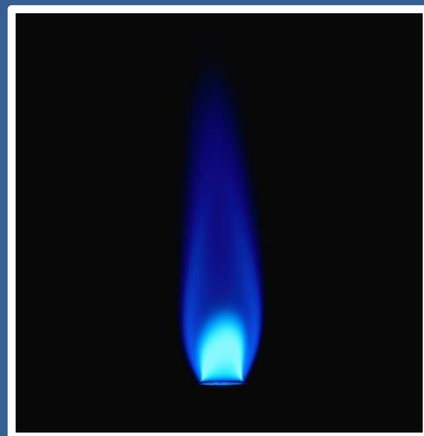
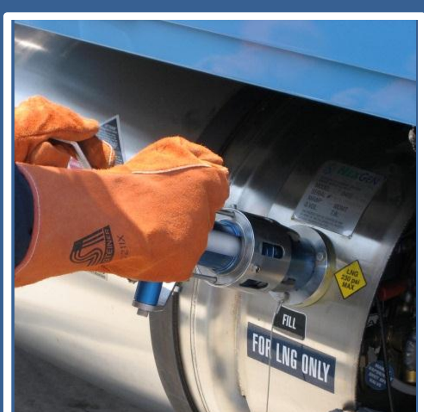
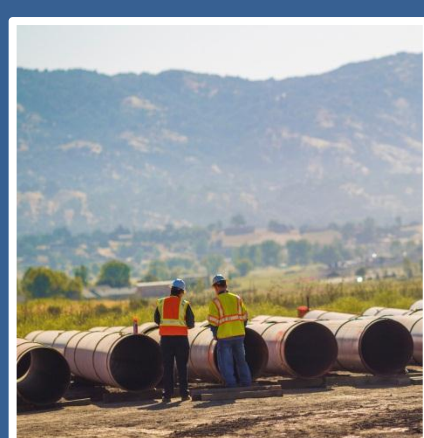
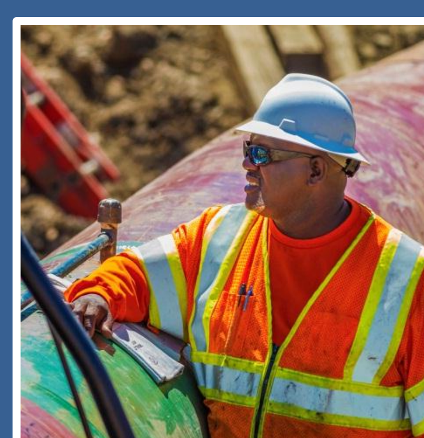
2016 CALIFORNIA GAS REPORT



Prepared by the California Gas and Electric Utilities







2016 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
Southern California Edison Company

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2016 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The 2016 *California Gas Report* presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2035. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years, in compliance with California Public Utilities Commission Decision D.95-01-039. The projections in the *California Gas Report* are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

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

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

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

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

2016 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

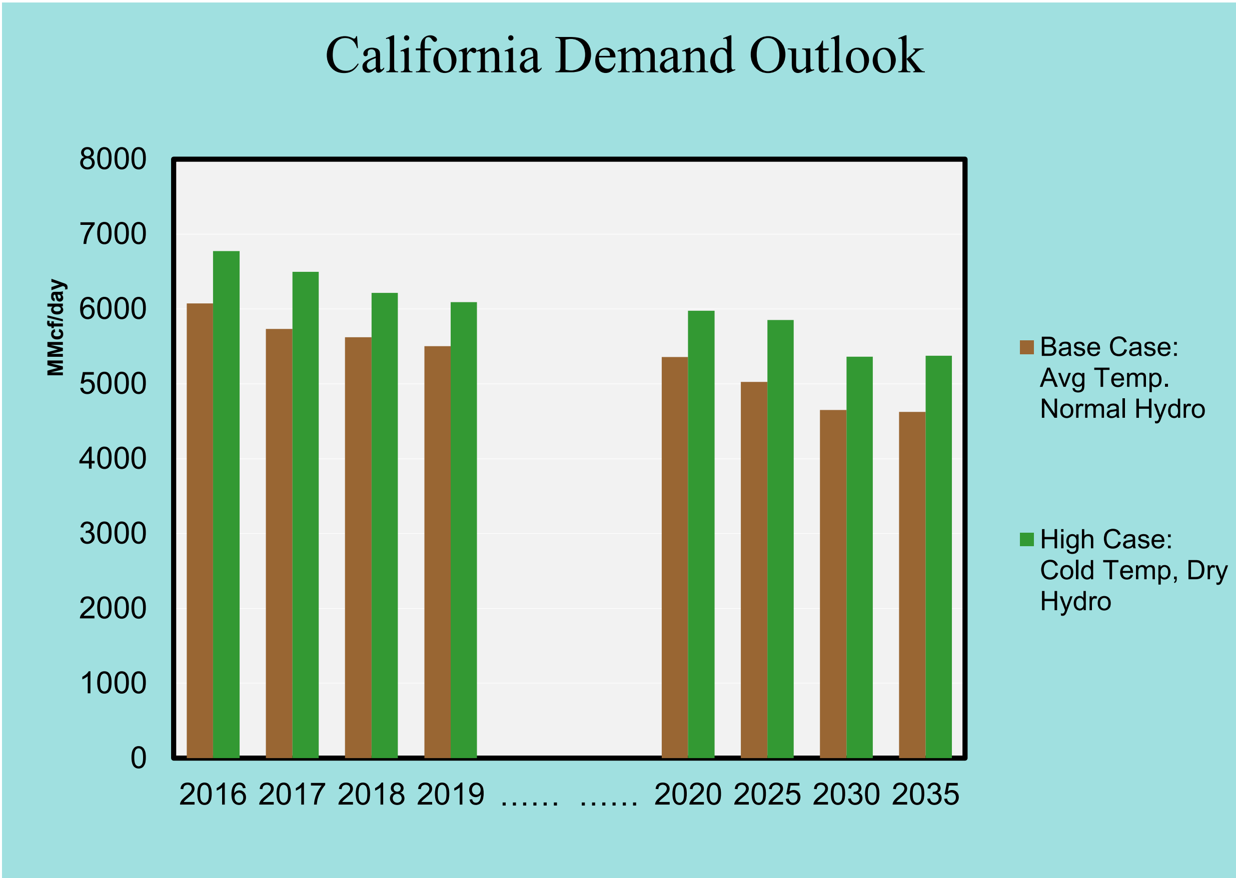
EXECUTIVE SUMMARY

DEMAND OUTLOOK

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

Residential gas demand is expected to decrease at an annual average rate of 0.5 percent. Demand in the commercial and industrial markets are expected to decline at an annual rate of 0.24 percent. Aggressive energy efficiency programs make a significant impact in managing growth in the residential, commercial, and industrial markets.

For the purpose of load-following as well as backstopping intermittent renewable resource generation, gas-fired generation will continue to be the primary technology to meet the ever-growing demand for electric power. However, overall gas demand for electric generation is expected to decline at 1.3 percent per year for the next 20 years due to more efficient power plants, statewide efforts to minimize greenhouse gas (GHG) emissions through aggressive programs pursuing demand-side reductions, and the acquisition of preferred power generation resources that produce little or no carbon emissions.



The graph above summarizes statewide gas demand under a base case and high case scenario. The base case refers to the expected gas demand for an average temperature year and normal hydroelectric power (hydro) year, and the high case refers to expected gas demand for a cold temperature year and dry hydro conditions. Under an average-temperature condition and a normal hydro year, gas demand for the state is projected to average 6,072 MMcf/d in 2016 decreasing to 4,626 MMcf/d by 2035, a decline of 1.35% per year.

In 2016, Northern California is projected to require an additional 2.3% of gas supply to meet demand for the high gas demand scenario, whereas southern California is projected to require an additional 4.0% of supply to meet demand under the high scenario condition. The weather scenario for each year is an independent event and each event has the same likelihood of occurring. The annual demand forecast for the base case and high case should therefore not be viewed as a combined event from year to year.

FOCUS ON EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on Customer Energy Efficiency (CEE) and other Demand-Side Management (DSM) programs in their utility electric and gas resource plans. California utilities are committed to helping their customers make the best possible choices regarding use of this increasingly valuable resource. Gas demand for electric power generation is expected to be moderated by CPUC-mandated goals for electric energy efficiency programs and renewable power. The base case forecasts in this report assume that renewable power will meet 33% of the state's electric needs by 2020 and 50% by 2030 and beyond.

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

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

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

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

Impact of Renewable Generation and Energy Efficiency Programs on Gas Demand

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

Notes:

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

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

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

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

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

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

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

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

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

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

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

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

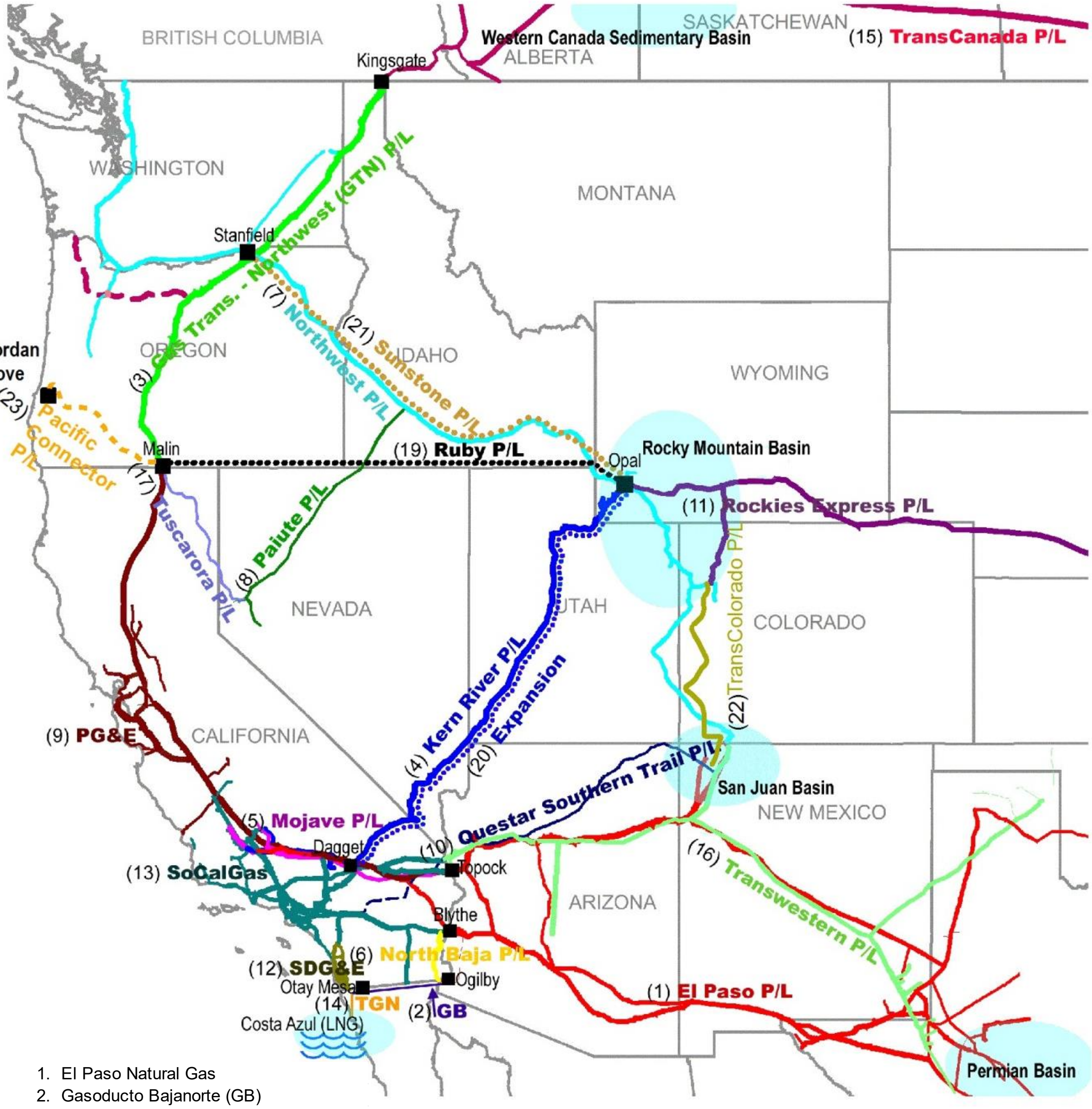
Over the past five years, California natural gas utilities, interstate pipelines, and in-state natural gas-storage facilities have increased their delivery and receipt capacity to meet natural gas demand growth. In addition, more projects have been proposed and some are under construction. The California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

Supply Outlook/Pipeline Capacity

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

Additional pipeline capacity and open access have contributed to long-term supply availability and gas-on-gas competition for the California market. In addition to Ruby, interstate pipelines currently serving California include El Paso Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission-Northwest, Transwestern Pipeline Company, Questar Southern Trails Pipeline, Tuscarora Pipeline, and the Baja Norte/North Baja Pipeline.

Western North American Natural Gas Pipelines



1. El Paso Natural Gas
2. Gasoducto Bajanorte (GB)
3. Gas Transmission Northwest (GTN)
4. Kern River Pipeline
5. Mojave Pipeline
6. North Baja Pipeline
7. Northwest Pipeline
8. Piute Pipeline
9. Pacific Gas & Electric Company
10. Questar Southern Trail Pipeline
11. Rockies Express
12. San Diego Gas & Electric Company
13. Southern California Gas Company
14. Transportadora de Gas Natural (TGN)
15. TransCanada Pipeline
16. Transwestern Pipeline
17. Tuscarora Pipeline
18. Unused
19. Ruby Pipeline
20. Kern River Expansion
21. Sunstone Pipeline
22. Transcolorado Pipeline
23. Pacific Connector Pipeline

Liquefied Natural Gas (LNG)

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

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

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

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

STATEWIDE CONSOLIDATED SUMMARY TABLES

The consolidated summary tables on the following pages show the statewide aggregations of projected gas supplies and gas requirements (demand) from 2016 to 2035 for average-temperature and normal-hydro years and cold-temperature and dry-hydro years.

Gas sales and transportation volumes are consolidated under the general category of system requirements. Details of gas transportation for individual utilities are given in the tabular data for Northern California and Southern California. The wholesale category includes the City of Long Beach Gas and Oil Department, San Diego Gas & Electric Company, Southwest Gas Corporation, City of Vernon, Alpine Natural Gas, Island Energy, West Coast Gas, Inc., and the municipalities of Coalinga and Palo Alto.

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

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

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

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

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

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

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.

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

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

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

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

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

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

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

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

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

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

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

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

Notes:

(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.

