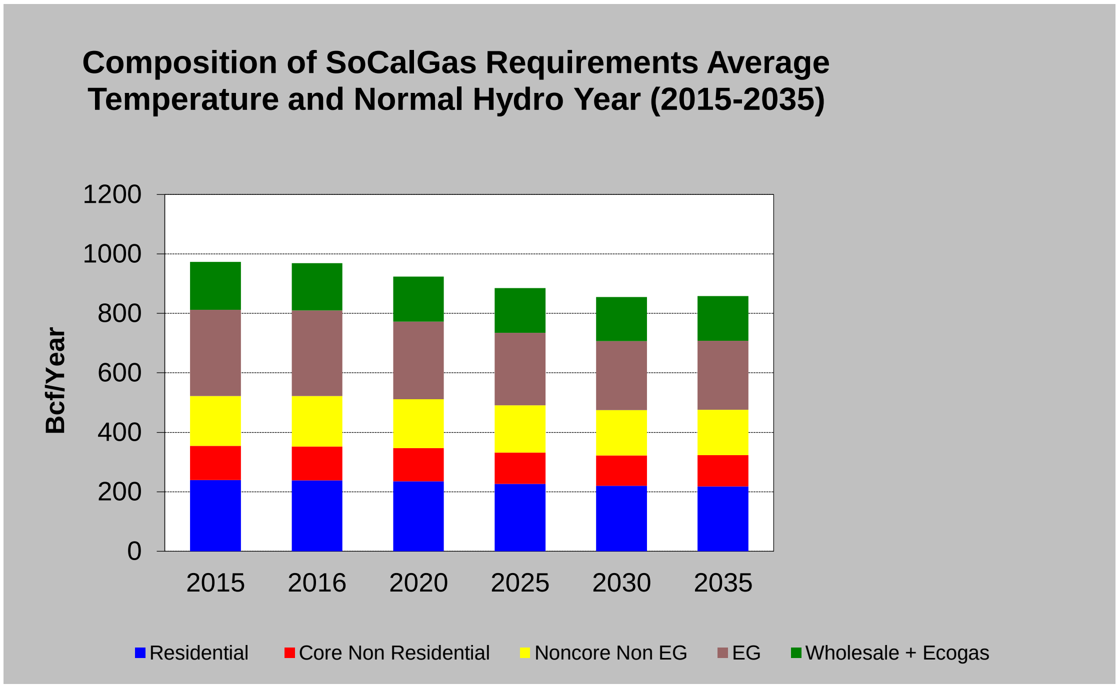
Since 2011, SoCalGas' service area housing market has gradually been recovering from its prior drastic downturn. Home building and meter hookups continue to increase modestly, with SoCalGas' annual active meters growing by about 29,000 (0.52%) in 2015. SoCalGas expects active meters to maintain moderate growth at about the same pace, growing an average of 0.51% per year from 2016 through 2035.

GAS DEMAND (REQUIREMENTS)

OVERVIEW

SoCalGas projects total gas demand to decline at an annual rate of 0.6% from 2016 to 2035. The decline in throughput demand is due to modest economic growth, CPUC-mandated energy efficiency (EE) standards and programs, renewable electricity goals, the decline in commercial and industrial demand, and conservation savings linked to Advanced Metering Infrastructure (AMI). By comparison, the 2014 CGR projected an annual decline in demand of 0.33% over the forecast horizon. The difference between the two forecasts is caused primarily by more modest meter and employment growth forecasts than those embodied in the 2014 *California Gas Report*.

The following chart shows the composition of SoCalGas' throughput for the recorded year 2015 (with weather-sensitive market segments adjusted to average year heating degree day assumptions) and forecasts for the 2016 to 2035 forecast period.



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 in Mexico.

From 2016 to 2035, residential demand is expected to decline from 239 Bcf to 218 Bcf. The decline is due to declining use per meter offsetting new meter growth. The core, non-residential markets are expected to decline from 113 Bcf in 2016 to 105 Bcf by 2035. The change reflects an annual rate of decline of 0.5% over the forecast period. The noncore, non-EG markets are expected to decline from 170 Bcf in 2016 to 153 Bcf by 2035. The annual rate of decline is approximately 0.5% due to very aggressive energy efficiency goals and associated programs. On the other hand, utility gas demand for EOR steaming operations, which had declined since the FERC-regulated Kern/Mojave interstate pipeline began offering direct service to California customers in 1992, has shown some growth in recent years. EOR steaming gas demand is expected to remain at about its 2015 level through 2035 as gains are offset by the depletion of older oil fields. Total electric generation load, including cogeneration and non-cogeneration EG for a normal hydro year, is expected to decline from 288 Bcf in 2016 to 232 Bcf in 2035, a decrease of 1.1% per year.

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, core commercial and core industrial markets. The largest demand variations due to temperature are likely to 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 defined 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.

In our 2016 CGR, average year and cold year HDD totals are 1,340 and 1,659 respectively, on a calendar year basis for SoCalGas. For SDG&E, these values are 1,288 and 1,656 HDDs, respectively. The average year values were computed as the simple average of annual HDD's for the years 1996 through 2015.

Hydro Condition

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

MARKET SECTORS

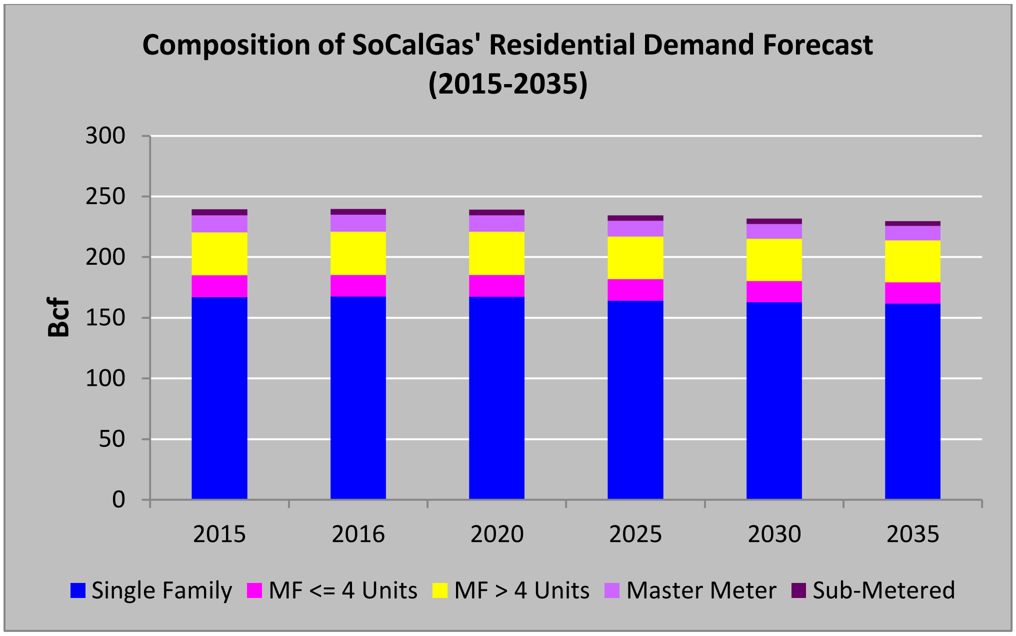
Residential

Residential demand adjusted for temperature totaled 239 Bcf in 2015 which is 3 Bcf lower than 2014 weather adjusted deliveries. The residential load is expected to decline on average by 0.5% per year from 239 Bcf in 2015 to 218 Bcf in 2035. The decrease in gas demand results from a combination of continued decline in residential use per meter, increases in marginal gas rates, the impact of savings from SoCalGas' Advanced Meter Infrastructure (AMI) project deployment which began in 2013 and CPUC authorized energy efficiency program savings in this market.

The total residential customer count for SoCalGas consists of five residential segment types: single family, small multi-family, large multi-family, master meter and sub-metered customers. The active meters for all residential customer classes were 5.46 million at the end of 2015. This amount reflects a 29,759 active meter increase between 2014 at year end and 2015 at year end. The overall observed 2014-2015 residential meter growth was 0.55%. Eight 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 slowdown in active meter growth reflects more modest new home construction activity since the boom ended in 2007.

The 2016 CGR shows that in 2015, single family and overall multi-family temperature-adjusted average annual use per meter was 474 therms and 312 therms, respectively. Over the forecast period, the demand per meter is expected to decline at an average annual rate of 0.7%. The decline in use per meter for residential customers is explained by conservation, improved building and appliance standards, energy efficiency programs, and demand reductions anticipated as the result of the deployment of AMI in the Southern California area. With AMI, customers will have more timely information available about their daily and hourly gas use and thereby are expected to use gas more efficiently. Mass deployment of SoCalGas' AMI modules began in 2013 and is expected to be completed by 2017. The deployment of SoCalGas' AMI will not only provide operating efficiencies but will also generate long term conservation benefits.

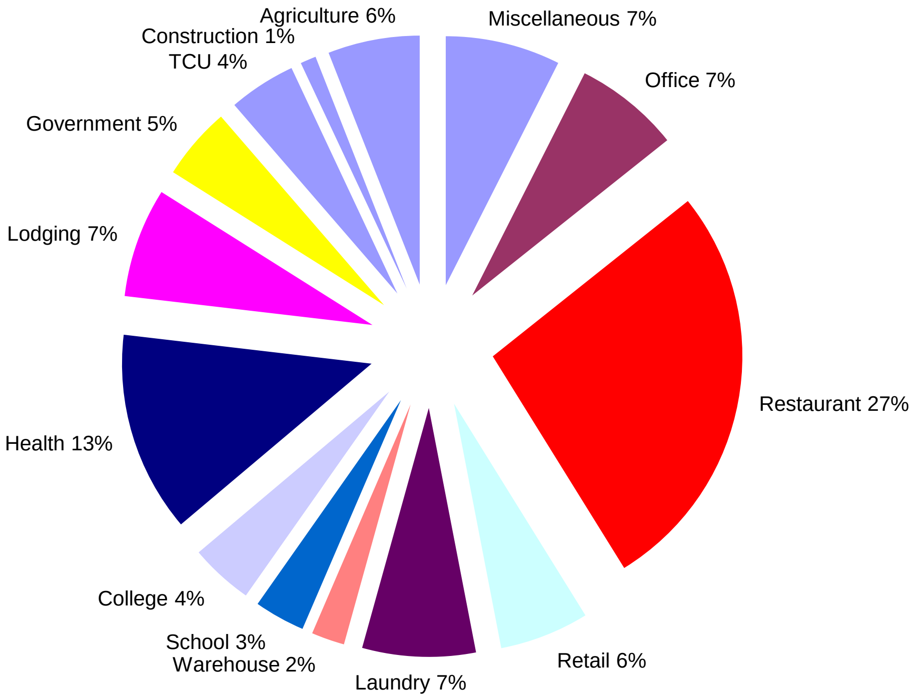
The projected residential natural gas demand will be influenced primarily by residential meter growth, moderated by the forecasted decline in use per customer. The residential load trend over the forecast period is illustrated in the graph below.



Commercial

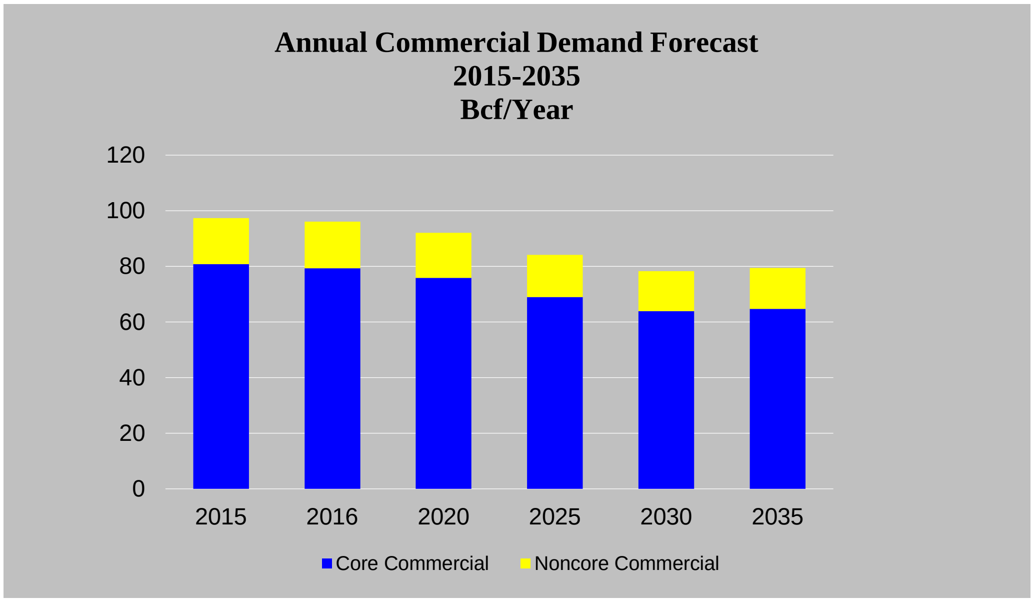
The commercial market consists of 14 business types identified by the customers' North American Industry Classification System (NAICS) codes. The restaurant business dominates this market with 27% of the usage in 2015. The health industry is next largest with a share of 13% of the overall market based on 2015 natural gas consumption.

Commercial Gas Demand by Business Type
Composition of Industry (2015)



The core commercial market demand is expected to decline over the forecast period. On a temperature-adjusted basis, the core commercial market demand in 2015 totaled 81 Bcf. By the year 2035, the load is anticipated to be approximately 65 Bcf. The average annual rate of decline from 2016 to 2035 is forecasted at 1% percent. The decline in gas usage is mainly the result of the impact of CPUC-authorized energy efficiency programs in this market.

Noncore commercial demand in 2015 was 16.4 Bcf. From 2016 through 2035, demand in this market is expected to decline slightly at approximately 0.55% annually to 14.7 Bcf. A key factor of the decreasing trend is the CPUC-authorized energy efficiency programs.

