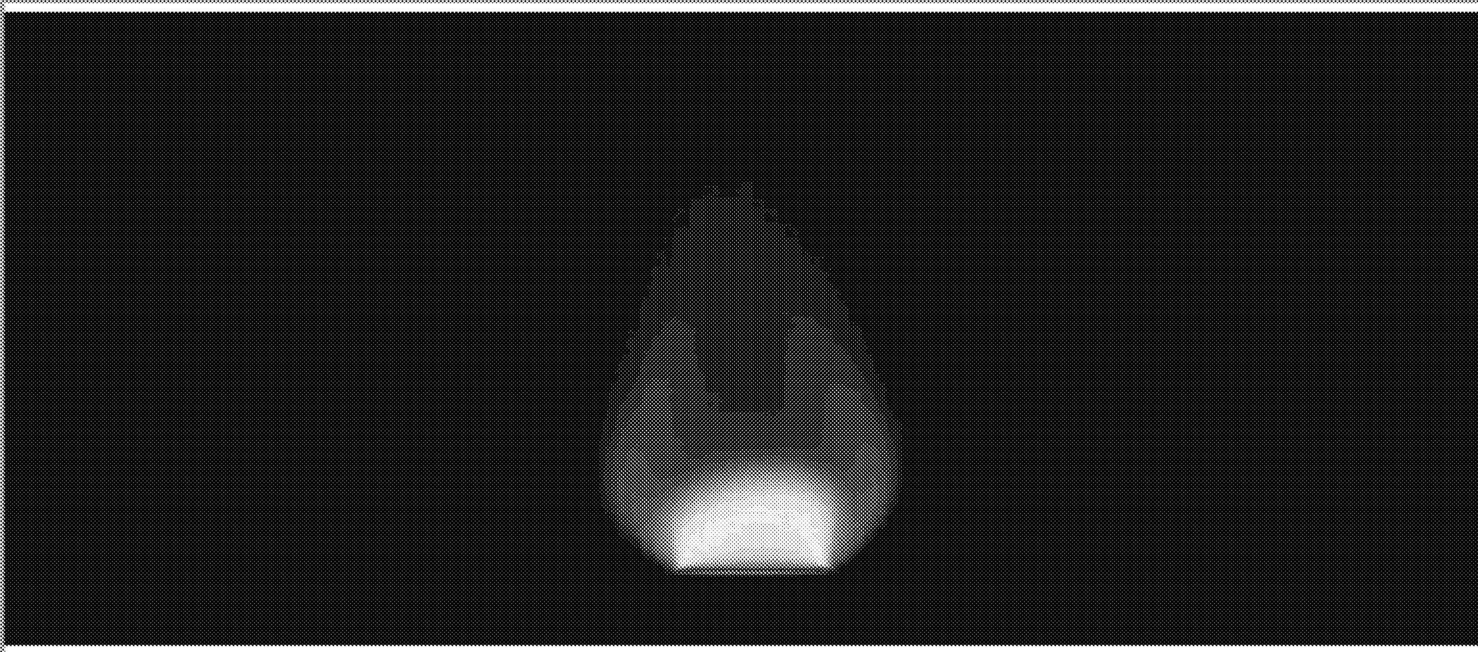
2018 California Gas Report

Prepared by the California Gas and Electric Utilities



Prepared in Compliance with California Public Utilities Commission

Decision D.95-01-039

2018 CALIFORNIA GAS REPORT

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
Sacramento Municipal Utilities District
Southern California Edison Company

2018 CALIFORNIA GAS REPORT

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2018 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The 2018 *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 (CPUC) 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, LLC. 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 (SDG&E).

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.

2018 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 0.5 percent per year from 2018 to 2035. The forecast decline is a combination of moderate growth in the Natural Gas Vehicle (NGV) market and across-the-board declines in most of the other market segments.

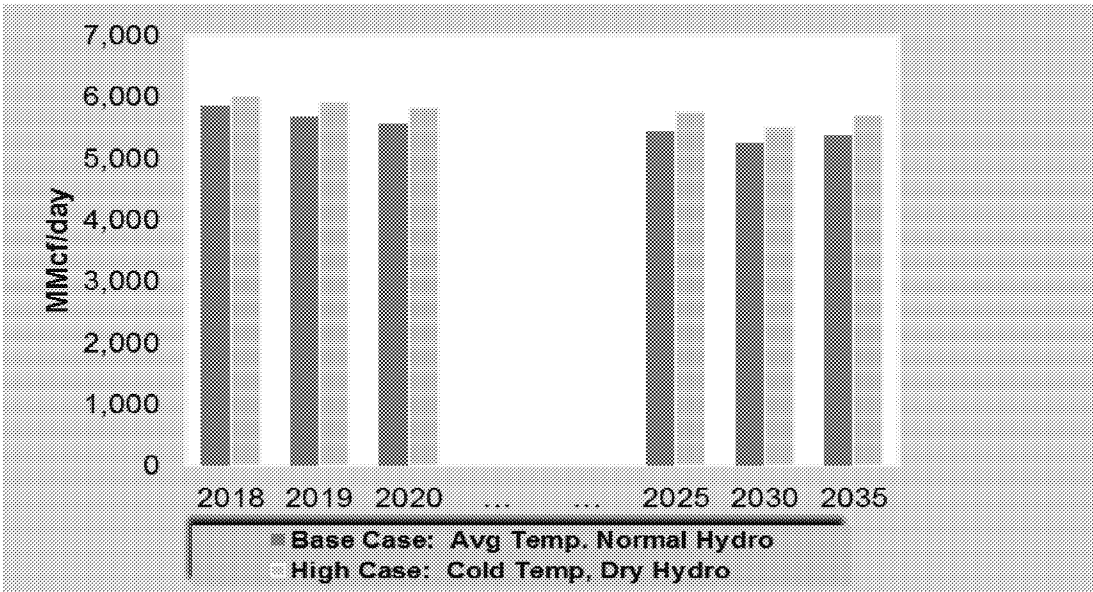
Residential gas demand is expected to decrease at an annual average rate of 1.4 percent. Demand in the commercial and industrial markets are expected to increase slightly at an annual rate of 0.2 percent. Stricter codes and standards coupled with more aggressive energy efficiency programs, in addition to the new goals laid out for SB350, are making a significant impact on the forecasted load for 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 1.4 percent per year for the next 17 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 below 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 5,871 MMcf/d in 2018 decreasing to 5,381 MMcf/d by 2035, a decline of 0.5 percent per year.

In 2018, Northern California is projected to require an additional 2 percent of gas supply to meet demand for the high gas demand scenario, whereas Southern California is projected to require an additional 3.4 percent 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.

CALIFORNIA DEMAND OUTLOOK



FOCUS ON EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on customer Energy Efficiency (EE) 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 percent of the state's electric needs by 2020 and 50 percent 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 from eligible renewable energy resources be increased to 50 percent per year 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.

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

	2018	2019	2020	2021	2022	2023	2024	2025	2030	2035
California Energy Requirements by CPUC-Jurisdictional Utilities (CAISO) (1)										
Electricity Demand (GWh)	256,866	255,070	254,828	254,529	254,920	254,599	253,740	253,018	248,293	243,718
33% Renewables by 2020 & 50% Renewables by 2030										
Renewable Electric Generation (GWh/Yr) (2)	74,491	79,072	84,093	88,322	92,791	97,002	100,988	105,002	124,147	121,859
Increase over 2017 Level (GWh/Yr) (3)	14,752	19,332	24,354	28,582	33,052	37,263	41,249	45,263	64,407	62,120
Gas Savings over 2017 Level (Bcf/Yr) (4)	90	117	148	173	201	226	250	275	391	377
Electric Energy Efficiency Goals (5)										
Electricity Savings over 2017 Level (GWh/Yr)	2,385	3,625	4,881	6,027	7,077	8,315	9,785	11,454	22,448	35,035
Gas Savings over 2017 Level (Bcf/Yr) (4)	14	22	30	37	43	50	59	70	136	213
Energy Efficiency Goal for Natural Gas Programs (6)										
Gas Savings over 2017 Level (Bcf/Yr)	9	18	27	36	45	53	61	69	102	102
Total Gas Savings (Bcf/Yr) (7)	113	157	205	246	288	329	370	413	629	691

Notes:

(1) Electricity demand forecast from the California Energy Commission: https://efiling.energy.ca.gov/GetDocument.aspx?tn=222582, LSE_and_BA_Tables_Med_Baseline_Demand_Mid_AAEEAAPV_Revised_CCA.xlsx, "form1.1c" tab. From 2030-2035 the average growth rate was used from the last five years (2026-2030) which is -0.371%.

(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, 2017.

(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/GetDocument.aspx?tn=223608, "Electricity Committed Efficiency CED 2017"; Mid Case, sums of STATE TOTAL. From 2030-2035 the average growth rate was used from the last five years (2026-2030): 1.74% for Residential and 3.44% for Non-Residential.

(6) Data from the California Energy Commission: https://efiling.energy.ca.gov/GetDocument.aspx?tn=223609, "Natural Gas Committed Efficiency CED 2017"; TOTAL STATE Mid Case Totals. From 2030-2035 the average growth rate was used from the last five years (2026-2030): 1.13% for Residential and 2.29% for Non-Residential.

(7) Total gas savings are annual savings from equipment installed after December 31, 2017.

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 predictable and are not always dispatchable.

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 percent Renewable Portfolio Standard (RPS) by 2020. SB 350 further raised the RPS target to 50 percent by 2030. The additional renewable energy will displace some of the natural gas currently being used to generate electricity in California, but the reduction will not be equal 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 needed ancillary services (load following, ramping, and quick starts) to balance the electric system in the short term until other technologies can mature.

It is expected that solar and wind generating units will provide most of the new renewable electric generation in the years ahead. Solar generation resources will be the dominant renewable resource because solar equipment costs have declined rapidly in the past few years. In addition, solar resources have 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.

GAS PRICE FORECAST

MARKET CONDITION

Since 2008, the North American gas supply landscape has shifted from conventional to unconventional developments driven by improvements in fracking technology. As a result, shale gas production has grown. Through 2017, improvements in fracking technology and horizontal drilling efficiencies in both dry and wet gas plays, such as with the large Permian Basin, have resulted in the supply from unconventional shale resources increasing faster than conventional supplies.

North America has ample amounts of supply that can be produced under $3/MMBtu. As mentioned above, shale plays a huge role in the supply portfolio. The bulk of the shale gas production will come from Marcellus and Utica plays and Permian Basin.

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.

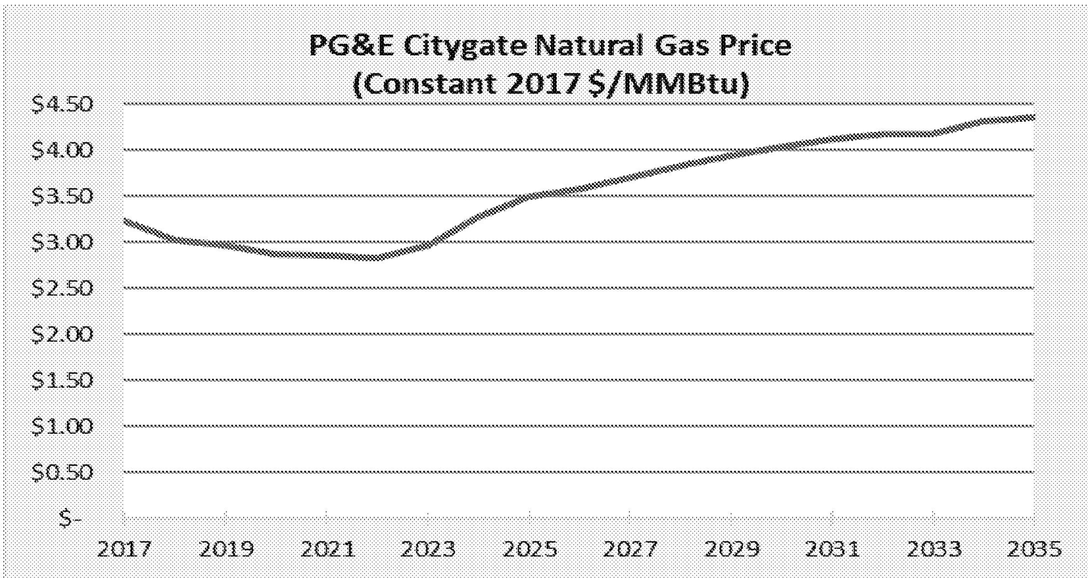
Mexico meets almost half of its natural gas demand with imports. Mexico's pipeline imports from the United States have increased significantly, and as of 2015, have accounted for approximately 80 percent of Mexico's natural gas imports. Mexico also imports natural gas from the Costa Azul LNG terminal, the Manzanillo LNG facility and the Altamira terminal. Driven by its power and industrial market sectors, Mexico's imports are expected to continue to grow 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.

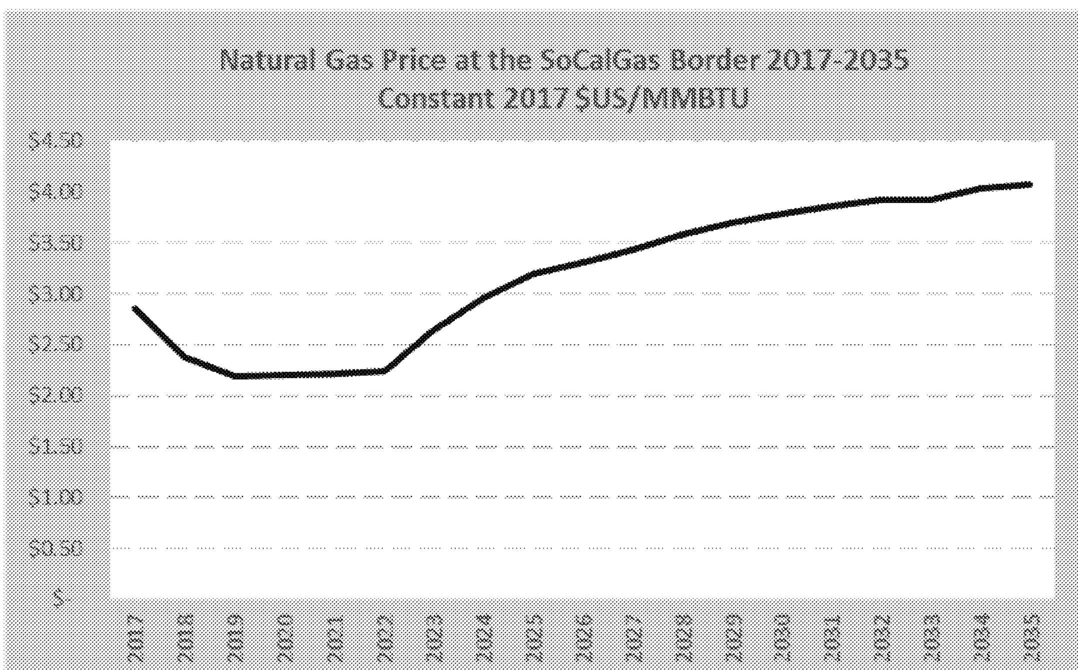
Industry experts currently forecast that North American gas supplies will be sufficient to meet expected demand growth, but at prices which are higher than recently low levels. While North American gas price increases will be somewhat tempered by renewable power generation additions both in the US and 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 $2.85/MMBtu in 2017, up modestly from an average of $2.41/MMbtu in 2016. The natural gas prices are expected to rise slightly to $2.45 in 2018 and reach $6.17/MMBtu by 2035. For the PG&E Citigate, the average natural gas price is $3.23/MMBtu and is forecasted to average $3.03/MMBtu in 2018 and will reach $6.51/MMBtu by 2035.

Consistent with the prior CGR practices, the 2018 CGR gas price forecast was developed using a combination of market prices and fundamental forecasts. The natural gas custom futures curve was extracted by Platt's for the 2018-2022 period. Fundamental price forecasts were used for 2023 and beyond. The forecasts for 2023 and 2024 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, such as Wood Mackenzie, PIRA, and the EIA.





It is important to recognize that the natural gas price forecast is inherently uncertain. SoCalGas and the respondents of the *2018 CGR* do not warrant the accuracy of the gas price projection. In no event shall SoCalGas, PG&E or the respondents of the *2018 CGR* be liable for the use of or reliance on this natural gas price forecast.

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

The Federal Energy Regulatory Commission (FERC) is responsible for authorizing the siting and construction of onshore and near-shore LNG import or export facilities. It also issues certificates of public convenience and necessity of LNG facilities engaged in interstate natural gas transportation by pipeline. Environmental assessments for proposed LNG facilities are also prepared by the FERC.

At the time of the writing of this report, FERC lists more than 110 LNG facilities as operational in the United States. Some facilities export natural gas from the U.S, and some provide natural gas supply to the interstate pipeline system or local distribution companies. There are also facilities that are used to store natural gas for periods of peak demand and other facilities produce LNG for vehicle fuel or for industrial use.

The current inventory of approved projects consists of thirteen export terminals and four import terminals. Not all of the approved terminals are shown to be under construction. The vast majority of the approved projects are concentrated in Louisiana, Texas and Georgia. The proposed and approved projects that border the Pacific Coast are all located in British Columbia. These approved projects are listed as *not be under construction* as of yet but if they go forward will be located in Kitimat, Squamish and Prince Rupert Island, British Columbia. For more up-to-date information on the citing and inventory of LNG projects, please refer to the FERC website.[1]

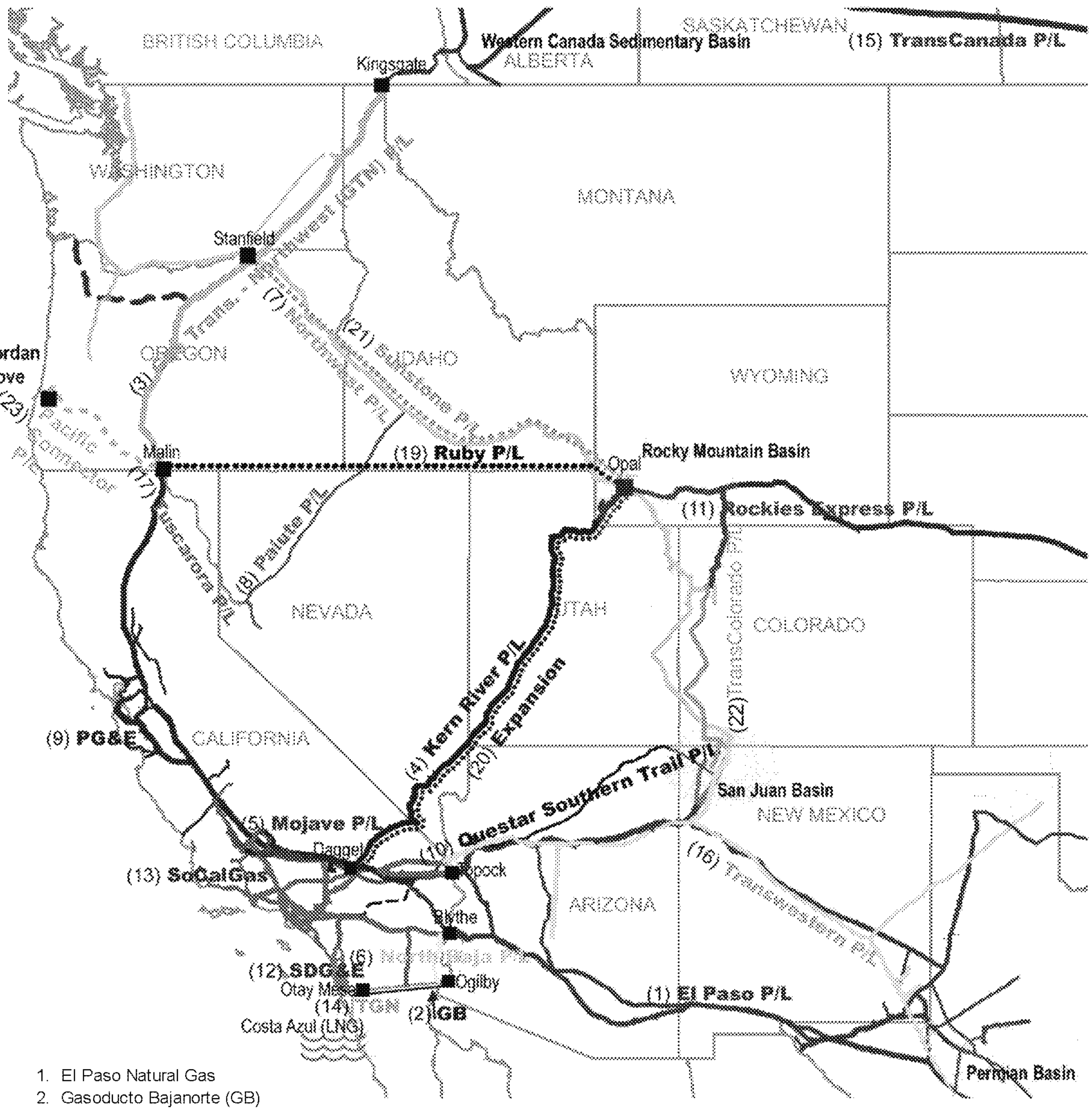
Supply Outlook/Pipeline Capacity

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 and also Mexico. 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.

[1] https://www.ferc.gov/industries/gas/indus-act/lng.asp

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)

Currently, there are three West Coast LNG facilities, two operating in Mexico and one operating in Alaska. The Costa Azul terminal and the KMS terminal, both operating in Mexico, remain the only two import facilities in western North America. The abundance of shale gas has changed the paradigm for LNG in the West.

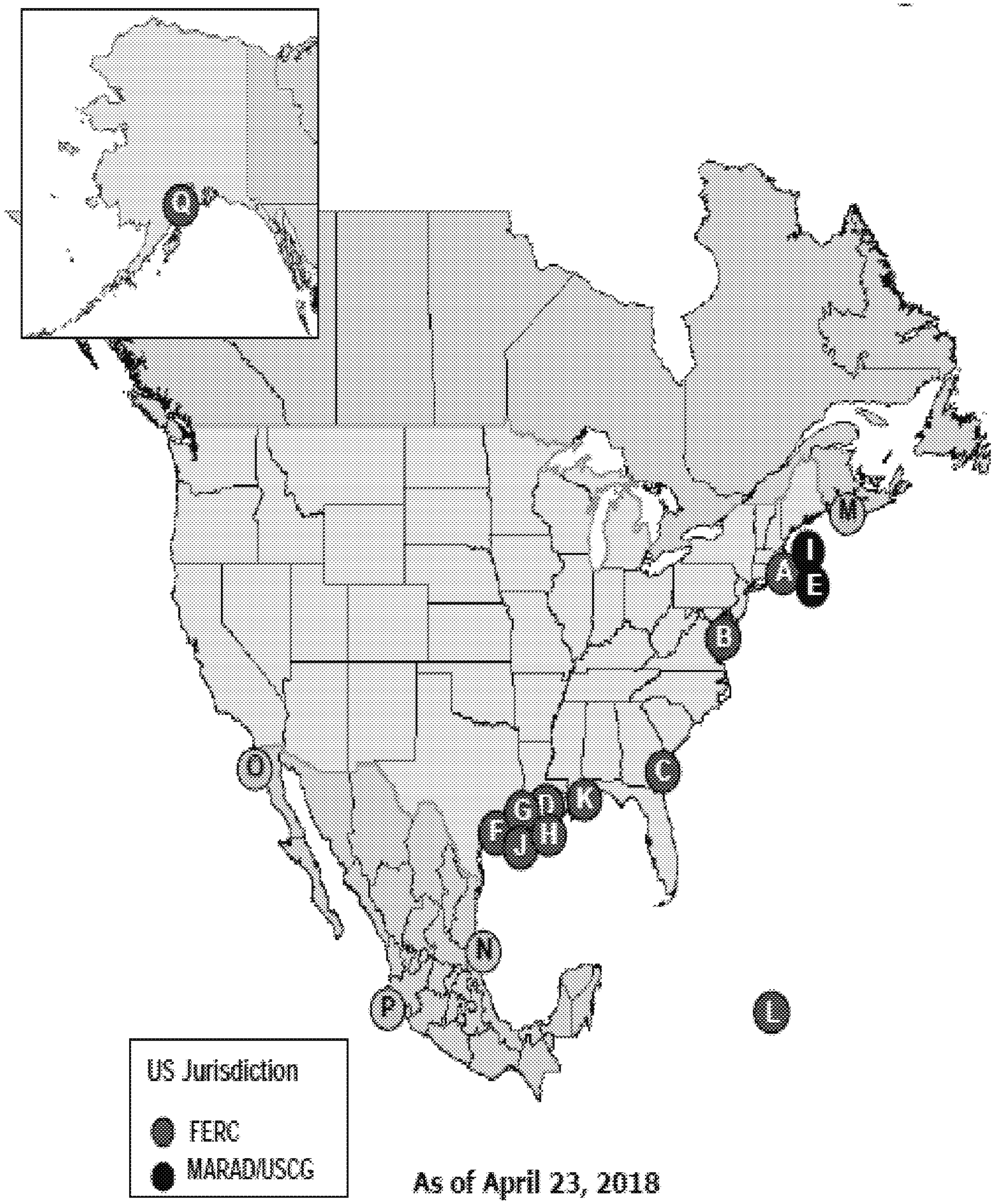
Details of the facilities are described in the table below.

North American West Coast LNG Terminals
As of Spring 2018

Western Region LNG Terminals

In Existence as of April 23, 2018

	Point Reference	Location	Owned By:		
1	O	Baja California, MEXICO	Sempra Energy: Costa Azul	Import Terminal	1 Bcf/d
2	P	Manzanillo, MEXICO	KMS: GNL de Manzanillo	Import Terminal	0.5 Bcf/d
3	Q	Kenai, ALASKA	Conoco Phillips	Export Terminal	0.2 Bcf/d



As of April 23, 2018

★ Authorized to re-export delivered LNG

Import Terminals

U.S.