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

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

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

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

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

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(2) Includes utility generation, wholesale generation, and cogeneration.
(3) The difference between California supply sources and California requirements is PG&E's forecast of off-system deliveries.
(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

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

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

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

Notes:
(1) Includes utility purchases and exchange/transport gas.
(2) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.
(3) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(4) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

STATEWIDE ANNUAL GAS REQUIREMENTS [1]
Cold Temperature [7] and Dry Hydro Year
MMcf/Day

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

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

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

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

Notes:
(1) Includes transportation gas.
(2) Electric generation includes cogeneration, PG&E-owned electric generation, and deliveries to power plants connected to the PG&E system. It excludes deliveries by the Kern Mojave and other pipelines.
(3) Northern Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

STATEWIDE RECORDED SOURCES AND DISPOSITION

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

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

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

Recorded 2011 Statewide Sources and Disposition Summary
MMcf/Day

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

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

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

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

Recorded 2012 Statewide Sources and Disposition Summary

MMcf/Day

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

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

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

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

Recorded 2013 Statewide Sources and Disposition Summary

MMcf/Day

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

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

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

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

Recorded 2014 Statewide Sources and Disposition Summary
MMcf/Day

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

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

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

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

Recorded 2015 Statewide Sources and Disposition Summary
MMcf/Day

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

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

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

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

STATEWIDE RECORDED HIGHEST SENDOUT

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

Estimated California Highest Summer Sendout (MMcf/d [4])

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

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

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

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

2016 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

Pacific Gas and Electric Company (PG&E) provides natural gas procurement, transportation, and storage services to 4.2 million residential customers and over 229,000 businesses in northern and central California. In addition to serving residential, commercial, and industrial markets, PG&E provides gas transportation and storage services to a variety of gas-fired electric generation plants in its service area. Other wholesale distribution systems, which receive gas transportation service from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are located in 37 counties from south of Bakersfield to north of Redding, with high concentrations in the San Francisco Bay Area and the Sacramento and San Joaquin valleys. In addition, some customers also utilize the PG&E system to meet their gas needs in Southern California.

The Northern California section of the report begins with an overview of the gas demand forecast followed by a discussion of the forecast methodology, economic conditions, and other factors affecting demand in various markets, including the regulatory environment. Following the gas demand forecast are discussions of gas supply and pipeline capacity. Abnormal Peak Day (APD) demands and supply resources, as well as gas balances, are discussed at the end of this section.

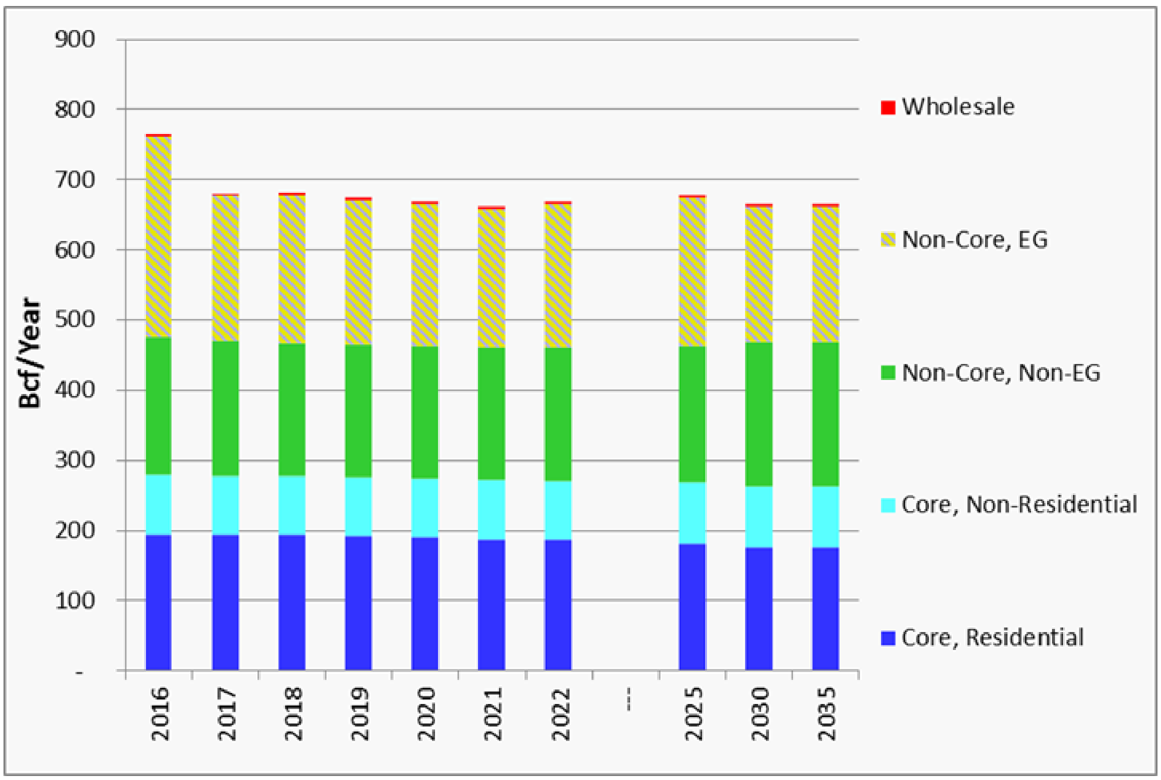
The forecast in this report covers the years 2016 through 2035. However, as a matter of convenience, the tabular data at the end of the section show only the years 2016 through 2022, and the years 2025, 2030, and 2035.

GAS DEMAND

OVERVIEW

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

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



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

The forecast rate of growth of the noncore electric generation market has decreased due to higher levels of renewable generation to meet the 50 percent goal in 2030 and higher gas transmission rates for electric generators. In this CGR, total gas demand by electric generators and cogenerators in Northern California for average hydrological conditions is estimated to decrease at a rate of about 0.4 percent per year from 2017 through 2035 (the forecast assumes that new rates from PG&E's 2015 Gas Transmission and Storage (GT&S) Rate Case are effective in November 2016). This total gas demand excludes gas delivered by nonutility pipelines to electric generators and cogenerators in PG&E's service area, such as deliveries by the Kern/Mojave pipelines to the La Paloma and Sunrise plants in central California. In addition, increasing quantities of renewable energy generation are expected to increase the need for load following and ancillary services such as regulation. These ancillary services are likely to be provided by gas-fired power plants, thus, affecting gas demand to some extent. PG&E's 2016 CGR forecast, however, does not capture this impact.

FORECAST METHOD

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

FORECAST SCENARIOS

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

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

Temperature Assumptions

Because space heating accounts for a high percentage of use, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. In previous CGRs, PG&E's average-year demand forecast assumed that temperatures in the forecast period would be equivalent to the average of observed temperatures during the past 20 years. PG&E is now building into its forecast an assumption of climate change. The climate change scenario is developed from work done at the National Center for Atmospheric Research (Boulder, Colorado), downscaled to the PG&E service area. Although the near-term temperatures of this scenario differ little from long-term averages, the years beyond 2016 begin to show the effects of a warming climate. For example, in 2020, total December/January heating degree days are only 3 percent below the 20-year average. By 2035, however, the impact is more significant, with the difference at 7 percent.

Of course, actual temperatures in the forecast period will be higher or lower than those assumed in the climate-change scenario and gas use will vary accordingly. PG&E's high-demand forecast assumes that winter temperatures in the forecast horizon will be the same as those that prevailed during November 2000-October 2001 and November 2009-October 2010.

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

Hydro Conditions

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

Gas Price and Rate Assumptions

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

MARKET SECTORS

Residential

Households in the PG&E service area are forecast to grow 0.5 percent annually from 2016-2035. However, gas use per household has been dropping in recent years due to improvements in appliance and building-shell efficiencies. This decline accelerated sharply in 2001 when gas prices spiked, causing temperature-adjusted residential gas demand to plunge by more than 8 percent. After recovering somewhat in 2002 and 2003, temperature-adjusted gas use per household reverted to its long-term trend and, despite slight upticks in 2009 and 2010 due to cold winters, has fallen on average 1.6 percent per year since 2004. Total residential demand is expected to decrease despite household growth due to continuing upgrades in appliance and building efficiencies, as well as warming temperatures.

Commercial

The number of commercial customers in the PG&E service area is projected to grow on average by 0.4 percent per year from 2016-2035. The 2000-2001 noncore-to-core migration wave has caused this class to be less temperature-sensitive than it had previously been, and has also tended to stunt overall growth in both customer base and gas use per customer. Gas use per commercial customer is projected to decline slightly over the forecast horizon due to continuing EE efforts as well as warmer temperatures. Over the next 20 years commercial sales are expected to grow at 0.1 percent per year.

Industrial

Gas requirements for PG&E's industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector plummeted by close to 20 percent in 2001 due to a combination of increasing gas prices, noncore-to-core migration, and a manufacturing sector mired in a severe downturn. After a slight recovery in 2002, demand from this sector fell another 6 percent in 2003 but has seen slow growth in the recent past due to low natural gas prices and increased capacity at local refineries, though these effects have been tempered by the continuing structural change in California's manufacturing sector. PG&E observed historically high demand from the industrial sector in 2014 and 2015 due in part to refinery demand. While the industrial sector has the potential for high year-to-year variability, over the long-term, industrial gas consumption is expected to grow slowly at 0.2 percent annually over the next 20 years.

Electric Generation

This sector includes cogeneration and power plants. Forecasts for this sector are subject to greater uncertainty due to the retirement of existing power plants with once-through cooling; the timing, location, and type of new generation, particularly renewable-energy facilities; construction of new electric transmission lines; and the impact of greenhouse gas (GHG) policies and regulations on both generation and load. Because of these uncertainties, the forecast is held constant at 2030 levels for 2035.

PG&E forecasts gas demand for most cogenerators by assuming a continuation of past usage, with modifications for expected expansions or closures. In this CGR, PG&E has assumed no additions of new onsite and export (demand- and supply-side) combined heat-and-power plants and retirement of existing plants when they are 40 years old. Operations at most cogeneration plants are not strongly affected by prices in the wholesale electricity market, because electricity is generated with some other product, usually steam, for an industrial process.

PG&E forecasts gas demand by power plants and market-sensitive cogenerators using the MarketBuilder software. MarketBuilder enables the creation of economic-equilibrium models of markets with geographically distributed supplies and demands, such as the North American natural gas market. PG&E uses MarketBuilder to model the electricity market in the WECC, which encompasses the electric systems from the Rocky Mountains to the Pacific coast and from northern Baja California to British Columbia and Alberta.

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

Sacramento Municipal Utility District Electric Generation

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

SMUD owns and operates a pipeline connecting the Cosumnes combined-cycle plant and the three cogeneration plants to PG&E's backbone system near Winters, California. SMUD owns an equity interest of approximately 3.6 percent in PG&E's Line 300 and approximately 4.2 percent in Line 401 for about 85 MMcf/d of capacity.

GREENHOUSE GAS LEGISLATION/ASSEMBLY BILL 32

During the forecast horizon covered by this CGR, there are many uncertainties that may significantly impact the future trajectory of natural gas demand. It is unclear at this time what the ultimate effect on natural gas demand will be from California's landmark California Global Warming Solutions Act of 2006 (Assembly Bill 32, or AB 32) and Clean Energy and Pollution Reduction Act of 2015 (Senate Bill 350, or SB 350). On the one hand, more aggressive EE programs and/or increased targets for renewable electricity supplies could significantly reduce the use of natural gas by residential and commercial customers and power plants. On the other hand, increased penetration of electric and NGVs could reduce gasoline use and overall GHG emissions, but increase consumption of natural gas.

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

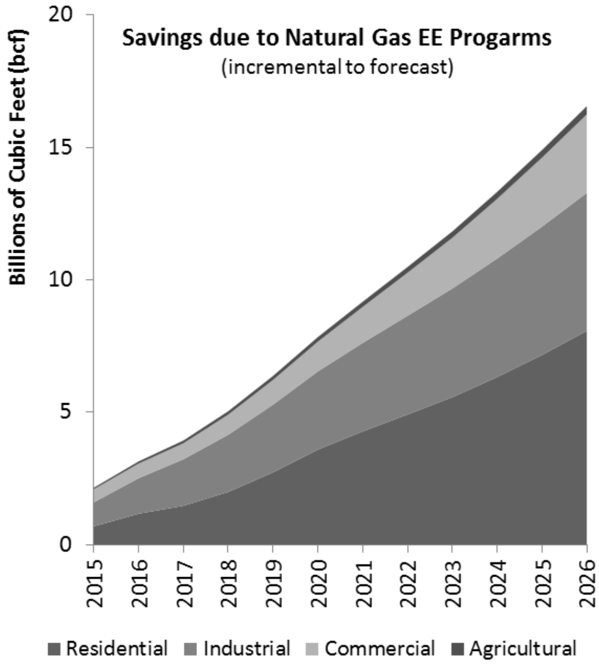
RENEWABLE ELECTRIC GENERATION

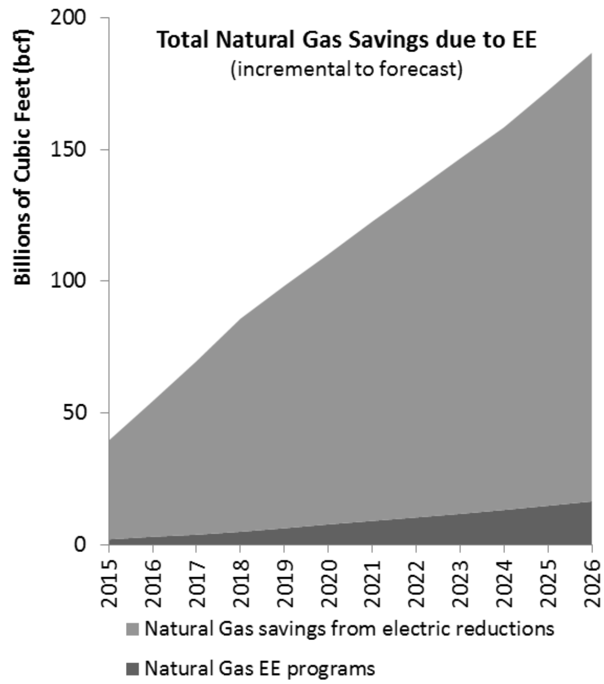
PG&E expects the growth of renewable electric generation due to higher renewable portfolios standards will result in a reduction in the demand for generation from natural gas-fueled resources. This overall reduction in demand may be accompanied by higher daily and hourly deviations between forecast and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

ENERGY EFFICIENCY PROGRAMS

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

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





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

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

Impact of SB 350 on Energy Efficiency

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

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

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

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

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

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

GAS SUPPLY, CAPACITY, AND STORAGE

OVERVIEW

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990s. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity and storage capacity have provided all customers with direct access to gas supplies, intra- and inter-state transportation, and related services.

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

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

GAS SUPPLY

California-Sourced Gas

Northern California-sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2015, PG&E's customers obtained on average 39 MMcf/d of California-sourced gas.

U.S. Southwest Gas

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

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

Canadian Gas

PG&E's customers can purchase gas from various suppliers in western Canada (British Columbia and Alberta) and transport it to California primarily through the Gas Transmission Northwest Pipeline. Likewise, they can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold inter- or intra-state pipeline capacity.