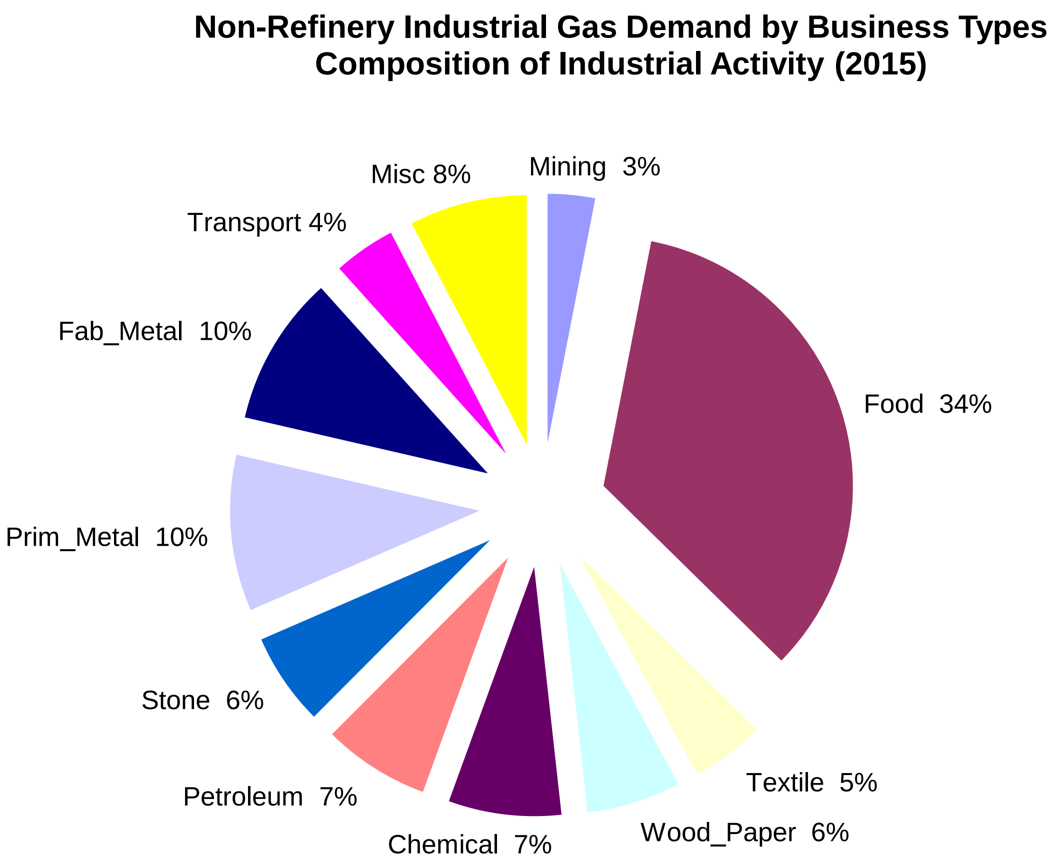


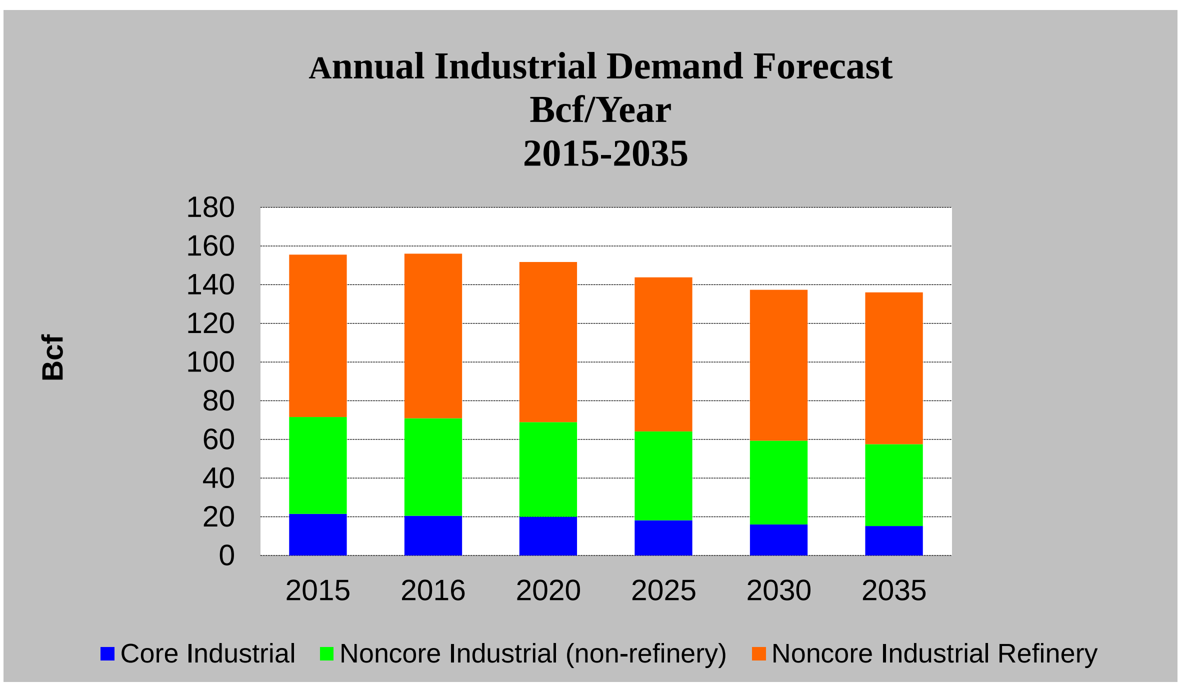
Industrial

Non-Refinery Industrial Demand

In 2015, temperature-adjusted core industrial demand was 21.6 Bcf, which was lower than 2014 deliveries by 0.4 Bcf. Core industrial market demand is projected to decrease by 1.7% per year from 21.6 Bcf in 2015 to 15.3 Bcf in 2035. This decrease in gas demand results from a combination of factors: a minor decrease in employment growth, minor increases in marginal gas rates, the municipalization of the City of Vernon, and CPUC-authorized energy efficiency programs.

The 2015 industrial gas demand served by SoCalGas is shown below. Food processing, with 34% of the total share, dominates this market.


Non-Refinery Industrial Gas Demand by Business Types
Composition of Industrial Activity (2015)
Mining 3%
Food 34%
Textile 5%
Wood_Paper 6%
Chemical 7%
Petroleum 7%
Stone 6%
Prim_Metal 10%
Fab_Metal 10%
Transport 4%
Misc 8%

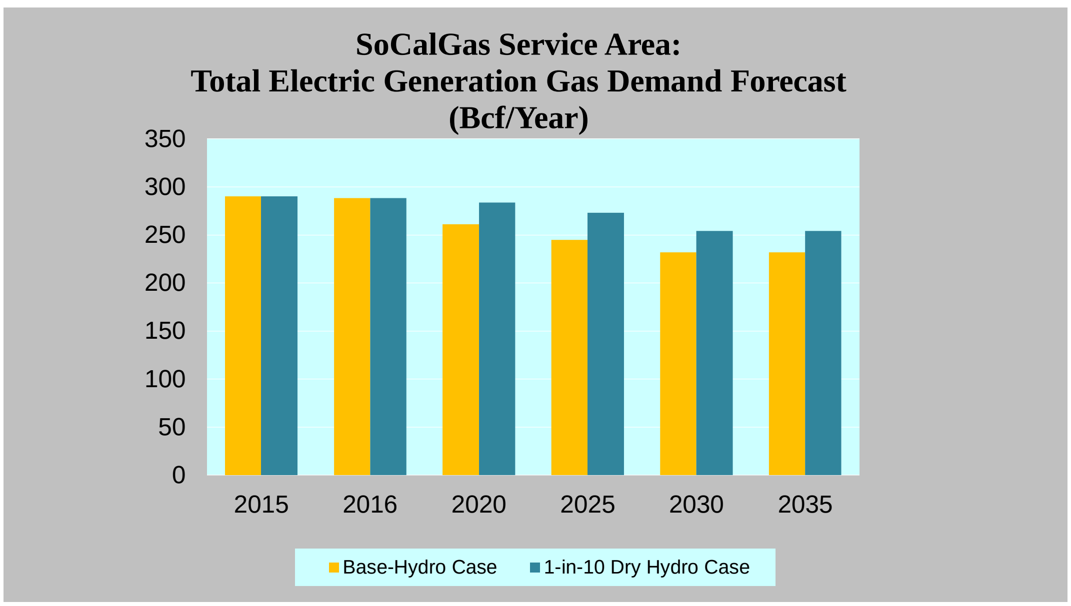

Annual Industrial Demand Forecast
Bcf/Year
2015-2035
Bcf
180
160
140
120
100
80
60
40
20
0
2015
2016
2020
2025
2030
2035
Core Industrial
Noncore Industrial (non-refinery)
Noncore Industrial Refinery

Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at a rate of 0.8% from 49.9 Bcf in 2015 to 42.2 Bcf by 2035. 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 CPUC-authorized energy efficiency programs designed to reduce gas demand and the expected implementation of regulations to aggressively reduce CO2 emissions by effectively increasing the gas commodity price for industrial customers.

Refinery-Industrial Demand

Refinery-industrial demand is comprised of gas consumption by petroleum refining customers, hydrogen producers and refined petroleum product transporters. Gas demand in the refinery industrial market sector is forecasted to decline about 0.34% per year over the 2016-2035 forecast period, from 84.0 Bcf in 2015 to 78.5 Bcf in 2035. The decrease over the forecast period is primarily due to the estimated savings from CPUC-authorized energy efficiency programs.

Electric Generation



The electric generation sector includes all commercial/industrial cogeneration, EOR-related cogeneration, and non-cogeneration electric generation. The forecast of electric generation (EG) load is subject to a high degree of uncertainty. Forecast uncertainty is in large part due to load sensitivity to weather conditions, the expiration of existing contracts with cogeneration facilities, and the construction and retirement of power plants and transmission lines. Additionally, many once-through-cooling (OTC) plants in California are scheduled to either retire or repower during the forecasted period. These are mostly gas-fired thermal plants, located near the coast, that use ocean water for cooling.

The forecast uses a power market simulation for the period of 2016 to 2030. The simulation reflects the anticipated dispatch of all EG resources in the SoCalGas service territory using a base electricity demand scenario under both average and low hydroelectric availability market conditions. The base case assumes that the state will reach its 50% Renewable Portfolio Standards by 2030, as mandated in SB 350. The base case also assumes the IOUs will meet D.13-10-040, or the energy storage procurement framework and design program. However, there is substantial uncertainty as to how this will be implemented, and its impact on gas throughput is unknown. Due to the large uncertainty in the timing and type of generating plants that could be added after 2030, the EG forecast is held constant at 2030 levels through 2035.

For electricity demand within California, SoCalGas relies on the California Energy Commission's (CEC) California Energy Demand 2016-2026 Revised/Final Forecast, dated January 2016. SoCalGas selected the Mid Energy Demand scenario with the Mid Additional Achievable Energy Efficiency (AAEE) scenario. For the first time in CEC forecasts, the Mid AAEE scenario shows a declining, long-term, state-wide energy demand; Southern California energy demand declines at a faster rate than Northern California. However, CEC's current electricity demand forecast does not include the doubling of energy efficiency programs, as mandated in SB 350, due to timing constraints. CEC is currently analyzing how it would implement these additional energy programs and their impacts on electricity demand.

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. Customers in this market segment install their own electric generation equipment for both economic reasons (gas powered systems produce electricity cheaper than purchasing it from a local electric utility) and reliability reasons (lower purchased power prices are realized only for interruptible service). In 2015, gas demand in the small cogeneration market was 23.7 Bcf. Demand is expected to be about 25 Bcf per year during the period from 2016 to 2020 due to relatively low gas to electric fuel prices. After 2020, cogeneration demand is projected to decline modestly to 24.4 Bcf by the year 2035. This represents an average decline of 0.32% per year. Overall, from 2016 through 2035, small cogeneration load is anticipated to decline at an annual average rate of 0.22%. A key factor in this decline is the expected implementation of regulations to reduce CO2 emissions which will increase the gas commodity price for many small cogeneration customers.

Industrial/Commercial Cogeneration >20 MW

For commercial/industrial cogeneration customers greater than 20 MW, gas demand is forecasted to decrease from 49 Bcf in 2016 to 44 Bcf in 2035. There are some uncertainties in this sector with respect to contract renewals. This forecast assumes that most of the existing facilities will continue to be cost–effective and thus will continue to operate at historical levels. However, a facility has signed a dispatchable contract recently with its local electric utilities; there may be more dispatchable contracts to follow. Additional changes to this assumption in the future could have a significant impact on the forecast.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. This market is forecasted to decline modestly at about 0.16% per year, decreasing from 22.5 Bcf in 2015 to 21.8 Bcf in 2035. The slight decline is mainly due to higher gas costs stemming from California's GHG carbon fees.

Enhanced Oil Recovery-Related Cogeneration

In 2015, recorded gas deliveries to the EOR-related cogeneration market were 3.8 Bcf, a 37% decrease from 2014. This decrease in load was due to changes in operations for some of the existing EOR-related cogeneration customers. EOR-related cogeneration demand is forecasted to remain at 3.8 Bcf throughout the forecast period.

Non-Cogeneration Electric Generation

For the base case (average hydro condition), gas demand is forecasted to decrease from 188 Bcf in 2016 to 138 Bcf in 2035. The main factors for the decline are an increasing RPS target level and decreasing electricity demand. SB 350 raised the RPS target level from 33% to 50% by 2030. As mentioned earlier, CEC's latest electricity demand forecast (Mid Base, Mid AAEE scenario) shows declining electricity demand. To account for dry climate conditions, a 1-in-10 dry hydro sensitivity gas demand forecast was created. This dry hydro forecast increases gas demand on average by 26 Bcf.

SoCalGas' forecast includes the addition of approximately 2,015 MW of new local, gas-fired combined cycle and peaking generating resources in its service area by 2023. However, the forecast also assumes 7,413 MW of local, gas-fired plants are and/or will be retired as a result of the state's once-through-cooling regulation and economics.

For this forecast, SoCalGas included energy storage resources in the model as required by D.13-10-040. Installed storage capacity data was based on the mid scenario from the CPUC's 2014 Long Term Procurement Plan assumptions. In the model, a state-wide installed capacity of 141 MW was added starting in 2017. Storage capacity increased to 1,125 MW by 2024.

Enhanced Oil Recovery – Steam

Recorded deliveries to the EOR steaming market in 2015 were 17.0 Bcf, an increase of approximately 4% from 2014. SoCalGas' EOR steaming demand is expected to stay at 17.0 Bcf from 2016 through the end of the forecast period. The EOR-related cogeneration demand is discussed in the Electric Generation section.

Crude oil futures prices appear to be flat for the next 8 years which is expected to result in California EOR operations staying steady going forward.

Wholesale and International

SoCalGas provides wholesale transportation service to SDG&E, the City of Long Beach Gas and Oil Department (Long Beach), Southwest Gas Corporation (SWG), and the City of Vernon (Vernon) and Ecogas Mexico, L. de R.L. de C.V. The wholesale load excluding SDG&E is expected to increase from 25.4 Bcf in 2016 to 27.8 Bcf in 2035.

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 0.4% per year from 131 Bcf in 2015 to 120 Bcf in 2035. Additional information regarding SDG&E's gas demand is provided in the SDG&E section of this report.

City of Long Beach

The wholesale load forecast is based on forecast information provided by the City of Long Beach Municipal Gas & Oil Department. Long Beach's gas use is expected to remain fairly constant, increasing from 8.0 Bcf in 2016 to 8.4 Bcf by 2035. Long Beach's locally supplied deliveries are estimated to stay steady at 1.0 Bcf from 2016 to 2035. SoCalGas' transportation to Long Beach is expected to increase gradually from 7.0 Bcf in 2016 to 7.4 Bcf by 2035. Refer to City of Long Beach Municipal Gas & Oil Department for more information.