A. Everett, MA: 1.035 Bcfd (GDF SUEZ - DOMAC)
B. Cove Point, MD: 1.8 Bcfd (Dominion - Cove Point LNG)
C. Elba Island, GA: 1.6 Bcfd (El Paso - Southern LNG)
D. Lake Charles, LA: 2.1 Bcfd (Southern Union - Trunkline LNG)
E. Offshore Boston: 0.8 Bcfd (Excelerate Energy – Northeast Gateway) ★
F. Freeport, TX: 1.5 Bcfd (Cheniere/Freeport LNG Dev.) ★
G. Sabine, LA: 4.0 Bcfd (Cheniere/Sabine Pass LNG) ★
H. Hackberry, LA: 1.8 Bcfd (Sempra - Cameron LNG)
I. Offshore Boston, MA: 0.4 Bcfd (GDF SUEZ – Neptune LNG)
J. Sabine Pass, TX: 2.0 Bcfd (ExxonMobil – Golden Pass) (Phase I & II)
K. Pascagoula, MS: 1.5 Bcfd (El Paso/Crest/Sonangol - Gulf LNG Energy LLC)
L. Peñuelas, PR: 0.3 Bcfd (EcoElectrica)

Canada

M. Saint John, NB: 1.0 Bcfd (Repsol/Fort Reliance - Canaport LNG)

Mexico

N. Altamira, Tamulipas: 0.7 Bcfd (Shell/Total/Mitsui – Altamira LNG)
O. Baja California, MX: 1.0 Bcfd (Sempra – Energia Costa Azul)
P. Manzanillo, MX: 0.5 Bcfd (KMS GNL de Manzanillo)

Export Terminals

U.S.

B. Cove Point, MD: 0.82 Bcfd (Dominion–Cove Point LNG) (CP13-113)
G. Sabine, LA: 2.8 Bcfd (Cheniere/Sabine Pass LNG – Trains 1, 2, 3 & 4)
Q. Kenai, AK: 0.2 Bcfd (ConocoPhillips)

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 2018 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, SDG&E, 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

	2018	2019	2020	2021	2022
California's Supply Sources					
Utility					
California Sources	87	87	87	87	87
Out-of-State	4,886	4,731	4,654	4,634	4,622
Utility Total	4,973	4,818	4,741	4,721	4,709
Non-Utility Served Load (1)	1,131	1,093	1,056	1,054	1,028
Statewide Supply Sources Total	**6,104**	**5,910**	**5,797**	**5,775**	**5,738**
California's Requirements					
Utility					
Residential	1,160	1,146	1,128	1,115	1,098
Commercial	495	492	488	485	479
Natural Gas Vehicles	50	53	56	59	62
Industrial	1,014	1,018	1,009	1,017	1,028
Electric Generation (2)	1,651	1,505	1,458	1,444	1,441
Enhanced Oil Recovery Steaming	46	46	45	46	46
Wholesale/International+Exchange	249	251	251	252	251
Company Use and Unaccounted-for	75	73	71	71	72
Utility Total	4,740	4,585	4,508	4,488	4,476
Non-Utility					
Enhanced Oil Recovery Steaming	651	647	642	641	639
EOR Cogeneration/Industrial	64	57	55	55	50
Electric Generation	416	389	359	359	340
Non-Utility Served Load (1)	1,131	1,093	1,056	1,054	1,028
Statewide Requirements Total (3)	**5,871**	**5,677**	**5,564**	**5,542**	**5,505**

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

	2023	2024	2025	2030	2035
California's Supply Sources					
Utility					
California Sources	87	87	87	87	87
Out-of-State	4,591	4,573	4,574	4,375	4,416
Utility Total	4,678	4,660	4,661	4,462	4,503
Non-Utility Served Load (1)	1,014	993	1,011	1,022	1,111
Statewide Supply Sources Total	**5,692**	**5,653**	**5,673**	**5,484**	**5,614**
California's Requirements					
Utility					
Residential	1,076	1,055	1,038	961	919
Commercial	471	463	457	430	420
Natural Gas Vehicles	65	69	73	93	120
Industrial	1,033	1,037	1,041	1,075	1,135
Electric Generation (2)	1,432	1,437	1,452	1,304	1,302
Enhanced Oil Recovery Steaming	46	45	46	46	46
Wholesale/International+Exchange	251	250	251	252	259
Company Use and Unaccounted-for	71	71	71	68	70
Utility Total	4,445	4,427	4,428	4,229	4,270
Non-Utility					
Enhanced Oil Recovery Steaming	636	636	631	694	821
EOR Cogeneration/Industrial	48	45	47	10	0
Electric Generation	331	312	333	318	290
Non-Utility Served Load (1)	1,014	993	1,011	1,022	1,111
Statewide Requirements Total (3)	**5,459**	**5,420**	**5,440**	**5,251**	**5,381**

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	**2018**	**2019**	**2020**	**2021**	**2022**
Northern California					
California Sources [1]	36	36	36	36	36
Out-of-State	2,312	2,191	2,139	2,141	2,154
Northern California Total	2,348	2,227	2,175	2,177	2,190
Southern California					
California Sources [2]	51	51	51	51	51
Out-of-State	2,574	2,540	2,515	2,493	2,468
Southern California Total	2,625	2,591	2,566	2,544	2,519
Utility Total	4,973	4,818	4,741	4,721	4,709
Non-Utility Served Load [3]	1,131	1,093	1,056	1,054	1,028
Statewide Supply Sources Total	**6,104**	**5,910**	**5,797**	**5,775**	**5,738**

Utility	**2023**	**2024**	**2025**	**2030**	**2035**
Northern California					
California Sources [1]	36	36	36	36	36
Out-of-State	2,162	2,180	2,204	2,116	2,154
Northern California Total	2,198	2,216	2,240	2,152	2,190
Southern California					
California Sources [2]	51	51	51	51	51
Out-of-State	2,429	2,393	2,371	2,259	2,262
Southern California Total	2,480	2,444	2,422	2,310	2,313
Utility Total	4,678	4,660	4,661	4,462	4,503
Non-Utility Served Load [3]	1,014	993	1,011	1,022	1,111
Statewide Supply Sources Total	**5,692**	**5,653**	**5,673**	**5,484**	**5,614**

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

	2018	2019	2020	2021	2022
Utility					
Northern California					
Residential	512	506	499	493	486
Commercial - Core	222	222	221	221	220
Natural Gas Vehicles - Core	7	8	9	9	10
Natural Gas Vehicles - Noncore	3	3	3	3	3
Industrial - Noncore	568	574	568	579	594
Wholesale	9	9	9	9	9
SMUD Electric Generation	117	117	117	117	117
Electric Generation [(2)]	633	514	476	473	477
Exchange (California)	1	1	1	1	1
Company Use and Unaccounted-for	42	40	39	39	40
Northern California Total [(3)]	2,115	1,994	1,942	1,944	1,957
Southern California					
Residential	648	640	629	622	612
Commercial - Core	223	221	218	214	209
Commercial - Noncore	50	50	49	49	49
Natural Gas Vehicles - Core	40	43	45	47	50
Industrial - Core	57	57	56	55	54
Industrial - Noncore	390	387	386	383	380
Wholesale	238	241	241	242	241
SDG&E+Vernon Electric Generation	167	165	159	159	156
Electric Generation [(4)]	733	710	705	694	692
Enhanced Oil Recovery Steaming	46	46	45	46	46
Company Use and Unaccounted-for	33	33	32	32	32
Southern California Total	2,625	2,591	2,566	2,544	2,519
Utility Total	4,740	4,585	4,508	4,488	4,476
Non-Utility Served Load [(5)]	1,131	1,093	1,056	1,054	1,028
Statewide Gas Requirements Total [(6)]	**5,871**	**5,677**	**5,564**	**5,542**	**5,505**

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 California 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

	2023	2024	2025	2030	2035
Utility					
Northern California					
Residential	479	472	465	439	410
Commercial - Core	220	219	218	214	205
Natural Gas Vehicles - Core	10	11	11	14	17
Natural Gas Vehicles - Noncore	3	3	3	3	3
Industrial - Noncore	608	619	629	690	761
Wholesale	9	9	9	9	9
SMUD Electric Generation	117	117	117	117	117
Electric Generation [2]	479	494	513	394	394
Exchange (California)	1	1	1	1	1
Company Use and Unaccounted-for	40	40	40	39	41
Northern California Total [3]	1,965	1,983	2,007	1,919	1,957
Southern California					
Residential	597	583	573	523	510
Commercial - Core	203	196	191	169	168
Commercial - Noncore	49	48	48	47	46
Natural Gas Vehicles - Core	53	55	59	77	100
Industrial - Core	52	50	49	41	37
Industrial - Noncore	373	368	363	344	336
Wholesale	241	240	241	243	249
SDG&E+Vernon Electric Generation	151	150	149	147	146
Electric Generation [4]	684	676	673	646	645
Enhanced Oil Recovery Steaming	46	45	46	46	46
Company Use and Unaccounted-for	31	31	31	29	29
Southern California Total	2,480	2,444	2,422	2,310	2,313
Utility Total	4,445	4,427	4,428	4,229	4,270
Non-Utility Served Load [5]	1,014	993	1,011	1,022	1,111
Statewide Gas Requirements Total [6]	**5,459**	**5,420**	**5,440**	**5,251**	**5,381**

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 California 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

	2018	2019	2020	2021	2022
California's Supply Sources					
Utility					
California Sources	87	87	87	87	87
Out-of-State	5,024	4,968	4,904	4,903	4,871
Utility Total	5,111	5,055	4,991	4,990	4,958
Non-Utility Served Load [1]	1,132	1,097	1,066	1,069	1,052
Statewide Supply Sources Total	**6,243**	**6,152**	**6,057**	**6,059**	**6,009**
California's Requirements					
Utility					
Residential	1,266	1,253	1,235	1,223	1,206
Commercial	516	514	510	506	500
Natural Gas Vehicles	50	53	56	59	62
Industrial	1,017	1,021	1,012	1,020	1,031
Electric Generation [2]	1,641	1,594	1,558	1,561	1,539
Enhanced Oil Recovery Steaming	46	46	45	46	46
Wholesale/International+Exchange	264	266	266	267	266
Company Use and Unaccounted-for	77	76	76	76	75
Utility Total	4,878	4,822	4,758	4,757	4,725
Non-Utility					
Enhanced Oil Recovery Steaming	652	648	643	642	640
EOR Cogeneration/Industrial	65	58	58	58	54
Electric Generation	415	391	365	369	357
Non-Utility Served Load [1]	1,132	1,097	1,066	1,069	1,052
Statewide Requirements Total [3]	**6,010**	**5,919**	**5,824**	**5,826**	**5,776**

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

	2023	2024	2025	2030	2035
California's Supply Sources					
Utility					
California Sources	87	87	87	87	87
Out-of-State	4,827	4,823	4,861	4,598	4,639
Utility Total	4,914	4,910	4,948	4,685	4,726
Non-Utility Served Load [1]	1,038	1,020	1,030	1,069	1,198
Statewide Supply Sources Total	**5,952**	**5,930**	**5,979**	**5,754**	**5,924**
California's Requirements					
Utility					
Residential	1,184	1,163	1,146	1,069	1,028
Commercial	492	485	478	451	442
Natural Gas Vehicles	65	69	73	93	120
Industrial	1,036	1,040	1,044	1,078	1,137
Electric Generation [2]	1,517	1,536	1,588	1,375	1,373
Enhanced Oil Recovery Steaming	46	45	46	46	46
Wholesale/International+Exchange	266	265	266	267	274
Company Use and Unaccounted-for	74	75	75	73	74
Utility Total	4,681	4,677	4,715	4,452	4,493
Non-Utility					
Enhanced Oil Recovery Steaming	637	638	634	712	878
EOR Cogeneration/Industrial	52	49	52	14	0
Electric Generation	348	333	345	343	320
Non-Utility Served Load [1]	1,038	1,020	1,030	1,069	1,198
Statewide Requirements Total [3]	**5,719**	**5,697**	**5,746**	**5,521**	**5,691**

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	**2018**	**2019**	**2020**	**2021**	**2022**
Northern California					
California Sources (1)	36	36	36	36	36
Out-of-State	2,360	2,249	2,211	2,212	2,234
Northern California Total	2,396	2,285	2,247	2,248	2,270
Southern California					
California Sources (2)	51	51	51	51	51
Out-of-State	2,664	2,719	2,693	2,691	2,637
Southern California Total	2,715	2,770	2,744	2,742	2,688
Utility Total	5,111	5,055	4,991	4,990	4,958
Non-Utility Served Load (3)	1,132	1,097	1,066	1,069	1,052
Statewide Supply Sources Total	**6,243**	**6,152**	**6,057**	**6,059**	**6,009**

Utility	**2023**	**2024**	**2025**	**2030**	**2035**
Northern California					
California Sources (1)	36	36	36	36	36
Out-of-State	2,252	2,277	2,339	2,202	2,240
Northern California Total	2,288	2,313	2,375	2,238	2,276
Southern California					
California Sources (2)	51	51	51	51	51
Out-of-State	2,575	2,546	2,523	2,396	2,399
Southern California Total	2,626	2,597	2,574	2,447	2,450
Utility Total	4,914	4,910	4,948	4,685	4,726
Non-Utility Served Load (3)	1,038	1,020	1,030	1,069	1,198
Statewide Supply Sources Total	**5,952**	**5,930**	**5,979**	**5,754**	**5,924**

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

	2018	**2019**	**2020**	**2021**	**2022**
Utility					
Northern California					
Residential	556	550	543	538	531
Commercial - Core	232	232	232	231	231
Natural Gas Vehicles - Core	7	8	9	9	10
Natural Gas Vehicles - Noncore	3	3	3	3	3
Industrial - Noncore	569	576	569	581	596
Wholesale	10	10	10	10	10
SMUD Electric Generation	117	117	117	117	117
Electric Generation [2]	624	515	490	485	498
Exchange (California)	1	1	1	1	1
Company Use and Unaccounted-for	43	41	41	41	41
Northern California Total [3]	2,163	2,052	2,014	2,015	2,037
Southern California					
Residential	710	703	692	685	675
Commercial - Core	233	231	227	224	219
Commercial - Noncore	51	51	50	50	50
Natural Gas Vehicles - Core	40	43	45	47	50
Industrial - Core	58	58	57	56	55
Industrial - Noncore	390	387	386	383	380
Wholesale	253	255	255	256	255
SDG&E+Vernon Electric Generation	167	181	177	178	174
Electric Generation [4]	733	781	774	782	750
Enhanced Oil Recovery Steaming	46	46	45	46	46
Company Use and Unaccounted-for	34	35	35	35	34
Southern California Total	2,715	2,770	2,744	2,742	2,688
Utility Total	4,878	4,822	4,758	4,757	4,725
Non-Utility Served Load [5]	1,132	1,097	1,066	1,069	1,052
Statewide Gas Requirements Total [6]	**6,010**	**5,919**	**5,824**	**5,826**	**5,776**

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 California 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

	2023	**2024**	**2025**	**2030**	**2035**
Utility					
Northern California					
Residential	524	517	510	485	456
Commercial - Core	230	230	229	224	216
Natural Gas Vehicles - Core	10	11	11	14	17
Natural Gas Vehicles - Noncore	3	3	3	3	3
Industrial - Noncore	609	620	631	691	763
Wholesale	10	10	10	9	9
SMUD Electric Generation	117	117	117	117	117
Electric Generation (2)	510	530	588	419	419
Exchange (California)	1	1	1	1	1
Company Use and Unaccounted-for	41	42	43	42	43
Northern California Total (3)	2,055	2,080	2,142	2,005	2,043
Southern California					
Residential	660	646	636	585	572
Commercial - Core	212	206	200	179	178
Commercial - Noncore	50	49	49	48	48
Natural Gas Vehicles - Core	53	55	59	77	100
Industrial - Core	54	52	50	43	38
Industrial - Noncore	373	368	363	344	336
Wholesale	255	255	255	257	263
SDG&E+Vernon Electric Generation	166	164	164	152	152
Electric Generation (4)	725	724	719	688	686
Enhanced Oil Recovery Steaming	46	45	46	46	46
Company Use and Unaccounted-for	33	33	32	31	31
Southern California Total	2,626	2,597	2,574	2,447	2,450
Utility Total	4,681	4,677	4,715	4,452	4,493
Non-Utility Served Load (5)	1,038	1,020	1,030	1,069	1,198
Statewide Gas Requirements Total (6)	**5,719**	**5,697**	**5,746**	**5,521**	**5,691**

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 California 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 and 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 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.

Recorded 2016 Statewide Sources and Disposition Summary
MMcf/Day

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave (10)	Other (1)	RUBY	Total
:hern California Gas Company									
Core + UAF (2)	86	417	114	48	196	0	31	0	892
Noncore Commercial/Industrial	63	126	113	18	122	0	9	0	450
EG (3)	104	207	185	30	200	0	15	0	740
EOR	5	11	10	2	11	0	1	0	39
Wholesale/Resale/International (4)	55	109	98	16	105	0	8	0	390
Total	313	870	519	113	633	0	63	0	2,511
fic Gas and Electric Company (5)									
Core	0	40	84	318	0	0	0	194	636
Noncore Industrial/Wholesale/EG (6)	33	198	100	837	30	0	15	400	1,613
Total	33	238	184	1,155	30	0	15	594	2,249
er Northern California									
Core (7)	12	0	0	0	0	0	13	37	62
-Utilities Served Load (8,9)									
Direct Sales/Bypass	429	0	0	0	697	14	0	0	1,140
TOTAL SUPPLIER	787	1,108	703	1,268	1,360	14	91	631	5,962

s:
Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
Includes NGV volumes
EG includes UEG, COGEN, and EOR Cogen.
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	13	59	17	7	25	0	-2	0	119
Noncore Commercial/Industrial	24	45	43	7	46	0	5	0	171
Total	37	105	59	14	71	0	3	0	290
SouthWest Gas									
Core	22	0	0	0	0	0	11.90	0.000	33.90
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	11.90	0.000	35.90

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

Recorded 2017 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)	100	443	127	54	208	0	-27	0	905
Noncore Commercial/Industrial	62	125	112	18	120	0	9	0	446
EG (3)	100	200	178	29	193	0	14	0	713
EOR	5	11	10	2	11	0	1	0	39
Wholesale/Resale/International (4)	56	112	100	16	108	0	8	0	401
Total	323	891	527	118	640	0	5	0	2,504
Pacific Gas and Electric Company (5)									
Core	0	18	65	319	-1	0	0	179	580
Noncore Industrial/Wholesale/EG (6)	29	208	99	840	34	0	12	420	1,642
Total	29	226	164	1,159	33	0	12	599	2,222
Other Northern California									
Core (7)	13	0	0	0	0	0	0	0	13
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	392	28	0	0	607	20	0	0	1,047
TOTAL SUPPLIER	757	1,145	691	1,277	1,280	20	17	599	5,786

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	14	62	17	7	26	0	-2	0	124
Noncore Commercial/Industrial	25	47	44	7	47	0	7	0	175
Total	38	108	61	14	73	0	4	0	299
SouthWest Gas									
Core	22	0	0	0	0	0	11.90	0	34.30
Noncore Commercial/Industrial	1.6	0	0	0	0	0	0.4	0	2
Total	26	0	0	0	0	0	12.30	0.000	36.30

(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)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
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	6,388	1,407	7,795
2016	07/28/2016	2,867	3,136	6,003	1,356	7,359
2017	08/28/2017	2,602	3,484	6,086	1,416	7,502

Estimated California Highest Winter Sendout (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
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	7,662	1,311	8,973
2016	02/02/2016	3,397	3,838	7,235	1,285	8,520
2017	12/21/2017	3,665	3,456	7,121	1,259	8,380

Notes:
(1) PG&E Pipe Ranger.
(2) SoCalGas Envoy.
(3) Source: Provided by the CEC. Data are from DOGGR, Monthly Oil and Gas Production and Injection Report, Lipmann Monthly Pipeline Reports. Nonutility Demand is equal to Kern-Mojave and California monthly average total flows less PG&E and SoCal Gas peak day supply from Kern-Mojave and California in-state production.

PG&E and SoCalGas sendouts are reported for the day on which the Utility Total sendout is maximum for the respective seasons each year. For each calendar year, Winter months are Jan, Feb, Mar, Nov and Dec; while Summer months are Apr, May, Jun, July, August, September and October.

2018 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

Pacific Gas and Electric Company (PG&E) owns and operates an integrated natural gas transmission, storage, and distribution system that includes most of northern and central California. As of December 31, 2017, PG&E's natural gas system consisted of approximately 42,800 miles of distribution pipelines, over 6,400 miles of backbone and local transmission pipelines, and various storage facilities. PG&E's backbone transmission system, composed primarily of Lines 300, 400, and 401, is used to transport gas from the company's interconnection with interstate pipelines, other local distribution companies, and California gas fields to PG&E's local transmission and distribution systems.

PG&E provides natural gas procurement, transportation, and storage services to approximately 4.2 million residential customers and over 200,000 commercial and industrial customers. 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.

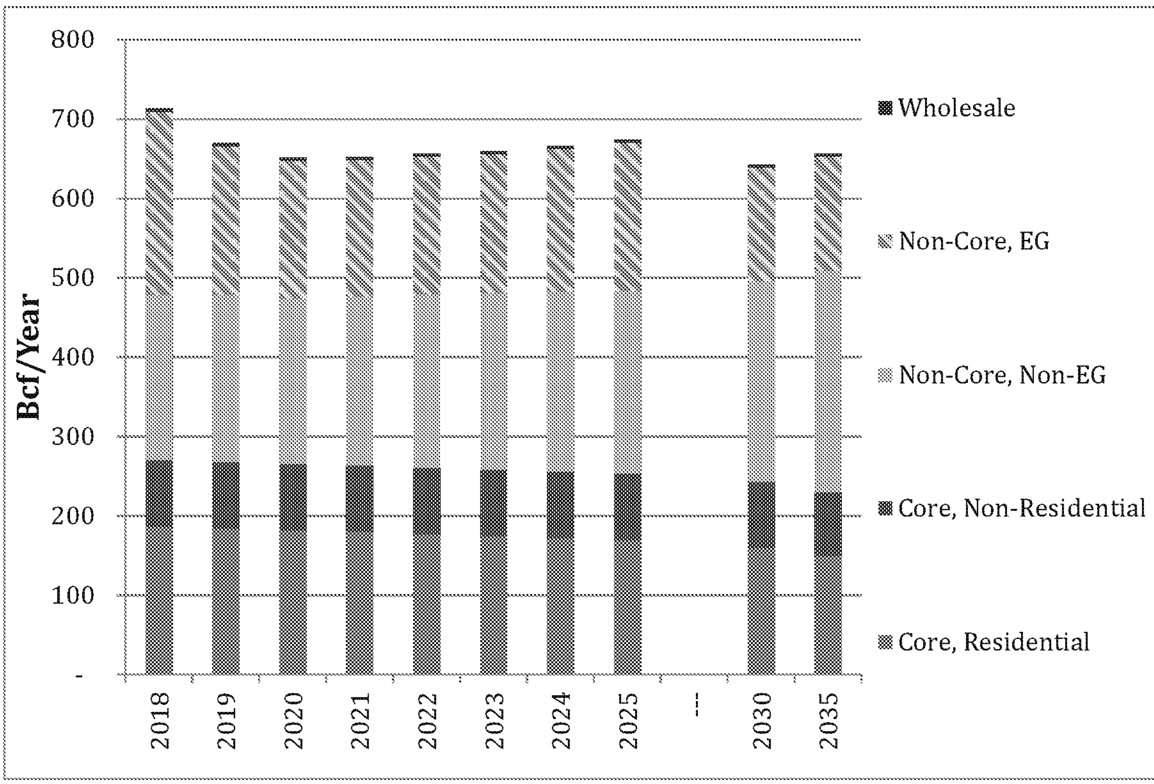
The forecast in this report covers the years 2018 through 2035. However, as a matter of convenience, the tabular data at the end of the section show only the years 2018 through 2025, and the years 2030, and 2035.

GAS DEMAND

OVERVIEW

PG&E's 2018 California Gas Report (CGR) average-year demand forecast projects total on-system demand to decline at annual average rate of 0.4 percent between 2018 and 2035. This is due to the combination of a 0.9 percent annual decline in the core market and an annual decline of 0.2 percent in the noncore market. By comparison, the 2016 CGR estimated a declining annual average rate of 0.6 percent per year, based on a 0.3 percent annual decline in the core market and a 0.9 percent annual decline 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 2016 CGR primarily due to increasing emphasis on Energy Efficiency (EE) and electrification.

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 1.7 percent per year from 2019 through 2035. 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 2018 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 weather conditions that have an approximate 1-in-10 likelihood of occurrence of cold temperature conditions and a vintage approach by considering a year for dry hydro conditions. Dry hydro conditions are represented by the November 2000 through October 2001 hydroelectric generation for both Northern California and the Pacific Northwest.

The California Public Utilities Commission approved PG&E's plan to retire the Diablo Canyon Power Plant units at the end of their current licenses in 2024 and 2025. Both forecasts reflect these retirements.

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. Although the near-term temperatures of this scenario differ little from long-term averages, the years beyond 2018 begin to show the effects of a warming climate. For example, in 2022, total December/January heating degree days are only 2 percent below the 20-year average. By 2035, however, the impact is more significant, with the difference at 9 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 have a 1-in-10 likelihood of occurrence and have the same hydro conditions as those that prevailed during October 2000-September 2001.