Rocky Mountain Gas

PG&E's customers have access to gas supplies from the Rocky Mountain area via the Kern River Pipeline, the Ruby Pipeline and via the Gas Transmission Northwest Pipeline interconnect at Stanfield, Oregon. The Ruby Pipeline came online in July 2011 and brings up to 1.5 billion cubic feet per day (bcf/d) of Rocky Mountain gas to Malin, Oregon. With Ruby pipeline, the share of Canadian gas to PG&E's system has been reduced somewhat while the Redwood path from Malin to PG&E Citygate has run at a higher utilization rate.

Storage

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

INTERSTATE PIPELINE CAPACITY

As a result of pipeline expansion and new projects, California utilities and end-users benefit from improved access to supply basins and enhanced gas-on-gas and pipeline-on-pipeline competition. Interstate pipelines serving northern and central California include the El Paso, Mojave, Transwestern, Gas Transmission Northwest, Paiute Pipeline Company, Ruby, Southern Trails, and Kern River pipelines. These pipelines provide northern and central California with access to gas-producing regions in the U.S. Southwest and Rocky Mountain areas, and in western Canada.

U.S. Southwest and Rocky Mountains

PG&E's Baja Path (Line 300) is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Southern Trails, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 1,016 MMcf/d.

Canada and Rocky Mountains

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

GAS SUPPLIES AND INFRASTRUCTURE PROJECTS

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

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

Liquefied Natural Gas Imports/Exports

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

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

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

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

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

North American Supply Development

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

GAS STORAGE

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

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

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

Gas Quality

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

Pipeline Safety

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

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

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

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

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

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

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

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

Storage Safety

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

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

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

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

Core Gas Aggregation Program

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

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

FEDERAL REGULATORY MATTERS

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

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

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

Kern River Gas Transmission (Kern River)

There are currently no significant regulatory issues.

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

There are currently no significant regulatory issues.

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

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

Gas Transmission Northwest (GTN) and Canadian Pipelines

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

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

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

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

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

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

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

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

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

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

OTHER REGULATORY MATTERS

Gas Exports

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

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

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

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

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

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

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

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

California State Senate Bill 350

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

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

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

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

ABNORMAL PEAK DAY DEMAND AND SUPPLY

APD DEMAND FORECAST

The APD forecast is a projection of demand under extreme weather conditions. PG&E uses a 1-in-90-year cold-temperature event as the design criterion. This criterion corresponds to a 27 degree Fahrenheit system-weighted mean temperature across the PG&E gas system. The PG&E core demand forecast corresponding to a 27 degree Fahrenheit temperature is estimated to be approximately 3.2 bcf/d. The PG&E load forecast shown here excludes all noncore demand and, in particular, excludes all electric generation (EG) demand. PG&E estimates that total noncore demand during an APD event would be approximately 2.5 bcf/d, with EG demand comprising between one-half to two-thirds of the total noncore demand.

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

APD SUPPLY REQUIREMENT FORECAST

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

PG&E's Core Gas Supply Department is responsible for procuring adequate flowing supplies to serve approximately 78 percent of PG&E's core gas usage. Core aggregators provide procurement services for the balance of PG&E's core customers and have the same obligation as PG&E Core Gas Supply to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

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

If core supplies are insufficient to meet core demand, PG&E can divert gas from noncore customers, including EG customers, to meet it. PG&E's tariffs contain diversion and Emergency Flow Order (EFO) noncompliance charges that are designed to cause the noncore market to either reduce or cease its use of gas, if required. Since little, if any, alternate fuel-burn capability exists today, supply diversions from the noncore would necessitate those noncore customers to curtail operations. The implication for the future is that under supply-shortfall conditions such as an APD, a significant portion of EG customers could be shut down with the impact on electric system reliability left as an uncertainty.

As mentioned above, PG&E projects that in the near term, noncore demand, including gas-fired EG, on an APD would be approximately 2.5 bcf/d. With the Wild Goose, Lodi, Gill Ranch, and Central Valley Gas storage facilities, more noncore demand will be satisfied in the event of an APD. The availability of supply for any given high-demand event, such as an APD, is dependent on a wide range of factors, including the availability of interstate flowing supplies and storage inventories.

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

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

Notes:

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

(2) Core Firm Storage Withdrawal capacity includes 98 MMcf/day contracted with an on-system independent storage provider.

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

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

Winter Peak Day Demand
(Million Cubic Feet per Day)

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

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

Summer Peak Day Demand
(Million Cubic Feet per Day)

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

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

2016 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA
TABULAR DATA

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

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

NOTES:

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

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

(3) UEG curtailments include voluntary oil burns due to economic, operational, and inventory reduction reasons as well as involuntary curtailments due to supply shortages and capacity constraints.

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

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY

AVERAGE DEMAND YEAR

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

NOTES:

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

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

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

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

(5) Forecast by SMUD.

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

(7) Deliveries to southern California.

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY

AVERAGE DEMAND YEAR

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

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

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY

HIGH DEMAND YEAR (1 in 10 Cold Year)

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

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

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY

HIGH DEMAND YEAR (1 in 10 Cold Year)

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

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

2016 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

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

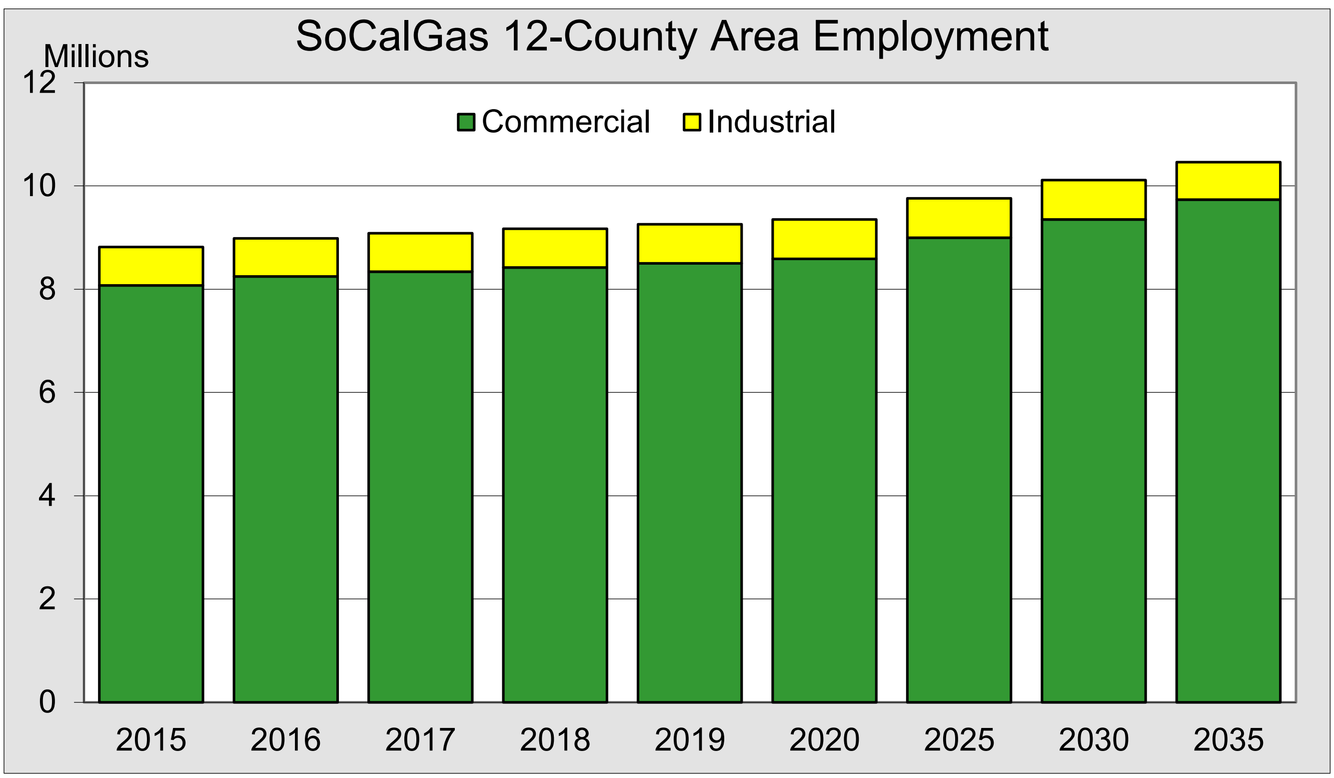
This report covers a 20-year demand and forecast period, from 2016 through 2035; only the consecutive years 2016 through 2022 and the point years 2025, 2030, and 2035 are shown in the tabular data in the next sections. These single point forecasts are subject to uncertainty, but represent best estimates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

The Southern California section of the *2016 California Gas Report* (CGR) begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The natural gas price forecast methodology used to develop the gas demand forecast is discussed followed by a review of the peak day demand forecast. Summary tables and figures underlying the forecast are also provided.

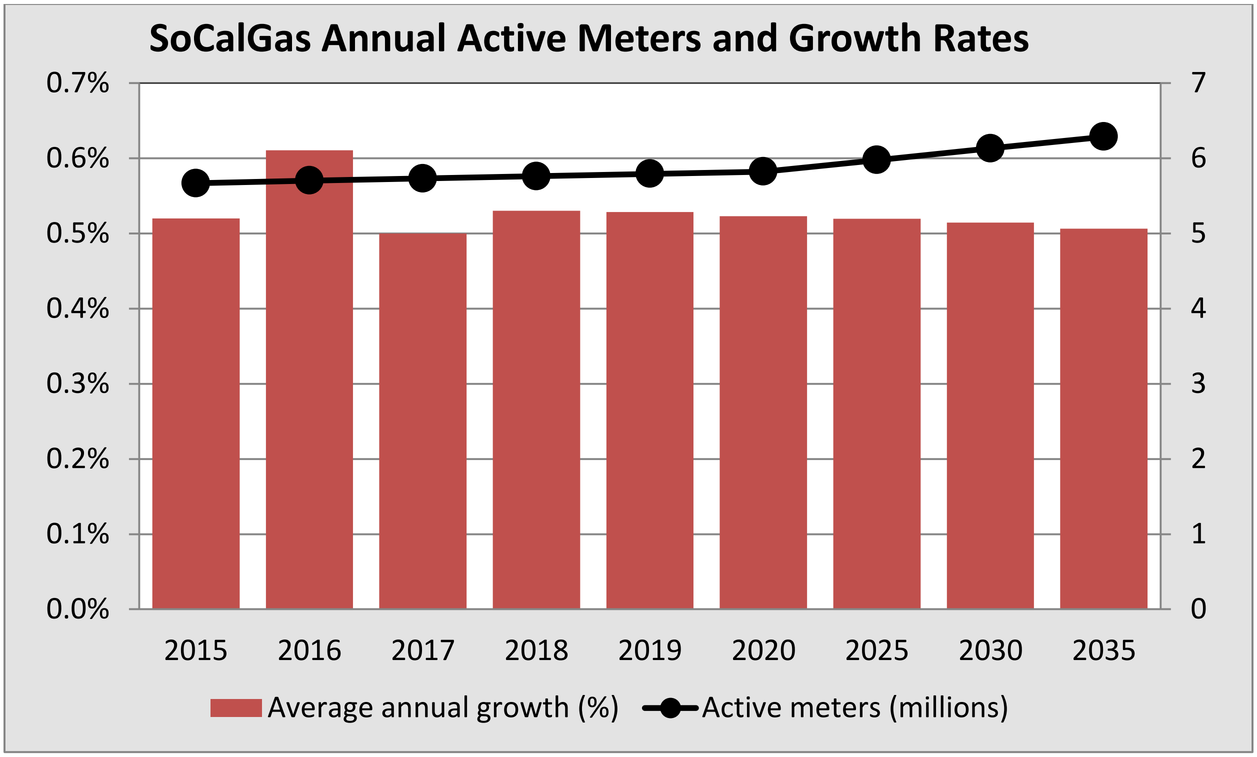
THE SOUTHERN CALIFORNIA ENVIRONMENT

ECONOMICS AND DEMOGRAPHICS

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



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



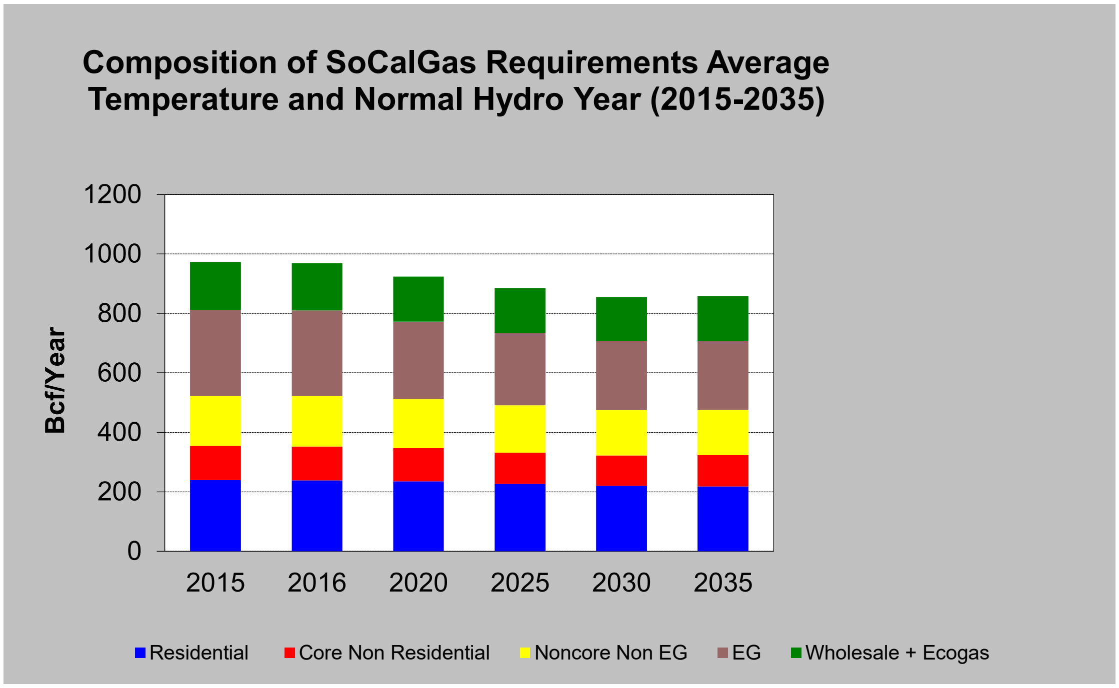
Since 2011, SoCalGas' service area housing market has gradually been recovering from its prior drastic downturn. Home building and meter hookups continue to increase modestly, with SoCalGas' annual active meters growing by about 29,000 (0.52%) in 2015. SoCalGas expects active meters to maintain moderate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

GAS DEMAND (REQUIREMENTS)

OVERVIEW

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

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



Notes:

(1) Core non-residential includes core commercial, core industrial, gas air-conditioning, gas engine, natural gas vehicles.
(2) Non-core non-EG includes non-core commercial, non-core industrial, industrial refinery, and EOR-steaming
(3) Retail electric generation includes industrial and commercial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(4) Wholesale includes sales to the City of Long Beach, City of Vernon, SDG&E, Southwest Gas and Ecogas in Mexico.