Southwest Gas

SoCalGas used the forecast prepared by Southwest Gas for this report. In 2016, SoCalGas expects to serve approximately 6.2 Bcf directly, with another 2.9 Bcf being served by PG&E under exchange arrangements with SoCalGas. The total load is expected to grow from 9.1 Bcf in 2016 to approximately 10.6 Bcf in 2035. Refer to Southwest Gas Corporation for more information.

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 left the SoCalGas retail system and interconnected with Vernon's municipal gas system. The forecasted throughput starts at 3.2 Bcf in 2016 and increases to 4.0 Bcf by 2021, after which the demand remains relatively flat through 2035. The forecasted throughput includes Core and Non-Core customers but excludes Malburg Power Plant throughput. 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.

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

SoCalGas used the forecast prepared by Ecogas for this report. Ecogas' use is expected to gradually increase from approximately 9.0 Bcf/year in 2016 to 9.2 Bcf/year by 2035. Refer to Ecogas or IENova, Ecogas's parent company, for more information.

Natural Gas Vehicles (NGV)

The NGV market is expected to continue to grow due to government (federal, state and local) incentives and regulations related to the purchase and operation of alternate fuel vehicles, growing numbers of natural gas engines and vehicles, and the cost differential between petroleum (gasoline and diesel) and natural gas. At the end of 2015, there were 310 compressed natural gas (CNG) fueling stations delivering 13.2 Bcf of natural gas during the year. The NGV market is expected to grow 3.3% per year, on average, over the forecast horizon.

ENERGY EFFICIENCY PROGRAMS

SoCalGas 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. Programs administered by SoCalGas include services that help customers evaluate their energy efficiency options and adopt recommended solutions, as well as simple equipment-retrofit improvements, such as rebates for new hot water heaters.

The forecast of cumulative natural gas savings due to SoCalGas' energy efficiency programs is provided in the figure below. The net load impact includes all energy efficiency programs that SoCalGas has forecasted to occur through year 2035. The goals for 2016 and beyond are based on the levels authorized by the CPUC in D.15-10-028.

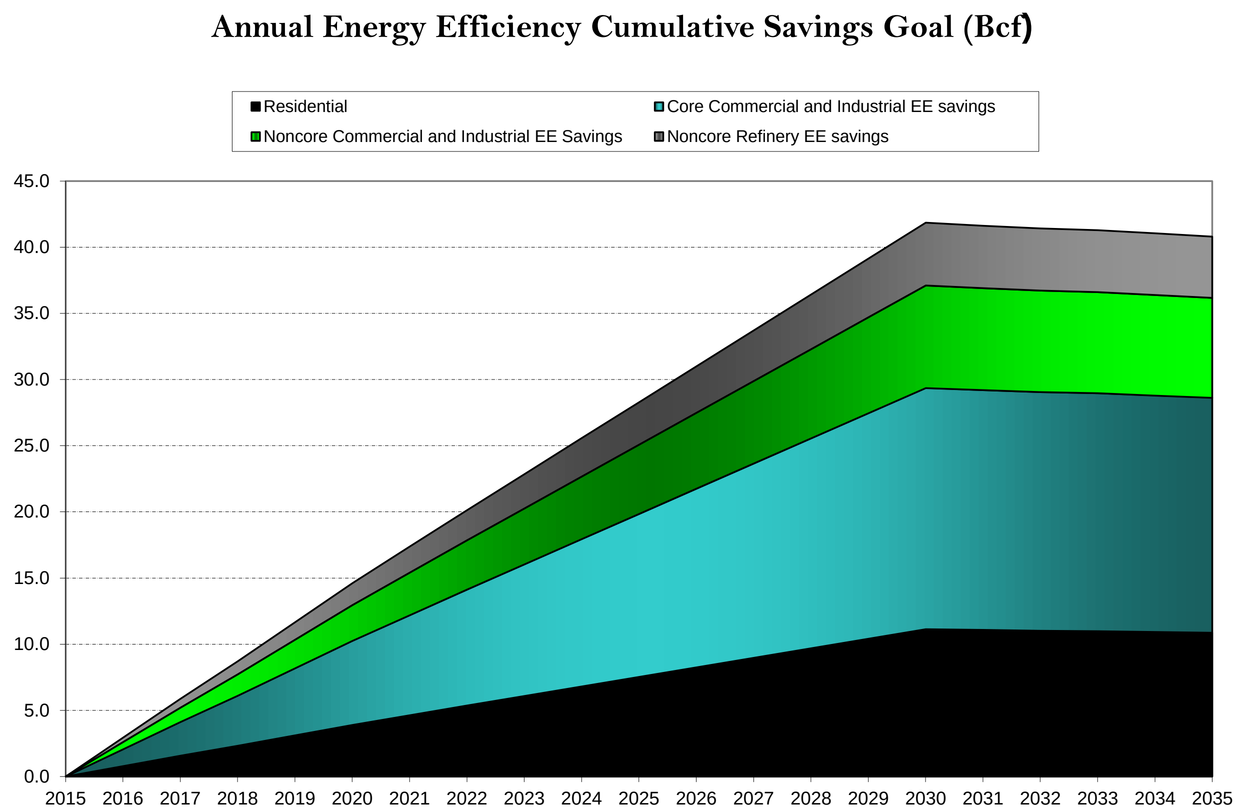
Conservation and energy efficiency savings are measured at the meter and include any interactive effects that may result from efficiency improvements of gas end uses; for instance, increased natural gas heating load that could result from efficiency improvements in lighting and appliances. These figures also include any reductions in natural gas demand for electric generation that may occur due to lower electric demand.

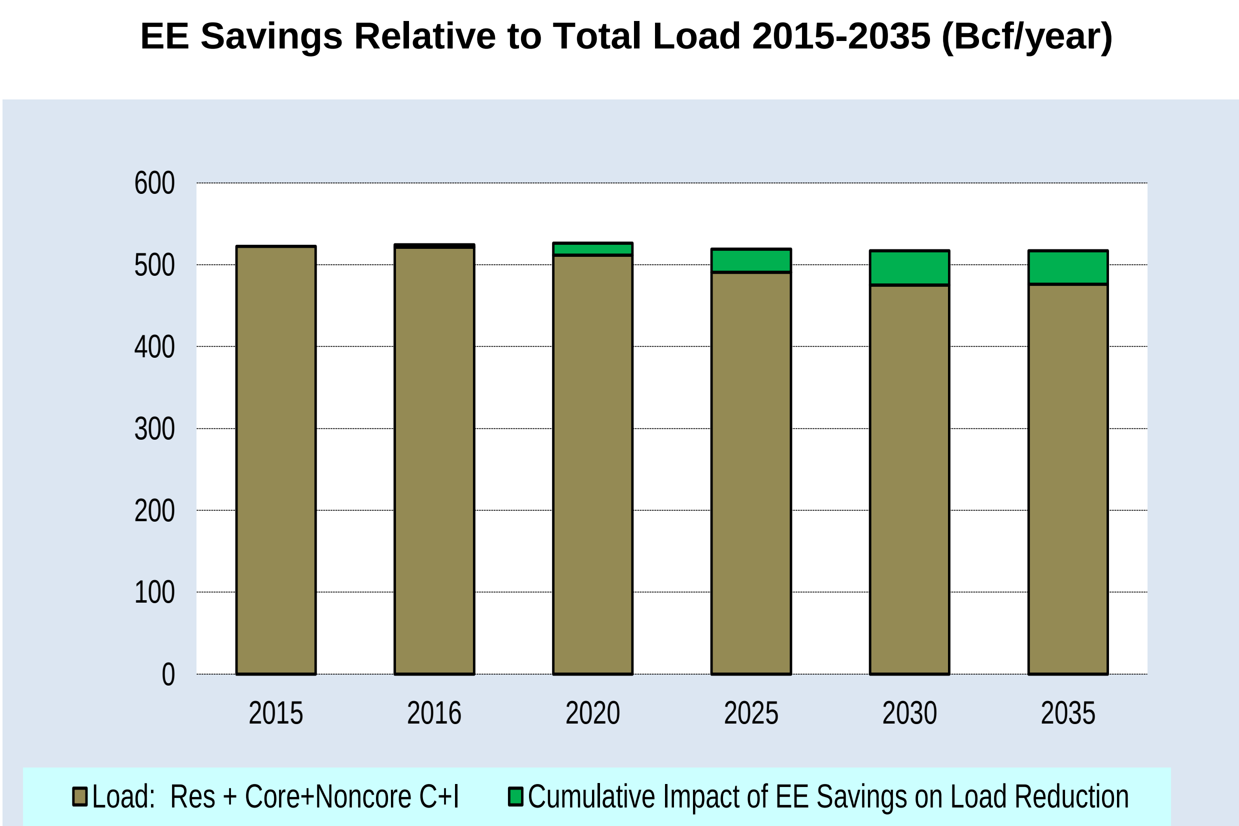
SB350, which was passed in fall 2015, requires the CEC, in coordination with the CPUC and the local public utilities, to set EE targets that double the CEC's AAEE mid-case forecast, subject to what is cost-effective and feasible.[3] This legislation will undoubtedly impact levels of EE savings. There are, however, a number of uncertainties that led the IOUs to treat SB350 impacts qualitatively and defer incorporating estimates of this savings until the next California Gas Report. These are:

- The deadline for the CEC and CPUC to establish SB350 targets is November 2017, 18 months from the time of this writing. A lot of work will need to be done to set these targets.
- There are already state requirements for IOUs to pursue all cost-effective EE. Given that the doubling goal is subject to what is cost-effective and achievable, a significant increase in savings while still maintaining a cost-effective portfolio would require changes to current cost-effectiveness practices.
- IOU EE programs are still operating under avoided costs that were last updated in 2011 and 2012. An update to avoided costs is likely in the next year or two and is likely to decrease what is currently determined to be cost-effective, as gas prices have dropped and/or stayed lower than forecast in 2011 and 2012 and higher levels of renewables have pushed down energy and capacity values.
- In the CPUC's EE proceeding, an effort is underway to update EE goals to reflect SB350 and AB802 impacts. This is not yet available and will be an important source for estimating SB350 EE impacts. It is expected that these updated goals will be available for incorporation into the next California Gas Report.

For these reasons, SoCalGas recommends using current levels of EE included in the 2015 IEPR in the forecast until the issues identified above are resolved. However, for context, the IOUs offer the following relative maximum impact of the bill on EE savings levels. Assuming sufficient cost effective measures can be identified, a doubling of cumulative EE savings by 2030 would result in approximately 600 MMTherms beyond current levels for all IOUs. However, the reader is cautioned that this is based on a literal reading of the bill language and the CEC forecast identified in the bill, without consideration of the challenges mentioned above.

[3] The actual bill text states: "On or before November 1, 2017, the commission, in collaboration with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The commission shall base the targets on a doubling of the midcase estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate, and the targets adopted by local publicly owned electric utilities pursuant to Section 9505 of the Public Utilities Code, extended to 2030 using an average annual growth rate, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety."


Annual Energy Efficiency Cumulative Savings Goal (Bcf)
Residential
Core Commercial and Industrial EE savings
Noncore Commercial and Industrial EE Savings
Noncore Refinery EE savings
45.0
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
0.0
2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035


EE Savings Relative to Total Load 2015-2035 (Bcf/year)
600
500
400
300
200
100
0
2015
2016
2020
2025
2030
2035
Load: Res + Core+Noncore C+I
Cumulative Impact of EE Savings on Load Reduction

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 estimated 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. Naturally occurring conservation that is not attributable to SoCalGas' energy efficiency activities is not included in the energy efficiency forecast.

GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

Southern California Gas Company and San Diego Gas & Electric Company 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 Mountains, Western Canada, and local California supplies. Recorded 2011 through 2015 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 averaged 122 MMcf/day in 2015.

SOUTHWESTERN U.S. GAS

Traditional Southwestern U.S. sources of natural gas will continue to supply most of Southern California's natural gas demand. This gas is primarily delivered via the El Paso Natural Gas and Transwestern pipelines. The San Juan Basin's gas supplies peaked in 1999 and have been declining at an annual rate of roughly 3%. In recent years, this rate of decline has accelerated. The Permian Basin's share of supply into Southern California has increased in recent years, although increasing demand in Mexico for natural gas supplies may significantly reduce the volume of Permian Basin supply available to Southern California in the future. SoCalGas and SDG&E have discussed this situation in more detail and have proposed a solution in A.13-12-013. The proposal requested to construct a North-South Pipeline from SoCalGas' Adelanto compressor station near Victorville down to the Moreno pressure limiting station in Moreno Valley.

ROCKY MOUNTAIN GAS

Rocky Mountain supply supplements 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. Many pipelines connect to Rocky Mountain region, which allows these supplies to be redirected from lower to higher value markets as conditions change.

CANADIAN GAS

Canadian gas only provides a small share of Southern California gas supplies due to the high cost of transport.

BIOGAS

Biogas is a mixture of methane and carbon dioxide produced by the bacterial degradation of organic matter. Biogas is a byproduct produced from 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 livestock manure, wastewater sewage, food waste, and green waste. When biogas is conditioned/upgraded to pipeline quality specifications, commonly referred to as "biomethane," it can be interconnected to a gas utility's pipeline and nominated for a specific end-use customer.[2] Biomethane may also be consumed onsite for a variety of uses, including electrical power generation from internal combustion engines, fuel cells, and turbines, or as a fuel source for natural gas vehicles. Currently, there are instances where biogas is being vented naturally or flared to the atmosphere. Venting and flaring wastes this valuable renewable resource and fails to support the state in achieving its emission reduction targets set forth by Assembly Bill ("AB") 32 and the Renewables Portfolio Standard ("RPS") goals, as processed renewable natural gas injected into a common carrier natural gas pipeline system can ultimately count toward satisfying AB 32 and RPS goals.

In February 2013, the CPUC issued an Order Instituting Rulemaking ("Rulemaking") to adopt standards and requirements, open access rules, and related enforcement provisions, pursuant to Assembly Bill 1900 (Gatto), which tasked state agencies to address any constituents of concern specifically found in biomethane, and to identify impediments to interconnecting to utility pipelines.[3] CARB released their report on May 15, 2013 which identifies 17 constituents of concern found in biomethane and provides direction on monitoring, testing, reporting and recordkeeping procedures for utilities and biomethane suppliers. The first phase of the Rulemaking - the identification of constituents of concern – resulted in the utilities filing revised tariff rules governing gas quality specifications in February 2014. The second phase of the Rulemaking began in April 2014 to determine "who should bear the costs of complying with the CPUC-adopted testing, monitoring, reporting, and recordkeeping requirements." (D.)15-06-029 on Phase II of the proceeding was issued in June 2015 adopting a policy and a five-year monetary incentive program to encourage biomethane producers to design, construct, and successfully operate biomethane projects that interconnect with the gas utilities' pipeline systems so as to inject biomethane that can be safely used at an end user's home or business. The monetary incentive program is a state-wide program that is capped at $40 million and provides a biomethane producer 50% of the project's interconnection costs, up to $1.5 million, to

[2] SoCalGas' Tariff Rule 30 (http://socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf) must be met in order to qualify for pipeline injection into SoCalGas' gas pipeline system.
[3] February 13, 2013 Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M050/K674/50674934.PDF

help offset interconnection costs associated with the successful interconnection of the biomethane facility to the utility pipeline system.