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° or 15° 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° 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 2018 CGR's high-demand scenario, as noted above, PG&E used the 1999 and 2015 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. Natural gas price forecasts are inherently uncertain and impact these market sectors that are sensitive to price. In late 2017, PG&E filed its 2019 Gas Transmission & Storage (GT&S) Rate Case, which significantly affects gas transmission and end use rates. PG&E assumed rates based on both its current rates and its filed request that are expected to be effective in 2019. This electric generation gas throughput projection is driven higher from lower gas prices relative to the filed 2019 GT&S Rate Case EG gas throughput forecast.

MARKET SECTORS

Residential

Households in the PG&E service area are forecast to grow 0.86 percent annually from 2018-2035. 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 from 2009 through 2011 due to cold winters, has fallen on average 1.1 percent per year since 2004. Total residential demand is expected to decrease despite household growth due to continuing upgrades in appliance and building efficiencies, conversion to electric appliances, 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 2018-2035. 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 over the forecast horizon due to continuing EE and electrification efforts as well as warmer temperatures. Over the next 18 years commercial sales are expected to decline at 0.8 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 2016 and 2017 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 at 1.7 percent annually over the next 18 years.[1]

Electric Generation

This sector includes cogeneration and power plants. Forecasts for this sector are subject to greater uncertainty due to the future gas price environment; 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 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, from 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,

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[1] PG&E notes that the emerging California GHG reduction discussed in the Market Sector section are not yet reflected in PG&E's econometric models. It is probable that once these policy assumptions are incorporated there would be a downward trend in PG&E's long-term throughput forecast. For details about PG&E's current forecast models, please see work papers.

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 2018-2035 uses the mid-case electricity demand forecast from the California Energy Commission's (CEC) 2017 Integrated Energy Policy Report. The forecast assumes that renewable energy generation will provide 33 percent of the state's retail sales in 2020, 40 percent by 2024, and 50 percent by 2030. Additionally, PG&E included the impact of electric battery storage at the mandated level of 580 MW by 2020. The impact of battery storage may limit gas throughput from peaking electric generators. 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 171 million cubic feet per day (MMcf/d), and the average load is about 117 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 87 MMcf/d of capacity.

POLICIES IMPACTING FUTURE GAS DEMAND

Renewable Electric Generation

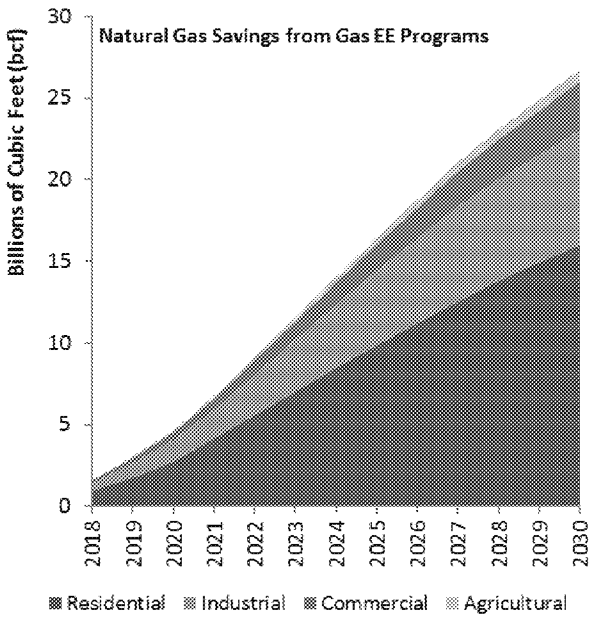
PG&E expects increased renewable electric generation due to current renewable portfolios standards and the Integrated Resource Planning Proceeding at the CPUC. While this increase in renewable generation will put downward pressure on the demand for generation from natural gas-fueled resources, the intermittent nature of some renewable generation (e.g., wind or solar power) will 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.

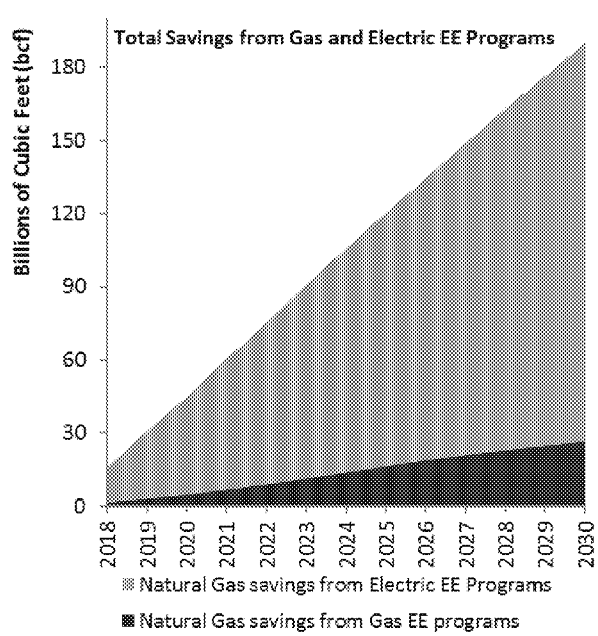
Energy Efficiency Programs

PG&E engages in many Energy Efficiency and conservation (EE) 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 Additional Achievable Energy Efficiency (AAEE) forecast from the CEC's California Energy Demand 2018-2030 Revised

Forecast.[2] The savings below include any interactive effects that may result from efficiency improvements of electric end uses; for example, efficiency improvements in lighting and electric appliances may lead to increased natural gas heating load. The graph on the right includes reductions in natural gas demand for electric generation that may occur due to lower electric demand.





Details of PG&E's 2016 and 2017 Energy Efficiency Portfolio can be found in California Public Utilities Commission (Commission or CPUC) Decision (D.) 15-10-028, which authorized programs and budgets for 2016, and D.17-09-025, which authorized, among other things, extending these programs into 2018.

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.[3] The CEC issued its final report doubling targets in

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[2] The California Energy Demand and the AAEE results are on the CEC's website: http://www.energy.ca.gov/2017_energypolicy/documents/

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

October 2017,[4] and the CPUC incorporated higher levels of EE savings in their EE goals for 2018 and beyond,[5] which was partially due to the adoption of an interim GHG adder in the Integrated Distributed Energy Resources (IDER) proceeding.[6] The CEC's final report suggests the state is on a path to meet or exceed the natural gas SB350 doubling goal after accounting for IOU programs, POU programs, and codes and standards – see figure 2 from the CEC report cited above.

[4] Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. 2017. Senate Bill 350: Doubling Energy Efficiency Savings by 2030. California Energy Commission. Publication Number: CEC-400-2017-010-CMF.
[5] D.17-09-025, Decision Adopting Energy Efficiency Goals for 2018-2030, CPUC, September, 28, 2017.
[6] D.17-08-022. Decision Adopting Interim Greenhouse Gas Adder, CPUC, August, 24, 2017.

GAS SUPPLY, CAPACITY, AND STORAGE

OVERVIEW

PG&E's natural gas market continues to provide all customers with direct access to gas supplies, intra- and inter-state transportation, and related services. Customers today have more options for supply sourcing than at any time in history.

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, the vast majority of the gas supplies that serve PG&E customers are sourced from out of state with only a small portion originating from California reservoirs, whose output continues to decline. Due to the development of shale gas resources across the U.S., supplies to California are ample, with several interstate pipelines available to deliver it.

GAS SUPPLY

California-Sourced Gas

Northern California-sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2017, PG&E's customers obtained on average 36 MMcf/d of California sourced gas out of an average of 2,517 MMcf/d total system demand.

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.

Renewable Natural Gas (RNG)

At the time of the filing of the *2018 California Gas Report*, none of the gas supplies purchased for the core market originate from RNG. However, PG&E is seeking Commission authority to participate in a program which will allow the utility to begin adding RNG to its supply portfolio, limited initially for its compressed natural gas (CNG) fueling stations.

Storage

In addition to storage services offered by PG&E, there are four independent storage providers (ISPs) in Northern California—Wild Goose Storage, LLC; Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. As of 2016, these facilities had an estimated total working gas capacity of roughly 236 billion cubic feet. In its 2019 GT&S Rate Case, PG&E has proposed to exit the commercial gas storage market and shift its storage services to a reliability-only model. As part of this proposal, PG&E would reduce its core storage capacity, and allow the ISPs to offer market-based storage services to core customers.

INTERSTATE PIPELINE CAPACITY

California utilities and end-users benefit from 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 1,000 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 2,065 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 associated gas production in the Permian Basin and eastern shale plays (e.g., the Haynesville in east Texas and west Louisiana and the Marcellus and Utica 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 Exports

With the rapid development of prolific, low-cost shale gas resources over the past ten years, U.S. imports of liquefied natural gas (LNG) have declined to insignificant levels. The United States is now a net exporter of LNG with exports reaching 1.94 Bcf/d in 2017.[7]

On the West Coast, the Jordan Cove Project in Oregon has resubmitted a revised application to FERC to site, construct, and operate a LNG export facility, and a companion 229-mile, 36-inch diameter natural gas pipeline with interconnections with the Ruby pipeline and the Gas Transmission Northwest pipeline. Additional work lies ahead to resolve issues of commercial contracts, FERC and local approvals, financing, and new pipelines, before plans can progress. Since several other LNG export facilities in the U.S. are already in operation, several others in the U.S. and Canada are further along in development, and a significant number of LNG export projects overseas have come on line, it is unclear whether the Jordan Cove Project will be approved.

If the Jordan Cove LNG export project is eventually built, it could directly compete for gas supplies available to Northern California.

U.S. Natural Gas Pipeline Exports to Mexico

With low domestic natural gas prices compared to world markets, the United States became a net exporter of natural gas in 2017[8]. 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 4.3 Bcf/d in 2017[9], and are projected to reach 7.0 Bcf/d by 2025[10]. 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 11.2 Bcf/d of export capacity as of 2017, with an additional 3.2 Bcf/d expected to come online in 2018.

Most of the exports to Mexico are supplied through Texas from the Permian Basin and Western Gulf basins. Production growth in the Permian Basin, combined with new pipeline capacity, will enable growing exports to Mexico.

[7] EIA, U.S. liquefied natural gas exports quadrupled in 2017, https://www.eia.gov/todayinenergy/detail.php?id=35512
[8] EIA, The United States exported more natural gas than it imported in 2017. https://www.eia.gove/todayinenergy/detail.php?id=35392
[9] EIA, U.S. Natural Gas Pipeline Exports to Mexico, https://www.eia.gov/dnav/ng/hist/n9132mx2A.htm
[10] EIA, Annual Energy Outlook 2018 – Natural Gas Imports and Exports Table (Reference Case)

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. and the Permian basin have become the main source of supply growth, resulting in record U.S. gas production in 2017. For California, one significant effect of the development of vast production in the eastern U.S. is the downward pressure on the price of Canadian supplies, which have been displaced in the eastern U.S. by Appalachian supplies. While some traditional supply basins have shown some modest declines in production, the Marcellus and Utica plays have grown from roughly 10 percent of U.S. production in 2012 to about 30 percent in 2017, 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 ISPs in addition to the long-standing PG&E fields at McDonald Island, Pleasant Creek, and Los Medanos. ISPs 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, LLC, 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 and more recently during the winter of 2017-2018; increased storage withdrawals allowed pipeline supplies to meet thermal generation needs outside of California.

In response to proposed federal and state gas storage safety regulations that will drive significant retrofit and ongoing operational costs, as well as other cost drivers related to its smaller storage facilities, PG&E has proposed in its 2019 GT&S Rate Case before the CPUC to exit the commercial gas storage market and shift its storage services to a reliability-only model. As part of this proposal, PG&E would reduce its core storage capacity, and allow ISPs to offer market-based storage services to the core. If PG&E's proposal is approved, Northern California would remain amply supplied with commercial storage from the ISPs.

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 March 15, 2018, PG&E filed its 2018 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 of 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 the following reports to the CPUC: (1) quarterly Transmission Pipeline Compliance Report; (2) semi-annual Gas Transmission & Storage Safety Report; and (3) annual Gas Distribution Pipeline Safety Report. 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 2017 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. Lloyd's Register performs annual compliance assessments of PG&E against API 1173. In November 2017, Lloyd's Register assessment found PG&E to be in compliance with the requirements of API 1173.

- **Process Safety:** PG&E's commitment in implementing process safety led to certification to chemical industry standard RC 14001® (Responsible Care® and International Standards Organization (ISO) 14001) in 2016, which we successfully maintained in 2017.

- **In-Line Inspection:** In 2017, PG&E increased "piggability" to roughly 28 percent of the approximately 6,600 miles of the Gas Transmission system, and used in-line inspection tools to inspect over 308 miles of transmission pipeline. Approximately two-thirds of PG&E's transmission system (about 4,100 miles) has been or will be upgraded to accept in-line inspection tools by the end of 2026.

- **Emergency Response Time:** PG&E exceeded its target and achieved first quartile performance with a 20.4 minute average response time to gas odor calls, responding to 137,927 gas odor calls in 2017.

- **Third Party Dig-In:** PG&E set a 2017 target of 1.92 dig-ins per 1,000 Underground Service Alert (USA) tickets. In 2017, PG&E experienced 1.89 dig-ins per 1,000 tickets and out-performed its target.

- **Community Pipeline Safety Initiative**: A multi-year program designed to enhance safety by improving access to pipeline right-of-way. 2017 goals included clearing 258 miles of trees and brush (vegetation miles) and 30 miles of structures located too close to gas pipelines and which pose an emergency access or safety concern. As of December 31, 2017, PG&E addressed approximately 93 percent of vegetation miles and 98 percent of structure miles.

Storage Safety

Aliso Canyon injections resumed in July 2017, however, the CPUC has limited the maximum allowable inventory and put in place a protocol for withdrawals from the field. This decreased storage capacity along with recent pipeline outages in Southern California has resulted in increased price volatility and the frequency of OFO's in Southern California. Such volatility can 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 OFO's.

Emergency regulations implemented by DOGGR on February 5, 2016, 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.

DOGGR is promulgating new regulations to replace the emergency regulations based on legislation introduced and passed on storage safety. Implementation of the proposed regulations is anticipated to occur October 1, 2018, and will have an impact on the available withdrawal capacity as operators retrofit the storage wells to meet the requirements to mitigate a single point of failure (i.e. install tubing and packer). PG&E in its 2019 GT&S Rate Case filing has included the impact of the proposed regulations, as well as into its Natural Gas Storage Strategy, which includes the decommissioning or sale of the Pleasant Creek and Los Medanos storage facilities.

Core Gas Aggregation Program

In June 2016, the Commission issued D.16-06-056, which among other items, approved the CTA Self-Managed Storage program whereby procurement of storage services for CTAs will transition from PG&E to the CTAs over a seven-year period commencing April 1, 2018. In February 2018, the Commission issued Resolution G-3537 (approving PG&E's Advice Letter 3884-

G), which grants modifications as filed to the CTA Self-Managed Storage under D.16-06-056, limited to the first two years of the seven-year phase-in specified in D.16-06-056. It requires PG&E to assess the possibility of using alternate resources for CTA Self-Managed Storage from the third year on. Commission staff will conduct workshops in 2018-2019 to assess phase-in and implications for system and core reliability.

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 had been under review by the U.S. Court of Appeals. The last of these requests was addressed in FERC Opinion 528-B issued May 3, 2018. In this Opinion, FERC mandated that El Paso file revised tariff records and a plan for the return of excess accruals to reflect the new federal corporate income tax rate in effect on January 1, 2018.

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, resolved non-rate issues in a FERC Order dated June 30, 2016, 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.

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

There are currently no significant regulatory updates.

OTHER REGULATORY MATTERS

Greenhouse Gas Legislation

During the forecast horizon covered by this CGR, there are many policies that may significantly impact the future trajectory of natural gas demand. Executive Order S-3-05 set a goal to reduce annual GHG emissions to 1990 levels by 2020 and to 80 percent below 1990 levels by 2050. The Global Warming Solutions Act of 2006 (Assembly Bill 32) established the 2020 GHG emission reduction goal into law, and was taken one step further with the passage of Senate Bill 32, calling for a 40 percent reduction in GHG emissions below 1990 levels by 2030. These goals are being accomplished by a suite of complimentary policies as well as the cap-and-trade program which was extended out to 2030 with the passage of Assembly Bill 398.

While GHG legislation was not explicitly incorporated into the forecast, gas rate forecasts do include GHG price projections,[11] and complimentary policies which aim to achieve the GHG emissions reductions goals were incorporated (see below for further discussion of these policies). Additionally, any trends embedded in historical demand patterns due to GHG goals and/or the compliance entities' participation in the cap-and-trade market would be translated into the forecast via projections of historical trends, but not explicitly incorporated.

Given utilization of fossil natural gas emits greenhouse gases, PG&E believes that renewable natural gas (RNG) must be part of the solution to reach California's GHG reduction goals. The injection of RNG (biomethane) into the pipeline system is a developing supply source. PG&E is very supportive of the State's GHG reduction goals and RNG policies, and is currently working with industry stakeholders to implement recent legislation designed to facilitate this growing industry. In the near term, PG&E anticipates sourcing RNG from dairies, landfills, and waste water treatment plants for injection into the pipeline system, and is working toward the

[11] California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) mid-case forecast to 2030. Extrapolated to 2035 using the real adder to the floor price (5 percent rate).

integration of innovative technologies to further enhance supply sources that will help the State to achieve its GHG and RNG policy goals.

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.

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

In March 2018, PG&E Gas Operations reported to the U.S. Environmental Protection Agency (EPA) GHG emissions in accordance with 40 Code of Federal Regulations Part 98 in four primary categories: GHG emissions in reporting year 2017 resulting from combustion at PG&E's seven compressor stations, where the annual emissions exceed 25,000 metric tons of CO2 equivalent (mtCO2e); the GHG emissions resulting from combustion of all customers except customers consuming more than 460 MMscf; certain vented and fugitive emissions from the seven compressor stations and natural gas distribution system; and GHG emissions from transmission pipeline blowdowns.

In April 2018, PG&E Gas Operations reported to the California Air Resources Board (CARB) GHG emissions approximately 38 million mtCO2e in three primary categories for reporting year 2017: GHG emissions resulting from combustion at seven compressor stations and one underground gas storage facility, where the annual emissions exceed 10,000 mtCO2e; 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.

Both the seven compressor stations obligation and PG&E's natural gas supplier obligation subject to the CARB mandatory reporting are subject to the CARB Cap-and-Trade Program. In 2017, CARB estimated that PG&E's responsibility for compliance obligations of GHG emissions as a natural gas supplier were approximately 16.7 million mtCO2e for reporting year 2016. CARB will issue the final 2016 PG&E's compliance obligations of GHG emissions as a natural gas supplier in October 2018.

In June 2018, PG&E filed the 2017 Annual Natural Gas Leakage Abatement Report and reported 3.2 billion standard cubic feet (Bscf) of methane emissions from intentional and unintentional releases. The annual report is a partial fulfillment of Rulemaking (R.) 15-01-008 to adopt rules and best practices aiming to reduce methane emissions from the Natural Gas System in application of SB 1371.

In addition, PG&E filed its first two-year Leak Abatement Compliance Plan in March 2018. This plan addresses the 26 best practices outlined in the Leak Abatement OIR D.17-06-015. It emphasizes minimizing methane emissions through changes to policies and procedures, personnel training, leak detection, leak repair and leak prevention. PG&E's plan includes increased frequency of leak surveys for its distribution pipelines to a 3-year cycle and a new program to accelerate the detection and repair of its distribution system largest leaks.

Finally, PG&E is an active member and founding partner in the voluntary EPA Natural Gas STAR and Methane Challenge Programs, respectively, where annual reports are submitted to the EPA showcasing PG&E's efforts and best practices to reduce methane emissions. PG&E has committed to reduce methane emissions in five categories under the Methane Challenge Program by 2020: excavation damages; pneumatic controllers, transmission pipeline blowdowns between compressor stations; venting of centrifugal compressors; and rod packing venting of reciprocating compressors.

California State Senate Bill 350

On October 7, 2015, Governor Brown signed into law SB 350 which 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. On February 8, 2018, the CPUC adopted an SB350 implementation process through D. 18-02-018. The decision recommends a statewide GHG reduction 2030 target for the electric sector of 42 million metric tons (MMT), establishes a two-year planning cycle for the IRP, and adopts a GHG abatement price to be used for planning purposes. Since the first IRP has not been completed, the Northern California gas demand forecasts do not consider IRP results. However, as the IRP process develops and matures, we anticipate IRP results will be considered in the development of future forecasts.

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 28.5 degree Fahrenheit system-weighted mean temperature across the PG&E gas system. The PG&E core demand forecast corresponding to a 28.5 degree Fahrenheit temperature is estimated to be approximately 2.9 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 served by pipeline and storage withdrawal capability during an APD event would be approximately 2.0 Bcf/d, with EG demand comprising between one-half to three-quarters 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 80 percent of PG&E's core gas usage. Core aggregators provide procurement services for the balance of PG&E's core customer usage 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 to serve it. PG&E's tariffs contain diversion and Emergency Flow Order non-compliance charges that are designed to induce the noncore market to curtail its use of gas, if required. However, with the opening of Ruby Pipeline in 2011 and the abundance of shale-based gas resources, California has access to ample gas supplies from many interstate pipeline interconnections and major supply sources. The possibility that cold weather in one producing basin might affect supply availability to PG&E to the degree that supply diversions could be required is much lower than it once might have been. Even during the cold weather event in December 2013, which was close to a 1 day in 10 year event, PG&E served all core load and virtually all noncore load. The very few noncore curtailments during that event were due to local transmission capacity constraints, not supply shortfalls, and did not affect EG. PG&E coordinates closely with CAISO to anticipate cold-weather events to avoid supply problems that could affect gas-fired generation and grid reliability. PG&E anticipates being able to serve a significant portion of noncore demand during an APD, but would do so only to the extent compatible with maintaining uninterrupted service to core customers.

As mentioned above, PG&E projects that in the near term, noncore demand served by pipeline and storage withdrawals, including gas-fired EG, on an APD would be approximately 2.0 Bcf/d. Additionally, the Independent Storage Providers, Wild Goose, Lodi, Gill Ranch, and Central Valley Gas facilities will support noncore demand in the event of an APD. While, 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, the sum of the foregoing facts means that the risk of grid reliability problems induced by gas supply shortfalls is less of a concern than in the early 2000s.

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

Line No.	APD Forecast	2018-19	2019-20[5]	2020-21[5]
1	**APD Core Demand[1]**	2,905	2,903	2,898
2	**Maximum Storage Withdrawal[2]**	4,211	3,157	3,157
3	**Maximum Firm Flowing Supply[3]**	3,103	3,103	3,103
4	**Total Resources To Meet Demands[4]**	5,200	4,317	4,317

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 28.5 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) The Maximum Storage Withdrawal capacity is based on PG&E information for its own storage fields and information the Independent Storage Providers reported to the U.S. Energy Information Administration for their storage fields (Report EIA-191).

(3) The Maximum Firm Flowing Supply includes firm Redwood and Baja capacities and nominal amounts of California gas production. These values are taken from PG&E's 2019 GT&S Rate Case application, filed 11/17/2017.

(4) The Total Resources to Meet Demands (Line No. 4) are less than the sum of Maximum Storage Withdrawal (Line No. 2) and Maximum Firm Flowing Supply (Line No. 3) because PG&E's system cannot simultaneously accommodate all flowing supplies and all storage withdrawals.

(5) The data shown in Line Nos. 2 and 4 for 2019-2020 and 2020-2021 assume implementation of the Natural Gas Storage Strategy (NGSS) as proposed in PG&E's 2019 GT&S Rate Case application, filed 11/17/2017.