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

Market Sensitivity

Temperature

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

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

Hydro Condition

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

MARKET SECTORS

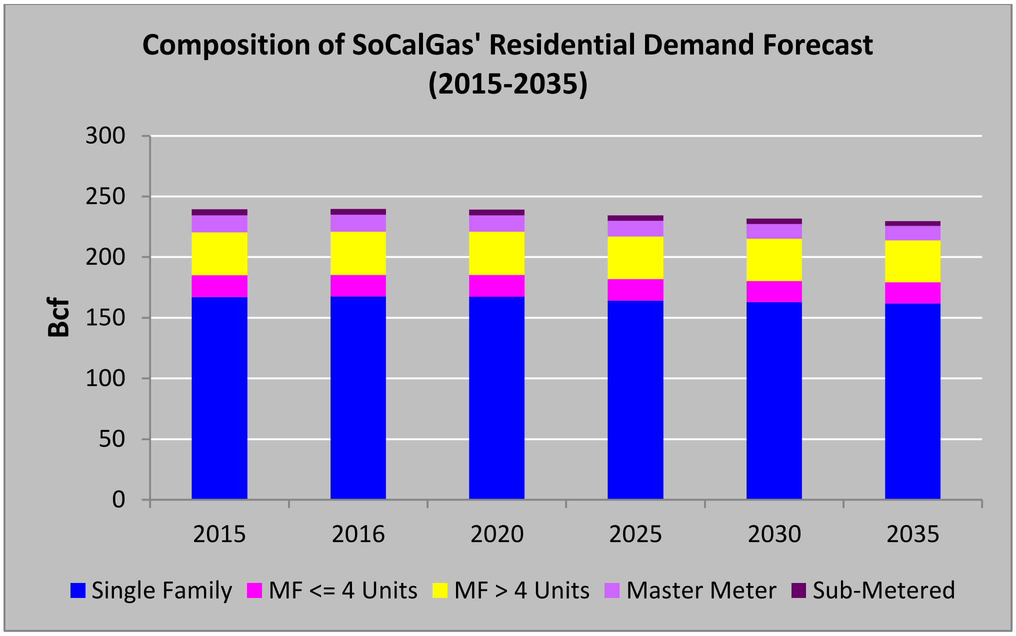
Residential

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

The total residential customer count for SoCalGas consists of five residential segment types: single family, small multi-family, large multi-family, master meter and sub-metered customers. The active meters for all residential customer classes were 5.46 million at the end of 2015. This amount reflects a 29,759 active meter increase between 2014 at year end and 2015 at year end. The overall observed 2014-2015 residential meter growth was 0.55%. Eight years before, the observed meter growth had been 53,326 new meters between 2006 and 2007, which amounts to an annual growth rate of 1.03%. The slowdown in active meter growth reflects more modest new home construction activity since the boom ended in 2007.

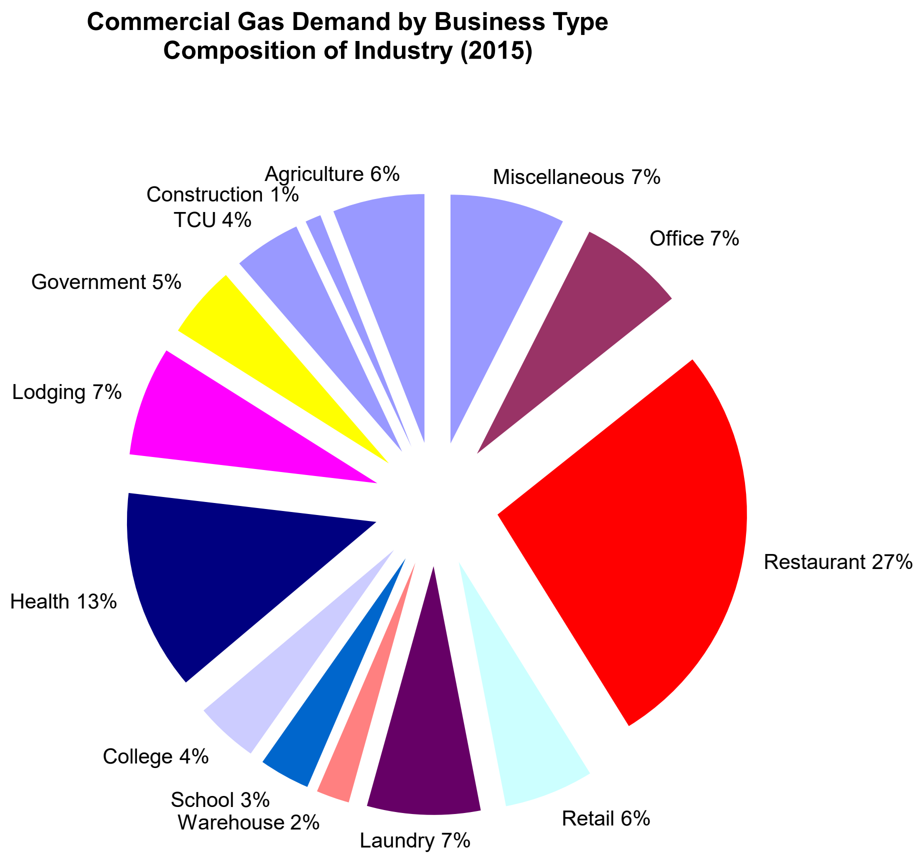
The 2016 CGR shows that in 2015, single family and overall multi-family temperature-adjusted average annual use per meter was 474 therms and 312 therms, respectively. Over the forecast period, the demand per meter is expected to decline at an average annual rate of 0.7%. The decline in use per meter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

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



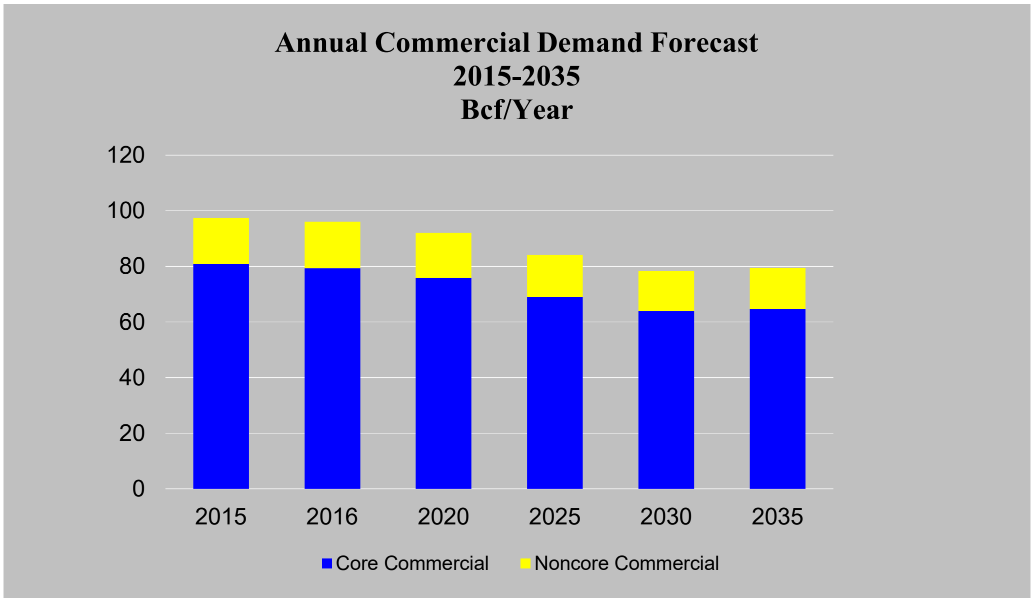
Commercial

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



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

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



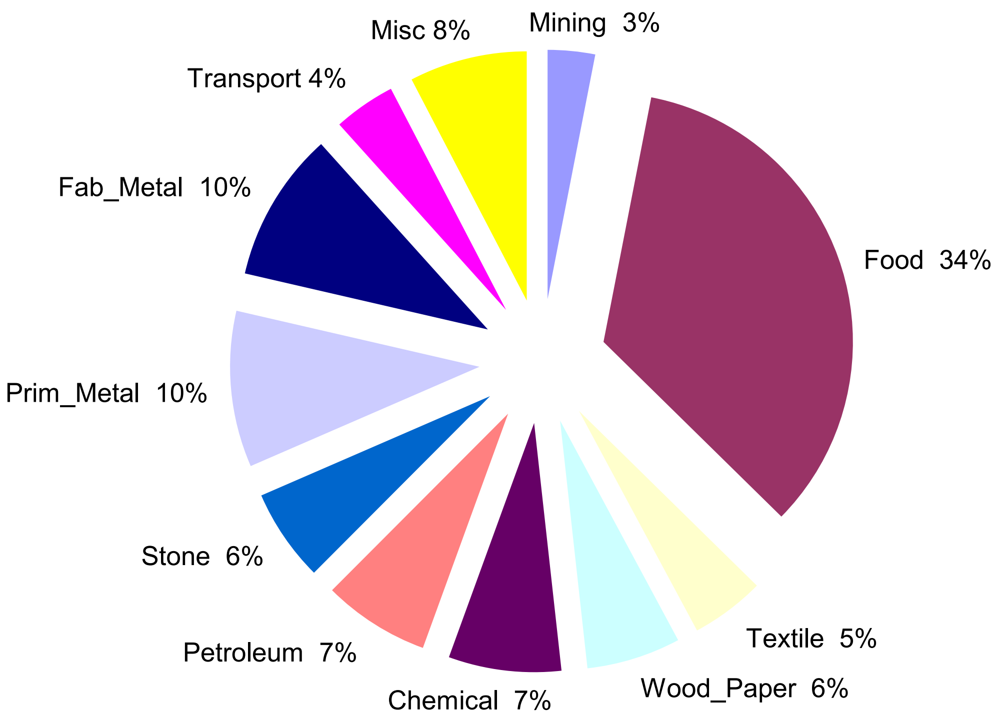
Industrial

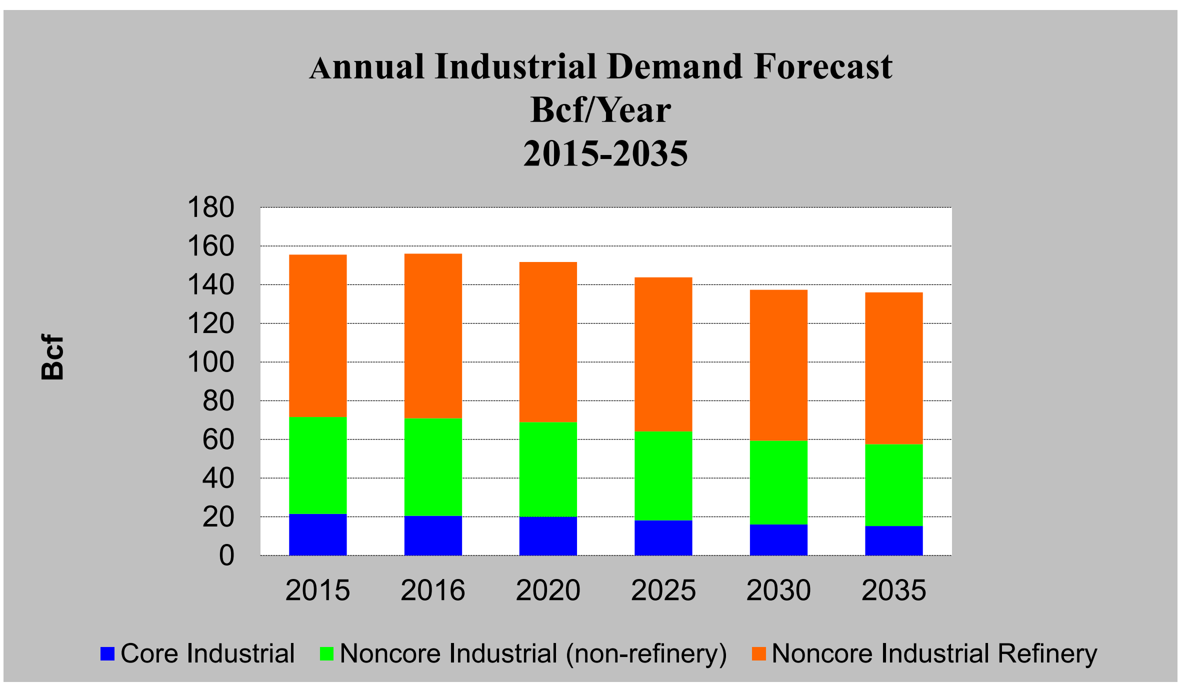
Non-Refinery Industrial Demand

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

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

Non-Refinery Industrial Gas Demand by Business Types
Composition of Industrial Activity (2015)



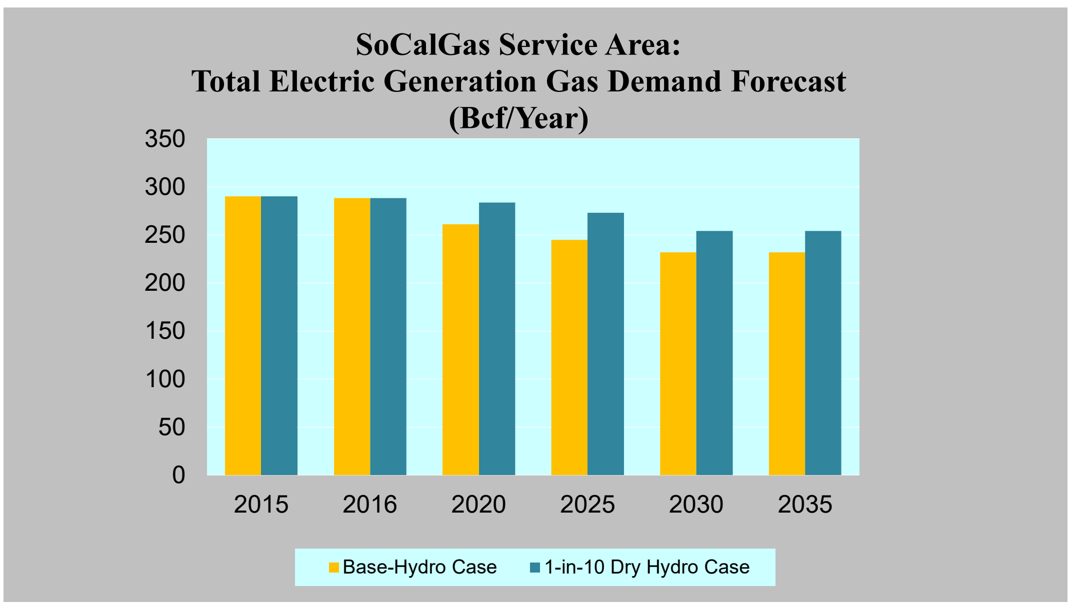


Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at a rate of 0.8% from 49.9 Bcf in 2015 to 42.2 Bcf by 2035. The reduced demand is primarily due to the departure of customers within the City of Vernon to wholesale service by the City of Vernon, the CPUC-authorized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

Refinery-Industrial Demand

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

Electric Generation



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

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

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

Industrial/Commercial/Cogeneration <20MW

The commercial/industrial cogeneration market segment is generally comprised of customers with generating capacity of less than 20 megawatts (MW) of electric power. Most of the cogeneration units in this segment are installed primarily to generate electricity for internal customer consumption rather than for the sale of power to electric utilities. Customers in this market segment install their own electric generation equipment for both economic reasons (gas powered systems produce electricity cheaper than purchasing it from a local electric utility) and reliability reasons (lower purchased power prices are realized only for interruptible service). In 2015, gas demand in the small cogeneration market was 23.7 Bcf. Demand is expected to be about 25 Bcf per year during the period from 2016 to 2020 due to relatively low gas to electric fuel prices. After 2020, cogeneration demand is projected to decline modestly to 24.4 Bcf by the year 2035. This represents an average decline of 0.32% per year. Overall, from 2016 through 2035, small cogeneration load is anticipated to decline at an annual average rate of 0.22%. A key factor in this decline is the expected implementation of regulations to reduce CO2 emissions which will increase the gas commodity price for many small cogeneration customers.