In January 2014 the Commission approved SoCalGas' application to offer a Biogas Conditioning/Upgrading Services Tariff in response to customer inquiries and requests. This service is designed to meet the current and future needs of biogas producers seeking to upgrade their biogas for beneficial uses such as pipeline injection, onsite power generation, or compressed natural gas vehicle refueling stations. There is growing interest regarding biogas production potential in SoCalGas' service territory from the following activities: non-hazardous-waste landfills, landfill diversion of organic waste material, wastewater treatment, concentrated animal feeding operations, and food/green waste processing.

INTERSTATE PIPELINE CAPACITY

Interstate pipeline delivery capability into SoCalGas and SDG&E on any given day theoretically is approximately 6,725 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	120
Kern/Mojave at Wheeler Ridge	885
Kern at Kramer Junction	750
Occidental at Wheeler Ridge	150
California Production	310
TGN at Otay Mesa	400
North Baja at Blythe	600
Total Potential Supplies	6,765

(1) Estimate of physical capacity.

FIRM RECEIPT CAPACITY

SoCalGas/SDG&E currently has firm receipt capacity at the following locations for its 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 (1,010) TGN Otay Mesa (400) NBP Blythe (600)
Northern	1,590	EPN Topock (540) TW Topock (300) 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 1,010 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.

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.

SoCalGas' storage fields attain a combined theoretical storage working inventory capacity of 137.1 Bcf by November 1 of each year. Of that, 83 Bcf is allocated to our Core residential, small industrial and commercial customers. About 4.2 Bcf of space is used for system balancing.[4] The remaining capacity is available to other customers. However, working inventory at Aliso Canyon (currently approximately 15 Bcf) cannot be used for anything other than reliability-related withdrawals until DOGGR authorizes SoCalGas to begin injecting gas into Aliso again.

ALISO CANYON

On October 23, 2015, a natural gas leak in well SS25 was detected at the Aliso Canyon natural gas storage facility owned by SoCalGas. The leak was stopped on February 11, 2016 and SS25 was permanently sealed on February 18, 2016.

As a result of the leak, SB 380 and new DOGGR regulations impose a moratorium on injections at the Aliso facility until SoCalGas complies with the regulations and conditions defined by SB380 and DOGGR's Comprehensive Safety Review for Aliso Canyon. This safety review requires that all 114 wells in the facility are either thoroughly tested for safe operation or removed from operation and isolated from the underground reservoir.

The implementation of these safety measures means that the Aliso Canyon facility is not available to the System Operator to be used to provide gas for system reliability in the Greater Los Angeles area. Only 15 billion cubic feet of working inventory natural gas remains in the Aliso Canyon underground reservoir—less than one-fifth of the working capacity of the facility. However, withdrawals have been authorized as necessary to support regional energy reliability this summer, consistent with a defined withdrawal protocol that promotes safe use of working inventory.

As a result of the constraints on the operations at Aliso Canyon, the California Energy Commission (Energy Commission), California Public Utilities Commission (CPUC), California Independent System Operator (California ISO) and the Los Angeles Department of Water and Power (LADWP) collaborated to develop a technical assessment of energy impacts to the electric grid stemming from the current gas supply limitations of Aliso Canyon. Technical staff from these four entities joined with staff from SoCalGas in a Technical Assessment Group to conduct an engineering analysis that details potential energy impacts in the coming summer months. These efforts culminated in the Aliso Canyon Action Plan, which identifies actions to reduce the risks of gas curtailments this summer, including using the current supply of 15

[4] Proposed to increase to 8 Bcf pending adoption of the Joint Motion for Adoption of Settlement Agreement in the Triennial Cost Allocation Proceeding (TCAP) Phase 1 application (A.14-12-017).

billion cubic feet stored in Aliso Canyon during periods of peak demand to avoid electrical interruptions, directing all shippers to closely match their scheduled gas deliveries with their actual demand every day, and asking customers to use less energy.

The Aliso Canyon Action Plan proposes implementation of 18 specific measures to reduce the possibility of electrical service interruptions this summer. These measures will reduce, but not eliminate, the risk of gas curtailments large enough to cause electricity interruptions. The measures fall into five major categories: efficient use of Aliso Canyon, noncore gas tariff changes, greater operational coordination, LADWP-specific measures, and measures aimed at reducing natural gas and electricity consumption.

REGULATORY ENVIRONMENT

State Regulatory Matters

TRIENNIAL COST ALLOCATION PROCEEDING (TCAP)

SoCalGas filed TCAP applications in December 2014 (A.14-012-017, Phase 1) and July 2015 (A.15-07-014, Phase 2) to update the allocation of the costs of providing gas service to customer classes and determine the transportation n rates it charges to customers. The Phase 1 Application includes updating the allocation of costs related to the underground storage of natural gas for the period 2016 through 2019. The Phase 2 Application includes updating the allocation of all other costs related to gas transportation service to various customer classes to recover the cost of service from the respective rate base, as well as the throughput forecasts used to set rates, for a three-year period of 2017-2019. A Settlement Agreement on the Phase 1 Application was filed in August 2015. A final CPUC Decision on both phases is expected in 2016.

PIPELINE SAFETY

On February 24, 2011, the CPUC approved an Order Instituting Rulemaking (OIR) to develop and adopt new regulations on pipeline safety. Through the OIR, the Commission will develop and adopt safety regulations that address topics such as construction standards, shut-off valves, maintenance requirements, records management and retention, ratemaking, and penalty provisions.

On June 9, 2011, the CPUC issued a decision requiring that the utilities file a plan to pressure test or replace transmission pipelines that have not been pressure tested. SoCalGas/SDG&E jointly filed their comprehensive Pipeline Safety Enhancement Plan (PSEP) on August 26, 2011. The comprehensive plan covers all of the utilities' approximately 4,000 miles of transmission lines (3,750 miles for SoCalGas and 250 miles for SDG&E) and would be implemented in two phases. Phase 1 focuses on populated areas of SoCalGas' and SDG&E's service territories and, if approved, would be implemented over a 10-year period, from 2012 to 2022. Phase 2 will cover unpopulated areas of SoCalGas' and SDG&E's service territories and will be filed with the CPUC at a later date.

The utilities' Pipeline Safety Enhancement Plan was transferred for consideration from the Pipeline Safety Rulemaking to the Triennial Cost Allocation Proceeding.

A proposed decision was issued in April 2014 which adopts the overall plan and a process to recover the associated costs subject to reasonableness reviews. In June 2014, the CPUC issued a final decision addressing SoCalGas and SDG&E's PSEP. Specifically, the decision determined the following for Phase 1 of the program:

- approved the utilities' model for implementing PSEP;
- approved a process, including a reasonableness review, to determine the amount that the utilities will be authorized to recover from ratepayers for the interim costs incurred through the date of the final decision to implement PSEP, which is recorded in regulatory accounts authorized by the CPUC;
- approved balancing account treatment, subject to a reasonableness review, for incremental costs yet to be incurred to implement PSEP; and
- established the criteria to determine the amounts that would not be eligible for cost recovery, including: certain costs incurred or to be incurred searching for pipeline test records, the cost of pressure testing pipelines installed after July 1, 1961 for which the company has not found sufficient records of testing, and any undepreciated balances for pipelines installed after 1961 that were replaced due to insufficient documentation of pressure testing.

SoCalGas and SDG&E are authorized to file an application with the CPUC for recovery of costs up to the date of the TCAP decision and then annually for costs incurred through the end of each calendar year beginning after December 31, 2015.

In December 2014, SoCalGas and SDG&E filed an application with the CPUC for recovery of a portion of costs recorded in the regulatory account through June 11, 2014. SoCalGas and SDG&E request recovery of $0.1 million and $26.8 million, respectively. The application is pending a decision from the CPUC.

SoCalGas and SDG&E filed an application with the CPUC in June 2015 requesting approval to establish regulatory accounts to record planning and engineering design costs associated with Phase 2 projects. The work is necessary to present detailed cost estimates in future filings with the CPUC. Phase 2 addresses about 660 miles of transmission pipelines that do not have sufficient documentation of a pressure test to at least 1.25 times the Maximum Allowable Operating Pressure (MAOP) that are located in less populated areas. This proceeding was also expanded to address interim cost recovery issues for Phase 1 and proceeding schedules for PSEP filings going forward. A decision from the CPUC is pending.

FEDERAL REGULATORY MATTERS

SoCalGas and SDG&E participate in FERC proceedings involving interstate natural gas pipelines serving California that can affect the cost of gas delivered to their customers. SoCalGas holds contracts for interstate transportation capacity on the El Paso, Kern River, Transwestern, and GTN and Canadian pipelines. SoCalGas and SDG&E also participate in FERC and Canadian regulatory proceedings involving the natural gas industry generally as those proceedings may impact their operations and policies.

El Paso

El Paso's rates have been the subject of extensive litigation at FERC in recent years. El Paso filed its third general rate case in five years in September 2010. The 2010 rate case proceeded to a hearing on all issues in 2011 (a first since 1959), with the FERC Commission issuing an initial decision, Opinion No. 528, in 2013 and a revised decision, Opinion No. 528-A, issued in 2016. Collectively, these decisions ruled on issues related to revenue requirements, abandonment costs, cost allocation, and rate design. The aforementioned FERC decisions are currently under review before the U.S. Court of Appeals.

Kern River

A final ruling was issued in 2013 in Kern River's 2004 general rate case. The ruling denied many rehearing requests to revisit the issues litigated in this case and accepted a series of orders retaining Kern River's original 1992 levelized rate design, resulting in reduced rates for eligible shippers, who renew their contracts for another 10- or 15-year period. At the time of this publication, there have not been any new general rate case filings made by Kern River.

Transwestern

Transwestern filed and the FERC approved a Settlement Agreement in its 2015 rate case. Under the terms of this agreement, settlement transportation base rates remain unchanged through October 2019, and Transwestern may not file another general rate case until July 2022. In the interim, the settlement agreement calls for separate proceedings to resolve issues related to capacity release procedures and gas quality.

Gas Transmission Northwest (GTN) and Canadian Pipelines

SoCalGas acquires its Canadian natural gas supplies from the NOVA Gas Transmission Limited (NGTL) pipeline located in Alberta, Canada and transports these supplies through the NGTL pipeline in Alberta, to the Foothills Pipe Lines Limited Company pipeline (Foothills) in British Columbia, and finally to GTN at the Canadian/U.S. international border.

NGTL filed and received approval in 2016 from its Canadian regulators for a settlement agreement on revenue requirements for its pipeline for 2016-17. Foothills filed and received approval from its Canadian regulators for its annual filing on rate changes for 2015, and separately for 2016. The annual transportation rate increases on both the NGTL and Foothills pipelines have been modest in recent years.

GTN filed and the FERC approved a Settlement Agreement in its 2015 rate case. Under the terms of this agreement, transportation base rates will decrease incrementally over six years and be approximately 20% lower by 2021 relative to current 2014 levels.

Coordination Between Gas and Electric Markets

In April 2015, FERC issued Order No. 809 to better coordinate scheduling protocols and emergency response measures between gas and electricity markets. Interstate pipelines must comply with the new business standards by April 1, 2016. Discussions are on-going to explore the potential for faster, computerized scheduling when shippers and confirming parties all submit electronic nominations and confirmations, including a streamlined confirmation process, if necessary.

In June 2015, SoCalGas and SDG&E filed A.15-06-020 seeking changes to its gas curtailment procedures on the SoCalGas and SDG&E system. A component of those changes included formalized and regular communication between the Utility Gas Control department and the electric grid operators prior to implementing a gas curtailment in order to minimize the impact to grid reliability while maintaining gas system integrity. A final decision from the CPUC on these changes is pending.

GREENHOUSE GAS ISSUES

National Policy

The national greenhouse gas program is largely based on the Clean Power Plan adopted by the U.S. Environmental Protection Agency pursuant to EPA's authority under the Clean Air Act. The Clean Power Plan establishes unique emission rate goals and mass equivalents for each state. It is projected to reduce carbon emissions from the power sector 32 percent from 2005 levels by 2030. Individual state targets are based on national uniform "emission performance rate" standards (pounds of CO2 per MWh) and each state's unique generation mix.
On February 9, 2016, the U.S. Supreme Court issued a stay of the Environmental Protection Agency's (EPA's) Clean Power Plan, freezing carbon pollution standards for existing power plants while the rule is under review at the U.S. Court of Appeals for the District of Columbia Circuit.

Assembly Bill 32

The Global Warming Solutions Act of 2006 (Assembly Bill 32) caps California's greenhouse gas (GHG) emissions at the 1990 level by 2020. AB 32 directed the California Air Resources Board (ARB) to adopt a GHG emissions cap on all major sources.

The electric and natural gas sectors will play an important role in achieving the emissions reduction goal. CARB's plan envisions that the electric sector will contribute at least 40 percent of the total direct GHG reductions even though the sector accounts for just 25 percent of California's GHG emissions.

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 CPUC, the CEC, and CARB. CARB however is statutorily empowered with developing and implementing the final regulations on GHG regulatory frameworks and compliance. Approved policies include both programmatic measures and market-based mechanisms to reduce GHG emissions. Cap-and-Trade is one technique being implemented by CARB. Other measures include increasing the amount of renewable energy power that enters the grid, ambitious energy efficiency incentive programs and incentives on electric vehicles and solar energy.

Greenhouse Gas (GHG) Rulemaking

Beginning on January 1, 2015, CARB's Cap-and-Trade Program expanded to include emissions from all SoCalGas customers. SoCalGas is required to purchase carbon allowances or offsets on behalf of our end-use customers for the emissions generated from the full combustion of the natural gas we deliver. Large end-use customers who emit at least 25,000 metric tons of CO2 equivalent per year have a direct obligation to the CARB for their own emissions; therefore, SoCalGas' obligation will not include these customers and they will not be responsible for compliance costs related to end-users from SoCalGas. The CPUC had recently completed a rulemaking proceeding to determine how the costs related to compliance with the Cap-and-Trade program will be included in end-use customers' rates. The rulemaking had also addressed how revenues generated from the sale of directly allocated allowances will be returned to ratepayers. The Rulemaking had initially determined that all Cap-and-Trade compliance costs will be included on a forecasted basis in customers' transportation rates beginning April 1, 2016. Customers with a direct obligation to the CARB for their emissions are exempt from SoCalGas' end-users compliance obligation, and will receive a volumetric credit called the "Cap-and-Trade Cost Exemption" for the amount of their transportation rates that contribute to these costs. All customers' rates will also include compliance costs related to SoCalGas' covered facilities, as well as for Lost and Unaccounted For (LUAF) gas.