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
2018	2,450	562	659	3,671
2019	2,449	563	545	3,557
2020	2,447	559	457	3,463
2021	2,445	578	457	3,480
2022	2,446	591	478	3,515
2023	2,446	603	483	3,532

Notes:
(1) Core demand calculated for 34.4-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
2018	383	688	734	1,805
2019	376	694	611	1,681
2020	369	684	504	1,557
2021	364	700	503	1,567
2022	358	714	541	1,613
2023	351	728	601	1,680

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

2018 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA
TABULAR DATA

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 2013-2017
MMCF/DAY

LINE		2013	2014	2015	2016	2017
	GAS SUPPLY TAKEN					
	CALIFORNIA SOURCE GAS					
1	Core Purchases	0	0	0	0	0
2	Customer Gas Transport & Exchange	57	49	37	33	29
3	Total California Source Gas	57	49	37	33	29
	OUT-OF-STATE GAS					
	Core Net Purchases					
6	Rocky Mountain Gas	223	202	219	194	178
7	U.S. Southwest Gas	207	126	147	124	84
8	Canadian Gas	330	328	345	318	319
	Customer Gas Transport					
10	Rocky Mountain Gas	774	763	689	445	461
11	U.S. Southwest Gas	180	398	360	298	304
12	Canadian Gas	432	428	798	837	832
13	Total Out-of-State Gas	2,146	2,247	2,558	2,217	2,178
14	STORAGE WITHDRAWAL(2)	395	344	238	260	328
15	Total Gas Supply Taken	2,598	2,640	2,833	2,510	2,534
	GAS SENDOUT					
	CORE					
19	Residential	538	437	450	461	483
20	Commercial	229	207	209	214	220
21	NGV	6	7	8	8	7
22	Total Throughput-Core	774	651	667	683	710
	NONCORE					
24	Industrial	519	533	534	544	543
25	Electric Generation (1)	987	990	1,025	783	698
26	NGV	1	1	1	1	2
27	Total Throughput-Noncore	1,507	1,524	1,560	1,329	1,244
28	WHOLESALE	10	8	8	8	9
29	Total Throughput	2,291	2,183	2,235	2,020	1,963
30	OFF-SYSTEM DELIVERIES(4)			251	217	233
31	CALIFORNIA EXCHANGE GAS	2	0	1	1	1
32	STORAGE INJECTION(2)	267	425	291	231	294
33	SHRINKAGE Company Use / Unaccounted for	39	32	56	42	44
34	Total Gas Send Out	2,598	2,640	2,833	2,510	2,534
	TRANSPORTATION & EXCHANGE					
38	CORE ALL END USES	152	144	142	141	139
39	NONCORE INDUSTRIAL	519	533	534	544	543
40	ELECTRIC GENERATION	987	990	1025	783	698
41	SUBTOTAL/RETAIL	1,658	1,666	1,701	1,469	1,380
43	WHOLESALE/INTERNATIONAL	10	8	8	8	9
45	TOTAL TRANSPORTATION AND EXCHANGE	1,668	1,674	1,709	1,477	1,389
	CURTAILMENT/ALTERNATIVE FUEL BURNS					
48	Residential, Commercial, Industrial	0	0	0	0	0
49	Utility Electric Generation	0	0	0	0	0
50	TOTAL CURTAILMENT(3)	0	0	0	0	0

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 2013 and 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		2018	2019	2020	2021	2022	LINE
	FIRM CAPACITY AVAILABLE						
1	**California Source Gas**	36	36	36	36	36	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**	3,116	3,116	3,116	3,116	3,116	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	36	36	36	36	36	6
7	**Out of State Gas (via existing facilities)**	2,312	2,191	2,139	2,141	2,154	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,348	2,227	2,175	2,177	2,190	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,348	2,227	2,175	2,177	2,190	11
	REQUIREMENTS FORECAST BY END USE						
	Core						
12	Residential(4)	512	506	499	493	486	12
13	Commercial	222	222	221	221	220	13
14	NGV	7	8	9	9	10	14
15	**Total Core**	742	736	729	723	716	15
	Noncore						
16	Industrial	568	574	568	579	594	16
17	SMUD Electric Generation(5)	117	117	117	117	117	17
18	PG&E Electric Generation(6)	633	514	476	473	477	18
19	NGV	3	3	3	3	3	19
20	Wholesale	9	9	9	9	9	20
21	California Exchange Gas	1	1	1	1	1	21
22	**Total Noncore**	1,331	1,218	1,174	1,182	1,201	22
23	**Off-System Deliveries(7)**	233	233	233	233	233	23
	Shrinkage						
24	Company use and Unaccounted for	42	40	39	39	40	24
25	**TOTAL END USE**	2,348	2,227	2,175	2,177	2,190	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	148	147	147	146	145	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	568	574	568	579	594	27
28	ELECTRIC GENERATION	750	631	593	590	594	28
29	SUBTOTAL/RETAIL	1,466	1,352	1,307	1,315	1,334	29
30	WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,475	1,362	1,317	1,325	1,343	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		2023	2024	2025	2030	2035	LINE
	FIRM CAPACITY AVAILABLE						
1	**California Source Gas**	36	36	36	36	36	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**	3,116	3,116	3,116	3,116	3,116	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	36	36	36	36	36	6
7	**Out of State Gas (via existing facilities)**	2,162	2,180	2,204	2,116	2,154	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,198	2,216	2,240	2,152	2,190	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,198	2,216	2,240	2,152	2,190	11
	REQUIREMENTS FORECAST BY END USE						
	Core						
12	Residential(4)	479	472	465	439	410	12
13	Commercial	220	219	218	214	205	13
14	NGV	10	11	11	14	17	14
15	**Total Core**	709	701	695	667	632	15
	Noncore						
16	Industrial	608	619	629	690	761	16
17	SMUD Electric Generation(5)	117	117	117	117	117	17
18	PG&E Electric Generation(6)	479	494	513	394	394	18
19	NGV	3	3	3	3	3	19
20	Wholesale	9	9	9	9	9	20
21	California Exchange Gas	1	1	1	1	1	21
22	**Total Noncore**	1,217	1,242	1,272	1,213	1,284	22
23	**Off-System Deliveries(7)**	233	233	233	233	233	23
	Shrinkage						
24	Company use and Unaccounted for	40	40	40	39	41	24
25	**TOTAL END USE**	2,198	2,216	2,240	2,152	2,190	25
	TRANSPORTATION & EXCHANGE						
26	CORE ALL END USES	145	144	143	140	135	26
27	NONCORE COMMERCIAL/INDUSTRIAL	608	619	629	690	761	27
28	ELECTRIC GENERATION	596	611	630	511	511	28
29	SUBTOTAL/RETAIL	1,349	1,373	1,402	1,341	1,407	29
30	WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,358	1,382	1,411	1,349	1,416	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		2018	2019	2020	2021	2022	LINE
	FIRM CAPACITY AVAILABLE						
1	**California Source Gas**	36	36	36	36	36	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**	3,116	3,116	3,116	3,116	3,116	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	36	36	36	36	36	6
7	**Out of State Gas (via existing facilities)**	2,360	2,249	2,211	2,212	2,234	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,396	2,285	2,247	2,248	2,270	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,396	2,285	2,247	2,248	2,270	11
	REQUIREMENTS FORECAST BY END USE						
	Core						
12	Residential[(4)]	556	550	543	538	531	12
13	Commercial	232	232	232	231	231	13
14	NGV	7	8	9	9	10	14
15	**Total Core**	796	790	783	778	772	15
	Noncore						
16	Industrial	569	576	569	581	596	16
17	SMUD Electric Generation[(5)]	117	117	117	117	117	17
18	PG&E Electric Generation[(6)]	624	515	490	485	498	18
19	NGV	3	3	3	3	3	19
20	Wholesale	10	10	10	10	10	20
21	California Exchange Gas	1	1	1	1	1	21
22	**Total Noncore**	1,324	1,221	1,190	1,196	1,224	22
23	**Off-System Deliveries[(7)]**	233	233	233	233	233	23
	Shrinkage						
24	Company use and Unaccounted for	43	41	41	41	41	24
25	**TOTAL END USE**	2,396	2,285	2,247	2,248	2,270	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	156	156	155	155	154	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	569	576	569	581	596	27
28	ELECTRIC GENERATION	741	632	607	602	615	28
29	SUBTOTAL/RETAIL	1,466	1,363	1,332	1,337	1,365	29
30	WHOLESALE/INTERNATIONAL	10	10	10	10	10	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,477	1,373	1,342	1,347	1,375	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		2023	2024	2025	2030	2035	LINE
	FIRM CAPACITY AVAILABLE						
1	**California Source Gas**	36	36	36	36	36	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**	3,116	3,116	3,116	3,116	3,116	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	36	36	36	36	36	6
7	**Out of State Gas (via existing facilities)**	2,252	2,277	2,339	2,202	2,240	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,288	2,313	2,375	2,238	2,276	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,288	2,313	2,375	2,238	2,276	11
	REQUIREMENTS FORECAST BY END USE						
	Core						
12	Residential(4)	524	517	510	485	456	12
13	Commercial	230	230	229	224	216	13
14	NGV	10	11	11	14	17	14
15	**Total Core**	764	757	750	723	689	15
	Noncore						
16	Industrial	609	620	631	691	763	16
17	SMUD Electric Generation(5)	117	117	117	117	117	17
18	PG&E Electric Generation(6)	510	530	588	419	419	18
19	NGV	3	3	3	3	3	19
20	Wholesale	10	10	10	9	9	20
21	California Exchange Gas	1	1	1	1	1	21
22	**Total Noncore**	1,249	1,281	1,349	1,240	1,312	22
23	**Off-System Deliveries(7)**	233	233	233	233	233	23
	Shrinkage						
24	Company use and Unaccounted for	41	42	43	42	43	24
25	**TOTAL END USE**	2,288	2,313	2,375	2,238	2,276	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	154	153	152	149	144	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	609	620	631	691	763	27
28	ELECTRIC GENERATION	627	647	705	536	536	28
29	SUBTOTAL/RETAIL	1,390	1,420	1,487	1,376	1,442	29
30	WHOLESALE/INTERNATIONAL	10	10	10	9	9	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,399	1,430	1,497	1,385	1,452	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.

2018 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.

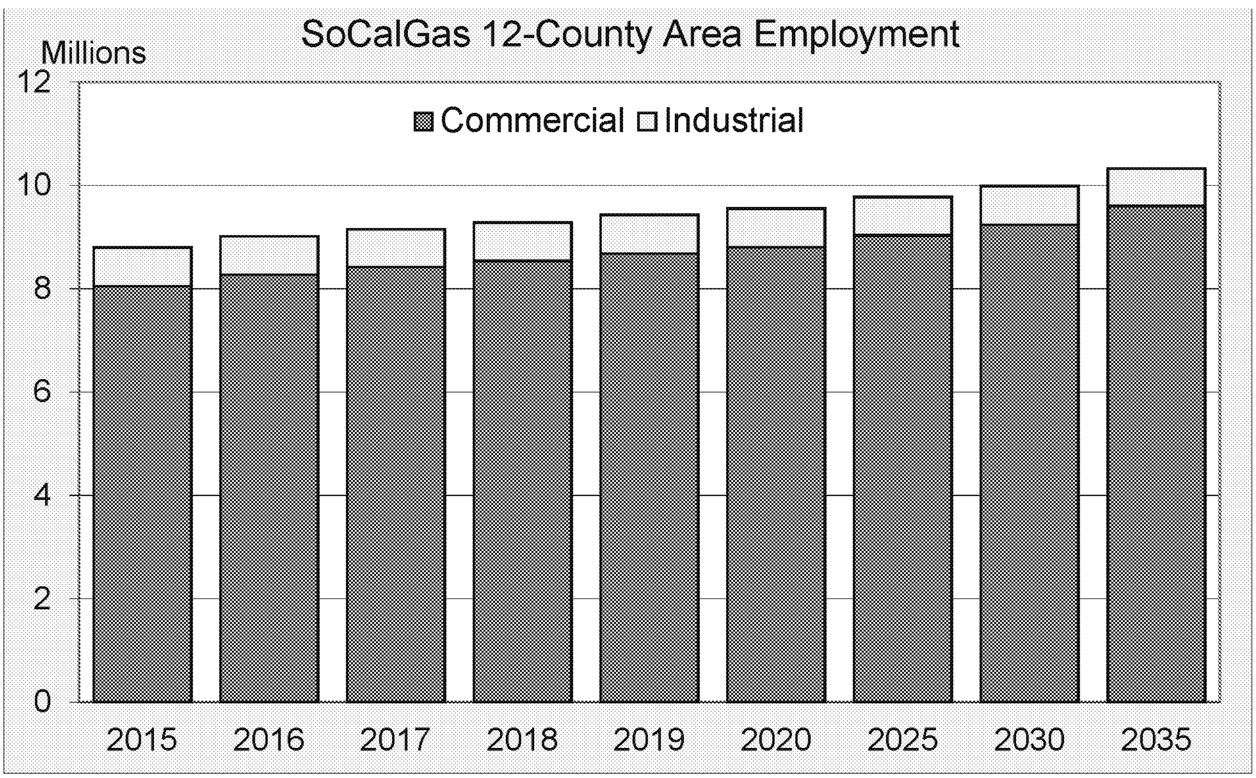
This report covers an 18-year demand and forecast period, from 2018 through 2035; only the consecutive years 2018 through 2022 and the point years 2023, 2024, 2025, 2030, and 2035 are shown in the tabular data in the next sections. These single point forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

The Southern California section of the *2018 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

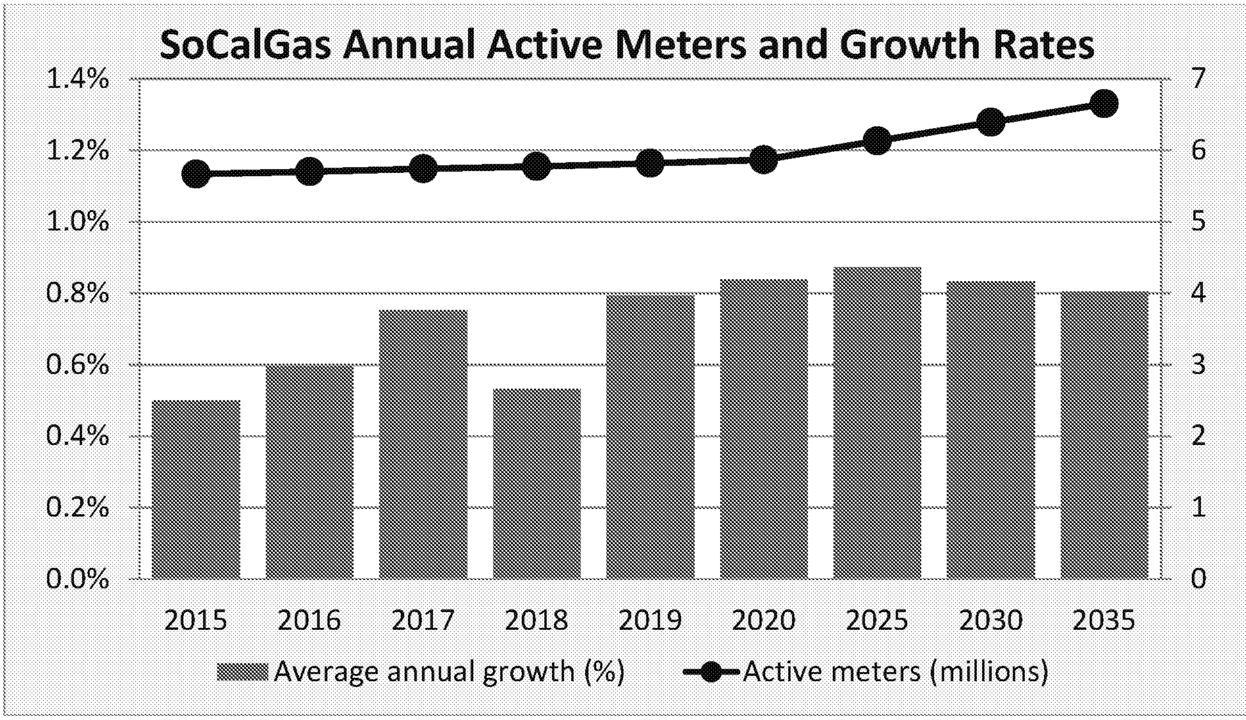
The gas demand projections are in large part determined by the long-term economic outlook for the SoCalGas service territory. As of mid-2018, southern California's economy is enjoying relatively strong growth after recovering from the 2007-to-2011 slump. Overall area jobs are expected to average modest 0.75 percent annual growth from 2018 through 2025. During the same period, local manufacturing and mining industrial employment are projected to grow by 0.1 percent per year, with commercial jobs growing about 0.8 percent annually. Construction jobs should remain robust, averaging 3.4 percent annual growth from 2018 through 2025. Other sectors with expected strong growth in the same period include wood products (jobs growing 2.8 percent per year) and professional and business services (2.4 percent per year).



Longer term, SoCalGas service-area employment is expected to increase fairly slowly as the area population's average age gradually increases--part of a national demographic trend of aging and retiring Baby Boomers. From 2018 through 2035, total area job growth should average 0.6 percent per year. Area industrial jobs are forecasted to shrink an average of 0.2 percent per year through 2035; we expect the industrial share of total employment to fall from 8.0 percent in 2018 to

7.0 percent by 2035. Commercial jobs are expected to grow an average of 0.7 percent annually from 2018 through 2035.

Since 2011, SoCalGas' service area housing market has gradually recovered from its prior drastic downturn. Recent years have seen more robust home building and meter hookups, with SoCalGas' annual active meters growing by 42,660 (0.75 percent) in 2017. SoCalGas expects active meters to maintain moderate growth, growing an average of 0.84 percent per year from 2018 through 2035.

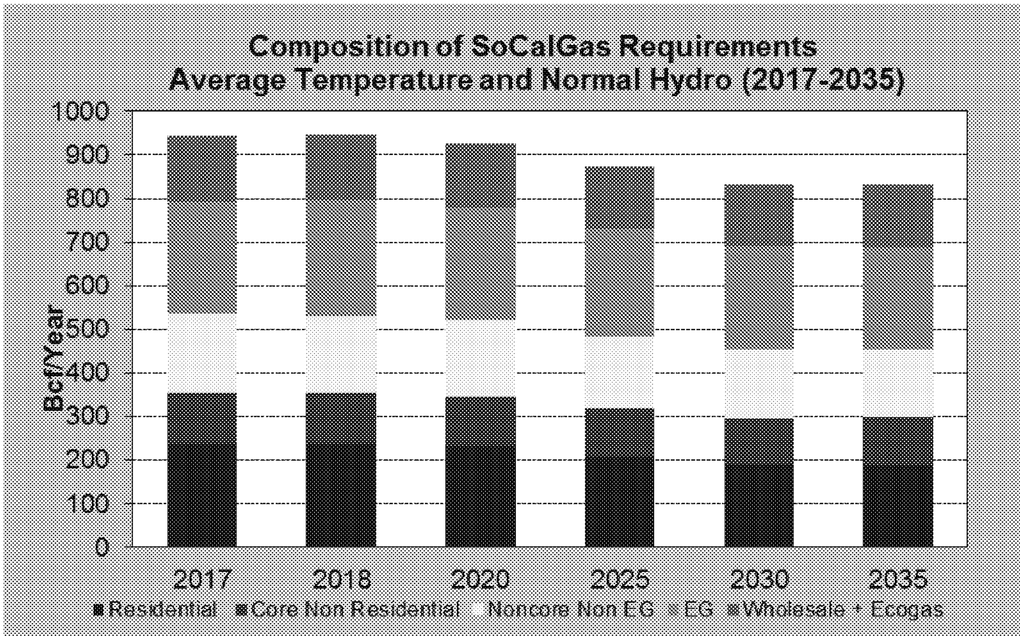


GAS DEMAND (REQUIREMENTS)

OVERVIEW

SoCalGas projects total gas demand to decline at an annual rate of 0.74 percent from 2018 to 2035. The decline in throughput demand is due to modest economic growth, CPUC-mandated energy efficiency (EE) standards and programs, tighter standards created by revised Title 24 Codes and Standards, renewable electricity goals, the decline in commercial and industrial demand, and conservation savings linked to Advanced Metering Infrastructure (AMI). By comparison, the 2016 CGR projected an annual decline in demand of 0.7 percent over the forecast horizon. The difference between the two forecasts is caused primarily by stricter goals on the energy efficiency portfolio, which includes the revised updates to the Title 24 codes and standards as well as SB350 goals that are designed to double EE savings by the year 2030.

From 2018 to 2035, residential demand is expected to decline from 236 Bcf to 186 Bcf. The decline is 1.4 percent per year, on average. The decline is due to declining use per meter-- primarily driven by very aggressive energy efficiency goals and associated programs-- offsetting new meter growth. The core, non-residential markets are expected to decline at an average annual rate of 0.28 percent or from 117 Bcf in 2018 to 112 Bcf by 2035. The noncore, non-EG markets are expected to decline from 177 Bcf in 2018 to 156 Bcf by 2035. The annual rate of decline is approximately 0.7 percent 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 large cogeneration and non-cogeneration EG for a normal hydro year, is expected to decline from 268 Bcf in 2018 to 235 Bcf in 2035, a decrease of 0.8 percent per year.



The chart shows the composition of SoCalGas' throughput for the recorded year 2017 (with weather-sensitive market segments adjusted to average year heating degree day assumptions) and forecasts for the 2018 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 Corporation and Ecogas in Mexico.

ASSUMPTIONS REGARDING PROPOSED ELECTRIFICATION POLICY:

The proposed policies impact the State's ability to reduce GHG emissions generated by gas consumption in residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030.

SoCalGas and SDG&E are monitoring policy that is currently being proposed at the state legislature. The California utilities are *aware of* and are *involved in* the conversation regarding the long-term role of natural gas and renewable natural gas in the state's building stock. This topic will be examined in the 2018 IEPR at the CEC and legislation that has been introduced. However, since no bill has been signed into law requiring policy changes to the use of natural gas in either residential or non-residential buildings, ***this report and the ensuing gas demand forecasts do not consider those policy changes.*** Any updates to the building code or other requirements set forth under law or regulation will be incorporated in future updates of this report, as appropriate.

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 core demand variations due to temperature are likely to occur in the month of December. Heating Degree Day (HDD) differences between the two temperature 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 2018 CGR, average temperature year and cold year HDD totals are 1,320 and 1,594 respectively, on a calendar year basis for SoCalGas. For SDG&E, these values are 1,246 and 1,515 HDDs, respectively. The average year values were computed as the simple average of annual HDD's for the years 1998 through 2017.

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.

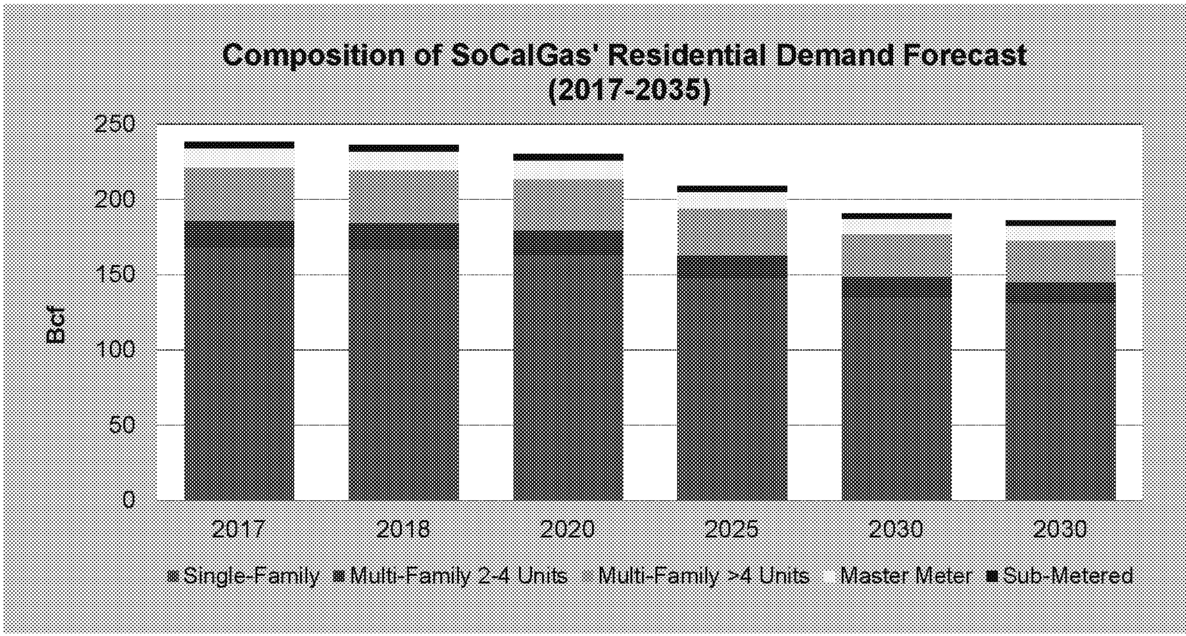
MARKET SECTORS

Residential

Residential demand adjusted for temperature totaled 238 Bcf in 2017 which is 1 Bcf lower than weather adjusted deliveries in 2015, the most recently completed year as of the previous CGR. The residential load is expected to decline on average by 1.4 percent per year from 238 Bcf in 2017 to 186 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. These energy efficiency savings are forecasted to lead to very large reductions in residential gas use equaling a total of 41 Bcf in year 2035.

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 5.54 million at the end of 2017. This amount reflects a 76,216 increase in active meters between 2015 at year end and 2017 at year end. The 2018 CGR shows that in 2017, single family and overall multi-family temperature adjusted average annual use per meter was 464 therms and 308 therms, respectively. Over the forecast period, the demand per meter is expected to decline at an average annual rate of 2.2 percent. The decline in use per meter for residential customers is explained by conservation, improved building and appliance standards, aggressive 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 the end of 2018. 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 is 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

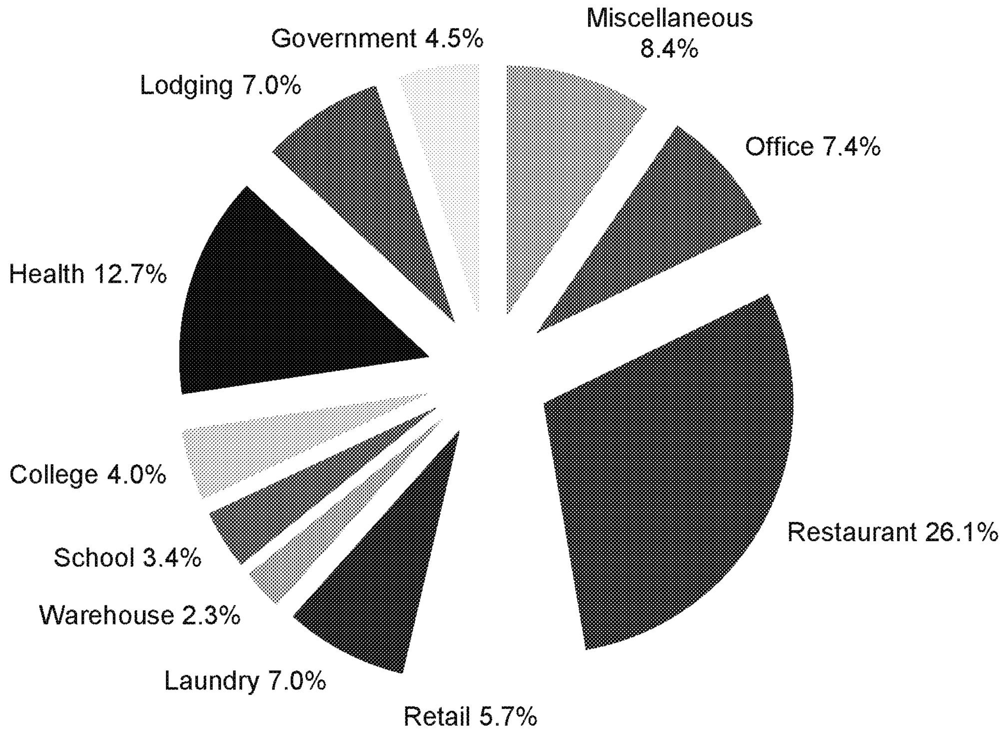


Commercial

The core commercial market demand is expected to decline over the forecast period. On a temperature-adjusted basis, the core commercial market demand in 2018 totaled 81.5 Bcf. By the year 2035, the load is anticipated to drop to approximately 61.5 Bcf. The average annual rate of decline from 2018 to 2035 is forecasted at 1.6 percent. The decline in gas usage is mainly the result of the impact of CPUC-authorized portfolio of energy efficiency programs and Title 24 codes building standards in this market.