Industrial/Commercial Cogeneration >20 MW

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

Refinery-Related Cogeneration

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

Enhanced Oil Recovery-Related Cogeneration

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

Non-Cogeneration Electric Generation

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

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

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

Enhanced Oil Recovery – Steam

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

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

Wholesale and International

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

San Diego Gas & Electric

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 0.4% per year from 131 Bcf in 2015 to 120 Bcf in 2035. Additional information regarding SDG&E's gas demand is provided in the SDG&E section of this report.

City of Long Beach

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

Southwest Gas

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

City of Vernon

The City of Vernon initiated municipal gas service to its electric power plant within the city's jurisdiction in June, 2005. Since 2005, there has also been a gradual increase of commercial/industrial gas demand as customers within the city boundaries have left the SoCalGas retail system and interconnected with Vernon's municipal gas system. The forecasted throughput starts at 3.2 Bcf in 2016 and increases to 4.0 Bcf by 2021, after which the demand remains relatively flat through 2035. The forecasted throughput includes Core and Non-Core customers but excludes Malburg Power Plant throughput. Vernon's commercial and industrial load is based on recorded historical usage for commercial and industrial customers already served by Vernon plus the customers that are expected to request retail service from Vernon.

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

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

Natural Gas Vehicles (NGV)

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

ENERGY EFFICIENCY PROGRAMS

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

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

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

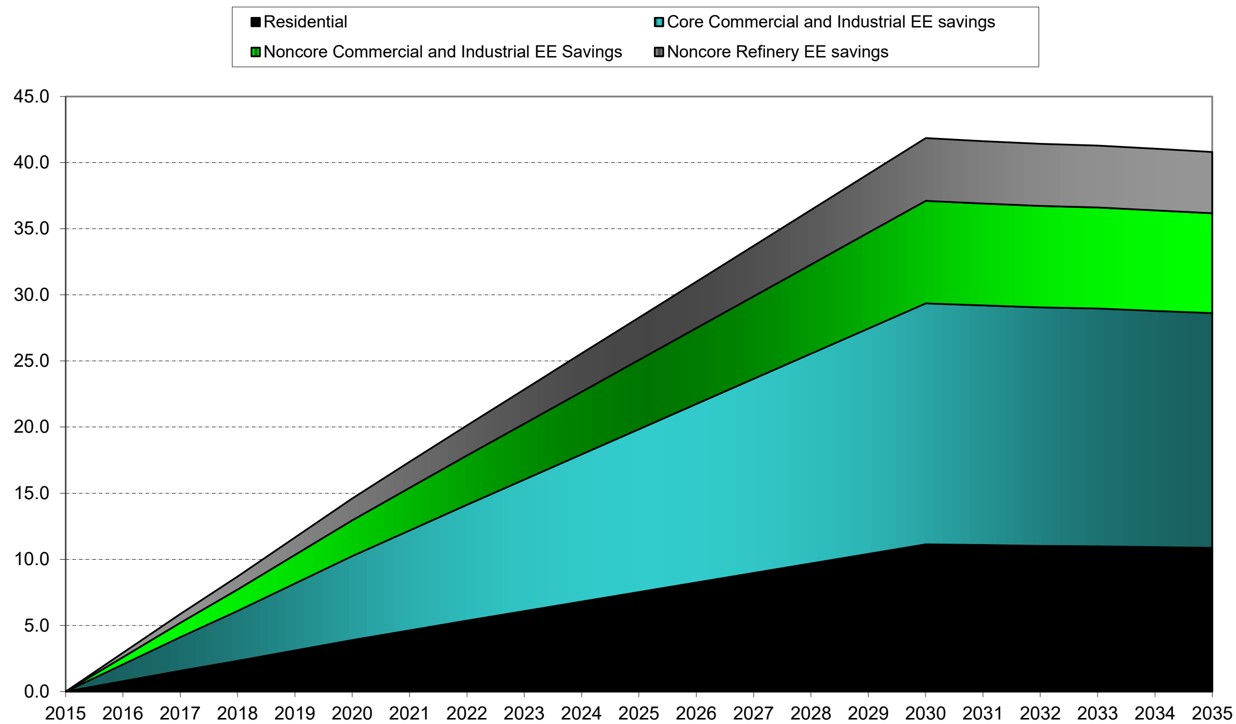
SB350, which was passed in fall 2015, requires the CEC, in coordination with the CPUC and the local public utilities, to set EE targets that double the CEC's AAEE mid-case forecast, subject to what is cost-effective and feasible.[3] This legislation will undoubtedly impact levels of EE savings. There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

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

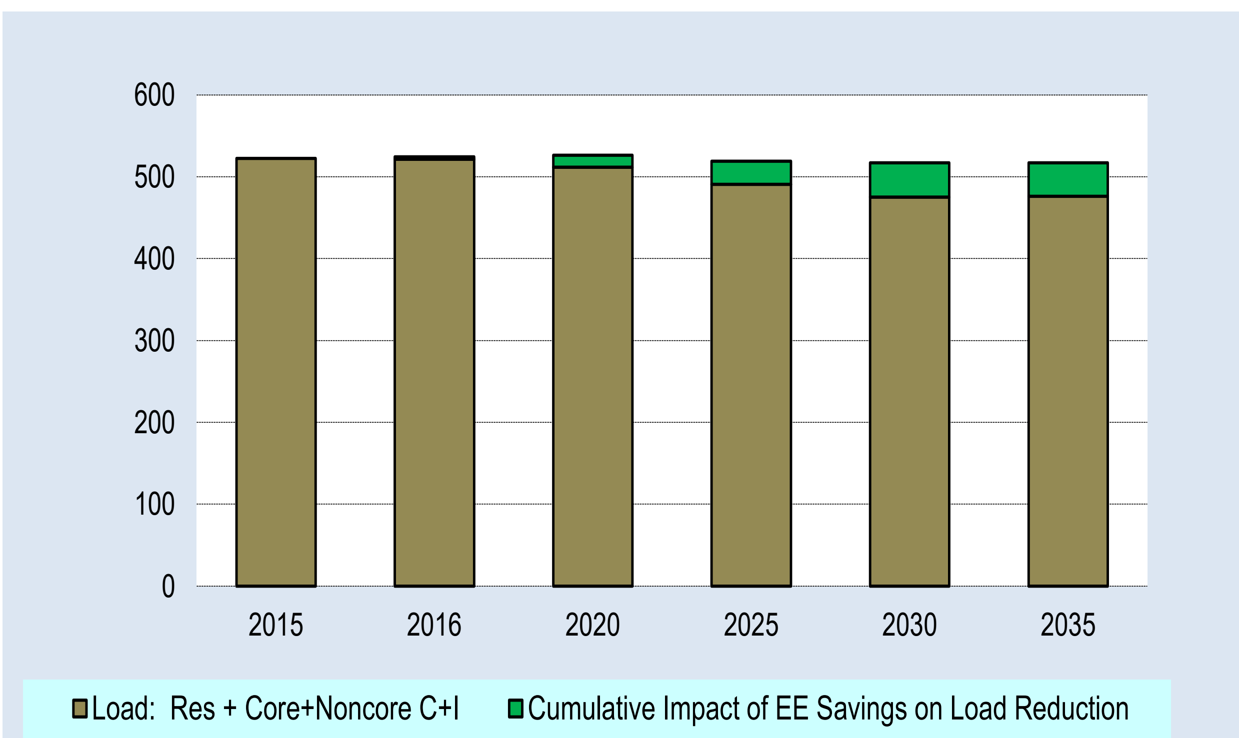
For these reasons, SoCalGas recommends using current levels of EE included in the 2015 IEPR in the forecast until the issues identified above are resolved. However, for context, the IOUs offer the following relative maximum impact of the bill on EE savings levels. Assuming sufficient cost effective measures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

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

Annual Energy Efficiency Cumulative Savings Goal (Bcf)



EE Savings Relative to Total Load 2015-2035 (Bcf/year)



Savings reported are for measures installed under SoCalGas' energy efficiency programs. Credit is only taken for measures that are installed as a result of SoCalGas' energy efficiency programs, and only for the estimated measure lives of the measures installed. Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. Naturally occurring conservation that is not attributable to SoCalGas' energy efficiency activities is not included in the energy efficiency forecast.

GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

Southern California Gas Company and San Diego Gas & Electric Company receive gas supplies from several sedimentary basins in the western United States and Canada including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains, Western Canada, and local California supplies. Recorded 2011 through 2015 receipts from gas supply sources can be found in the Sources and Disposition tables in the Executive Summary.

CALIFORNIA GAS

Gas supply available to SoCalGas from California sources averaged 122 MMcf/day in 2015.

SOUTHWESTERN U.S. GAS

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

ROCKY MOUNTAIN GAS

Rocky Mountain supply supplements traditional Southwestern U.S. gas sources for Southern California. This gas is delivered to Southern California primarily on the Kern River Gas Transmission Company's pipeline, although there is also access to Rockies gas through pipelines interconnected to the San Juan Basin. Many pipelines connect to Rocky Mountain region, which allows these supplies to be redirected from lower to higher value markets as conditions change.

CANADIAN GAS

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

BIOGAS

Biogas is a mixture of methane and carbon dioxide produced by the bacterial degradation of organic matter. Biogas is a byproduct produced from processes including, but not limited to, anaerobic digestion, anaerobic decomposition, and thermo-chemical decomposition under sub-stoichiometric conditions. These processes are applied to biodegradable biomass materials, such as livestock manure, wastewater sewage, food waste, and green waste. When biogas is conditioned/upgraded to pipeline quality specifications, commonly referred to as "biomethane," it can be interconnected to a gas utility's pipeline and nominated for a specific end-use customer.[2] Biomethane may also be consumed onsite for a variety of uses, including electrical power generation from internal combustion engines, fuel cells, and turbines, or as a fuel source for natural gas vehicles. Currently, there are instances where biogas is being vented naturally or flared to the atmosphere. Venting and flaring wastes this valuable renewable resource and fails to support the state in achieving its emission reduction targets set forth by Assembly Bill ("AB") 32 and the Renewables Portfolio Standard ("RPS") goals, as processed renewable natural gas injected into a common carrier natural gas pipeline system can ultimately count toward satisfying AB 32 and RPS goals.

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

[2] SoCalGas' Tariff Rule 30 (http://socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf) must be met in order to qualify for pipeline injection into SoCalGas' gas pipeline system.

[3] February 13, 2013 Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions. http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M050/K674/50674934.PDF

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

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

INTERSTATE PIPELINE CAPACITY

Interstate pipeline delivery capability into SoCalGas and SDG&E on any given day theoretically is approximately 6,725 MMcf/day based on the Federal Energy Regulatory Commission (FERC) Certificate Capacity or SoCalGas' estimated physical capacity of upstream pipelines. These pipeline systems provide access to several large supply basins, located in: New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains, Western Canada, and LNG.

Upstream Capacity to Southern California

Pipeline	Upstream Capacity (MMcf/d)
El Paso at Blythe	1,210
El Paso at Topock	540
Transwestern at Needles	1,150
PG&E at Kern River	650 (1)
Southern Trails at Needles	120
Kern/Mojave at Wheeler Ridge	885
Kern at Kramer Junction	750
Occidental at Wheeler Ridge	150
California Production	310
TGN at Otay Mesa	400
North Baja at Blythe	600
Total Potential Supplies	6,765

(1) Estimate of physical capacity.

FIRM RECEIPT CAPACITY

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

SoCalGas/SDG&E Current Firm Receipt Capacity

Transmission Zone	Total Transmission Zone Firm Access (MMcf/d)	Specific Point of Access (1) (Limitations)(2) (MMcf/d)
Southern	1,210	EPN Ehrenberg (1,010) TGN Otay Mesa (400) NBP Blythe (600)
Northern	1,590	EPN Topock (540) TW Topock (300) TW North Needles (800) QST North Needles (120) KR Kramer Junction (550)
Wheeler Ridge	765	KR/MP Wheeler Ridge (765) PG&E Kern River Station (520) OEHI Gosford (150)
Line 85	160	California Supply
Coastal	150	California Supply
Other	N/A	California Supply
Total	3,875	

(1) Pipelines

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

(2) Transmission Zone Contract Limitations:

Southern Zone:

- In total EPN Ehrenberg and NBP Blythe cannot exceed 1,010 MMcfd.
- In total EPN Ehrenberg, NBP Blythe and TGN Otay Mesa cannot exceed 1,210 MMcfd.

Northern Zone:

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

Wheeler Ridge Zone:

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

STORAGE

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

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

ALISO CANYON

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

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

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

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

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

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

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

REGULATORY ENVIRONMENT

State Regulatory Matters

TRIENNIAL COST ALLOCATION PROCEEDING (TCAP)

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

PIPELINE SAFETY

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

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

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

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

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

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

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

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

FEDERAL REGULATORY MATTERS

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

El Paso

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

Kern River

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

Transwestern

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

Gas Transmission Northwest (GTN) and Canadian Pipelines

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

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

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

Coordination Between Gas and Electric Markets

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

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

GREENHOUSE GAS ISSUES

National Policy

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

Assembly Bill 32

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

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

California is in the process of implementing a broad portfolio of policies and regulations aimed at reducing greenhouse gas (GHG) emissions. This process is a collaborative effort underway at the CPUC, the CEC, and CARB. CARB however is statutorily empowered with developing and implementing the final regulations on GHG regulatory frameworks and compliance. Approved policies include both programmatic measures and market-based mechanisms to reduce GHG emissions. Cap-and-Trade is one technique being implemented by CARB. Other measures include increasing the amount of renewable energy power that enters the grid, ambitious energy efficiency incentive programs and incentives on electric vehicles and solar energy.