Revenues generated from the sale of directly allocated allowances would initially have been returned as a fixed, once-annual California Climate Credit to all residential households on their April bills. Nonresidential customers were not to have received a California Climate Credit. An Application for Rehearing on the use of the revenues generated from the sale of directly allocated allowances was granted in April 2016. As such, the introduction of Cap-and-Trade costs into rates and the distribution of the gas California Climate Credit has been delayed.

Reporting and Cap-and-Trade Obligations

In 2015, SoCalGas reported GHG emissions to the Environmental Protection Agency, in accordance with 40 Code of Federal Regulations Part 98, in three primary categories: combustion emissions at three compressor stations and two storage fields, where total annual GHG emissions exceeded the 25,000 metric tons of CO2 equivalent (mtCO2e) threshold for GHG reporting; vented and fugitive emissions from four compressor stations, two storage fields and the natural gas distribution system and the GHG emissions resulting from combustion of natural gas delivered to all customers except for customers consuming more than 460 MMcf.

In 2015, SoCalGas reported to the California Air Resources Board (CARB) GHG emissions approximately 43 million mtCO2e in three primary categories: combustion emissions at six compressor stations and two storage fields, where annual emissions exceed 10,000 mtCO2e; vented and fugitive emissions from three compressor stations, two storage fields and the natural gas distribution system and the GHG emissions resulting from combustion of natural gas delivered to all customers.

The five facilities subject to the EPA mandatory reporting regulation are also subject to the CARB Cap-and-Trade Program. On January 1, 2015, natural gas suppliers became subject to the Cap-and-Trade Program and now have a compliance obligation for GHG emissions from the natural gas use of their small customers (i.e., those customers who are not covered directly under CARB's Cap-and-Trade program). SoCalGas estimated that responsibility for compliance obligations of GHG emissions as a natural gas supplier were approximately 20.5 million mtCO2e for 2015. CARB will issue the final 2015 compliance obligations of GHG emissions as a natural gas supplier in October 2016.

In 2014, Rulemaking (R.) 15-01-008 was initiated by the Commission to carry out the intent of SB 1371 (Statutes 2014, Chapter 525).1 SB 1371 requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipelines consistent with Public Utilities Code Section 961 (d), § 192.703 (c) of Subpart M of Title 49 of the CFR, the Commission's General Order 112-F, and the state's goal of reducing GHG emissions. As part of this rulemaking, natural gas utilities are required to annually report methane emissions from intentional and unintentional releases and their leak management practices by May 15. In 2014, SoCalGas reported an estimated 1.2 bcf of methane emissions from intentional and unintentional releases. Currently, these emissions are not subject to the CARB Cap-and-Trade Program.

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. Under EPA's Mandatory Reporting of Greenhouse Gases rule, all vehicle and engine manufacturers outside of the light-duty sector must report emission rates of carbon dioxide, nitrous oxide, and methane from their products.

Low Carbon Fuel Standard

On January 18, 2007, former 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. 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 CO2 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. Further, the CPUC has recently authorized the utilities to sell LCFS credits generated both by their use of low-carbon fuel vehicles and those generated by public refueling stations. The revenue generated by the sale of these credits will be returned to the customers who generated the credits, further enhancing the value of low-carbon fuels.

Programmatic Emission Reduction Measures

The CEC, CPUC and CARB are considering or have approved a variety of non market-based measures to reduce GHG emissions. Some of these programs include: the California Energy Efficiency Green Building Standards, the Green State Buildings Executive Order, the 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 (CHP) and distributed generation portfolio standards or feed-in tariffs; increasing the electric renewables portfolio standard to 33% by 2020 and to 50% by 2030; implementing the CARB Short-Lived Climate Pollutants strategy and revising the CARB Regulation for GHG Emission Standards for Crude Oil and Natural Gas Facilities. There is also an on-going Rulemaking (R.) 15-01-008 to implement SB 1371 which requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities. This proceeding is led by the CPUC in consultation with CARB —the first phase will develop the overall policies and guidelines for a natural gas leak abatement program consistent with SB 1371. The second phase will develop ratemaking and performance-based financial incentives associated with the natural gas leak abatement program determined through Phase 1 of the proceeding. Energy efficiency and renewables are considered fundamental to GHG 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.

GAS PRICE FORECAST

MARKET CONDITION

North American production from conventional supplies has been declining for the past several years as gas prices have continued to fall from prior peaks. Through 2015, improvements in fracking technology and horizontal drilling efficiencies in both dry and wet gas plays have resulted in supplies from unconventional shale resources increasing faster than conventional supply declines through 2015. However, the low gas and oil price environment of the past several years has taken a toll on drilling efforts whereby efficiency gains were no longer able to offset drilling declines, and total North American production has been declining this year.

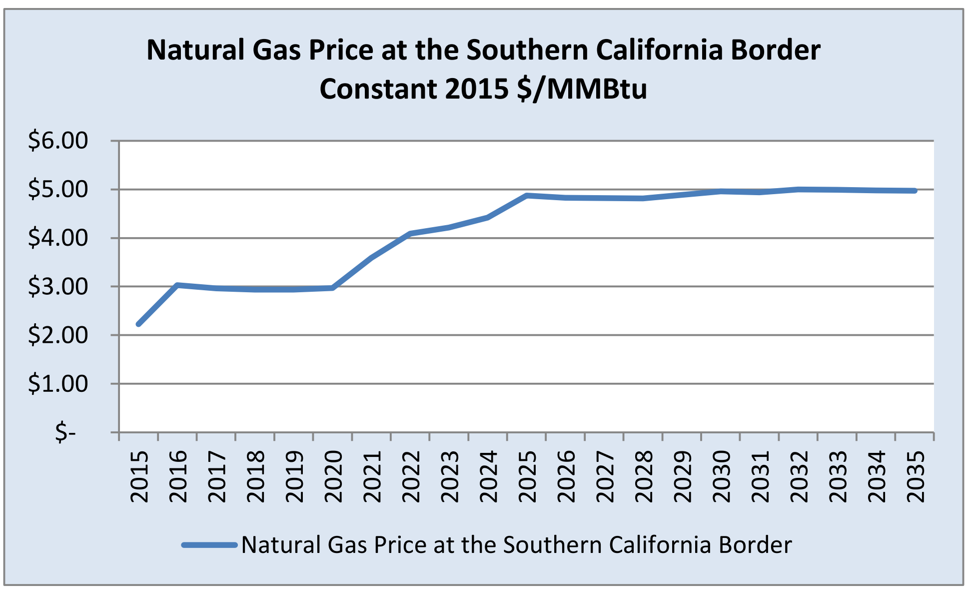
Also in response to the low gas price environment, gas demand has been rising, primarily from coal-to-gas fuel switching in the power sector, and most recently from increasing exports to Mexico by pipe and overseas via LNG as domestic liquefaction projects are commissioned. These exports are expected to continue increasing over the next several years as additional domestic liquefaction projects are placed into service, and as new pipeline projects delivering gas to and within Mexico are completed. The level of LNG exports are subject to much uncertainty since they will be competing with increasing LNG supplies from new liquefaction facilities built overseas.

Industry experts currently forecast that North American gas supplies will be sufficient to meet expected demand growth, but at prices which are higher than recently low levels. While North American gas price increases will be somewhat tempered by renewable power generation additions both in the US and in Mexico, continuing closures of coal-fired generation to meet environmental goals will also provide price support.

DEVELOPMENT OF THE FORECAST

Natural gas prices for the SoCalGas border are expected to average out at $2.61/MMBtu in 2015, down from $3.83/MMbtu in 2014. The natural gas prices are expected to increase to $6.36/MMBtu by 2035.

Consistent with the prior CGR practices, the 2016 CGR gas price forecast was developed using a combination of market prices and fundamental forecasts. NYMEX futures prices were used for the 2016-2020 period. Fundamental price forecasts were used for 2021 and beyond. The forecasts for 2021 and 2022 reflect a blending of market and fundamental prices, with declining weights for market prices (and corresponding increasing weights for the fundamental price forecast) over the two-year period. The fundamental gas price forecast represents an average of the forecasts developed by the CEC and independent consultants.



It is important to recognize that the natural gas price forecast is inherently uncertain. SoCalGas and the respondents of the *2016 CGR* do not warrant the accuracy of the gas price projection. In no event shall SoCalGas or the respondents of the *2016 CGR* be liable for the use of or reliance on this natural gas price forecast.

PEAK DAY DEMAND AND DELIVERABILITY

Since April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand have been procured as 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. For each utility's service area, the extreme peak day is defined as a service area average temperature so cold that it would, on average, occur only once every 35 years. This definition translates to a system average temperature of 40.1 degrees Fahrenheit for SoCalGas' service area and 42.9 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. Storage withdrawal plus 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 forecasted retail core peak day demand.

Retail Core Peak Day Demand and Supply Requirements (MMcf/Day)[4]

Year	SoCalGas Retail Core Demand (1)	SDG&E Retail Core Demand (2)	Total Demand	Firm Storage Withdrawal (3)	Flowing Supply
2016	2,947	387	3,334	2,225	1,109
2017	2,944	395	3,339	2,225	1,114
2018	2,931	396	3,326	2,225	1,101
2019	2,917	395	3,312	2,225	1,087
2020	2,899	396	3,294	2,225	1,069
2021	2,875	394	3,270	2,225	1,045
2022	2,849	393	3,242	2,225	1,017

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 was 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.
(4) SoCalGas and SDG&E are only obligated to design their systems to maintain service to retail and wholesale core customers during a 1-in-35 winter peak day temperature event .

The tables below provide system-wide Winter (December month) peak day demand projections on SoCalGas' system and High Sendout demand during Summer (July, August or September month as designated) periods.

Winter Peak Day Demand
(MMcf/Day)

Year	Core (1)	Noncore NonEG (2)	Electric Generation (3)	Total Demand
2016	2,947	1,012	1,054	5,013
2017	2,944	1,019	1,051	5,014
2018	2,931	1,019	1,048	4,997
2019	2,917	1,017	1,045	4,978
2020	2,899	1,016	1,042	4,956
2021	2,875	1,009	1,036	4,921
2022	2,849	1,003	1,029	4,882

Notes:
(1) 1-in-35 peak temperature cold day for 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 High Sendout Day Demand
(MMcf/Day)

Year	High Demand Month (1)	Core (2)	Noncore NonEG (3)	Electric Generation (4)	Total Demand
2016	Sep	652	644	2,084	3,380
2017	Sep	653	642	2,005	3,301
2018	Sep	651	641	1,924	3,216
2019	Sep	648	639	1,843	3,130
2020	Sep	644	637	1,773	3,055
2021	Sep	639	633	1,705	2,977
2022	Sep	633	628	1,667	2,928

Notes:
(1) Month of High Sendout gas demand during summer (July, August or September).
(2) Average daily summer demand SoCalGas core.
(3) Average daily summer demand. Includes SoCalGas retail and wholesale load.
(4) Highest demand on a summer day under 1-in-10 dry hydro conditions.

2016 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY
TABULAR DATA

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2011 TO 2015

Line	CAPACITY AVAILABLE		2011	2012	2013	2014	2015
1	California Source Gas						
	Out-of-State Gas						
2	California Offshore -POPCO / PIOC						
3	El Paso Natural Gas Co.						
4	Transwestern Pipeline Co.						
5	Kern / Mojave						
6	PGT / PG&E						
7	Other						
8	Total Out-of-State Gas						
9	TOTAL CAPACITY AVAILABLE						
	GAS SUPPLY TAKEN						
10	California Source Gas		175	148	153	143	122
	Out-of-State Gas						
11	Other Out-of-State		2,452	2,728	2,514	2,538	2,397
12	Total Out-of-State Gas		2,452	2,728	2,514	2,538	2,397
13	TOTAL SUPPLY TAKEN		2,627	2,876	2,667	2,681	2,519
14	Net Underground Storage Withdrawal		(4)	(42)	106	(63)	40
15	TOTAL THROUGHPUT (1)(2)		2,623	2,834	2,773	2,618	2,559
	DELIVERIES BY END-USE						
16	Core	Residential	696	644	646	541	548
17		Commercial	217	216	222	202	207
18		Industrial	61	61	62	58	58
19		NGV	28	29	31	33	35
20		Subtotal	1,002	950	961	834	848
21	Noncore	Commercial	60	60	60	53	52
22		Industrial	363	365	368	379	362
23		EOR Steaming	27	29	35	44	46
24		Electric Generation	726	922	848	863	795
25		Subtotal	1,176	1,376	1,311	1,339	1,255
26	Wholesale/International		407	477	465	410	428
27	Co. Use & LUAF		38	31	36	35	28
28	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,623	2,834	2,773	2,618	2,559
	TRANSPORTATION AND EXCHANGE						
29	Core	All End Uses	29	35	45	49	52
30	Noncore	Commercial/Industrial	423	425	428	432	414
31		EOR Steaming	27	29	35	44	46
32		Electric Generation	726	922	848	863	795
33		Subtotal-Retail	1,205	1,411	1,356	1,388	1,307
34	Wholesale/International		407	477	465	410	428
35	TOTAL TRANSPORTATION & EXCHANGE		1,612	1,888	1,821	1,798	1,735
36	CURTAILMENT (3)						
37	REFUSAL						
38		Total BTU Factor (Dth/Mcf)	1.0209	1.021	1.0266	1.0300	1.0353

NOTES:

(1) The wholesale volumes only reflect natural gas supplied by SoCalGas; and, do not include supplies from other sources. Refer to the supply source data provided in each utility's report for a complete accounting of their supply sources.

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

(3) The table does not explicitly show any curtailment numbers for the recorded years because, during some curtailment events, the estimate of the curtailed volume is not available. While the table does not explicitly show any curtailment numbers for the recorded years, the noncore customer usage data implicitly captures the effects of any curtailment events.