Noncore commercial 2017 temperature-adjusted usage demand was 17.7 Bcf. From 2017 through 2035, demand in this market is expected to decline slightly at approximately 0.22 percent annually to 17.0 Bcf. Key factors of the decreasing trend are the CPUC-authorized energy efficiency programs, and the implementation of regulations to reduce CO_2 emissions by effectively increasing the gas price for noncore commercial customers.

Commercial Gas Demand by Business Type
Composition of Industry (2017)

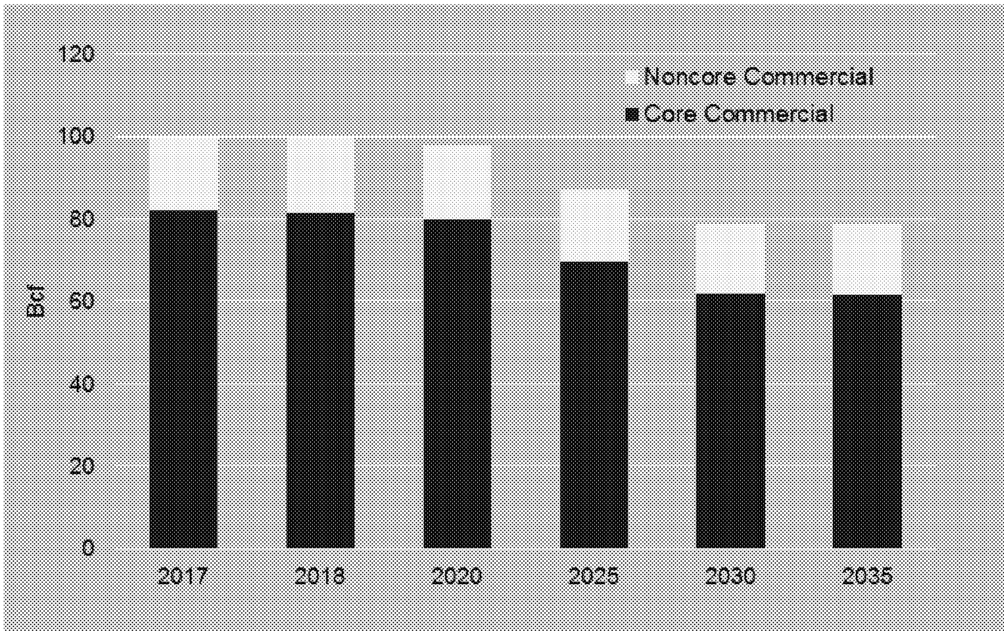


The commercial market consists of 14 business types identified by the customers' North American Industry Classification System (NAICS) codes. The restaurant business dominates this market with 26.1 percent of the usage in 2017, which represents usage in both core and noncore commercial market segments. The health industry is next largest with a share of 12.7 percent of the overall market based on 2017 natural gas consumption.

Annual Commercial Demand Forecast 2017-2035

Bcf/Year

Average Year Weather Design

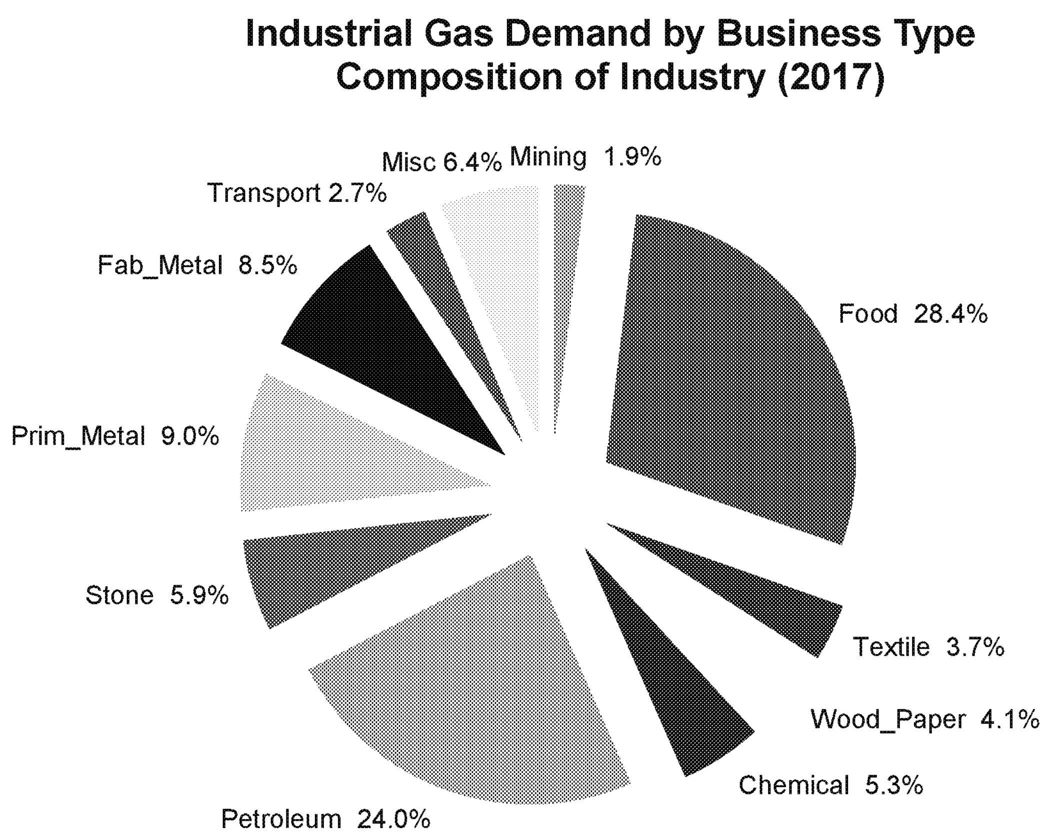


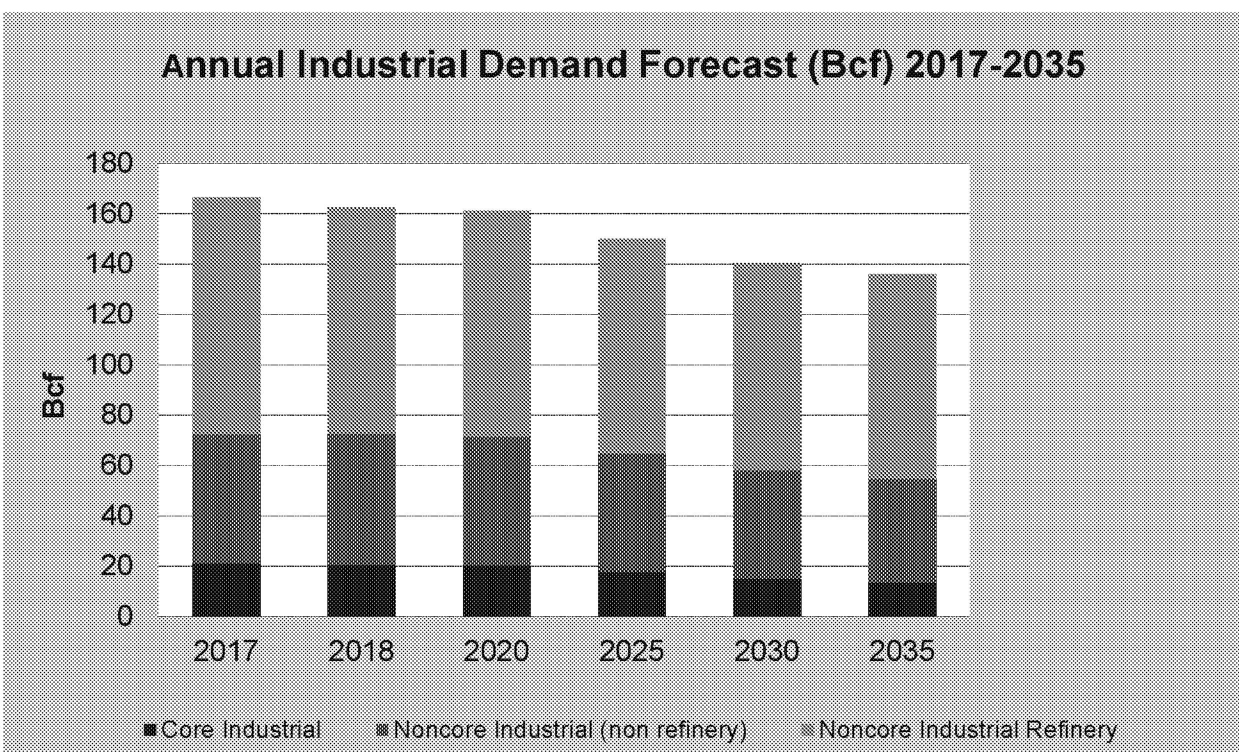
Industrial

Non-Refinery Industrial Demand

In 2017, temperature-adjusted core industrial demand was 21.2 Bcf. Core industrial market demand is projected to decrease by 2.5 percent per year from 12.2 Bcf in 2017 to 13.6 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 and CPUC-authorized energy efficiency programs.

The 2017 industrial gas demand served by SoCalGas is shown below. Food processing, with 28.4 percent of the total share, dominates this market. The graph below summarizes the core and noncore market by size of business unit type.


Industrial Gas Demand by Business Type
Composition of Industry (2017)
Misc 6.4%
Mining 1.9%
Transport 2.7%
Fab_Metal 8.5%
Food 28.4%
Prim_Metal 9.0%
Stone 5.9%
Textile 3.7%
Wood_Paper 4.1%
Chemical 5.3%
Petroleum 24.0%

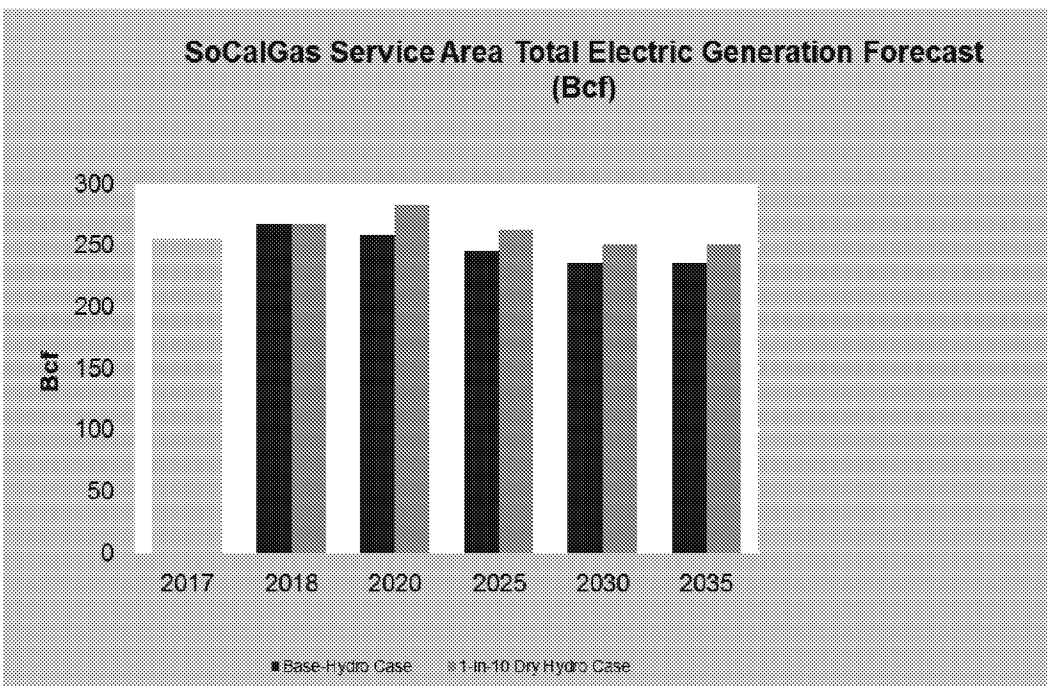

Annual Industrial Demand Forecast (Bcf) 2017-2035
180
160
140
120
100
80
60
40
20
0
Bcf
2017
2018
2020
2025
2030
2035
Core Industrial
Noncore Industrial (non refinery)
Noncore Industrial Refinery

Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at an annual rate of 1.22 percent from 51.3 Bcf in 2017 to 41.1 Bcf by 2035. The reduced demand is primarily due to the CPUC-authorized energy efficiency programs, the departure of customers within the City of Vernon to wholesale service by the City of Vernon, and the implementation of regulations to aggressively reduce CO2 emissions by increasing the gas 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 0.8 percent per year over the 2017-2035 forecast period, from 94.0 Bcf in 2017 to 81.3 Bcf in 2035. The decrease in 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 2018 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 percent 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 CEC's California Energy Demand 2018-2030 Revised/Final Forecast, dated January 2018. SoCalGas selected the Mid Energy Demand scenario with the Mid Additional Achievable Energy Efficiency (AAEE) and Additional Achievable Photovoltaic (AAPV) scenario. In their CEC forecast, the state-wide energy demand is lower than prior forecasts used in the 2016 CGR. However, for Southern California, the energy demand is slightly higher for the years 2020-2030 than prior CEC electric demand forecasts.

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 2017, gas demand in the small cogeneration market was 26.6 Bcf. Demand is expected to be about 27.6 Bcf in 2018 due to relatively low gas to electric fuel prices. After 2018, cogeneration demand is projected to decline modestly to 23.3 Bcf (an average of 0.99 percent/year) by the year 2035. The reduced demand is primarily due to the implementation of regulations to reduce CO_2 emissions by increasing the gas price for small cogeneration customers.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. This market is forecasted to decline modestly at about 0.41 percent per year, decreasing from 22.8 Bcf in 2017 to 21.2 Bcf in 2035. The decline is mainly due to higher gas costs stemming from California's GHG carbon fees.

Electric Generation, Including Large Cogen

Electric generation customers are comprised of utility electric generation (UEG) customers, various exempt wholesale generation customers (EWG) and large cogeneration customers where usage exceeds 20 MW. For the base case (average hydro condition), gas demand is forecasted to decrease from 214 Bcf in 2018 to 187 Bcf in 2030. The main factors for the decline are an increasing RPS target level, retirement of older gas-fired plants, and the addition of more efficient gas-fired plants. SB 350 raised the RPS target level from 33 percent to 50 percent by 2030. SoCalGas' forecast includes the addition of approximately 2,324 MW of new, local, gas-fired combined cycle and peaking generating resources in its service area by 2024. However, the forecast also assumes 7,415 MW of local, gas-fired plants will be retired during the same time period as a result of the state's once-through-cooling regulation and economics. 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 by 21 Bcf, on average.

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 390 MW was added starting in 2018. Storage capacity increases to 1,340 MW by 2024.

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 35 Bcf in 2017 to 39 Bcf in 2035. The change reflects a 0.53 percent average annual increase.

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 0.58 percent per year from 116 Bcf in 2017 to 105 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 decline slightly, from 9 Bcf in 2017 to 8 Bcf by 2035. Refer to City of Long Beach Municipal Gas & Oil Department for more information.

Southwest Gas Corporation

SoCalGas used the forecast prepared by Southwest Gas for this report. In 2017, SoCalGas expects to serve approximately 8 Bcf directly. The total load is expected to grow to approximately 11 Bcf in 2035. The annual expected rate of growth is 1.5 percent. 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 8.6 Bcf in 2017 and increases to 9.2 Bcf by 2035. The forecasted throughput includes Core and Non-Core customers and includes 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 9.9 Bcf/year in 2017 to 11.8 Bcf/year by 2035. Refer to Ecogas or IENova, Ecogas's parent company, for more information.

Enhanced Oil Recovery-Steam

In 2017, recorded gas deliveries to the EOR market were 17 Bcf. EOR demand is forecasted to remain at 17 Bcf throughout the forecast period. 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.

The EOR-related cogeneration demand is discussed in the Electric Generation section.

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, and the cost differential between petroleum (gasoline and diesel) and natural gas, which although shrunk over the past few years is beginning to increase, and is expected to reach a margin that will make NGVs much more economically attractive. At the end of 2017, there were 317 compressed natural gas (CNG) fueling stations delivering 14.04 Bcf of natural gas during the year. The NGV market is expected to grow 5.4 percent per year, on average, over the forecast horizon.

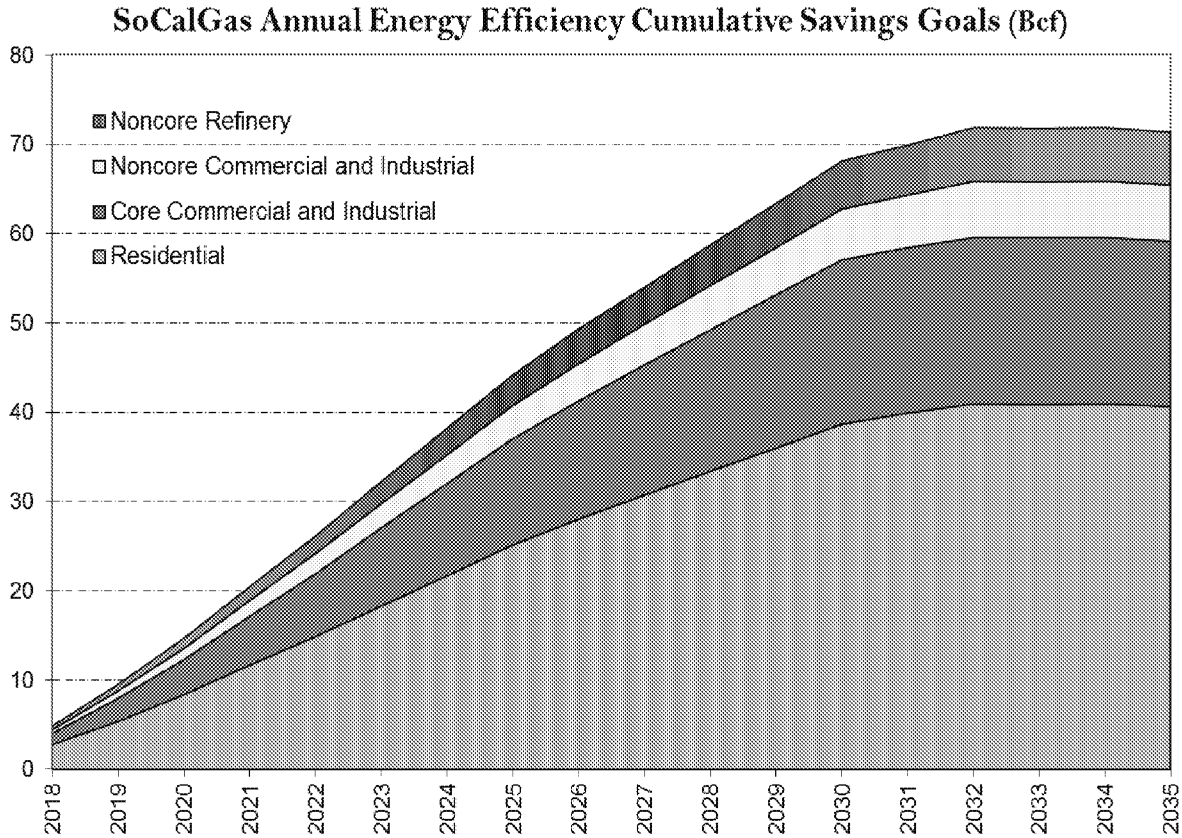
ENERGY EFFICIENCY PROGRAMS

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 2018-2030 are based on the levels authorized by the CPUC in D.17-09-025, which is based on the Energy Efficiency Potential and Goals Study for 2018 and Beyond.[12] This decision established energy savings goals for ratepayer-funded energy efficiency program portfolios for 2018 and beyond based on assessment of economic potential using the Total Resource Cost test, the 2016 update to the Avoided Cost Calculator and a greenhouse gas adder that reflects the California Air Resources Board Cap-and-Trade Allowance Price Containment Reserve Price. Forecasts from 2030-2035 are flat, given the uncertainty in energy efficiency potential that far into the future.

[12] Energy Efficiency Potential and Goals Study for 2018 and Beyond, Navigant Consulting, August 23, 2017.

Combined EE Portfolio of EE Programs and Codes and Standards:



The EE portfolio combines the EE customer programs goals and the Title 24 Codes and Standards, which were tightened in 2016. As of the time of the filing of this report, EE programs generated approximately 45 percent of EE savings and Title 24 Codes and Standards constituted approximately 55 percent of the EE portfolio. The Title 24 Standards are expected to get tighter in 2023, however. Tighter potential standards in 2023 were not built into the forecast because they have not been authorized.

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

SoCalGas and SDG&E 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 2013 through 2017 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 and SDG&E from California sources averaged 323 MMcf/day in 2017.

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 percent. 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 reduce the volume of Permian Basin supply available to Southern California in the future.

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 that supplying other markets 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.

RENEWABLE NATURAL GAS (RNG)

Biomethane, or renewable natural gas (RNG), plays an important and growing role in helping California meet its environmental goals. Currently, RNG is predominantly recovered from organic waste streams, including landfills, agricultural operations, and wastewater treatment facilities. Sourcing RNG from these resources not only provides GHG reductions for natural gas users, but also helps to better manage these waste streams.

To date, there is a significant amount of RNG being used in California natural gas vehicles (NGVs). The most recent data from the Low Carbon Fuel Standard (LCFS) program depicts that just over two-thirds of fuel delivered to NGVs in 2017 was RNG. Figure 1 below shows how RNG's role in this important program has grown over time. Since 2013, RNG has delivered more than 2.3 million metric tons of carbon reductions and displaced more than 300 million gallons of diesel fuel.13

[13] Low Carbon Fuel Standard Reporting Tool Quarterly Summaries: https://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm

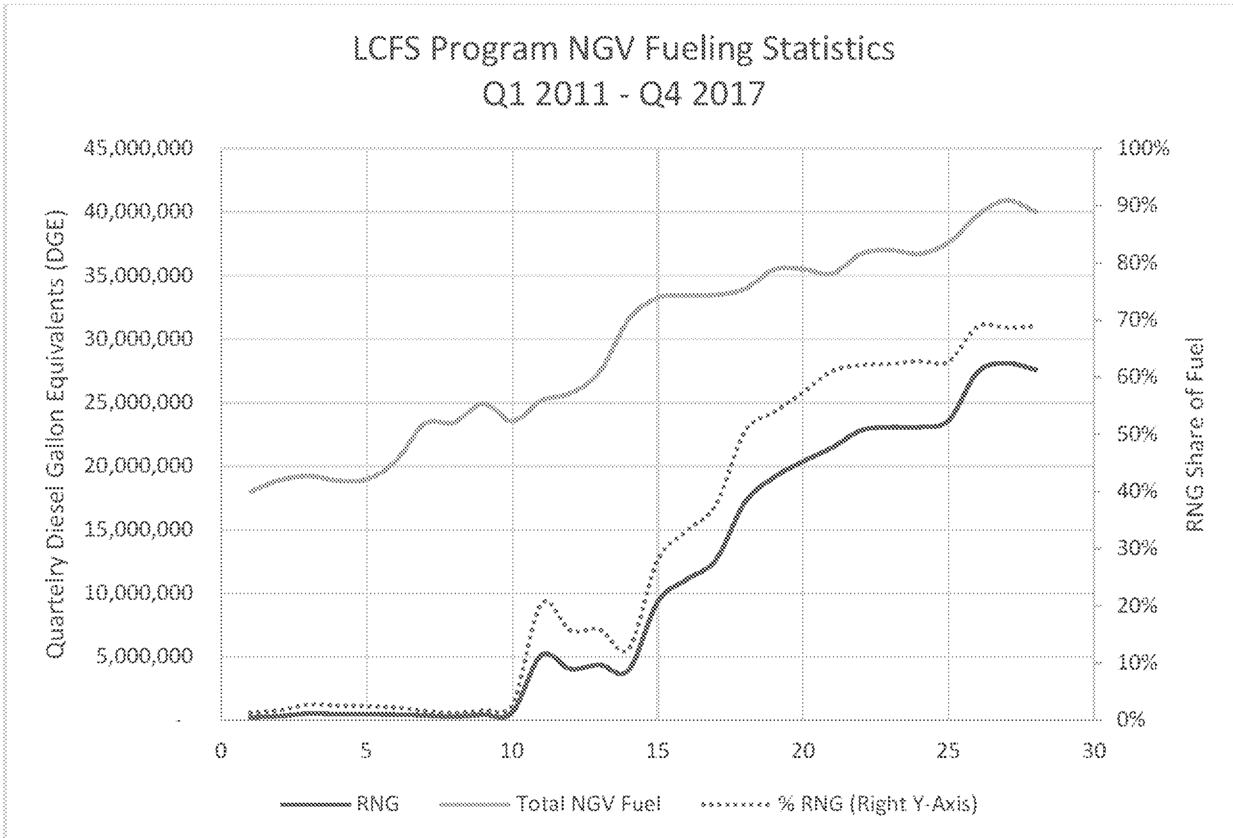


Figure 1 - RNG's growing role in California's transportation fuel market.