Greenhouse Gas (GHG) Rulemaking

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

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

Reporting and Cap-and-Trade Obligations

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

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

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

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

Motor Vehicle Emissions Reductions

National GHG policy-makers realize that motor vehicles are one of the largest sources of GHG emissions, and one of the potential solutions is the substitution of natural gas and electricity for the current diesel and gasoline energy sources. This transition to cleaner fuels will also increase the demand for both natural gas and natural gas-generated electricity. Under EPA's Mandatory Reporting of Greenhouse Gases rule, all vehicle and engine manufacturers outside of the light-duty sector must report emission rates of carbon dioxide, nitrous oxide, and methane from their products.

Low Carbon Fuel Standard

On January 18, 2007, former Governor Schwarzenegger signed an Executive Order establishing the low carbon fuel standard (LCFS). LCFS requires a 10 percent carbon intensity reduction by 2020 in the transportation sector. The LCFS requires fuel providers to ensure that the mix of fuel they sell into the California market meets, on average, a declining standard for GHG emissions measured in CO2 equivalent gram per unit of fuel energy sold. As stated above, the transition to cleaner fuels will increase the demand for both natural gas and natural gas-generated electricity in order to meet the needs of a cleaner state transportation fleet, which will increasingly utilize electricity and natural gas in the future. Further, the CPUC has recently authorized the utilities to sell LCFS credits generated both by their use of low-carbon fuel vehicles and those generated by public refueling stations. The revenue generated by the sale of these credits will be returned to the customers who generated the credits, further enhancing the value of low-carbon fuels.

Programmatic Emission Reduction Measures

The CEC, CPUC and CARB are considering or have approved a variety of non market-based measures to reduce GHG emissions. Some of these programs include: the California Energy Efficiency Green Building Standards, the Green State Buildings Executive Order, the CPUC's adopted goal of "zero net energy" for all new residential construction by 2020 and a similar goal for commercial buildings by 2030; potential combined heat and power (CHP) and distributed generation portfolio standards or feed-in tariffs; increasing the electric renewables portfolio standard to 33% by 2020 and to 50% by 2030; implementing the CARB Short-Lived Climate Pollutants strategy and revising the CARB Regulation for GHG Emission Standards for Crude Oil and Natural Gas Facilities. There is also an on-going Rulemaking (R.) 15-01-008 to implement SB 1371 which requires the adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipeline facilities. This proceeding is led by the CPUC in consultation with CARB —the first phase will develop the overall policies and guidelines for a natural gas leak abatement program consistent with SB 1371. The second phase will develop ratemaking and performance-based financial incentives associated with the natural gas leak abatement program determined through Phase 1 of the proceeding. Energy efficiency and renewables are considered fundamental to GHG emission reduction in the electric sector. As a result, integration of additional renewables will require quick-start peaking capacity for firming and shaping of intermittent power, which in the foreseeable future will be gas-fired combustion turbines.

GAS PRICE FORECAST

MARKET CONDITION

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

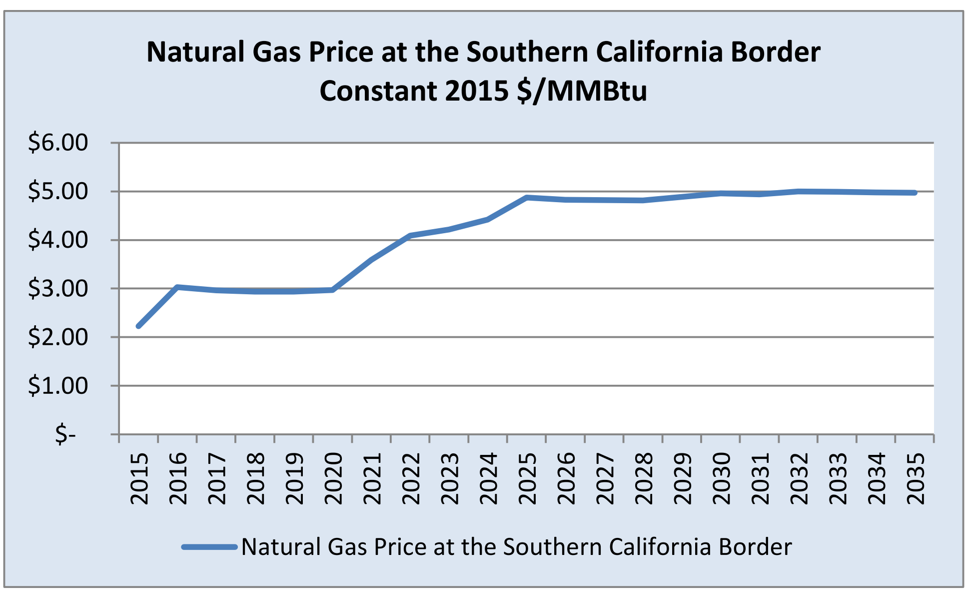
Also in response to the low gas price environment, gas demand has been rising, primarily from coal-to-gas fuel switching in the power sector, and most recently from increasing exports to Mexico by pipe and overseas via LNG as domestic liquefaction projects are commissioned. These exports are expected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

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

DEVELOPMENT OF THE FORECAST

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

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



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

PEAK DAY DEMAND AND DELIVERABILITY

Since April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand have been procured as a combined portfolio. SoCalGas and SDG&E plan and design their systems to provide continuous service to their core customers under an extreme peak day event. For each utility's service area, the extreme peak day is defined as a service area average temperature so cold that it would, on average, occur only once every 35 years. This definition translates to a system average temperature of 40.1 degrees Fahrenheit for SoCalGas' service area and 42.9 degrees Fahrenheit for SDG&E's service area.

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

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

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

Notes:
(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation.
(2) 1-in-35 peak temperature cold day SDG&E core sales and transportation.
(3) This amount was approved by the CPUC for SoCalGas and SDG&E to serve the combined core portfolio of SoCalGas' and SDG&E's retail core customers in CPUC D.08-12-020 on 12/4/2008 at p. 12.
(4) SoCalGas and SDG&E are only obligated to design their systems to maintain service to retail and wholesale core customers during a 1-in-35 winter peak day temperature event .

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

Winter Peak Day Demand
(MMcf/Day)

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

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

Summer High Sendout Day Demand
(MMcf/Day)

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

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

2016 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY
TABULAR DATA

SOUTHERN CALIFORNIA GAS COMPANY

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

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

NOTES:
(1) The wholesale volumes only reflect natural gas supplied by SoCalGas; and, do not include supplies from other sources. Refer to the supply source data provided in each utility's report for a complete accounting of their supply sources.
(2) Deliveries by end-use includes sales, transportation, and exchange volumes and data includes effect of prior period adjustments.
(3) The table does not explicitly show any curtailment numbers for the recorded years because, during some curtailment events, the estimate of the curtailed volume is not available. While the table does not explicitly show any curtailment numbers for the recorded years, the noncore customer usage data implicitly captures the effects of any curtailment events.

TABLE 1-SCG

SOUTHERN CALIFORNIA GAS COMPANY

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

AVERAGE TEMPERATURE YEAR

LINE			2016	2017	2018	2019	2020	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		160	160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) [1/]		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) [2/]		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) [3/]		1,590	1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	7
	GAS SUPPLY TAKEN							
8	California Source Gas		122	122	122	122	122	8
9	Out-of-State		2,559	2,527	2,485	2,459	2,436	9
10	TOTAL SUPPLY TAKEN		2,681	2,649	2,607	2,581	2,558	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [4/]		2,681	2,649	2,607	2,581	2,558	12
	REQUIREMENTS FORECAST BY END-USE [5/]							
13	CORE [6/]	Residential	652	652	650	647	641	13
14		Commercial	217	217	214	211	207	14
15		Industrial	56	57	56	55	55	15
16		NGV	37	38	40	42	43	16
17		Subtotal-CORE	961	964	960	955	947	17
18	NONCORE	Commercial	46	45	45	45	44	18
19		Industrial	371	367	366	363	361	19
20		EOR Steaming	46	46	46	46	46	20
21		Electric Generation (EG)	788	760	738	724	714	21
22		Subtotal-NONCORE	1,251	1,218	1,195	1,178	1,165	22
23	WHOLESALE &	Core	183	187	188	188	188	23
24	INTERNATIONAL	Noncore Excl. EG	48	47	47	48	48	24
25		Electric Generation (EG)	204	199	185	180	178	25
26		Subtotal-WHOLESALE & INTL.	435	434	420	415	414	26
27		Co. Use & LUAF	33	33	32	32	32	27
28	SYSTEM TOTAL THROUGHPUT [4/]		2,681	2,649	2,607	2,581	2,558	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	56	57	57	57	56	29
30	NONCORE	Commercial/Industrial	417	412	411	408	405	30
31		EOR Steaming	46	46	46	46	46	31
32		Electric Generation (EG)	788	760	738	724	714	32
33		Subtotal-RETAIL	1,307	1,275	1,252	1,235	1,222	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	435	434	420	415	414	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,742	1,709	1,671	1,650	1,636	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

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

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

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

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

TABLE 2-SCG

SOUTHERN CALIFORNIA GAS COMPANY

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

AVERAGE TEMPERATURE YEAR

LINE			2021	2022	2025	2030	2035	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		160	160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) [1/]		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) [2/]		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) [3/]		1,590	1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	7
	GAS SUPPLY TAKEN							
8	California Source Gas		122	122	122	122	122	8
9	Out-of-State		2,404	2,382	2,334	2,252	2,260	9
10	TOTAL SUPPLY TAKEN		2,526	2,504	2,456	2,374	2,382	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [4/]		2,526	2,504	2,456	2,374	2,382	12
	REQUIREMENTS FORECAST BY END-USE [5/]							
13	CORE [6/]	Residential	639	634	620	603	598	13
14		Commercial	204	199	189	175	177	14
15		Industrial	54	53	50	44	42	15
16		NGV	45	47	52	61	69	16
17		Subtotal-CORE	941	932	911	882	886	17
18	NONCORE	Commercial	44	43	42	40	40	18
19		Industrial	358	353	345	333	332	19
20		EOR Steaming	46	46	46	46	46	20
21		Electric Generation (EG)	692	684	671	636	636	21
22		Subtotal-NONCORE	1,139	1,126	1,104	1,055	1,054	22
23	WHOLESALE &	Core	189	189	189	192	197	23
24	INTERNATIONAL	Noncore Excl. EG	48	48	48	49	49	24
25		Electric Generation (EG)	178	178	174	166	165	25
26		Subtotal-WHOLESALE & INTL.	415	414	411	407	411	26
27		Co. Use & LUAF	31	31	31	30	30	27
28	SYSTEM TOTAL THROUGHPUT [4/]		2,526	2,504	2,456	2,374	2,382	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	56	56	55	55	58	29
30	NONCORE	Commercial/Industrial	401	396	387	373	372	30
31		EOR Steaming	46	46	46	46	46	31
32		Electric Generation (EG)	692	684	671	636	636	32
33		Subtotal-RETAIL	1,195	1,182	1,159	1,110	1,112	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	415	414	411	407	411	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,610	1,597	1,570	1,517	1,523	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

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

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

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

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

TABLE 3-SCG

SOUTHERN CALIFORNIA GAS COMPANY

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

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

LINE			2016	2017	2018	2019	2020	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		160	160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,590	1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	7
	GAS SUPPLY TAKEN							
8	California Source Gas		122	122	122	122	122	8
9	Out-of-State		2,665	2,706	2,671	2,640	2,612	9
10	TOTAL SUPPLY TAKEN		2,787	2,828	2,793	2,762	2,734	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 4/		2,787	2,828	2,793	2,762	2,734	12
	REQUIREMENTS FORECAST BY END-USE 5/							
13	CORE 6/	Residential	723	723	721	718	712	13
14		Commercial	230	230	227	223	220	14
15		Industrial	57	58	58	57	56	15
16		NGV	37	38	40	42	43	16
17		Subtotal-CORE	1,047	1,050	1,045	1,040	1,031	17
18	NONCORE	Commercial	47	47	46	46	45	18
19		Industrial	371	367	366	363	361	19
20		EOR Steaming	46	46	46	46	46	20
21		Electric Generation (EG)	788	825	807	788	775	21
22		Subtotal-NONCORE	1,252	1,285	1,265	1,244	1,228	22
23	WHOLESALE &	Core	200	205	205	206	206	23
24	INTERNATIONAL	Noncore Excl. EG	48	47	48	48	48	24
25		Electric Generation (EG)	204	206	195	191	187	25
26		Subtotal-WHOLESALE & INTL.	452	458	448	444	441	26
27		Co. Use & LUAF	35	35	35	34	34	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,787	2,828	2,793	2,762	2,734	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	59	60	60	59	59	29
30	NONCORE	Commercial/Industrial	418	414	412	409	406	30
31		EOR Steaming	46	46	46	46	46	31
32		Electric Generation (EG)	788	825	807	788	775	32
33		Subtotal-RETAIL	1,311	1,344	1,325	1,303	1,287	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	452	458	448	444	441	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,764	1,802	1,772	1,748	1,728	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

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

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

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

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

TABLE 4-SCG

SOUTHERN CALIFORNIA GAS COMPANY

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

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

LINE			2021	2022	2025	2030	2035	LINE
	CAPACITY AVAILABLE							
1	California Line 85 Zone (California Producers)		160	160	160	160	160	1
2	California Coastal Zone (California Producers)		150	150	150	150	150	2
	Out-of-State Gas							
3	Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/		765	765	765	765	765	3
4	Southern Zone (EPN,TGN,NBP) 2/		1,210	1,210	1,210	1,210	1,210	4
5	Northern Zone (TW,EPN,QST, KR) 3/		1,590	1,590	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,565	3,565	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE		3,875	3,875	3,875	3,875	3,875	7
	GAS SUPPLY TAKEN							
8	California Source Gas		122	122	122	122	122	8
9	Out-of-State		2,598	2,579	2,527	2,426	2,433	9
10	TOTAL SUPPLY TAKEN		2,720	2,701	2,649	2,548	2,555	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 4/		2,720	2,701	2,649	2,548	2,555	12
	REQUIREMENTS FORECAST BY END-USE 5/							
13	CORE 6/	Residential	709	703	689	671	666	13
14		Commercial	216	211	200	185	188	14
15		Industrial	55	54	51	45	43	15
16		NGV	45	47	52	61	69	16
17		Subtotal-CORE	1,025	1,016	992	962	965	17
18	NONCORE	Commercial	45	44	43	41	42	18
19		Industrial	358	353	345	333	332	19
20		EOR Steaming	46	46	46	46	46	20
21		Electric Generation (EG)	768	763	748	696	697	21
22		Subtotal-NONCORE	1,217	1,207	1,183	1,117	1,117	22
23	WHOLESALE &	Core	206	206	206	210	215	23
24	INTERNATIONAL	Noncore Excl. EG	48	48	48	49	49	24
25		Electric Generation (EG)	189	189	186	178	177	25
26		Subtotal-WHOLESALE & INTL.	444	444	441	437	441	26
27		Co. Use & LUAF	34	34	33	32	32	27
28	SYSTEM TOTAL THROUGHPUT 4/		2,720	2,701	2,649	2,548	2,555	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	59	59	58	58	60	29
30	NONCORE	Commercial/Industrial	402	398	388	374	373	30
31		EOR Steaming	46	46	46	46	46	31
32		Electric Generation (EG)	768	763	748	696	697	32
33		Subtotal-RETAIL	1,276	1,265	1,241	1,175	1,177	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	444	444	441	437	441	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,720	1,710	1,682	1,611	1,618	35
	CURTAILMENT (RETAIL & WHOLESALE)							
36		Core	0	0	0	0	0	36
37		Noncore	0	0	0	0	0	37
38		TOTAL - Curtailment	0	0	0	0	0	38

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

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

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

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

2016 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT

City of Long Beach Municipal Gas & Oil Department

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

Serving approximately 150,000 customers, Long Beach is the largest California municipal gas utility and the fifth largest municipal gas utility in the United States. Long Beach's service territory includes the cities of Long Beach and Signal Hill, and sections of surrounding communities including Lakewood, Bellflower, Compton, Seal Beach, Paramount, and Los Alamitos. Long Beach's customer load profile is 53 percent residential and 47 percent commercial/industrial.