TABLE 1-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2016 THRU 2020

AVERAGE TEMPERATURE YEAR

LINE			2016	2017	2018	2019	2020	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		122	122	122	122	122	8
9	Out-of-State		2,559	2,527	2,485	2,459	2,436	9
10	TOTAL SUPPLY TAKEN		2,681	2,649	2,607	2,581	2,558	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 4/		2,681	2,649	2,607	2,581	2,558	12
	REQUIREMENTS FORECAST BY END-USE 5/							
13	CORE 6/	Residential	652	652	650	647	641	13
14		Commercial	217	217	214	211	207	14
15		Industrial	56	57	56	55	55	15
16		NGV	37	38	40	42	43	16
17		Subtotal-CORE	961	964	960	955	947	17
18	NONCORE	Commercial	46	45	45	45	44	18
19		Industrial	371	367	366	363	361	19
20		EOR Steaming	46	46	46	46	46	20
21		Electric Generation (EG)	788	760	738	724	714	21
22		Subtotal-NONCORE	1,251	1,218	1,195	1,178	1,165	22
23	WHOLESALE &	Core	183	187	188	188	188	23
24	INTERNATIONAL	Noncore Excl. EG	48	47	47	48	48	24
25		Electric Generation (EG)	204	199	185	180	178	25
26		Subtotal-WHOLESALE & INTL.	435	434	420	415	414	26
27		Co. Use & LUAF	33	33	32	32	32	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,681	2,649	2,607	2,581	2,558	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	56	57	57	57	56	29
30	NONCORE	Commercial/Industrial	417	412	411	408	405	30
31		EOR Steaming	46	46	46	46	46	31
32		Electric Generation (EG)	788	760	738	724	714	32
33		Subtotal-RETAIL	1,307	1,275	1,252	1,235	1,222	33
34	WHOLESALE & INTERNATIONAL	All End Uses	435	434	420	415	414	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,742	1,709	1,671	1,650	1,636	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.)

	2016	2017	2018	2019	2020
4/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.8	0.7	0.7	0.7	0.6

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

	2016	2017	2018	2019	2020
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	938	940	935	930	922

TABLE 2-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2021 THRU 2035

AVERAGE TEMPERATURE YEAR

LINE			2021	2022	2025	2030	2035	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		122	122	122	122	122	8
9	Out-of-State		2,404	2,382	2,334	2,252	2,260	9
10	TOTAL SUPPLY TAKEN		2,526	2,504	2,456	2,374	2,382	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 4/		2,526	2,504	2,456	2,374	2,382	12
	REQUIREMENTS FORECAST BY END-USE 5/							
13	CORE 6/	Residential	639	634	620	603	598	13
14		Commercial	204	199	189	175	177	14
15		Industrial	54	53	50	44	42	15
16		NGV	45	47	52	61	69	16
17		Subtotal-CORE	941	932	911	882	886	17
18	NONCORE	Commercial	44	43	42	40	40	18
19		Industrial	358	353	345	333	332	19
20		EOR Steaming	46	46	46	46	46	20
21		Electric Generation (EG)	692	684	671	636	636	21
22		Subtotal-NONCORE	1,139	1,126	1,104	1,055	1,054	22
23	WHOLESALE &	Core	189	189	189	192	197	23
24	INTERNATIONAL	Noncore Excl. EG	48	48	48	49	49	24
25		Electric Generation (EG)	178	178	174	166	165	25
26		Subtotal-WHOLESALE & INTL.	415	414	411	407	411	26
27		Co. Use & LUAF	31	31	31	30	30	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,526	2,504	2,456	2,374	2,382	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	56	56	55	55	58	29
30	NONCORE	Commercial/Industrial	401	396	387	373	372	30
31		EOR Steaming	46	46	46	46	46	31
32		Electric Generation (EG)	692	684	671	636	636	32
33		Subtotal-RETAIL	1,195	1,182	1,159	1,110	1,112	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	415	414	411	407	411	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,610	1,597	1,570	1,517	1,523	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.)

	2021	2022	2025	2030	2035
4/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.6	0.6	0.5	0.4	0.4

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

	2021	2022	2025	2030	2035
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	916	907	885	856	858

TABLE 3-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2016 THRU 2020

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2016	2017	2018	2019	2020	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		122	122	122	122	122	8
9	Out-of-State		2,665	2,706	2,671	2,640	2,612	9
10	TOTAL SUPPLY TAKEN		2,787	2,828	2,793	2,762	2,734	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 4/		2,787	2,828	2,793	2,762	2,734	12
	REQUIREMENTS FORECAST BY END-USE 5/							
13	CORE 6/	Residential	723	723	721	718	712	13
14		Commercial	230	230	227	223	220	14
15		Industrial	57	58	58	57	56	15
16		NGV	37	38	40	42	43	16
17		Subtotal-CORE	1,047	1,050	1,045	1,040	1,031	17
18	NONCORE	Commercial	47	47	46	46	45	18
19		Industrial	371	367	366	363	361	19
20		EOR Steaming	46	46	46	46	46	20
21		Electric Generation (EG)	788	825	807	788	775	21
22		Subtotal-NONCORE	1,252	1,285	1,265	1,244	1,228	22
23	WHOLESALE &	Core	200	205	205	206	206	23
24	INTERNATIONAL	Noncore Excl. EG	48	47	48	48	48	24
25		Electric Generation (EG)	204	206	195	191	187	25
26		Subtotal-WHOLESALE & INTL.	452	458	448	444	441	26
27		Co. Use & LUAF	35	35	35	34	34	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,787	2,828	2,793	2,762	2,734	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	59	60	60	59	59	29
30	NONCORE	Commercial/Industrial	418	414	412	409	406	30
31		EOR Steaming	46	46	46	46	46	31
32		Electric Generation (EG)	788	825	807	788	775	32
33		Subtotal-RETAIL	1,311	1,344	1,325	1,303	1,287	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	452	458	448	444	441	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,764	1,802	1,772	1,748	1,728	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.)

	2016	2017	2018	2019	2020
4/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.9	0.8	0.8	0.7	0.7

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

	2016	2017	2018	2019	2020
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	1,023	1,025	1,020	1,015	1,006

TABLE 4-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2021 THRU 2035

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2021	2022	2025	2030	2035	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		122	122	122	122	122	8
9	Out-of-State		2,598	2,579	2,527	2,426	2,433	9
10	TOTAL SUPPLY TAKEN		2,720	2,701	2,649	2,548	2,555	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 4/		2,720	2,701	2,649	2,548	2,555	12
	REQUIREMENTS FORECAST BY END-USE 5/							
13	CORE 6/	Residential	709	703	689	671	666	13
14		Commercial	216	211	200	185	188	14
15		Industrial	55	54	51	45	43	15
16		NGV	45	47	52	61	69	16
17		Subtotal-CORE	1,025	1,016	992	962	965	17
18	NONCORE	Commercial	45	44	43	41	42	18
19		Industrial	358	353	345	333	332	19
20		EOR Steaming	46	46	46	46	46	20
21		Electric Generation (EG)	768	763	748	696	697	21
22		Subtotal-NONCORE	1,217	1,207	1,183	1,117	1,117	22
23	WHOLESALE &	Core	206	206	206	210	215	23
24	INTERNATIONAL	Noncore Excl. EG	48	48	48	49	49	24
25		Electric Generation (EG)	189	189	186	178	177	25
26		Subtotal-WHOLESALE & INTL.	444	444	441	437	441	26
27		Co. Use & LUAF	34	34	33	32	32	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,720	2,701	2,649	2,548	2,555	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	59	59	58	58	60	29
30	NONCORE	Commercial/Industrial	402	398	388	374	373	30
31		EOR Steaming	46	46	46	46	46	31
32		Electric Generation (EG)	768	763	748	696	697	32
33		Subtotal-RETAIL	1,276	1,265	1,241	1,175	1,177	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	444	444	441	437	441	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,720	1,710	1,682	1,611	1,618	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.)

	2021	2022	2025	2030	2035
4/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.7	0.6	0.5	0.5	0.5

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

	2021	2022	2025	2030	2035
6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	1,000	991	967	936	937

2016 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 forecast requirements prepared by the Long Beach Gas & Oil Department (Long Beach) are shown on the following tables for the years 2016 through 2035.

Serving approximately 150,000 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 53 percent residential and 47 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 5 percent 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.

2016 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 2011 THRU 2015

LINE	GAS SUPPLY AVAILABLE	2011	2012	2013	2014	2015	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	1.1	1.2	1.9	2.4	0.7	13
14	Received for Exchange/Transport	0	0	0	0	0	14
15	Total California Source Gas	1.1	1.2	1.9	2.4	0.7	15
16	Purchases from Other Utilities	-	-	-	-	-	16
	Out-of-State Gas						
17	Pacific Interstate Companies	-	-	-	-	-	17
18	Additional Core Supplies	-	-	-	-	-	18
19	Incremental Supplies	24.3	23.2	23.5	19.2	21.9	19
20	Out-of-State Transport	-	-	-	-	-	20
21	Total Out-of-State Gas	24.3	23.2	23.5	19.2	21.9	21
22	Subtotal	25.5	24.4	25.4	21.5	22.5	22
23	Underground Storage Withdrawal	-	-	-	-	-	23
24	TOTAL Gas Supply Taken & Transported	25.5	24.4	25.4	21.5	22.5	24

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2011 THRU 2015

LINE	ACTUAL DELIVERIES BY END-USE		2011	2012	2013	2014	2015	LINE
1	CORE	Residential	14.9	13.7	14.2	11.5	11.9	1
2	CORE/NONCORE	Commercial	5.6	5.4	5.9	5.4	5.4	2
3	CORE/NONCORE	Industrial	3.6	3.4	3.4	3.3	3.7	3
4		Subtotal	24.1	22.5	23.6	20.3	20.9	4
5	NON CORE	Non-EOR Cogeneration	0.8	1.6	1.5	0.9	1.2	5
6		EOR Cogen. & Steaming	-	-	-	-	-	6
7		Electric Utilities	-	-	-	-	-	7
8		Subtotal	0.8	1.6	1.5	0.9	1.2	8
9	WHOLESALE	Residential	-	-	-	-	-	9
10		Com. & Ind., others	-	-	-	-	-	10
11		Electric Utilities	-	-	-	-	-	11
12		Subtotal-WHOLESALE	-	-	-	-	-	12
13		Co. Use & LUAF	0.6	0.2	0.2	0.4	0.4	13
14		Subtotal-END USE	25.5	24.4	25.4	21.5	22.5	14
15		Storage Injection	-	-	-	-	-	15
16	SYSTEM TOTAL-THROUGHPUT		25.5	24.4	25.4	21.5	22.5	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	2.7	2.7	2.5	2.3	2.3	18
19		Non-EOR Cogeneration	0.8	1.6	1.5	0.8	1.1	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	3.5	4.3	3.9	3.1	3.4	22
23	WHOLESALE	All End Uses	-	-	-	-	-	23
24	TOTAL TRANSPORTATION & EXCHANGE		3.5	4.3	3.9	3.1	3.4	24
	ACTUAL CURTAILMENT							
25		Residential	-	-	-	-	-	25
26		Commercial/Industrial	-	-	-	-	-	26
27		Non-EOR Cogeneration	-	-	-	-	-	27
28		EOR Cogen. & Steaming	-	-	-	-	-	28
29		Electric Utilites	-	-	-	-	-	29
30		Wholesale	-	-	-	-	-	30
31		TOTAL- Curtailment	-	-	-	-	-	31
32	REFUSAL		-	-	-	-	-	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 2016 THRU 2020

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2016	2017	2018	2019	2020	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		0.8	0.7	0.7	0.7	0.6	4
5	Out-of-State Gas		22.1	22.8	23.0	23.0	23.1	5
6	TOTAL SUPPLY TAKEN		22.9	23.5	23.7	23.7	23.8	6
7	Net Underground Storage Withdrawal		-	-	-	-	-	7
8	TOTAL THROUGHPUT (1)		22.9	23.5	23.7	23.7	23.8	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	13.2	13.6	13.6	13.7	13.8	9
10		Commercial	5.0	5.1	5.1	5.1	5.1	10
11		NGV	0.5	0.6	0.6	0.6	0.6	11
12		Subtotal-CORE	18.7	19.2	19.3	19.4	19.4	12
13	NONCORE	Industrial	3.0	3.1	3.1	3.1	3.1	13
14		Non-EOR Cogeneration	1.0	0.9	1.1	1.0	1.0	14
15		EOR	-	-	-	-	-	15
16		Utility Electric Generation	-	-	-	-	-	16
17		NGV	-	-	-	-	-	17
18		Subtotal-NONCORE	4.0	4.1	4.2	4.1	4.1	18
19		Co. Use & LUAF	0.2	0.2	0.2	0.2	0.2	19
20	SYSTEM TOTAL THROUGHPUT (1)		22.9	23.5	23.7	23.7	23.8	20
21	SYSTEM CURTAILMENT		-	-	-	-	-	21
	TRANSPORTATION							
22	CORE	All End Uses	-	-	-	-	-	22
23	NONCORE	Industrial	2.0	2.0	2.0	2.0	2.0	23
24		Non-EOR Cogeneration	0.9	0.8	0.9	0.9	0.9	24
25		EOR	-	-	-	-	-	25
26		Utility Electric Generation	-	-	-	-	-	26
27		Subtotal NONCORE	2.9	2.9	3.0	2.9	2.9	27
28	TOTAL TRANSPORTATION		2.9	2.9	3.0	2.9	2.9	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 2021 THRU 2035

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2021	2022	2025	2030	2035	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		0.6	0.6	0.5	0.4	0.4	4
5	Out-of-State Gas		23.2	23.3	23.6	24.0	24.3	5
6	TOTAL SUPPLY TAKEN		23.8	23.9	24.0	24.4	24.7	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		23.8	23.9	24.0	24.4	24.7	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	13.8	13.9	14.0	14.3	14.6	9
10		Commercial	5.1	5.1	5.1	5.1	5.2	10
11		NGV	0.6	0.6	0.6	0.6	0.6	11
12		Subtotal-CORE	19.5	19.5	19.7	20.0	20.3	12
13	NONCORE	Industrial	3.1	3.1	3.1	3.1	3.1	13
14		Non-EOR Cogeneration	1.0	1.0	1.0	1.0	1.0	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	4.1	4.1	4.1	4.1	4.1	18
19		Co. Use & LUAF	0.2	0.2	0.2	0.2	0.2	19
20	SYSTEM TOTAL THROUGHPUT (1)		23.8	23.9	24.0	24.4	24.7	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	0	0	0	0	0	22
23	NONCORE	Industrial	2.0	2.0	2.0	2.0	2.0	23
24		Non-EOR Cogeneration	0.9	0.9	0.9	0.9	0.9	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	3.0	2.9	2.9	2.9	2.9	27
28	TOTAL TRANSPORTATION		3.0	2.9	2.9	2.9	2.9	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 2016 THRU 2020