The California NGV market represents an important growth opportunity for RNG due to the economic incentives available from the LCFS program and the Federal Renewable Fuel Standard, which help to offset the price premium between RNG and relatively abundant traditional natural gas. NGV demand in California is forecasted to grow, driven primarily by the urgent need to reduce smog-forming tailpipe NOx emissions from heavy-duty diesel engines, and the growing price spread between gasoline and diesel and natural gas. The Energy Information Administration (EIA) forecasts a 5.3 percent annual growth rate for NGV volumes in the Pacific region through 2050.14

At the time of the filing of the 2018 California Gas Report, none of the gas supplies purchased by SoCalGas for the core market originate from RNG. However, SoCalGas is seeking Commission authority to begin adding RNG to their supply portfolio. Pending Commission approval, advice letter #5295 seeks the authorization of a Pilot program to allow SoCalGas to procure RNG for use in its fleet and utility-owned public access NGV fueling stations, thereby encouraging further development of RNG sources, reducing GHG emissions, and advancing California's environmental policies.

In addition to decarbonizing California's transportation sector, RNG can play a significant role in decarbonizing other existing natural gas end uses in California. Around 90 percent of

[14] EIA 2018 Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/

Californian's use natural gas for space and water heating today, and delivering RNG through existing natural gas infrastructure to these appliances has the potential to seamlessly decarbonize these end-uses without disrupting customer behavior or preference.

INTERSTATE PIPELINE CAPACITY

Interstate pipeline delivery capability into SoCalGas and SDG&E on any given day theoretically is approximately 6,665 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. Note that the capacity to deliver to the SoCalGas system does not equal the ability to take away from SoCalGas' pipelines.

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	210
TGN at Otay Mesa	400
North Baja at Blythe	600
Total Potential Supplies	**6,665**

(1) Estimate of physical capacity.

STORAGE

Underground storage of natural gas plays a vital role in balancing the region's energy supply and demand, and for system-wide reliability.[15] Natural gas storage is also used to meet peak daily and seasonal gas demand and to hedge against price volatility in natural gas commodity markets. In addition, natural gas storage has played a role in addressing emergency situations, including extreme weather and wildfires.[16] SoCalGas owns and operates four natural gas storage facilities within southern California: Aliso Canyon, Honor Rancho, La Goleta, and Playa Del Rey.

In southern California, natural gas storage fields are in areas with specific underground geologic characteristics, and in proximity to local gas consumers and transmission and distribution pipelines. Storage natural gas is withdrawn and delivered to customers through SoCalGas' transmission and distribution system when customer demand exceeds flowing natural gas supplies and for system balancing.

SoCalGas' natural gas storage fields have a combined theoretical storage working inventory capacity of approximately 137.1 Bcf.[17] However, the combined working inventory for SoCalGas is reduced due to current working inventory regulatory restrictions imposed at Aliso Canyon.

Since 2015,[18] DOGGR has maintained restrictions on SoCalGas' use of Aliso Canyon. Aliso Canyon historically has had a stated natural gas storage inventory of 86.2 Bcf. As of July 19, 2017, DOGGR has authorized Aliso Canyon to operate with gas storage inventory up to 68.6 Bcf.[19] As of December 11, 2017, the CPUC has authorized a maximum inventory of 24.6 Bcf.[20] More recently, on June 18, 2018, the CPUC proposed increasing the maximum inventory to 34 Bcf to support system reliability.[21] The CPUC and DOGGR may, in the future, authorize a different maximum inventory. Additionally, SoCalGas may only withdraw from Aliso Canyon's inventory as a reliability-related "last resort", consistent with the CPUC's "Aliso Canyon Withdrawal Protocol."[22] These withdrawal protocols allow for the withdrawal of natural gas from Aliso Canyon under a strict set of imposed protocols and principals. In recognition of the safety enhancements SoCalGas

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[15] California Council on Science and Technology (CCST), January 2018, Long-Term Viability of Underground Natural Gas Storage in California, An Independent Review of Scientific and Technical Information, Conclusion 2.4 at 504, available at: http://ccst.us/publications/2018/Full TechnicalReportv2.pdf

[16] Id., Conclusion 2.5 at 506.

[17] SoCalGas 2019 GRC Filing, Exhibit SCG-10-R, p. NPN-3 and NPN-4.

[18] Aliso Canyon experienced a natural gas leak in well SS25 on October 23, 2015. The leak was stopped on February 11, 2016 and SS25 was permanently sealed on February 18, 2016

[19] DOGGR has authorized Aliso Canyon to operate at pressures up to 2,926 psia, which translates into an inventory of 68.6 Bcf.

[20] See, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/715_Supplement_2017-12-11_FINAL.pdf

[21] See, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/Draft715Report_Summer2018.pdf

[22] See, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/11.2Protocol%PublicUtilitiesCommission.pdf

has completed at Aliso Canyon and the importance of Aliso Canyon to southern California reliability,[23] SoCalGas continues to request that regulators lift the above restrictions to better support southern California energy reliability.

STORAGE REGULATIONS

Since 2015, the CPUC, DOGGR and PHMSA have proposed and adopted various regulations addressing natural gas storage requirements and standards including safety and reliability. SoCalGas is committed to working with various regulating bodies and policy makers to promote safe and reliable energy and natural gas storage services.

REGULATORY ENVIRONMENT

State Regulatory Matters

GENERAL RATE CASE (GRC)

On December 20, 2017, SoCalGas filed its TY 2019 GRC Revised Testimony (correcting any errors that were not feasible to incorporate into testimony at the time of the October 6 Application, A.17-10-008, and for currently known errors identified after filing) to set authorized base revenues for the four-year period 2019-2022 that will allow it to operate safely and reliably at reasonable rates over the GRC cycle. SoCalGas is requesting authorized revenues of $2,989 million, which is a $480 million or 19 percent, increase over authorized 2018 levels (at present rate includes the cost of capital true up.) On April 6, 2018, SoCalGas served supplemental GRC testimony incorporating its analysis of the recently enacted federal tax reform legislation. A final CPUC decision on the TY2019 GRC is expected in the 4th quarter of 2018.

TRIENNIAL COST ALLOCATION PROCEEDING (TCAP)

SoCalGas files TCAP's every three years to update the allocation of the resources and costs of providing gas service to customer classes and determine the transportation rates it charges to customers. The next TCAP is anticipated to be filed in the summer of 2018 to update the allocation of costs to the 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 2020-2022. A final CPUC Decision would not be expected until 2019.

[23] SoCalGas has completed a comprehensive safety review of the facility and created multiple layers of safety at Aliso Canyon, and in July of 2017 the CPUC and Division of Oil, Gas, and Geothermal Resources formally determined that Aliso Canyon is safe to operate, any risks of failure had been identified and addressed, and well integrity had been verified. See, e.g., July 19, 2017, SB 380 Findings and Concurrence Regarding the Safety of the Aliso Canyon Gas Storage Facility.

ELECTRIFICATION POLICY PROPOSALS

SoCalGas and SDG&E are monitoring potential electrification policies currently being considered in the State Legislature. Proposed policies would support a potential state goal of reducing residential and commercial buildings' GHG emissions by at least 40 percent below 1990 levels by January 1, 2030. The California utilities are aware of and are involved in the related conversation regarding the long-term role of natural gas in the state's building stock. This topic will be examined in the 2018 Integrated Energy Policy Report (IEPR) at the CEC. However, since no bill has been signed into law requiring changes to the use of natural gas in either residential or non-residential buildings, this report and its included gas demand forecasts do not consider those potential policy changes. Future CGRs will incorporate any appropriate legally-binding updates to building codes or other requirements.

PIPELINE SAFETY

In 2011 the CPUC issued an Order Instituting Rulemaking (OIR) to develop and adopt new regulations on pipeline safety, requiring that the utilities file implementation plans to test or replace natural gas transmission pipelines that do not have sufficient record of a pressure test.

SoCalGas and SDG&E jointly filed their comprehensive Pipeline Safety Enhancement Plan (PSEP) on August 26, 2011. The comprehensive plan covered all of the utilities' approximately 4,000 miles of transmission lines and would be implemented in two phases. Phase 1 focuses on populated areas. Phase 2 covers less populated areas of SoCalGas' and SDG&E's service territories.

On June 2014, the CPUC issued a final decision approving the utilities' plan for implementing PSEP, and established criteria to determine the costs that may be recovered from ratepayers and the processes for reasonableness review and recovery of such costs.

Various PSEP-related proceedings are pending before the CPUC regarding the reasonableness review and cost recovery requests. As of December 31, 2017, SoCalGas and SDG&E has received approval for recovery of $33 million, which was approved in the first reasonableness review filed in December 2014. In 2016, the CPUC issued a final decision authorizing SoCalGas and SDG&E to recover in rates 50 percent of Phase 1 project costs recorded in PSEP regulatory accounts as of January 1 each year, subject to refund, pending reasonableness review. The decision also incorporates a forward-looking schedule to file reasonableness review applications in 2016 and 2018, file a forecast application for pre-approval of Phase 2 projects and to include PSEP costs not the subject of prior applications in future GRC's.

From 2011 through 2017, SoCalGas and SDG&E have invested approximately $1.3 billion and $355 million, respectively, in PSEP, with additional expenditures planned.

In September 2016, SoCalGas and SDG&E filed a joint application with the CPUC for its second PSEP reasonableness review and rate recovery of costs of certain Phase 1 pipeline safety projects completed by June 30, 2015 and recorded in their authorized regulatory accounts. The total costs submitted for review are $178 million ($163 million for SoCalGas and $15 million for SDG&E). SoCalGas and SDG&E expect a decision from the CPUC in 2018.

In March 2017, SoCalGas and SDG&E filed an application with the CPUC requesting approval of the forecasted revenue requirement necessary to recover the costs associated with twelve Phase 1B and Phase 2A pipeline safety projects. The California Utilities expect to incur total costs for the twelve projects of approximately $255 million ($198 million in capital expenditures and $57 million in O&M). SoCalGas and SDG&E expect a CPUC decision in 2018.

SAN JOAQUIN VALLEY (SJV) OIR

In 2014, Governor Edmund G. Brown, Jr. signed into law Assembly Bill (AB) 2672. This legislation added Public Utilities (Pub. Util.) Code Section 783.5, seeking to increase affordable access to energy for disadvantaged communities in the San Joaquin Valley (SJV). Pursuant to Pub. Util. Code § 783.5, Rulemaking (R.) 15-03-010 was initiated in March 2015, with the initial scope of the proceeding limited to identifying eligible disadvantaged communities. D.17-05-014 adopted a methodology for the identification of communities eligible under Section 783.5, and subsequently Phase 2 commenced to address pilot projects and data gathering needs for evaluation of economically feasible energy options for the identified communities.

Pursuant to the updated scoping ruling in R.15-03-010 issued in December 2017, SoCalGas submitted natural gas pilot proposals in January 2018 for seven communities to extend existing pipelines, install gas service to each household, and replace existing propane appliances with new, energy efficient natural gas appliances. The cost for these seven pilot proposals is estimated to be $99 million ($85 million in capital costs and $14 million in O&M costs), which includes "to the meter" construction, "beyond the meter" construction, and Program Management Office (PMO) costs. The CPUC is also considering whether some or all of the communities should be served by all-electric pilot projects. Accordingly, some or all of SoCalGas' proposed projects may not be adopted. A decision is expected in the third quarter of 2018.

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. For the better part of 2017, FERC did not have a quorum of Commissioners.

There has not been any significant activity in this area since the 2016 California Gas Report was published. The items noted below reflect this fact.

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, a revised decision, Opinion No. 528-A, issued in 2016, and a further (and likely final) decision, Opinion No. 528-B, in May of 2018. Collectively, these decisions ruled on issues related to revenue requirements, abandonment costs, cost allocation, and rate design. These FERC decisions are currently under review before the U.S. Court of Appeals in the District of Columbia Circuit.

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 percent lower by 2021 relative to current 2014 levels.

GREENHOUSE GAS ISSUES

National Policy

The national greenhouse gas program has been 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 established unique emission rate goals and mass equivalents for each state. It was 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 CO_2 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 was under review at the U.S. Court of Appeals for the District of Columbia Circuit. In March 2017, President Trump signed an executive order to review the Clean Power Plan and if appropriate, suspend, revise or rescind the rule. Subsequently, on October 10, 2017 the EPA released a proposed rule to repeal the Clean Power Plan.

Assembly Bill 32

The Global Warming Solutions Act of 2006 (Assembly Bill 32) requires California to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. AB 32 directed the California Air Resources Board (CARB) to adopt rules and regulations to achieve the "maximum technologically feasible and cost-effective GHG emission reductions."[24] CARB was also required to prepare and approve a Scoping Plan that provides a roadmap to reach the 2020 emissions reduction target. The Scoping Plan was first approved by CARB in 2008 and must be updated every 5 years. The most recent update, as of this writing, was made in December 2017. The Scoping Plan Updates involve a collaborative process through engagement with the Legislature, State agencies, and a diverse set of stakeholders with public input facilitated through workshops and other meetings. The result is a policy framework that comprises a broad portfolio of GHG reduction strategies and regulations, including market-based compliance mechanisms, performance standards, technology requirements and voluntary reductions.

Senate Bill 32

Senate Bill 32 (SB 32) was enacted on September 8, 2016 and went into effect on January 1, 2017. The law extended the goals of AB 32 by setting a 2030 emissions target of 40 percent below 1990 levels. The continuation of the Global Warming Solutions Act keeps California on track with the emission reduction goals of the Paris Agreement. The 2017 Scoping Plan Update incorporated the 2030 goal and constructed California's climate policy portfolio that includes doubling building efficiency, increasing renewable power by 50 percent, cleaner zero and near-zero emission vehicles, reducing short-lived climate pollutants such as black carbon and limiting industry emissions through a cap-and-trade program. The companion bill to SB 32, AB 197, provided increased legislative oversight of CARB and directed it to take certain actions to improve local air quality. Those actions include requiring the public posting of air quality and GHG information, adopt rules

[24] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32

and regulations that protect disadvantaged communities from air toxins and to consider the social cost of carbon when preparing plans to meet GHG reduction goals.

Senate Bill 350

The Clean Energy and Pollution Reduction Act, or Senate Bill 350, was signed into law on October 7, 2015 and sets ambitious goals that will help the State achieve the emissions reduction targets of SB 32. SB 350 increases and extends the renewable portfolio standard targets to 50 percent by 2030. Additionally, the law requires the state to double statewide energy efficiency savings in both the electric and natural gas sectors by 2030. The GHG reduction targets associated with these requirements are to be incorporated into Integrated Resource Plans (IRPs), which detail how each required utility will reduce GHGs, deploy clean energy resources and otherwise meet the resources needs of their customers. The Energy Commission is coordinating with other state agencies including the CPUC, CARB and CAISO, to implement the bill. SoCalGas has been engaged with these agencies throughout the process and has been providing input.

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 CARB for their own emissions; therefore, SoCalGas' obligation does not include these customers and they will not be responsible for compliance costs related to end-users from SoCalGas. The CPUC completed a rulemaking proceeding in late 2015 to determine how the costs related to compliance with the Cap-and-Trade program will be included in end-use customers' rates[25]. 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 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.

In the same CPUC decision, it was determined that revenues generated from the sale of directly allocated allowances would be returned as a fixed, once-annual, California Climate Credit to all residential households on their April bills. Nonresidential customers were not to receive 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 was delayed. In March 2018, the CPUC issued its Final Decision (D. 18-02-017), which directed IOUs to recover Cap-and-Trade costs and distribute the California Climate Credit. It found that 1) only residential customers are eligible for the

[25] CPUC D. 15-10-032

California Climate Credit, with the initial Climate Credit to be distributed in October 2018 and in April ever year thereafter; 2) GHG compliance costs can be incorporated in transportation rates beginning July 1, 2018, with 2018 costs amortized over 18 months; and 4) the accumulated 2015-2017 GHG costs and revenues are to be netted, with the remaining balance either distributed in the 2018 Climate Credit or amortized in transportation rates.

Reporting and Cap-and-Trade Obligations

SoCalGas reports GHG emissions to the Environmental Protection Agency, in accordance with 40 Code of Federal Regulations Part 98, in three primary categories. The categories include the following: combustion emissions at three compressor stations and two storage fields, where total annual GHG emissions exceed the 25,000 metric tons of CO^2 equivalent (mtCO2e) threshold for GHG reporting; vented and fugitive emissions from three compressor stations and two storage fields; fugitive emissions from the natural gas distribution system and GHG emissions resulting from combustion of natural gas delivered to all customers except for customers consuming more than 460 MMcf.

In 2016, SoCalGas reported to CARB approximately 44 million mtCO^{2}e of emissions in three primary categories: combustion emissions at four compressor stations and two storage fields, where annual emissions exceed 10,000 mtCO^{2}e; 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 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). More recently, SoCalGas estimated that responsibility for compliance obligations of GHG emissions as a natural gas supplier were approximately 21.6 million mtCO2e for 2017. CARB will issue the final 2017 compliance obligations of GHG emissions as a natural gas supplier in November 2018.

In 2014, Rulemaking (R.) 15-01-008 was initiated by the Commission to carry out the intent of SB 1371 (Statutes 2014, Chapter 525). 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 their methane emissions from intentional and unintentional releases as well as their leak management practices. In 2016, SoCalGas reported an estimated 3.7 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 grams 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 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. SoCalGas opted into the LCFS program in 2013 and currently generates credits from utility-owned Compressed Natural Gas (CNG) refueling stations that serve both company vehicles and the general public. The value from the credits generated is returned to CNG customers by reducing the price at the pump. SoCalGas recently filed an Advice Letter with the CPUC to initiate a Voluntary Renewable Natural Gas Procurement Pilot program. The program would enable SoCalGas to procure and dispense Renewable Natural Gas (RNG) at its utility-owned CNG stations. RNG is an eligible alternative fuel under LCFS program *and* EPA's Renewable Fuel Standard (RFS). Therefore, it generates Renewable Identification Number credits from the RFS program in addition to the LCFS credits. Also, RNG has as lower carbon intensity than traditional CNG and will generate more credits per unit of energy under the LCFS program. SoCalGas anticipates the Pilot will result in more value returned to its CNG customers while supporting the development of the RNG market. Currently, CARB is undergoing a formal rulemaking process on proposed amendments to the LCFS regulation that would extend it to 2030 and set new carbon intensity targets amongst other topics.

Programmatic Emission Reduction

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 percent by 2020 and to 50 percent by 2030; implementing CARB Short-Lived Climate Pollutants strategy and revising 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. In D.17-06-015, utilities were ordered to implement a Natural Gas Leak Abatement Program consistent with twenty-six Best Practices for emission mitigation.

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 renewable energy sources 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.

Renewable Natural Gas (RNG) from Biogas

Since methane comes from the decomposition of organic matter, there are ways to generate natural gas other than extracting it from the ground. Biogas is produced from existing waste streams and a variety of renewable and sustainable biomass sources, including animal waste, crop residuals and food waste. Organic waste from dairies and farms can be repurposed into biogas. The most common source of biogas is the naturally-occurring biological breakdown of organic waste at facilities such as wastewater treatment plants and landfills.

The abundance of these materials allows for production of substantial quantities of biogas. A study conducted by UC Davis estimates that more than 20 percent of California's current residential natural gas use can be provided by biogas derived from our state's existing organic waste alone.[26] In the transportation sector, that's enough to replace around 20 percent of the fuel used by heavy-duty trucks in the state. This can help reduce the need for other fossil-based fuels while boosting our supplies with a locally sourced renewable fuel. Looking outside California, the opportunity to produce biogas is vast. According to estimates, the United States could produce up to 10 trillion cubic feet of biogas annually by 2030 — that's more than five times California's projected natural gas consumption.[27]

When biogas is used to fuel vehicles, it can provide major reductions in GHG emissions - in addition to clean air benefits. According to the California Air Resources Board,[28] biogas sourced from landfill-diverted food and green waste can provide a 125 percent reduction in greenhouse gas emissions, and biogas from dairy manure can result in a 400 percent reduction in greenhouse gas emissions when replacing traditional vehicle fuels.

When biogas is conditioned/upgraded to pipeline quality specifications, commonly referred to as "biomethane" or "renewable natural gas (RNG)," it can be interconnected to a gas utility's pipeline and nominated for a specific end-use customer.[29] Biogas may also be consumed onsite for a variety of uses, including electrical power generation from internal combustion engines,

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[26] *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute,* Prepared for the California Air Resources Board and the California Environmental Protection Agency by Amy Jaffe, Principal Investigator. STEPS Program, Institute of Transportation Studies, UC Davis

[27] U.S. Department of Energy. 2016. *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, Volume 1: Economic Availability of Feedstocks.* M. H. Langholtz, B. J. Stokes, and L. M. Eaton (Leads), ORNL/TM-2016/160. Oak Ridge National Laboratory, Oak Ridge, TN. 448p. doi: 10.2172/1271651; 2030 Values achievable at $60/Ton

[28] California Air Resources Board, *Low Carbon Fuel Standard Pathway Certified Carbon Intensities*

[29] 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.

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 Senate Bill (SB) 1383, whereas captured and processed renewable natural gas injected into a common carrier natural gas pipeline system can ultimately count towards satisfying AB 32 and SB 1383 emission reduction goals.

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.

In 2015, pursuant to CPUC D. 15-06-029, the CPUC adopted the biomethane interconnector monetary incentive program[2]. The objective of the program is to encourage the development of biomethane projects that are interconnected to the utilities' gas pipeline systems. The initial incentive program contributed up to 50 percent of the interconnection costs, with a cap of $1.5 million per project. The statewide funding for the monetary incentive program is capped at $40 million.[30]

On September 24, 2016, the interconnector monetary incentive program was modified when Gov. Jerry Brown signed AB 2313 into law. The senate bill increased the maximum funding for this incentive program to up to $3 million per project. This bill also allows for dairy cluster projects --defined as three or more dairies in close proximity-- to include gathering line costs as a qualifying interconnection expense, and increases the maximum incentive for these projects to $5 million per project. The monetary incentive is available to eligible Biomethane Interconnectors until December 31, 2021, or until the program has exhausted its $40 million cap.

RNG is an increasingly important component of the State's efforts to decarbonize the economy. The primary policy in California currently driving RNG development is SB 1383, the Short-Lived Climate Pollutants: Organic Waste Methane Emissions Reductions. As required by SB 1383, R.17-06-015 was instituted to "direct gas corporations to implement not less than five dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system and allow for rate recovery of reasonable infrastructure costs."31 For these pilot projects the gas corporations may fund and recover in rates the cost of pipeline infrastructure, including biogas collection lines and interconnection to existing pipelines, removing many upfront costs developers would otherwise have to incur. It is anticipated the Selection Committee will select the no less than five dairy pilot projects in late 2018 or early 2019.

SB1383 requires the CPUC to take the following actions:

- Work with the CEC and CARB to "consider policies to support the development and use of renewable gas that reduce short-lived climate pollutants (SLCPs) in the state." (See Health and Safety Code Section 39730.8(d)).

[30] This program is funded by California utility customers and administered by Southern California Gas Company (SoCalGas®) under the auspices of the California Public Utilities Commission. Program funds, including any funds utilized for rebates or incentives, will be allocated on a first-come, first-served basis until such funds are no longer available. This program may be modified or terminated without prior notice

[31] Order Instituting Rulemaking to Implement Diary Biomethane Pilot Projects to Demonstrate Interconnection to the Common Carrier Pipeline System in Compliance with Senate Bill 1383 (issued June 22, 2017) (OIR), at 2.

- Work with CARB to "establish energy infrastructure development and procurement policies to encourage dairy biomethane projects to reduce methane emissions from livestock and dairy operations by at least 40 percent below the dairy and livestock sectors' 2013 level by the year 2030." (See Health and Safety Code Section 39730.7(d)(1)(A)).

- Work with the CEC and CARB to "develop recommendations surrounding development and use of renewable gas, including biomethane and biogas, as part of its 2017 Integrated Energy Policy Report (IEPR)". (See Health and Safety Code Section 39730.8(b)).[32]

Other RNG policies include Assembly Bill 1900, CPUC R.13-02-008 (Biomethane OIR Phase II) and Public Utilities Code Section 399.24, which promotes "in-state production and distribution of biomethane." SoCalGas is supportive of these policies and other efforts to encourage development of the RNG market.

[32] OIR, at 5.

PEAK DAY DEMAND

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are 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. On the extreme peak day event, service to all noncore customers is assumed to be fully interrupted. The criteria for extreme peak day design is defined as a 1-in-35 likelihood event for each utility's service area. This criteria correlates to a system average temperature of 40.3 degrees Fahrenheit for SoCalGas' service area and 42.8 degrees Fahrenheit for SDG&E's service area.

Demand on an extreme peak day is met through a combination of withdrawals from underground storage facilities and flowing pipeline supplies. The following table provides forecasted core extreme peak day demand.

Core Extreme Peak Day Demand
(MMcf/Day)

Year	SoCalGas Core Demand 1/	SDG&E Core Demand 2/	Other Core Demand 3/	Total Demand
2018	3,003	407	117	3,527
2019	2,987	406	118	3,511
2020	2,966	405	119	3,490
2021	2,945	403	120	3,468
2022	2,916	398	120	3,435
2023	2,870	396	121	3,388
2024	2,833	395	122	3,350

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) 1-in-35 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach and City of Vernon.

The CPUC has also mandated that SoCalGas and SDG&E design its system to provide service to both core and noncore customers under a winter temperature condition with an expected recurrence interval of 10 years. The demand forecast for this 1-in-10 year cold day condition is shown in the table below.