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

Long Beach receives a small amount of its gas supply directly into its pipeline system from local production fields that are located within Long Beach's service territory, as well as offshore. Currently, Long Beach receives approximately 5 percent of its gas supply from local production. The majority of Long Beach supplies are purchased at the California border, primarily from the Southwestern United States. Long Beach, as a wholesale customer, receives intrastate transmission service for this gas from SoCalGas.

2016 CALIFORNIA GAS REPORT

CITY OF LONG BEACH MUNICIPAL GAS AND OIL DEPARTMENT
TABULAR DATA

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

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

LINE	GAS SUPPLY AVAILABLE	2011	2012	2013	2014	2015	LINE
	California Source Gas						
1	Regular Purchases	-	-	-	-	-	1
2	Received for Exchange/Transport	-	-	-	-	-	2
3	Total California Source Gas	-	-	-	-	-	3
4	Purchases from Other Utilities	-	-	-	-	-	4
	Out-of-State Gas						
5	Pacific Interstate Companies	-	-	-	-	-	5
6	Additional Core Supplies	-	-	-	-	-	6
7	Incremental Supplies	-	-	-	-	-	7
8	Out-of-State Transport	-	-	-	-	-	8
9	Total Out-of-State Gas	-	-	-	-	-	9
10	Subtotal	-	-	-	-	-	10
11	Underground Storage Withdrawal	-	-	-	-	-	11
12	GAS SUPPLY AVAILABLE	-	-	-	-	-	12
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	1.1	1.2	1.9	2.4	0.7	13
14	Received for Exchange/Transport	0	0	0	0	0	14
15	Total California Source Gas	1.1	1.2	1.9	2.4	0.7	15
16	Purchases from Other Utilities	-	-	-	-	-	16
	Out-of-State Gas						
17	Pacific Interstate Companies	-	-	-	-	-	17
18	Additional Core Supplies	-	-	-	-	-	18
19	Incremental Supplies	24.3	23.2	23.5	19.2	21.9	19
20	Out-of-State Transport	-	-	-	-	-	20
21	Total Out-of-State Gas	24.3	23.2	23.5	19.2	21.9	21
							22
22	Subtotal	25.5	24.4	25.4	21.5	22.5	
							23
23	Underground Storage Withdrawal	-	-	-	-	-	
							24
24	TOTAL Gas Supply Taken & Transported	25.5	24.4	25.4	21.5	22.5	

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

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

LINE	ACTUAL DELIVERIES BY END-USE		2011	2012	2013	2014	2015	LINE
1	CORE	Residential	14.9	13.7	14.2	11.5	11.9	1
2	CORE/NONCORE	Commercial	5.6	5.4	5.9	5.4	5.4	2
3	CORE/NONCORE	Industrial	3.6	3.4	3.4	3.3	3.7	3
4		Subtotal	24.1	22.5	23.6	20.3	20.9	4
5	NON CORE	Non-EOR Cogeneration	0.8	1.6	1.5	0.9	1.2	5
6		EOR Cogen. & Steaming	-	-	-	-	-	6
7		Electric Utilities	-	-	-	-	-	7
8		Subtotal	0.8	1.6	1.5	0.9	1.2	8
9	WHOLESALE	Residential	-	-	-	-	-	9
10		Com. & Ind., others	-	-	-	-	-	10
11		Electric Utilities	-	-	-	-	-	11
12		Subtotal-WHOLESALE	-	-	-	-	-	12
13		Co. Use & LUAF	0.6	0.2	0.2	0.4	0.4	13
14		Subtotal-END USE	25.5	24.4	25.4	21.5	22.5	14
15		Storage Injection	-	-	-	-	-	15
16	SYSTEM TOTAL-THROUGHPUT		25.5	24.4	25.4	21.5	22.5	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	2.7	2.7	2.5	2.3	2.3	18
19		Non-EOR Cogeneration	0.8	1.6	1.5	0.8	1.1	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	3.5	4.3	3.9	3.1	3.4	22
23	WHOLESALE	All End Uses	-	-	-	-	-	23
24	TOTAL TRANSPORTATION & EXCHANGE		3.5	4.3	3.9	3.1	3.4	24
	ACTUAL CURTAILMENT							
25		Residential	-	-	-	-	-	25
26		Commercial/Industrial	-	-	-	-	-	26
27		Non-EOR Cogeneration	-	-	-	-	-	27
28		EOR Cogen. & Steaming	-	-	-	-	-	28
29		Electric Utilites	-	-	-	-	-	29
30		Wholesale	-	-	-	-	-	30
31		TOTAL- Curtailment	-	-	-	-	-	31
32	REFUSAL		-	-	-	-	-	32

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

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY

ESTIMATED YEARS 2016 THRU 2020

AVERAGE TEMPERATURE YEAR

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

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

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

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

AVERAGE TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2021	2022	2025	2030	2035	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		0.6	0.6	0.5	0.4	0.4	4
5	Out-of-State Gas		23.2	23.3	23.6	24.0	24.3	5
6	TOTAL SUPPLY TAKEN		23.8	23.9	24.0	24.4	24.7	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		23.8	23.9	24.0	24.4	24.7	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	13.8	13.9	14.0	14.3	14.6	9
10		Commercial	5.1	5.1	5.1	5.1	5.2	10
11		NGV	0.6	0.6	0.6	0.6	0.6	11
12		Subtotal-CORE	19.5	19.5	19.7	20.0	20.3	12
13	NONCORE	Industrial	3.1	3.1	3.1	3.1	3.1	13
14		Non-EOR Cogeneration	1.0	1.0	1.0	1.0	1.0	14
15		EOR	0	0	0	0	0	15
16		Utility Electric Generation	0	0	0	0	0	16
17		NGV	0	0	0	0	0	17
18		Subtotal-NONCORE	4.1	4.1	4.1	4.1	4.1	18
19		Co. Use & LUAF	0.2	0.2	0.2	0.2	0.2	19
20	SYSTEM TOTAL THROUGHPUT (1)		23.8	23.9	24.0	24.4	24.7	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	0	0	0	0	0	22
23	NONCORE	Industrial	2.0	2.0	2.0	2.0	2.0	23
24		Non-EOR Cogeneration	0.9	0.9	0.9	0.9	0.9	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	3.0	2.9	2.9	2.9	2.9	27
28	TOTAL TRANSPORTATION		3.0	2.9	2.9	2.9	2.9	28

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

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

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

1 in 35 TEMPERATURE YEAR

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

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

CITY OF LONG BEACH - GAS & OIL DEPARTMENT

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY

ESTIMATED YEARS 2021 THRU 2035

1 in 35 TEMPERATURE YEAR

LINE	CAPACITY AVAILABLE		2021	2022	2025	2030	2035	LINE
1	California Source Gas							1
2	Out-of-State Gas							2
3	TOTAL CAPACITY AVAILABLE							3
	GAS SUPPLY TAKEN							
4	California Source Gas		0.7	0.6	0.5	0.5	0.5	4
5	Out-of-State Gas		27.2	27.3	27.6	28.0	28.4	5
6	TOTAL SUPPLY TAKEN		27.9	27.9	28.1	28.5	28.9	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT (1)		27.9	27.9	28.1	28.5	28.9	8
	REQUIREMENTS FORECAST BY END-USE (1)							
9	CORE	Residential	16.5	16.6	16.8	17.1	17.5	9
10		Commercial	5.9	5.9	5.9	5.9	5.9	10
11		NGV	0.6	0.6	0.6	0.6	0.6	11
12		Subtotal-CORE	23.0	23.1	23.3	23.7	24.0	12
13	NONCORE	Industrial	3.5	3.5	3.5	3.5	3.5	13
14		Non-EOR Cogeneration	1.1	1.1	1.1	1.1	1.1	14
15		EOR	0	0	0	0	0	15
16		Utility Electric Generation	0	0	0	0	0	16
17		NGV	0	0	0	0	0	17
18		Subtotal-NONCORE	4.6	4.6	4.6	4.6	4.6	18
19		Co. Use & LUAF	0.3	0.3	0.3	0.3	0.3	19
20	SYSTEM TOTAL THROUGHPUT (1)		27.9	27.9	28.1	28.5	28.9	20
21	SYSTEM CURTAILMENT		0	0	0	0	0	21
	TRANSPORTATION							
22	CORE	All End Uses	0	0	0	0	0	22
23	NONCORE	Industrial	2.3	2.3	2.3	2.3	2.3	23
24		Non-EOR Cogeneration	1.0	1.0	1.0	1.0	1.0	24
25		EOR	0	0	0	0	0	25
26		Utility Electric Generation	0	0	0	0	0	26
27		Subtotal NONCORE	3.3	3.3	3.3	3.3	3.3	27
28	TOTAL TRANSPORTATION		3.3	3.3	3.3	3.3	3.3	28

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

2016 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

San Diego Gas & Electric Company (SDG&E) is a combined gas and electric distribution utility serving more than three million people in San Diego and the southern portions of Orange counties. SDG&E delivered natural gas to 870,000 customers in San Diego County in 2015, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2015 were approximately 120 billion cubic feet (Bcf), which is an average of 327 million cubic feet per day (MMcf/day).

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

GAS DEMAND

OVERVIEW

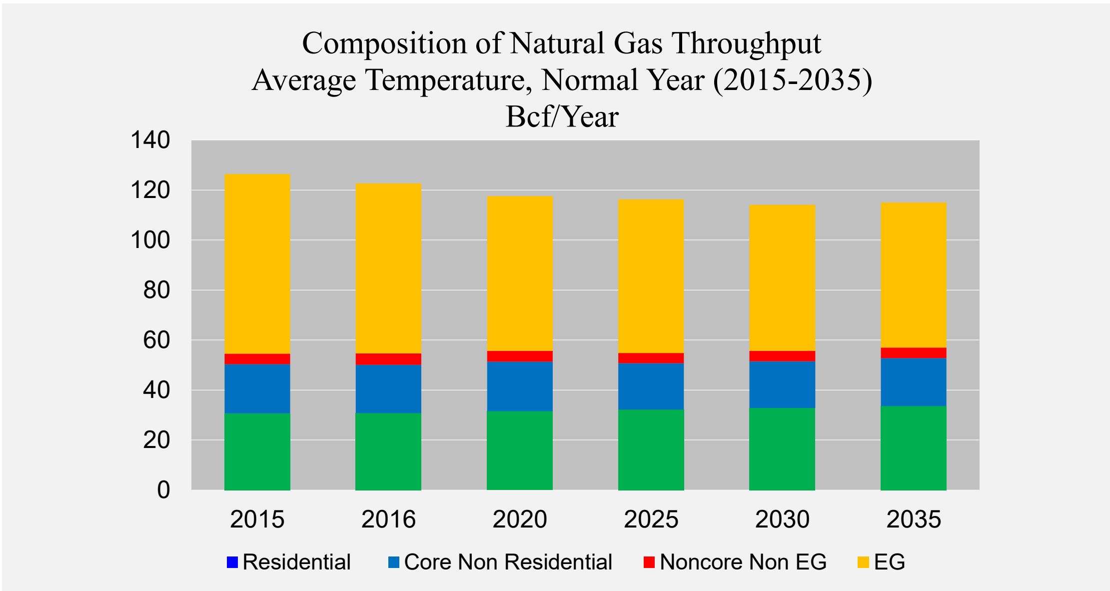
SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above.

This projection of natural gas requirements, excluding electric generation (EG) demand, is derived from models that integrate demographic assumptions, economic growth, energy prices, energy efficiency programs, customer information programs, building and appliance standards, weather and other factors. Non-EG gas demand is projected to remain virtually flat between 2015 and 2035. Overall demand adjusted for average temperature conditions totaled 126 Bcf in 2015. By the year 2035, the total demand is expected to reach 115 Bcf. The change reflects an annual average decline of 0.40%.

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

ECONOMICS AND DEMOGRAPHICS

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



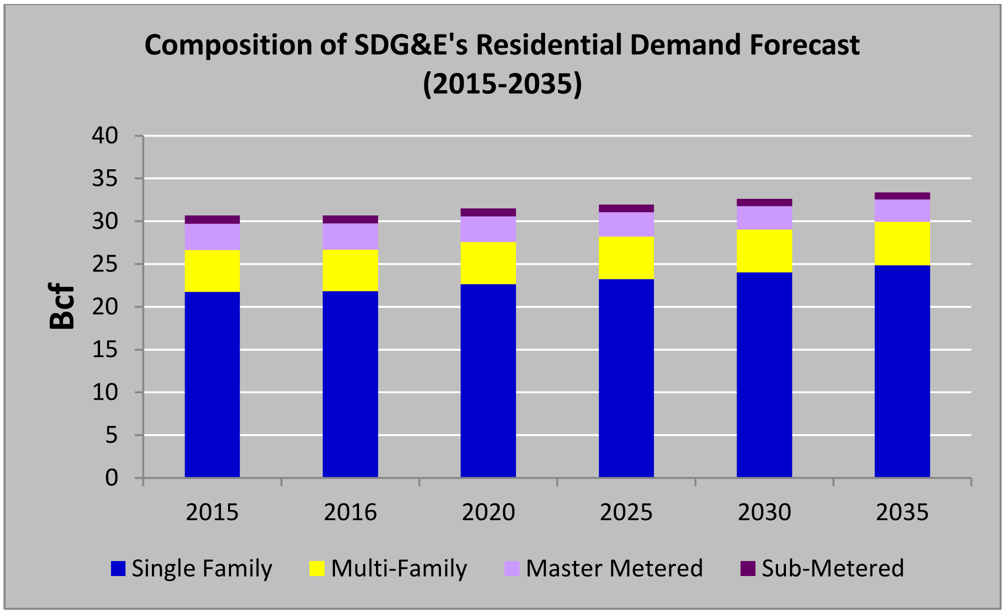
MARKET SECTORS

Residential

The total residential customer count for SDG&E consists of four residential segment types. These are single family and multi-family customers, as well as master meter and sub-metered customers. The active meters for all residential customer classes averaged 839,947 in 2015. This total reflects a 4,194 meter increase relative to the 2014 total. Overall residential meter growth from 2014-2015 was 0.50%.