1 in 35 TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2016	2017	2018	2019	2020	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		0.9	0.8	0.8	0.7	0.7	4
5	Out-of-State Gas		26.6	26.7	26.9	27.0	27.1	5
6	TOTAL SUPPLY TAKEN		27.5	27.5	27.7	27.7	27.8	6
7	Net Underground Storage Withdrawal		-	-	-	-	-	7
8	TOTAL THROUGHPUT (1)		27.5	27.5	27.7	27.7	27.8	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	16.2	16.2	16.3	16.4	16.5	9
10		Commercial	5.8	5.8	5.8	5.8	5.9	10
11		NGV	0.6	0.6	0.6	0.6	0.6	11
12		Subtotal-CORE	22.7	22.7	22.8	22.9	23.0	12
13	NONCORE	Industrial	3.4	3.5	3.5	3.5	3.5	13
14		Non-EOR Cogeneration	1.2	1.0	1.2	1.1	1.1	14
15		EOR	-	-	-	-	-	15
16		Utility Electric Generation	-	-	-	-	-	16
17		NGV	-	-	-	-	-	17
18		Subtotal-NONCORE	4.6	4.5	4.6	4.6	4.6	18
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	0.3	19
20	SYSTEM TOTAL THROUGHPUT (1)		27.5	27.5	27.7	27.7	27.8	20
21	SYSTEM CURTAILMENT		-	-	-	-	-	21
	TRANSPORTATION							
22	CORE	All End Uses	-	-	-	-	-	22
23	NONCORE	Industrial	2.3	2.3	2.3	2.3	2.3	23
24		Non-EOR Cogeneration	1.0	0.9	1.0	1.0	1.0	24
25		EOR	-	-	-	-	-	25
26		Utility Electric Generation	-	-	-	-	-	26
27		Subtotal NONCORE	3.3	3.2	3.3	3.3	3.3	27
28	TOTAL TRANSPORTATION		3.3	3.2	3.3	3.3	3.3	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 2021 THRU 2035

1 in 35 TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2021	2022	2025	2030	2035	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		0.7	0.6	0.5	0.5	0.5	4
5	Out-of-State Gas		27.2	27.3	27.6	28.0	28.4	5
6	TOTAL SUPPLY TAKEN		27.9	27.9	28.1	28.5	28.9	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		27.9	27.9	28.1	28.5	28.9	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	16.5	16.6	16.8	17.1	17.5	9
10		Commercial	5.9	5.9	5.9	5.9	5.9	10
11		NGV	0.6	0.6	0.6	0.6	0.6	11
12		Subtotal-CORE	23.0	23.1	23.3	23.7	24.0	12
13	NONCORE	Industrial	3.5	3.5	3.5	3.5	3.5	13
14		Non-EOR Cogeneration	1.1	1.1	1.1	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	4.6	4.6	4.6	4.6	4.6	18
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	0.3	19
20	SYSTEM TOTAL THROUGHPUT (1)		27.9	27.9	28.1	28.5	28.9	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	0	0	0	0	0	22
23	NONCORE	Industrial	2.3	2.3	2.3	2.3	2.3	23
24		Non-EOR Cogeneration	1.0	1.0	1.0	1.0	1.0	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	3.3	3.3	3.3	3.3	3.3	27
28	TOTAL TRANSPORTATION		3.3	3.3	3.3	3.3	3.3	28

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

2016 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 delivered natural gas to 870,000 customers in San Diego County in 2015, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2015 were approximately 120 billion cubic feet (Bcf), which is an average of 327 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

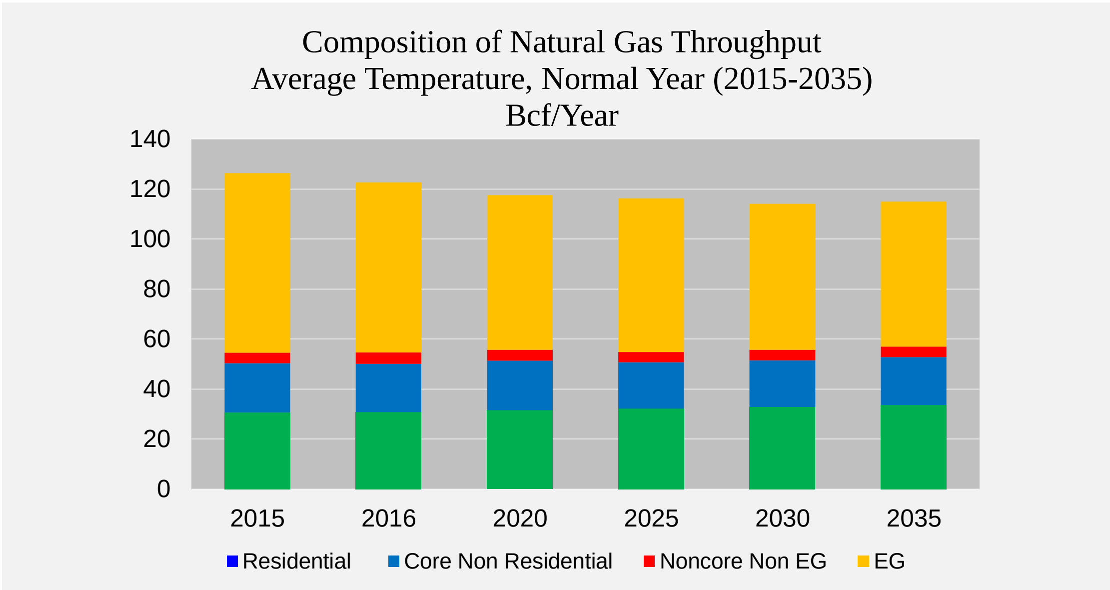
SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above.

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 virtually flat between 2015 and 2035. Overall demand adjusted for average temperature conditions totaled 126 Bcf in 2015. By the year 2035, the total demand is expected to reach 115 Bcf. The change reflects an annual average decline of 0.40%.

Assumptions for SDG&E's gas transportation requirements for EG are included as part of the wholesale market sector description for SoCalGas.

ECONOMICS AND DEMOGRAPHICS

San Diego County's total employment is forecasted to grow an average of 1.1% annually from 2016 to 2035; the subset of industrial (mining and manufacturing) jobs is projected to grow about 0.2% per year during the same period. From 2016 to 2035, the county's inflation-adjusted Gross Product is expected to grow at an average annual rate of 2.6%. (Gross Product is the local equivalent of national Gross Domestic Product, a measure of the total economic output of the area economy.) The number of SDG&E gas meters is expected to increase an average of 1.2% annually from 2016 through 2035.



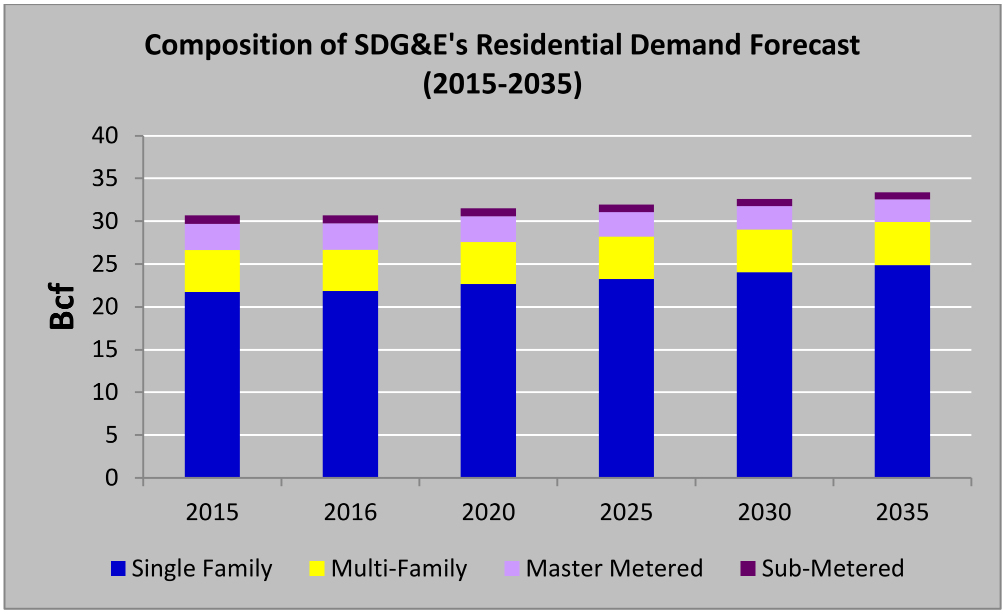
MARKET SECTORS

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 839,947 in 2015. This total reflects a 4,194 meter increase relative to the 2014 total. Overall residential meter growth from 2014-2015 was 0.50%.

Residential demand adjusted for average temperature conditions totaled 31 Bcf in 2015. By the year 2035, the residential demand is expected to reach 34 Bcf. The change reflects a 0.45% average annual growth rate.

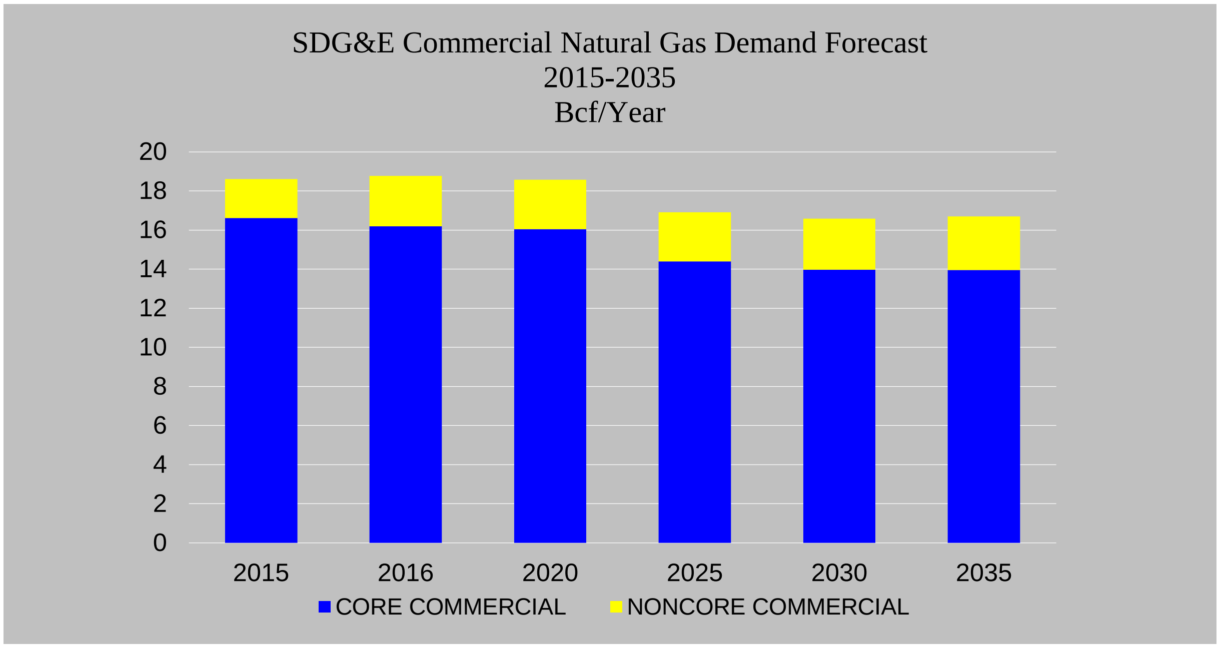
The projected residential natural gas demand is influenced primarily by residential meter growth moderated by the forecasted declining use per customer due to energy efficiency improvements in building shell design, appliance efficiency and CPUC-authorized EE programs plus the additional efficiency gains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



Commercial

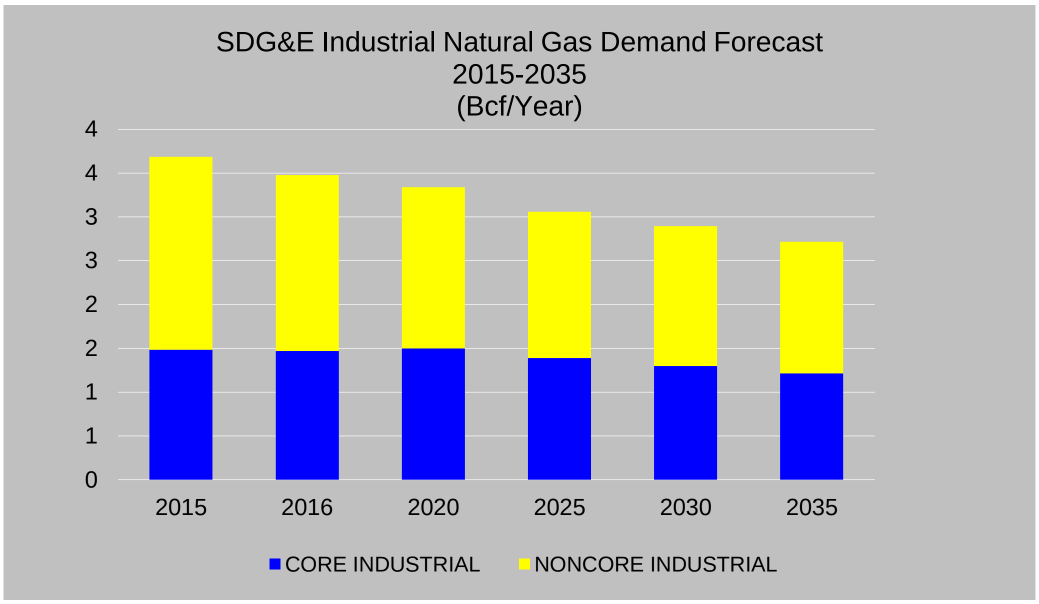
On a temperature-adjusted basis, the core commercial demand in 2015 totaled 17 Bcf. By the year 2035, the SDG&E core commercial load is expected to decline to 14 Bcf.

SDG&E's non-core commercial load in 2015 was 2 Bcf. Over the forecast period, gas demand in this market is projected to show moderate growth mostly driven by increased economic activity and employment. Non-core commercial load is projected to grow to 3 Bcf by 2035, an average annual increase of 1.5%.


SDG&E Commercial Natural Gas Demand Forecast
2015-2035
Bcf/Year
20
18
16
14
12
10
8
6
4
2
0
2015
2016
2020
2025
2030
2035
CORE COMMERCIAL
NONCORE COMMERCIAL

Industrial

In 2015, temperature-adjusted core industrial demand was 1.5 Bcf. The core industrial market demand is projected to decrease at an average rate of 1% per year from 1.5 Bcf in 2015 to 1.2 Bcf in 2035. This result is due to slightly lower forecasted growth in industrial production and the impact of savings from CPUC-authorized energy efficiency programs in the industrial sector.