Winter Cold Day Demand Condition (MMcf/Day)

Year	SoCalGas Core (1)	SDG&E Core (2)	Other Core (3)	Noncore NonEG (4)	Electric Generation (5)	Total Demand
2018	2,838	384	100	658	985	4,965
2019	2,822	382	101	654	989	4,949
2020	2,802	381	102	654	1,048	4,987
2021	2,781	379	102	651	1,036	4,950
2022	2,753	375	103	647	1,030	4,908
2023	2,708	373	104	639	979	4,804
2024	2,672	372	104	632	990	4,771

Notes:
(1) 1-in-10 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-10 peak temperature cold day SDG&E core sales and transportation.
(3) 1-in-10 peak temperature cold day core demand of Southwest Gas Corporation, City of Long Beach and City of Vernon.
(4) Noncore-Non-EG includes noncore Non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and all end-use customers of Ecogas.
(5) UEG/EWG Base Hydro + all other Cogeneration customers

The SoCalGas and SDG&E system is a winter peaking system; peak demand is expected to occur during the winter operating season of November through March. For this reason, the CPUC has not mandated a summer design standard. For informational purposes only, the table below presents a forecast of summer demand on the SoCalGas and SDG&E system.

Summer High Sendout Day Demand (MMcf/Day)

Year	High Demand Month (1)	SoCalGas Core (2)	SDG&E Core (3)	Other Core (4)	Noncore NonEG (5)	Electric Generation (6)	Total Demand
2018	Sep	639	95	23	543	1,768	3,068
2019	Sep	636	95	23	542	1,964	3,260
2020	Sep	630	95	24	541	1,922	3,211
2021	Sep	624	94	24	538	1,680	2,960
2022	Sep	615	94	24	534	1,622	2,890
2023	Sep	603	93	24	527	1,544	2,792
2024	Sep	593	93	24	521	1,576	2,808

Notes:
(1) Month of High Sendout gas demand during summer (July, August or September).
(2) Average daily summer SoCalGas core sales and transportation.
(3) Average daily summer SDG&E core sales and transportation.
(4) Average daily summer core demand of Southwest Gas Corporation, City of Long Beach and City of Vernon.
(6) Average daily summer demand. Noncore-Non-EG includes noncore Non-EG end-use customers of SoCalGas, SDG&E, Southwest Gas Corporation, City of Long Beach, City of Vernon, and all end-use customers of Ecogas.
(5) Highest demand during the high demand month under 1-in-10 dry hydro conditions except year 2018, when the Electric Generation highest demand is based on 2018 hydro condition.

2018 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY
TABULAR DATA

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY

RECORDED YEARS 2013 TO 2017

Line	CAPACITY AVAILABLE		2013	2014	2015	2016	2017
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		153	143	122	89	84
	Out-of-State Gas						
11	Other Out-of-State		2,514	2,538	2,397	2,342	2,434
12	Total Out-of-State Gas		2,514	2,538	2,397	2,342	2,434
13	TOTAL SUPPLY TAKEN		2,667	2,681	2,519	2,431	2,518
14	Net Underground Storage Withdrawal		106	(63)	40	80	(14)
15	TOTAL THROUGHPUT (1)(2)		2,773	2,618	2,559	2,511	2,504
	DELIVERIES BY END-USE						
16	Core	Residential	646	541	548	557	565
17		Commercial	222	202	207	213	214
18		Industrial	62	58	58	55	55
19		NGV	31	33	35	36	38
20		Subtotal	961	834	848	861	872
21	Noncore	Commercial	60	53	52	57	56
22		Industrial	368	379	362	391	389
23		EOR Steaming	35	44	46	39	39
24		Electric Generation	848	863	795	740	713
25		Subtotal	1,311	1,339	1,255	1,228	1,198
26	Wholesale/International		465	410	428	390	401
27	Co. Use & LUAF		36	35	28	31	33
28	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,773	2,618	2,559	2,511	2,504
	TRANSPORTATION AND EXCHANGE						
29	Core	All End Uses	45	49	52	56	62
30	Noncore	Commercial/Industrial	428	432	414	449	446
31		EOR Steaming	35	44	46	39	39
32		Electric Generation	848	863	795	740	713
33		Subtotal-Retail	1,356	1,388	1,307	1,284	1,260
34	Wholesale/International		465	410	428	390	401
35	TOTAL TRANSPORTATION & EXCHANGE		1,821	1,798	1,735	1,674	1,660
36	CURTAILMENT (3)						
37	REFUSAL						
38		Total BTU Factor (Dth/Mcf)	1.0266	1.0300	1.0353	1.0345	1.0343

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 2018 THRU 2022

AVERAGE TEMPERATURE YEAR

LINE			2018	2019	2020	2021	2022	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	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/		870	1,200	1,590	1,590	1,590	5
6	Total Out-of-State Gas		2,845	3,175	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,055	3,385	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		51	51	51	51	51	8
9	Out-of-State		2,574	2,540	2,515	2,493	2,468	9
10	TOTAL SUPPLY TAKEN		2,625	2,591	2,566	2,544	2,519	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,625	2,591	2,566	2,544	2,519	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	648	640	629	622	612	13
14		Commercial	223	221	218	214	209	14
15		Industrial	57	57	56	55	54	15
16		NGV	40	43	45	47	50	16
17		Subtotal-CORE	968	960	948	939	925	17
18	NONCORE	Commercial	50	50	49	49	49	18
19		Industrial	390	387	386	383	380	19
20		EOR Steaming	46	46	45	46	46	20
21		Electric Generation (EG)	733	710	705	694	692	21
22		Subtotal-NONCORE	1,218	1,192	1,186	1,172	1,166	22
23	WHOLESALE &	Core	188	188	188	188	187	23
24	INTERNATIONAL	Noncore Excl. EG	51	53	53	53	54	24
25		Electric Generation (EG)	167	165	159	159	156	25
26		Subtotal-WHOLESALE & INTL.	406	406	401	401	397	26
27		Co. Use & LUAF	33	33	32	32	32	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,625	2,591	2,566	2,544	2,519	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	65	65	66	66	66	29
30	NONCORE	Commercial/Industrial	439	437	435	432	429	30
31		EOR Steaming	46	46	45	46	46	31
32		Electric Generation (EG)	733	710	705	694	692	32
33		Subtotal-RETAIL	1,283	1,258	1,252	1,239	1,232	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	406	406	401	401	397	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,689	1,663	1,652	1,639	1,629	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.)

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2017 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2018	2019	2020	2021	2022
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.7	0.7	0.6	0.6	0.6
7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.					
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	934	925	912	903	888

TABLE 2-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2023 THRU 2035

AVERAGE TEMPERATURE YEAR

LINE			2023	2024	2025	2030	2035	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	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 [4/]		3,775	3,775	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas [5/]		51	51	51	51	51	8
9	Out-of-State		2,429	2,393	2,371	2,259	2,262	9
10	TOTAL SUPPLY TAKEN		2,480	2,444	2,422	2,310	2,313	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [6/]		2,480	2,444	2,422	2,310	2,313	12
	REQUIREMENTS FORECAST BY END-USE [7/]							
13	CORE [8/]	Residential	597	583	573	523	510	13
14		Commercial	203	196	191	169	168	14
15		Industrial	52	50	49	41	37	15
16		NGV	53	55	59	77	100	16
17		Subtotal-CORE	905	885	871	810	815	17
18	NONCORE	Commercial	49	48	48	47	46	18
19		Industrial	373	368	363	344	336	19
20		EOR Steaming	46	45	46	46	46	20
21		Electric Generation (EG)	684	676	673	646	645	21
22		Subtotal-NONCORE	1,152	1,137	1,129	1,083	1,073	22
23	WHOLESALE &	Core	187	186	187	188	194	23
24	INTERNATIONAL	Noncore Excl. EG	54	54	54	55	55	24
25		Electric Generation (EG)	151	150	149	147	146	25
26		Subtotal-WHOLESALE & INTL.	392	390	390	389	395	26
27		Co. Use & LUAF	31	31	31	29	29	27
28	SYSTEM TOTAL THROUGHPUT [6/]		2,480	2,444	2,422	2,310	2,313	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	66	66	66	70	79	29
30	NONCORE	Commercial/Industrial	422	416	411	391	383	30
31		EOR Steaming	46	45	46	46	46	31
32		Electric Generation (EG)	684	676	673	646	645	32
33		Subtotal-RETAIL	1,218	1,203	1,196	1,152	1,152	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	392	390	390	389	395	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,610	1,594	1,586	1,541	1,547	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.)

4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.

5/ Average 2017 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2023	2024	2025	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.5	0.5	0.5	0.4	0.4

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

	2023	2024	2025	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	867	847	833	766	762

TABLE 3-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2018 THRU 2022

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

LINE			2018	2019	2020	2021	2022	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	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/		870	1,200	1,590	1,590	1,590	5
6	Total Out-of-State Gas		2,845	3,175	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE 4/		3,055	3,385	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		51	51	51	51	51	8
9	Out-of-State		2,664	2,719	2,693	2,691	2,637	9
10	TOTAL SUPPLY TAKEN		2,715	2,770	2,744	2,742	2,688	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,715	2,770	2,744	2,742	2,688	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	710	703	692	685	675	13
14		Commercial	233	231	227	224	219	14
15		Industrial	58	58	57	56	55	15
16		NGV	40	43	45	47	50	16
17		Subtotal-CORE	1,042	1,034	1,021	1,013	999	17
18	NONCORE	Commercial	51	51	50	50	50	18
19		Industrial	390	387	386	383	380	19
20		EOR Steaming	46	46	45	46	46	20
21		Electric Generation (EG)	733	781	774	782	750	21
22		Subtotal-NONCORE	1,219	1,265	1,255	1,261	1,226	22
23	WHOLESALE &	Core	202	202	202	202	201	23
24	INTERNATIONAL	Noncore Excl. EG	51	53	53	54	54	24
25		Electric Generation (EG)	167	181	177	178	174	25
26		Subtotal-WHOLESALE & INTL.	420	436	432	434	429	26
27		Co. Use & LUAF	34	35	35	35	34	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,715	2,770	2,744	2,742	2,688	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	67	68	68	69	69	29
30	NONCORE	Commercial/Industrial	440	438	436	434	430	30
31		EOR Steaming	46	46	45	46	46	31
32		Electric Generation (EG)	733	781	774	782	750	32
33		Subtotal-RETAIL	1,286	1,333	1,323	1,329	1,294	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	420	436	432	434	429	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,706	1,769	1,755	1,763	1,723	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.)
4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.
5/ Average 2017 recorded California Source Gas; production less than capacity due to reservoir performance and economics.
6/ Excludes own-source gas supply of 0.8 0.7 0.7 0.7 0.6 gas procurement by the City of Long Beach
7/ Requirement forecast by end-use includes sales, transportation, and exchange volumes.
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 1,008 999 986 977 962

TABLE 4-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2023 THRU 2035

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

LINE			2023	2024	2025	2030	2035	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		60	60	60	60	60	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 4/		3,775	3,775	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		51	51	51	51	51	8
9	Out-of-State		2,575	2,546	2,523	2,396	2,399	9
10	TOTAL SUPPLY TAKEN		2,626	2,597	2,574	2,447	2,450	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,626	2,597	2,574	2,447	2,450	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	660	646	636	585	572	13
14		Commercial	212	206	200	179	178	14
15		Industrial	54	52	50	43	38	15
16		NGV	53	55	59	77	100	16
17		Subtotal-CORE	979	959	945	883	888	17
18	NONCORE	Commercial	50	49	49	48	48	18
19		Industrial	373	368	363	344	336	19
20		EOR Steaming	46	45	46	46	46	20
21		Electric Generation (EG)	725	724	719	688	686	21
22		Subtotal-NONCORE	1,193	1,187	1,177	1,125	1,115	22
23	WHOLESALE &	Core	201	200	201	202	208	23
24	INTERNATIONAL	Noncore Excl. EG	54	54	54	55	56	24
25		Electric Generation (EG)	166	164	164	152	152	25
26		Subtotal-WHOLESALE & INTL.	421	419	419	409	415	26
27		Co. Use & LUAF	33	33	32	31	31	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,626	2,597	2,574	2,447	2,450	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	68	68	69	72	81	29
30	NONCORE	Commercial/Industrial	423	417	412	392	384	30
31		EOR Steaming	46	45	46	46	46	31
32		Electric Generation (EG)	725	724	719	688	686	32
33		Subtotal-RETAIL	1,262	1,255	1,246	1,197	1,197	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	421	419	419	409	415	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,683	1,673	1,665	1,605	1,612	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.)
4/ Represents the outlook for firm receipt capacities at the time of publication; subject to change over the span of the CGR timeframe.
5/ Average 2017 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2023	2024	2025	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.6	0.6	0.5	0.5	0.5

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

	2023	2024	2025	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	941	921	906	839	835

2018 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 2018 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 five 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.

2018 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT
TABULAR DATA

TABLE 1-LB

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2013 THRU 2017

LINE	GAS SUPPLY AVAILABLE	2013	2014	2015	2016	2017
	California Source Gas					
1	Regular Purchases	-	-	-	-	-
2	Received for Exchange/Transport	-	-	-	-	-
3	Total California Source Gas	-	-	-	-	-
4	Purchases from Other Utilities	-	-	-	-	-
	Out-of-State Gas					
5	Pacific Interstate Companies	-	-	-	-	-
6	Additional Core Supplies	-	-	-	-	-
7	Incremental Supplies	-	-	-	-	-
8	Out-of-State Transport	-	-	-	-	-
9	Total Out-of-State Gas	-	-	-	-	-
10	Subtotal	-	-	-	-	-
11	Underground Storage Withdrawal	-	-	-	-	-
12	GAS SUPPLY AVAILABLE	-	-	-	-	-
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.9	2.4	0.7	0.9	0.6
14	Received for Exchange/Transport	-	-	-	-	-
15	Total California Source Gas	1.9	2.4	0.7	0.9	0.6
16	Purchases from Other Utilities	-	-	-	-	-
	Out-of-State Gas					
17	Pacific Interstate Companies	-	-	-	-	-
18	Additional Core Supplies	-	-	-	-	-
19	Incremental Supplies	23.5	19.2	21.9	22.8	24.6
20	Out-of-State Transport	-	-	-	-	-
21	Total Out-of-State Gas	23.5	19.2	21.9	22.8	24.6
22	Subtotal	25.4	21.5	22.5	23.7	25.2
23	Underground Storage Withdrawal	-	-	-	-	-
24	TOTAL Gas Supply Taken & Transported	25.4	21.5	22.5	23.7	25.2

TABLE 1A-LB

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2013 THRU 2017

LINE	ACTUAL DELIVERIES BY END-USE		2013	2014	2015	2016	2017
1	CORE	Residential	14.2	11.5	11.9	11.9	11.8
2	CORE/NONCORE	Commercial	5.9	5.4	5.4	5.8	6.0
3	CORE/NONCORE	Industrial	3.4	3.3	3.7	3.9	4.7
4		Subtotal	23.6	20.3	20.9	21.6	22.5
5	NON CORE	Non-EOR Cogeneration	1.5	0.9	1.2	1.9	2.2
6		EOR Cogen. & Steaming	-	-	-	-	-
7		Electric Utilities	-	-	-	-	-
8		Subtotal	1.5	0.9	1.2	1.9	2.2
9	WHOLESALE	Residential	-	-	-	-	-
10		Com. & Ind., others	-	-	-	-	-
11		Electric Utilities	-	-	-	-	-
12		Subtotal-WHOLESALE	-	-	-	-	-
13		Co. Use & LUAF	0.2	0.4	0.4	0.2	0.5
14		Subtotal-END USE	25.4	21.5	22.5	23.7	25.1
15		Storage Injection	-	-	-	-	-
16	SYSTEM TOTAL-THROUGHPUT		25.4	21.5	22.5	23.7	25.1
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	N/A
18		Commercial/Industrial	2.5	2.3	2.3	2.6	2.9
19		Non-EOR Cogeneration	1.5	0.8	1.1	1.8	2.0
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A
22		Subtotal-RETAIL	3.9	3.1	3.4	4.3	5.0
23	WHOLESALE	All End Uses	-	-	-	-	-
24	TOTAL TRANSPORTATION & EXCHANGE		3.9	3.1	3.4	4.3	5.0
	ACTUAL CURTAILMENT						
25		Residential	-	-	-	-	-
26		Commercial/Industrial	-	-	-	-	-
27		Non-EOR Cogeneration	-	-	-	-	-
28		EOR Cogen. & Steaming	-	-	-	-	-
29		Electric Utilites	-	-	-	-	-
30		Wholesale	-	-	-	-	-
31		TOTAL- Curtailment	-	-	-	-	-
32	REFUSAL		-	-	-	-	-

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

TABLE 2- LB

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2018 THRU 2020

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2018	2019	2020	2021	LINE
1	California Source Gas						
2	Out-of-State Gas						
3	TOTAL CAPACITY AVAILABLE						
	GAS SUPPLY TAKEN						
4	California Source Gas		0.7	0.7	0.6	0.6	
5	Out-of-State Gas		23.0	23.0	23.1	23.2	
6	TOTAL SUPPLY TAKEN		23.7	23.7	23.8	23.8	
7	Net Underground Storage Withdrawal		-	-	-	0	
8	TOTAL THROUGHPUT (1)		23.7	23.7	23.8	23.8	
	REQUIREMENTS FORECAST BY END-USE (1)						
9	CORE	Residential	13.6	13.7	13.8	13.8	
10		Commercial	5.1	5.1	5.1	5.1	
11		NGV	0.6	0.6	0.6	0.6	
12		Subtotal-CORE	19.3	19.4	19.4	19.5	
13	NONCORE	Industrial	3.1	3.1	3.1	3.1	
14		Non-EOR Cogeneration	1.1	1.0	1.0	1.0	
15		EOR	-	-	-	0	
16		Utility Electric Generation	-	-	-	0	
17		NGV	-	-	-	0	
18		Subtotal-NONCORE	4.2	4.1	4.1	4.1	
19		Co. Use & LUAF	0.2	0.2	0.2	0.2	
20	SYSTEM TOTAL THROUGHPUT (1)		23.7	23.7	23.8	23.8	
21	SYSTEM CURTAILMENT		-	-	-	0	
	TRANSPORTATION						
22	CORE	All End Uses	-	-	-	0	
23	NONCORE	Industrial	2.0	2.0	2.0	2.0	
24		Non-EOR Cogeneration	0.9	0.9	0.9	0.9	
25		EOR	-	-	-	0	
26		Utility Electric Generation	-	-	-	0	
27		Subtotal NONCORE	3.0	2.9	2.9	3.0	
28	TOTAL TRANSPORTATION		3.0	2.9	2.9	3.0	

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

TABLE 3-LB

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

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

TABLE 6- LB

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2018 THRU 2020

1 in 35 TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2018	2019	2020	2021	LINE
1	California Source Gas						
2	Out-of-State Gas						
3	TOTAL CAPACITY AVAILABLE						
	GAS SUPPLY TAKEN						
4	California Source Gas		0.8	0.7	0.7	0.7	
5	Out-of-State Gas		26.9	27.0	27.1	27.2	
6	TOTAL SUPPLY TAKEN		27.7	27.7	27.8	27.9	
7	Net Underground Storage Withdrawal		-	-	-	-	
8	TOTAL THROUGHPUT (1)		27.7	27.7	27.8	27.9	
	REQUIREMENTS FORECAST BY END-USE (1)						
9	CORE	Residential	16.3	16.4	16.5	16.5	
10		Commercial	5.8	5.8	5.9	5.9	
11		NGV	0.6	0.6	0.6	0.6	
12		Subtotal-CORE	22.8	22.9	23.0	23.0	
13	NONCORE	Industrial	3.5	3.5	3.5	3.5	
14		Non-EOR Cogeneration	1.2	1.1	1.1	1.1	
15		EOR	-	-	-	-	
16		Utility Electric Generation	-	-	-	-	
17		NGV	-	-	-	-	
18		Subtotal-NONCORE	4.6	4.6	4.6	4.6	
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	
20	SYSTEM TOTAL THROUGHPUT (1)		27.7	27.7	27.8	27.9	
21	SYSTEM CURTAILMENT		-	-	-	-	
	TRANSPORTATION						
22	CORE	All End Uses	-	-	-	-	
23	NONCORE	Industrial	2.3	2.3	2.3	2.3	
24		Non-EOR Cogeneration	1.0	1.0	1.0	1.0	
25		EOR	-	-	-	-	
26		Utility Electric Generation	-	-	-	-	
27		Subtotal NONCORE	3.3	3.3	3.3	3.3	
28	TOTAL TRANSPORTATION		3.3	3.3	3.3	3.3	

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

TABLE 7-LB

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

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

2018 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

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 880,394 customers in San Diego County in 2017, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2017 were approximately 115 billion cubic feet (Bcf), which is an average of 314 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

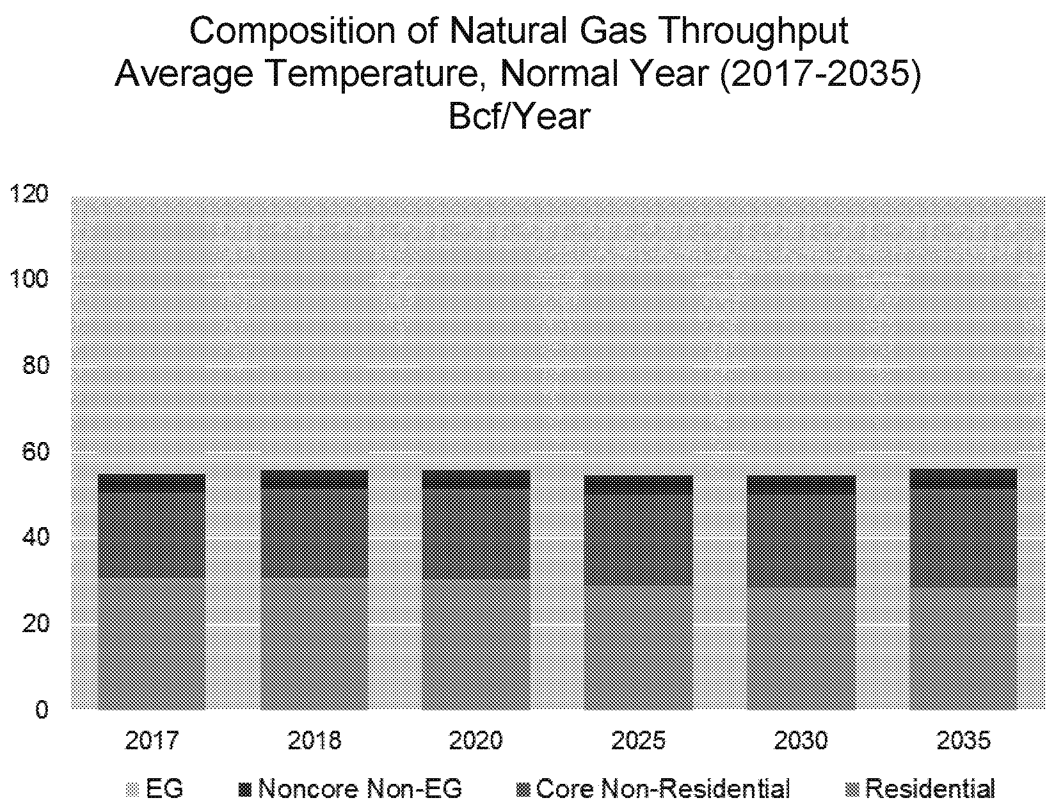
SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above.

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 2018 and 2035, steady at approximately 56 Bcf. Overall demand adjusted for average temperature conditions totaled 115 Bcf in 2017, down from 126 Bcf in 2015. By the year 2035, the total demand is expected to decline to 103 Bcf. The change reflects an annual average decline of 0.40 percent.

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

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. San Diego County's total employment is forecasted to grow an average of 0.8 percent annually from 2018 to 2035; the subset of industrial (mining and manufacturing) jobs is projected to grow about 0.1 percent per year during the same period. From 2018 to 2035, the county's inflation-adjusted Gross Product is expected to average decent 2.2 percent annual growth. (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 0.73 percent annually from 2018 through 2035.



SDG&E's forecasted gas demand is expected to decline at an average annual rate of 0.4 percent. The decline is driven by future projected reductions in the EG load. Additional factors pulling the load forecast down are energy efficiency programs and new requirements on Title 24 building codes and standards.

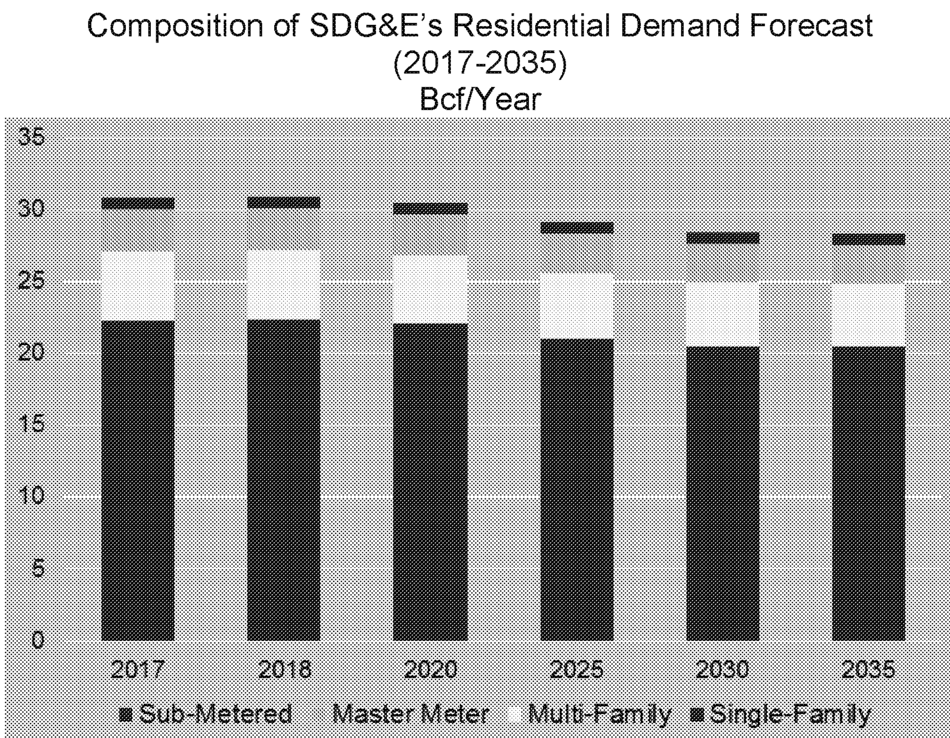
MARKET SECTORS

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 850,136 in 2017. This total reflects a 10,148 meter increase relative to the 2015 total. Overall residential meter growth from 2015-2017 averaged 0.60 percent per year.