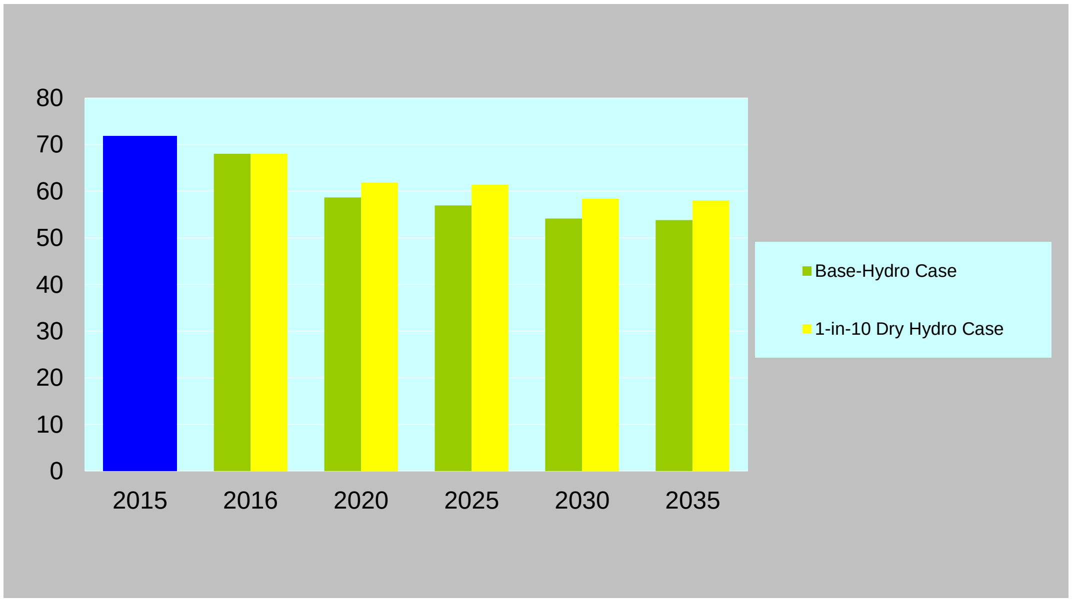


Non-core industrial load in 2015 was 2.2 Bcf and is expected to decline at an average rate of -1.6% per year to 1.6 Bcf by 2035. CPUC-mandated energy efficiency programs more than offset any modest gains from industrial economic growth.

Electric Generation

Total EG, including cogeneration and non-cogeneration EG, is expected to decrease at an annual average rate of 1.0% from 72 Bcf in 2015 to 58 Bcf in 2035. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.

SDGE's Service Area
Total Electric Generation Gas Demand Forecast
2015-2035
(Bcf/Year)



Cogeneration

Small Electric Generation load from self-generation totaled 16.2 Bcf in 2015. By 2035, small EG load is expected to rise to 18.5 Bcf – growing an average of 0.7% per year reflecting economic growth.

Non-Cogeneration Electric Generation

The forecast of large EG loads in SDG&E's service area is based on the power market simulation noted in SoCalGas' Electric Generation chapter for "Non-Cogeneration EG" demand. EG demand is forecasted to decrease from 51 Bcf in 2016 to 36 Bcf in 2030. This forecast includes approximately 800 MW of new thermal peaking generating resources in its service area by 2020. However, it also assumes that approximately 1,118 MW of the existing plants are retired during the same time period. The EG forecast is held constant at 2030 levels through 2035 as previously explained.

A 1-in-10 year dry hydro sensitivity forecast has also been developed. A dry hydro year increases SDG&E's EG demand on average for the forecast period by approximately 4 Bcf per year. For additional information on EG assumptions, such as renewable generation, greenhouse gas adders and sensitivity to electric demand and attainment of renewables' goals, refer to the Non-Cogeneration Electric Generation section of the SoCalGas Electric Generation chapter.

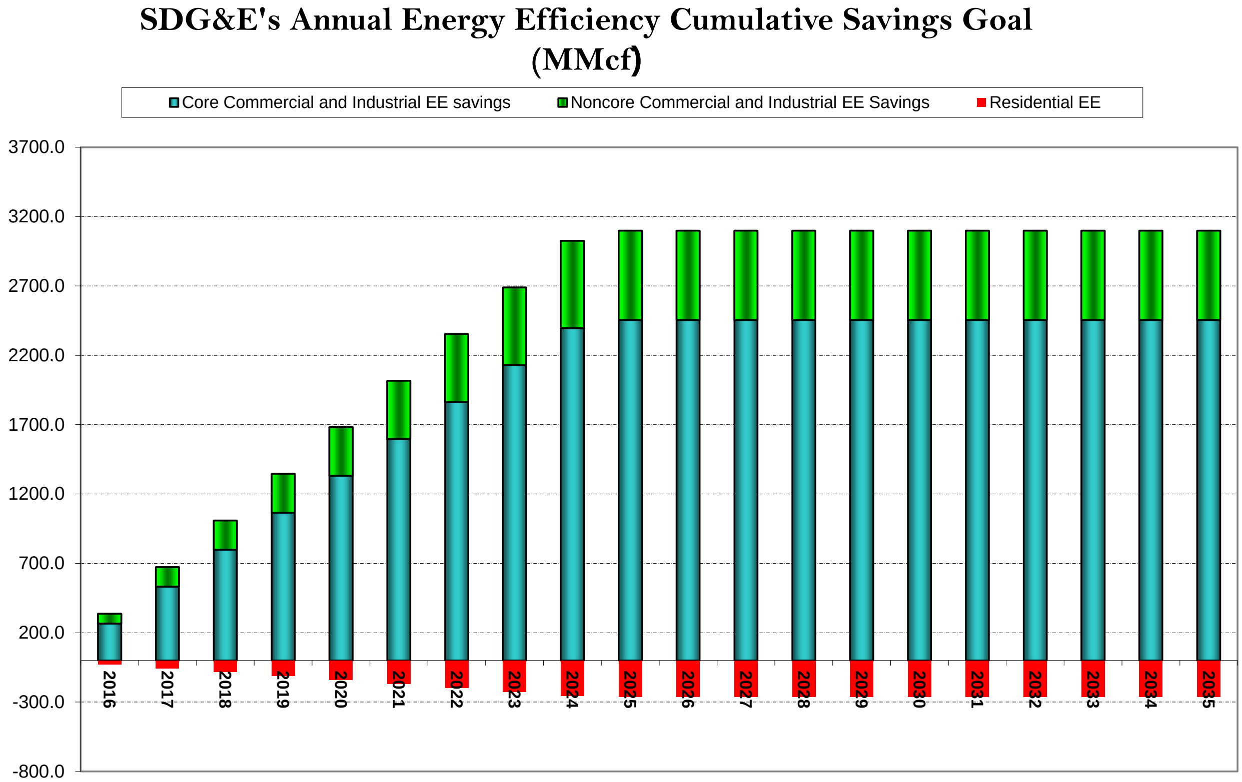
Natural Gas Vehicles (NGV)

The NGV market is expected to continue to grow due to government (federal, state and local) incentives and regulations related to the purchase and operation of alternate fuel vehicles, growing numbers of natural gas engines and vehicles, and the cost differential between petroleum (gasoline and diesel) and natural gas. At the end of 2015, there were 34 compressed natural gas (CNG) fueling stations delivering 1.7 Bcf of natural gas during the year. The NGV market is expected to grow at an annual rate of 4.4% over the forecast period.

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 load impact forecast from SDG&E’s integrated gas and electric energy efficiency programs for selected years is shown in the graph below. The net load impact includes all Energy Efficiency programs, both gas and electric, that SDG&E has forecasted to be implemented beginning in year 2016 and occurring through the year 2035. Savings and goals for these programs are based on the program goals authorized by the Commission in D.15-10-028.



Savings reported are for measures installed under SDG&E's gas and electric 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.[1] Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. Naturally occurring conservation that is not attributable to SDG&E's Energy Efficiency activities is not included in the Energy Efficiency forecast.

Notes:

(1) "Hard" impacts include measures requiring a physical equipment modification or replacement. SDG&E does not include "soft" impacts, e.g., energy management services type measures.

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 D.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

Since April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand have been 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.

2016 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY
TABULAR DATA

San Diego Gas and Electric Company
Recorded Years 2011-2015
Annual Gas Supply and Sendout (MMCF/Day)

LINE	Actual Deliveries by End-Use		2011	2012	2013	2014	2015
1	**CORE**	Residential	88	83	85	68	67
2		Commercial	50	50	52	49	49
3		Industrial	0	0	0	0	0
4	*Subtotal -*	*CORE*	138	134	137	117	116
5	**NONCORE**	Commercial	0	0	0	0	0
6		Industrial	12	13	12	11	11
7		Non-EOR Cogen/EG	69	100	70	72	74
8		Electric Utilities	87	134	147	121	126
9	*Subtotal -*	*NONCORE*	169	247	229	204	211
10	**WHOLESALE**	All End Uses	0	0	0	0	0
11	*Subtotal -*	*Co Use & LUAF*	5	4	5	2	0
12	**SYSTEM TOTAL THROUGHPUT**		312	384	371	323	327
	Actual Transport & Exchange						
13	**CORE**	Residential	0	0	1	1	1
14		Commercial	10	11	12	11	12
15	**NONCORE**	Industrial	12	13	12	11	11
16		Non-EOR Cogen/EG	69	100	70	72	74
17		Electric Utilities	87	134	147	121	126
18	*Subtotal -*	*RETAIL*	179	258	242	216	224
19	**WHOLESALE**	All End Uses	0	0	0	0	0
20	**TOTAL TRANSPORT & EXCHANGE**		179	258	242	216	224
	Storage						
21		*Storage Injection*	0	0	0	0	0
22		*Storage Withdrawal*	0	0	0	0	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:	1.018	1.017	1.024	1.035	1.040

San Diego Gas and Electric Company
Recorded Years 2011-2015
Annual Gas Supply Taken (MMCF/Day)

LINE		2011	2012	2013	2014	2015
	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**					

	Gas Supply Taken	2011	2012	2013	2014	2015
	California Source Gas					
11	Regular Purchases	0	0	0	0	0
12	Received for Exchange/Transport	0	0	0	0	0
13	**Total California Source Gas**	0	0	0	0	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	132	126	129	107	103
18	Out-of-State Transport-Others	179	258	242	216	224
19	**Total Out-of-State Gas**	312	384	371	323	327
20	**TOTAL Gas Supply Taken & Transported**	312	384	371	323	327

TABLE 1-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2016 THRU 2020

AVERAGE TEMPERATURE YEAR

LINE			2016	2017	2018	2019	2020	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		338	336	322	317	315	5
6	TOTAL SUPPLY TAKEN		338	336	322	317	315	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		338	336	322	317	315	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	84	86	86	86	86	9
10		Commercial	44	45	45	44	44	10
11		Industrial	4	4	4	4	4	11
12		NGV	5	5	5	6	6	12
13		Subtotal-CORE	137	140	140	140	140	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	5	5	5	5	5	15
16		Electric Generation (EG)	186	181	167	162	160	16
17		Subtotal-NONCORE	198	193	179	174	172	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		338	336	322	317	315	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	14	14	14	14	20
21	NONCORE	Commercial/Industrial	13	12	12	12	12	21
22		Electric Generation (EG)	186	181	167	162	160	22
23	TOTAL TRANSPORTATION & EXCHANGE		212	207	193	188	186	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:

	2016	2017	2018	2019	2020
transportation (CAT) in MDth/d:	129	131	131	131	131

TABLE 2-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2021 THRU 2035

AVERAGE TEMPERATURE YEAR

LINE			2021	2022	2025	2030	2035	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		315	315	310	303	306	5
6	TOTAL SUPPLY TAKEN		315	315	310	303	306	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		315	315	310	303	306	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	87	87	88	90	92	9
10		Commercial	43	42	39	38	38	10
11		Industrial	4	4	4	4	3	11
12		NGV	6	7	8	9	11	12
13		Subtotal-CORE	140	140	139	141	144	13
14	NONCORE	Commercial	7	7	7	7	8	14
15		Industrial	5	5	5	4	4	15
16		Electric Generation (EG)	160	160	156	148	147	16
17		Subtotal-NONCORE	172	172	168	159	159	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		315	315	310	303	306	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	14	14	15	16	20
21	NONCORE	Commercial/Industrial	12	12	11	12	12	21
22		Electric Generation (EG)	160	160	156	148	147	22
23	TOTAL TRANSPORTATION & EXCHANGE		186	186	181	175	175	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:

	2021	2022	2025	2030	2035
transportation (CAT) in MDth/d:	131	131	130	131	133

TABLE 3-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2016 THRU 2020

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2016	2017	2018	2019	2020	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		351	357	346	342	338	5
6	TOTAL SUPPLY TAKEN		351	357	346	342	338	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		351	357	346	342	338	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	94	96	97	97	97	9
10		Commercial	47	49	48	47	47	10
11		Industrial	4	4	4	4	4	11
12		NGV	5	5	5	6	6	12
13		Subtotal-CORE	150	154	154	154	154	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	5	5	5	5	5	15
16		Electric Generation (EG)	186	188	177	173	169	16
17		Subtotal-NONCORE	198	200	189	185	181	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		351	357	346	342	338	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	15	15	15	15	20
21	NONCORE	Commercial/Industrial	13	12	12	12	12	21
22		Electric Generation (EG)	186	188	177	173	169	22
23	TOTAL TRANSPORTATION & EXCHANGE		213	215	204	200	196	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:

	2016	2017	2018	2019	2020
transportation (CAT) in MDth/d:	141	145	145	145	145

TABLE 4-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2021 THRU 2035

COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2021	2022	2025	2030	2035	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		339	341	336	329	333	5
6	TOTAL SUPPLY TAKEN		339	341	336	329	333	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		339	341	336	329	333	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	97	98	99	101	103	9
10		Commercial	46	45	42	41	41	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	7	8	9	11	12
13		Subtotal-CORE	153	154	153	155	159	13
14	NONCORE	Commercial	7	7	7	7	8	14
15		Industrial	5	5	5	4	4	15
16		Electric Generation (EG)	171	172	168	160	159	16
17		Subtotal-NONCORE	183	184	180	171	171	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		339	341	336	329	333	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	15	15	15	16	17	20
21	NONCORE	Commercial/Industrial	12	12	11	12	12	21
22		Electric Generation (EG)	171	172	168	160	159	22
23	TOTAL TRANSPORTATION & EXCHANGE		198	199	194	188	188	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:

	2021	2022	2025	2030	2035
transportation (CAT) in MDth/d:	143	145	143	145	148

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2016 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.

Combined Heat and Power (CHP)
Combined Heat and Power (CHP) is the sequential production of electricity and thermal energy from the same fuel source. Historically, CHP has been perceived as an efficient technology and is promoted in California as a preferred electric generation resource.

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 60^{o} 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.

PSEP
Pipeline Safety Enhancement Plan.

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.

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2016 CALIFORNIA GAS REPORT

RESPONDENTS

RESPONDENTS

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

- Pacific Gas and Electric Company
- San Diego Gas 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 has been formed by the respondents and cooperating utilities to prepare this report. The following individuals served on this committee.

Working Committee

- Rose-Marie Payan (Chairperson)-SoCalGas/SDG&E
- Sharim Chaudhury- SoCalGas/SDG&E
- Igor Grinberg- PG&E
- Ipek Connolly- PG&E
- Jeff Huang – SoCalGas/SDG&E
- Michelle Clay-Ijomah-SDG&E
- Eric Hsu-PG&E
- Anthony Dixon- CEC
- Angela Tanghetti – CEC

Observers

- Richard Myers– CPUC Energy Division
- Matthew Karle- CPUC Energy Division

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