Residential demand adjusted for average temperature conditions totaled 31 Bcf in 2017. By the year 2035, the residential demand is expected to drop to 28 Bcf. The change reflects a 0.47 percent average annual rate of decline.

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.

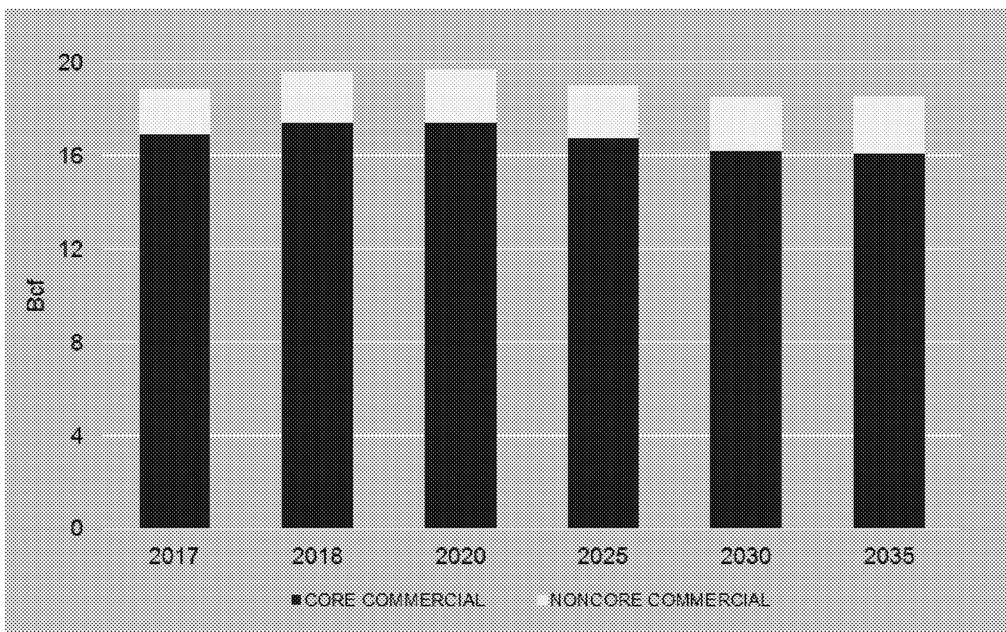


Commercial

On a temperature-adjusted basis, the core commercial demand in 2017 totaled 16.9 Bcf. By the year 2035, the SDG&E core commercial load is expected to decline to 16.1 Bcf.

SDG&E's non-core commercial load in 2017 was 1.9 Bcf. Over the forecast period, gas demand in this market is projected to grow an average of 1.3 percent per year to 2.4 Bcf by 2035, driven by increased economic activity and employment

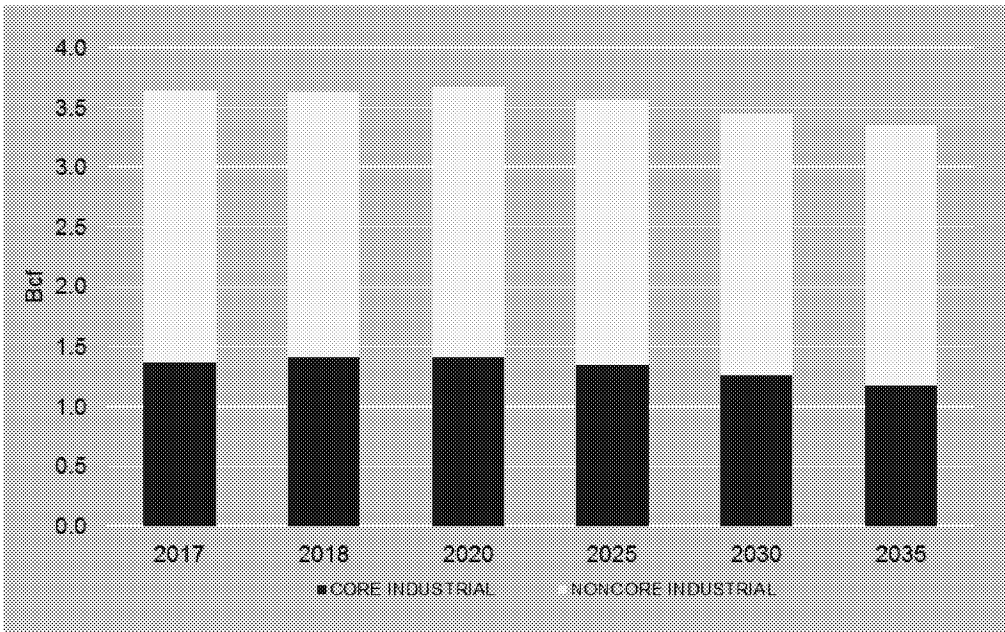
Commercial Sector's Natural Gas Demand Forecast
2017-2035
Bcf/year



Industrial

In 2017, temperature-adjusted core industrial demand was 1.37 Bcf. By 2035, the core industrial load is expected to decline to 1.18 Bcf. The core industrial market demand is projected to decrease at an average rate of 0.8 percent per year. 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.

SDG&E
Industrial Sector's Natural Gas Demand Forecast
(2017-2035)
Bcf/Year

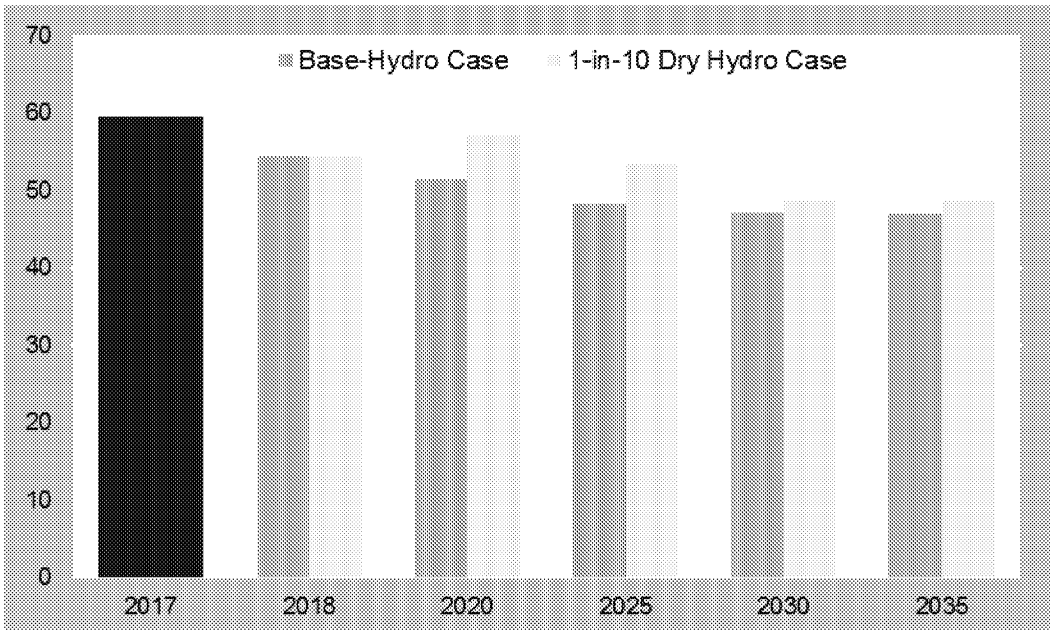


Non-core industrial load in 2017 was 2.3 Bcf and is expected to shrink about 0.2 percent per year to 2.2 Bcf by 2035. Demand-dampening effects of higher carbon-allowance fees will more than offset slight increases from economic growth.

Electric Generation

Total EG, including cogeneration and non-cogeneration EG, was 60 Bcf in 2017, down from 72 Bcf in 2015, as reported in the 2016 California Gas Report. EG load is expected to decline another 5 Bcf in 2018 and eventually decline to 47 Bcf by the year 2035. The average annual rate of decline is 1.3 percent for the period 2017-2035. 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
2017-2035
(Bcf/Year)



Cogeneration

Small Electric Generation load from self-generation totaled 8.5 Bcf in 2017. By 2035, small EG load is expected to rise to 8.8 Bcf – growing an average of 0.2 percent per year reflecting economic growth, partly offset by impacts of higher carbon-allowance fees.

Electric Generation Including Large Cogeneration (>20 MW)

The forecast of large EG loads in SDG&E's service area is based on the power market simulation noted in SoCalGas' EG chapter for "Electric Generation Including All Cogeneration". EG demand is forecasted to decrease from 46 Bcf in 2018 to 38 Bcf in 2030. This forecast includes approximately 500 MW of new thermal peaking generating resources in its service area by end of 2018. However, it also assumes that approximately 859 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 5 Bcf per year. For additional information on EG assumptions, such as renewable generation, GHG adders and sensitivity to electric demand and attainment of renewables' goals, refer to the Electric Generation section of the SoCalGas Electric Generation chapter.

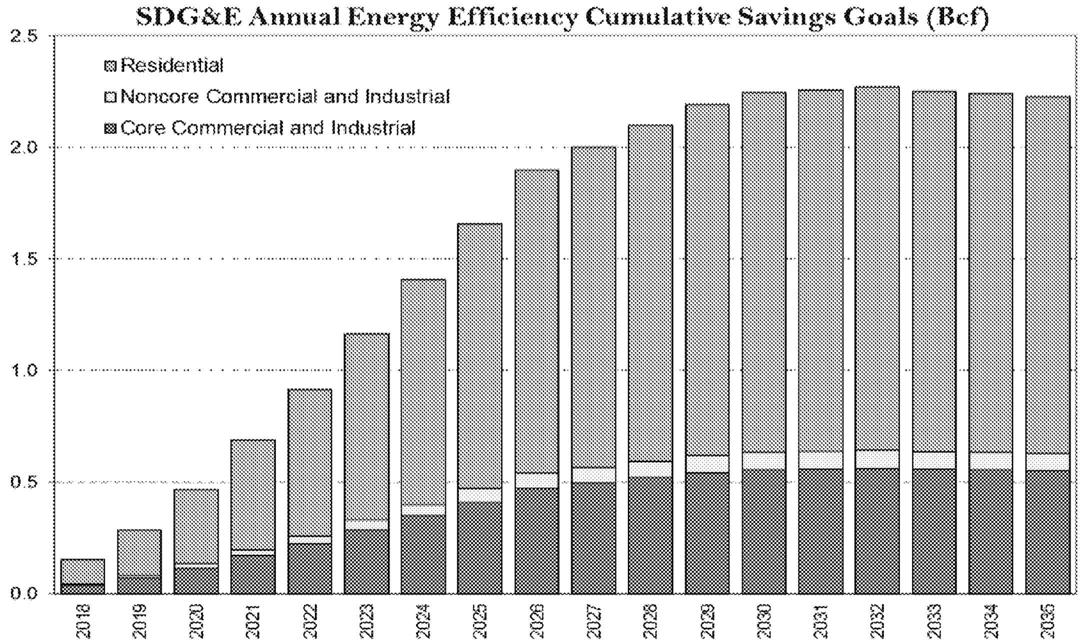
Natural Gas Vehicles (NGV)

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, and the cost differential between petroleum (gasoline and diesel) and natural gas, which although shrank over the past few years is beginning to increase, and is expected to reach a margin that will make NGVs much more economically attractive. At the end of 2017, there were 34 compressed natural gas (CNG) fueling stations delivering 1.77 Bcf of natural gas during the year. The NGV market is expected to grow at an annual rate of 7.1 percent 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 2018 and occurring through the year 2035 in addition to the Title 24 Codes and Standards expected over the 2018-2035 horizon. Savings and goals for these programs are based on the program goals authorized by the Commission in D.17-09-025.



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.

2018 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY
TABULAR DATA

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND SENDOUT (MMCF/DAY)
RECORDED YEARS 2013-2017

LINE	Actual Deliveries by End-Use		2013	2014	2015	2016	2017
1	**CORE**	Residential	85	68	67	71	72
2		Commercial	52	49	49	51	52
3		Industrial	0	0	0	-	-
4	*Subtotal -*	*CORE*	137	117	116	122	124
5	**NONCORE**	Commercial	0	0	0	-	-
6		Industrial	12	11	11	12	11
7		Non-EOR Cogen/EG	70	72	74	60	71
8		Electric Utilities	147	121	126	99	92
9	*Subtotal -*	*NONCORE*	229	204	211	171	174
10	**WHOLESALE**	All End Uses	0	0	0	-	-
11	*Subtotal -*	*Co Use & LUAF*	5	2	9	(3)	1
12	**SYSTEM TOTAL THROUGHPUT**		371	323	336	290	299
	Actual Transport & Exchange						
13	**CORE**	Residential	1	1	1	1	1
14		Commercial	12	11	12	13	13
15	**NONCORE**	Industrial	12	11	11	12	11
16		Non-EOR Cogen/EG	70	72	74	60	71
17		Electric Utilities	147	121	126	99	92
18	*Subtotal -*	*RETAIL*	242	216	224	185	188
19	**WHOLESALE**	All End Uses	0	0	0	-	-
20	**TOTAL TRANSPORT & EXCHANGE**		242	216	224	185	188
	Storage						
21		*Storage Injection*	0	0	0	-	-
22		*Storage Withdrawal*	0	0	0	-	-
	Actual Curtailment						
23		Residential	0	0	0	-	-
24		Com/Indl & Cogen	0	0	0	-	-
25		Electric Generation	0	0	0	-	-
26	**TOTAL CURTAILMENT**		0	0	0	-	-
27	**REFUSAL**		0	0	0	-	-
	ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes						
		MMbtu/Mcf:	1.024	1.035	1.040	1.036	1.040

NB: This file and MMCFD Supplies are used in the odd year reports (see P 17-18 of CGR)

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY TAKEN (MMCF/DAY)

RECORDED YEARS 2013-2017

LINE		2013	2014	2015	2016	2017
	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	2013	2014	2015	2016	2017
	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	129	107	112	105	111
18	Out-of-State Transport-Others	242	216	224	185	188
19	**Total Out-of-State Gas**	371	323	336	290	299
20	**TOTAL Gas Supply Taken & Transported**	371	323	336	290	299
	(MMCFD)					

TABLE 1-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2018 THRU 2022

AVERAGE TEMPERATURE YEAR

LINE			2018	2019	2020	2021	2022	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		306	302	296	295	291	5
6	TOTAL SUPPLY TAKEN		306	302	296	295	291	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		306	302	296	295	291	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	85	84	83	83	81	9
10		Commercial	48	48	48	48	47	10
11		Industrial	4	4	4	4	4	11
12		NGV	5	6	6	6	7	12
13		Subtotal-CORE	142	142	141	141	139	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	149	145	141	140	138	16
17		Subtotal-NONCORE	161	157	153	152	150	17
18		Co. Use & LUAF	3	3	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		306	302	296	295	291	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	15	15	15	16	16	20
21	NONCORE	Commercial/Industrial	12	12	12	12	12	21
22		Electric Generation (EG)	149	145	141	140	138	22
23	TOTAL TRANSPORTATION & EXCHANGE		176	172	168	168	166	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/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual value based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2018 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

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:

	2018	2019	2020	2021	2022
transportation (CAT) in MDth/d:	132	132	131	130	128

TABLE 2-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2023 THRU 2035

AVERAGE TEMPERATURE YEAR

LINE			2023	2024	2025	2030	2035	LINE
	CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas 1/		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Out-of-State		287	285	284	280	286	5
6	TOTAL SUPPLY TAKEN		287	285	284	280	286	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		287	285	284	280	286	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	81	80	80	78	78	9
10		Commercial	47	46	46	44	44	10
11		Industrial	4	4	4	3	3	11
12		NGV	7	8	8	12	17	12
13		Subtotal-CORE	139	138	138	137	142	13
14	NONCORE	Commercial	6	6	6	6	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	134	133	132	129	129	16
17		Subtotal-NONCORE	146	145	144	141	142	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		287	285	284	280	286	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	16	16	17	19	22	20
21	NONCORE	Commercial/Industrial	12	12	12	12	13	21
22		Electric Generation (EG)	134	133	132	129	129	22
23	TOTAL TRANSPORTATION & EXCHANGE		162	161	161	160	164	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/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual value based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2018 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

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:

	2023	2024	2025	2030	2035
transportation (CAT) in MDth/d:	128	127	126	123	125

TABLE 3-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2018 THRU 2022

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

LINE			2018	2019	2020	2021	2022	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Out-of-State		316	327	322	323	318	5
6	TOTAL SUPPLY TAKEN		316	327	322	323	318	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		316	327	322	323	318	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	93	92	91	91	89	9
10		Commercial	50	50	50	50	49	10
11		Industrial	4	4	4	4	4	11
12		NGV	5	6	6	6	7	12
13		Subtotal-CORE	152	152	151	151	149	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	149	160	156	157	154	16
17		Subtotal-NONCORE	161	172	168	169	166	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		316	327	322	323	318	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	15	16	16	16	16	20
21	NONCORE	Commercial/Industrial	12	12	12	12	12	21
22		Electric Generation (EG)	149	160	156	157	154	22
23	TOTAL TRANSPORTATION & EXCHANGE		176	188	184	185	182	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/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual value based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2018 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

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:

	2018	2019	2020	2021	2022
transportation (CAT) in MDth/d:	142	141	140	140	138

TABLE 4-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2023 THRU 2035

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

LINE			2023	2024	2025	2030	2035	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		574	574	574	574	574	2
3	TOTAL CAPACITY AVAILABLE		574	574	574	574	574	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Out-of-State		312	309	309	296	299	5
6	TOTAL SUPPLY TAKEN		312	309	309	296	299	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		312	309	309	296	299	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	89	88	88	86	85	9
10		Commercial	49	48	48	46	46	10
11		Industrial	4	4	4	4	3	11
12		NGV	7	8	8	12	17	12
13		Subtotal-CORE	149	148	148	148	151	13
14	NONCORE	Commercial	6	6	6	6	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	148	146	146	134	133	16
17		Subtotal-NONCORE	160	158	158	146	146	17
18		Co. Use & LUAF	3	3	3	2	2	18
19	SYSTEM TOTAL THROUGHPUT		312	309	309	296	299	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	16	17	17	19	22	20
21	NONCORE	Commercial/Industrial	12	12	12	12	13	21
22		Electric Generation (EG)	148	146	146	134	133	22
23	TOTAL TRANSPORTATION & EXCHANGE		176	175	175	165	168	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/ Nominal capacity to receive gas from the Southern Zone of SoCalGas is based on current conditions, and is an annual value based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2018 and after, assume capacity at same levels. Actual capacity through the CGR timeframe is subject to change.

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:

	2023	2024	2025	2030	2035
transportation (CAT) in MDth/d	138	136	136	134	134

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2018 CALIFORNIA GAS REPORT

GLOSSARY

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AAEE

Additional Achievable Energy Efficiency.

AAPV

Additional Achievable Photovoltaic Scenario.

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.

BSCF

Billion Standard Cubic Feet.

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° 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.

Curtailment

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

DSM

Demand Side Management.

EE

Energy Efficiency.

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: 65°F; PG&E 60°F). A basis for computing how much electricity and gas are needed for space heating purposes. For example, for a 50°F 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.

IEPR

The Integrated Energy Policy Report.

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.

LCFS

Low carbon fuel standard.

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 utility's customers.

LUAF

Lost and Unaccounted For.

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° Fahrenheit and at a standard pressure of approximately 15 pounds per square inch.

MMCF/DAY

Million cubic feet of gas per day.

$MtCO^2e$

Metric Tons of CO^2 equivalent.

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.

O&M

Operations and Maintenance.

Off-System Sales

Gas sales to customers outside the utility's service area.**OIR**
Order Instituting Rulemaking.

Out-Of-State Gas

Gas from sources outside the state of California.

PHMSA

Pipeline and Hazardous Materials Safety Administration.

PMO

Program Management Office.

Priority of Service (SoCalGas + SDG&E)

In the event of a curtailment situation, SoCalGas and SDG&E curtail gas usage to customers in the following order:

- Up to 60 percent (November thru March) or 40 percent (April thru October) of dispatched electric generation load;
- Up to 100 percent of non-electric generation noncore except for refineries;
- Up to 100 percent of refineries and up to 100 percent of the remaining dispatched electric generation load;
- Non-Residential Core customers; and
- Residential Core customers.

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 than 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.

USA
Underground service alert.

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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2018 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 (*State-Wide Chairperson)*-SoCalGas/SDG&E
- Sharim Chaudhury- SoCalGas/SDG&E
- Scott Wilder-SoCalGas/SDG&E
- Erin Brooks----SoCalGas
- Athena Besa-SDG&E
- Andrew Sickles—SDG&E
- Igor Grinberg- PG&E
- Christopher Benitez-PG&E
- Todd Peterson-PG&E
- Jeff Huang - SoCalGas/SDG&E
- Michelle Clay-Ijomah-SDG&E
- Robert Gulliksen- CEC
- Angela Tanghetti - CEC
- Hazel Aragon-- CEC

Observers

- Franz Cheng– CPUC Energy Division
- Jean Spencer- CPUC Energy Division

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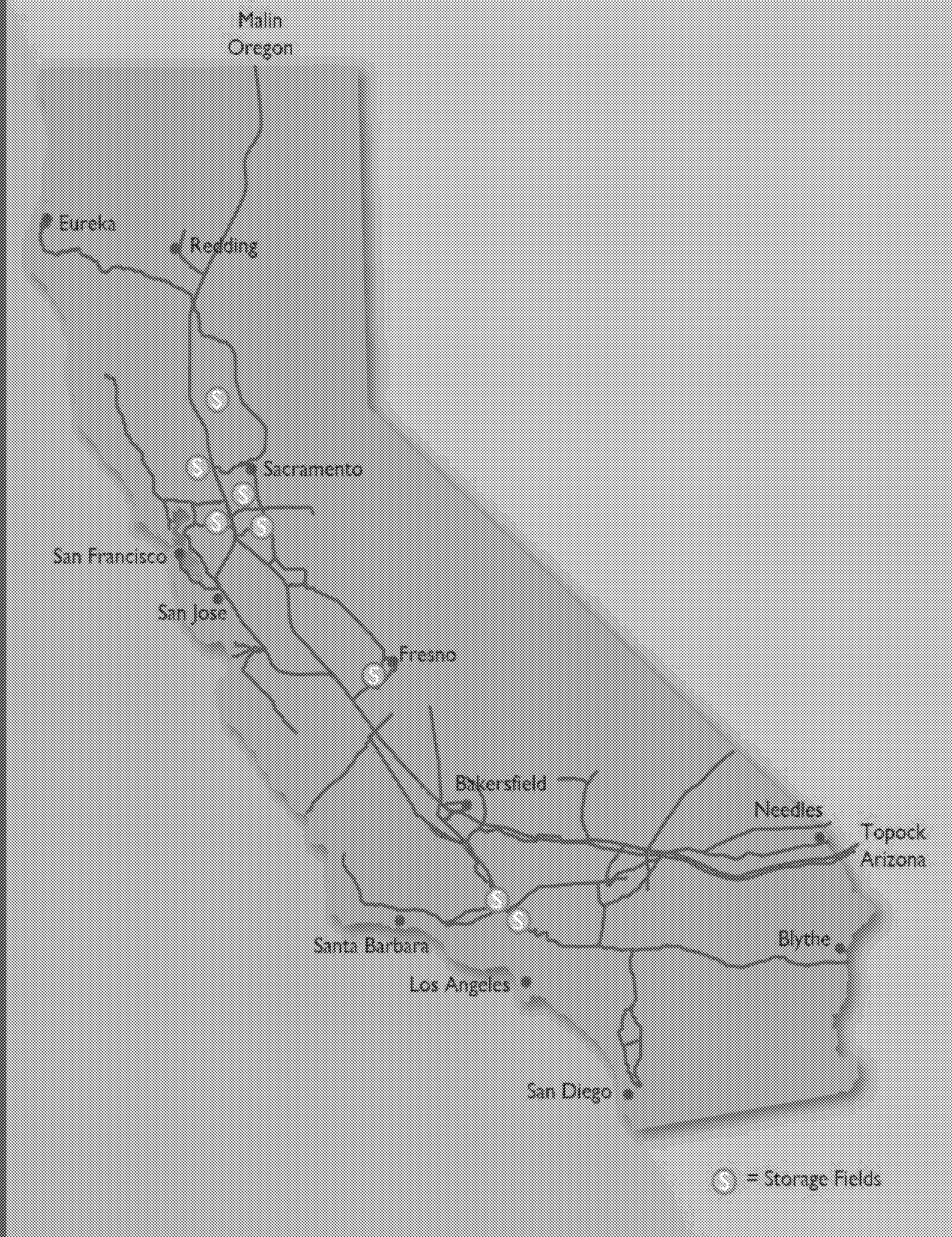
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