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

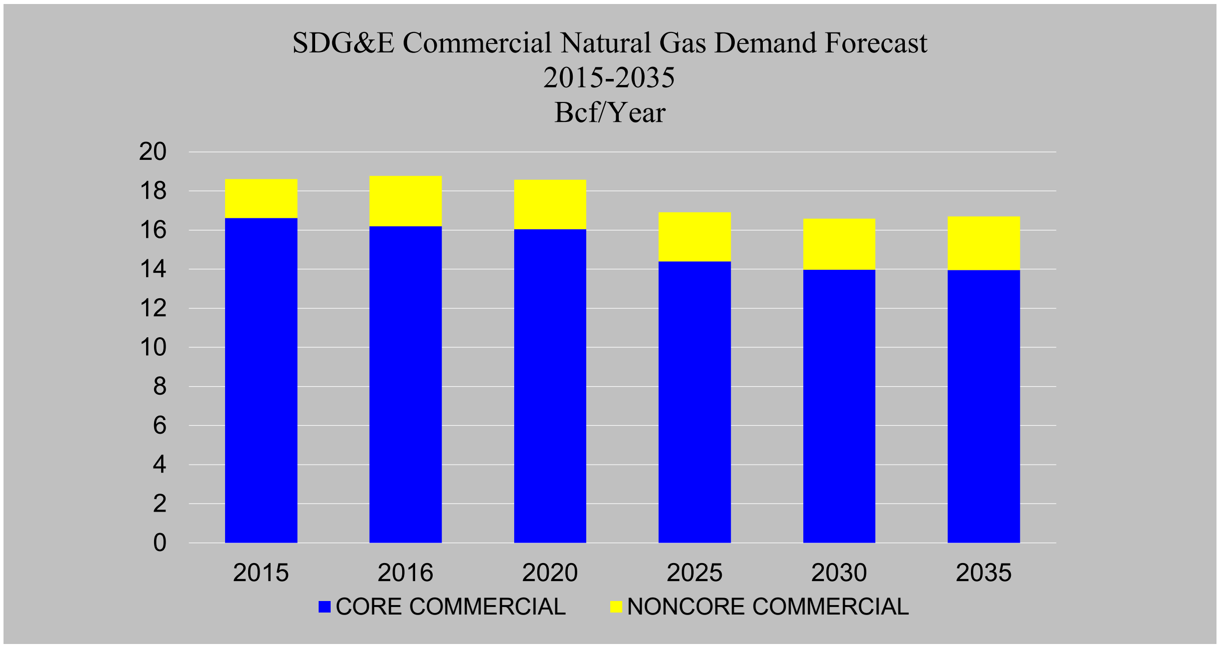
The projected residential natural gas demand is influenced primarily by residential meter growth moderated by the forecasted declining use per customer due to energy efficiency improvements in building shell design, appliance efficiency and CPUC-authorized EE programs plus the additional efficiency gains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



Commercial

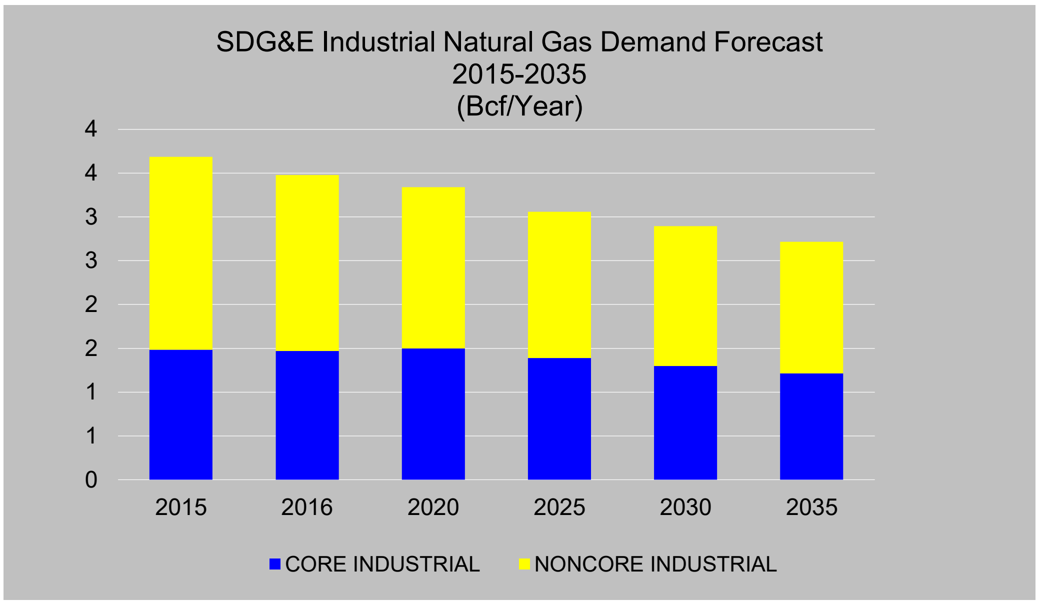
On a temperature-adjusted basis, the core commercial demand in 2015 totaled 17 Bcf. By the year 2035, the SDG&E core commercial load is expected to decline to 14 Bcf.

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


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

Industrial

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

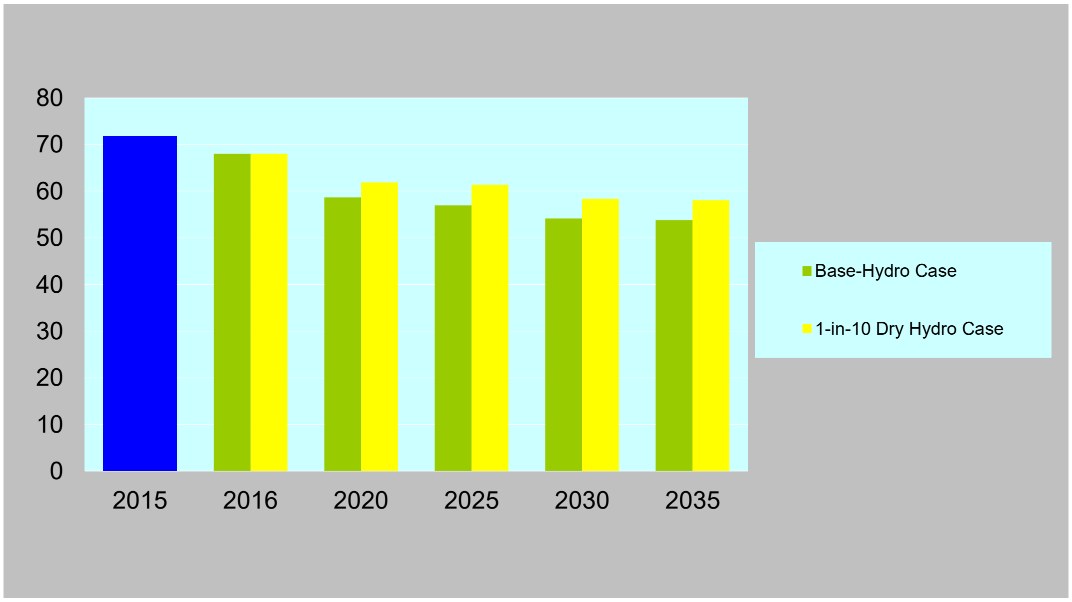


Non-core industrial load in 2015 was 2.2 Bcf and is expected to decline at an average rate of -1.6% per year to 1.6 Bcf by 2035. CPUC-mandated energy efficiency programs more than offset any modest gains from industrial economic growth.

Electric Generation

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

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



Cogeneration

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

Non-Cogeneration Electric Generation

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

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

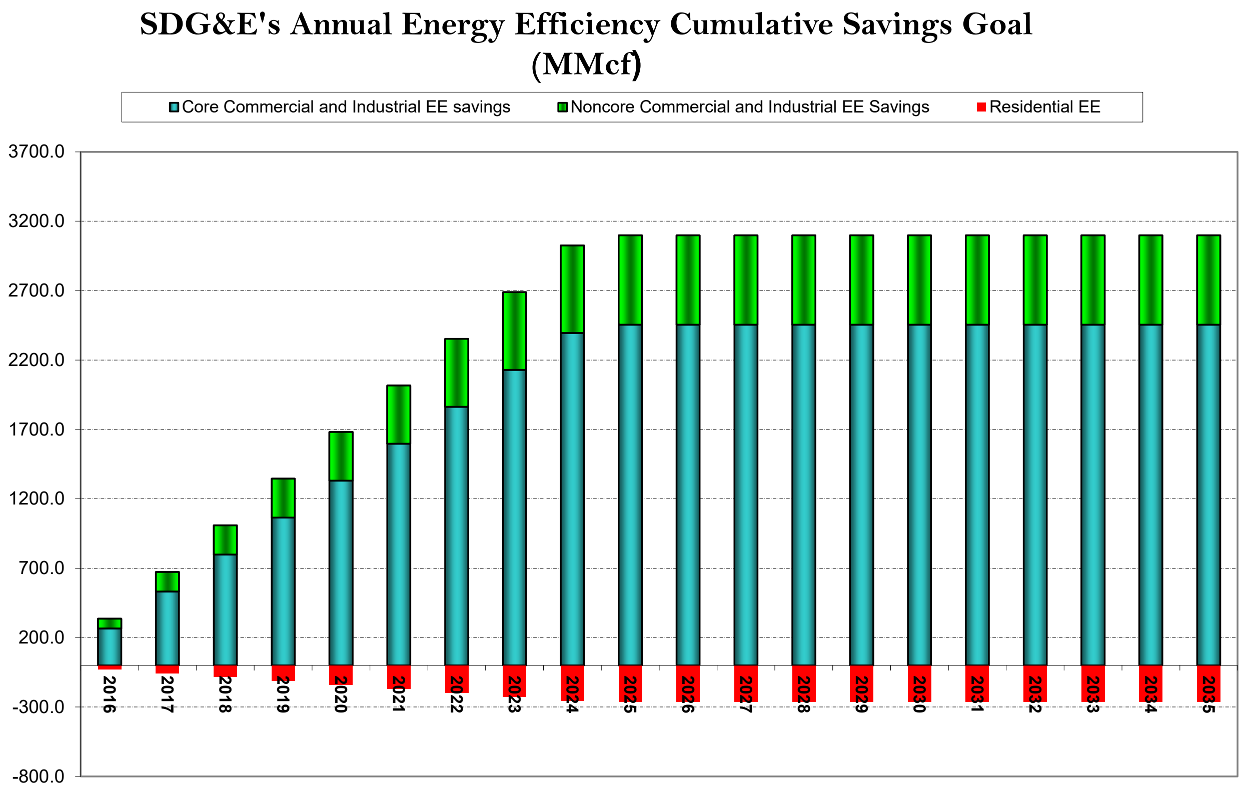
Natural Gas Vehicles (NGV)

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

ENERGY EFFICIENCY PROGRAMS

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

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



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

Notes:

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

GAS SUPPLY

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

PEAK DAY DEMAND

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

2016 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY
TABULAR DATA

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

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

ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes

	2011	2012	2013	2014	2015
MMbtu/Mcf:	1.018	1.017	1.024	1.035	1.040

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

LINE		2011	2012	2013	2014	2015
	CAPACITY AVAILABLE					
1	**California Sources**					
	Out of State gas					
2	California Offshore (POPCO/PIOC)					
3	El Paso Natural Gas Company					
4	Transwestern Pipeline company					
5	Kern River/Mojave Pipeline Company					
6	TransCanada GTN/PG&E					
7	Other					
8	**TOTAL Output of State**					
9	Underground storage withdrawal					
10	**TOTAL Gas Supply available**					

	Gas Supply Taken	2011	2012	2013	2014	2015
	California Source Gas					
11	Regular Purchases	0	0	0	0	0
12	Received for Exchange/Transport	0	0	0	0	0
13	**Total California Source Gas**	0	0	0	0	0
14	**Purchases from Other Utilities**	0	0	0	0	0
	Out-of-State Gas					
15	Pacific Interstate Companies	0	0	0	0	0
16	Additional Core Supplies	0	0	0	0	0
17	Supplemental Supplies-Utility	132	126	129	107	103
18	Out-of-State Transport-Others	179	258	242	216	224
19	**Total Out-of-State Gas**	312	384	371	323	327
20	**TOTAL Gas Supply Taken & Transported**	312	384	371	323	327

TABLE 1-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

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

AVERAGE TEMPERATURE YEAR

LINE			2016	2017	2018	2019	2020	LINE
	CAPACITY AVAILABLE 1/ & 2/							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas 1/		607	607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	607	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Southern Zone of SoCalGas		338	336	322	317	315	5
6	TOTAL SUPPLY TAKEN		338	336	322	317	315	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		338	336	322	317	315	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	84	86	86	86	86	9
10		Commercial	44	45	45	44	44	10
11		Industrial	4	4	4	4	4	11
12		NGV	5	5	5	6	6	12
13		Subtotal-CORE	137	140	140	140	140	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	5	5	5	5	5	15
16		Electric Generation (EG)	186	181	167	162	160	16
17		Subtotal-NONCORE	198	193	179	174	172	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		338	336	322	317	315	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	14	14	14	14	20
21	NONCORE	Commercial/Industrial	13	12	12	12	12	21
22		Electric Generation (EG)	186	181	167	162	160	22
23	TOTAL TRANSPORTATION & EXCHANGE		212	207	193	188	186	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

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

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

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

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

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

TABLE 2-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

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

AVERAGE TEMPERATURE YEAR

LINE			2021	2022	2025	2030	2035	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		607	607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	607	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Out-of-State		315	315	310	303	306	5
6	TOTAL SUPPLY TAKEN		315	315	310	303	306	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		315	315	310	303	306	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	87	87	88	90	92	9
10		Commercial	43	42	39	38	38	10
11		Industrial	4	4	4	4	3	11
12		NGV	6	7	8	9	11	12
13		Subtotal-CORE	140	140	139	141	144	13
14	NONCORE	Commercial	7	7	7	7	8	14
15		Industrial	5	5	5	4	4	15
16		Electric Generation (EG)	160	160	156	148	147	16
17		Subtotal-NONCORE	172	172	168	159	159	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		315	315	310	303	306	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	14	14	15	16	20
21	NONCORE	Commercial/Industrial	12	12	11	12	12	21
22		Electric Generation (EG)	160	160	156	148	147	22
23	TOTAL TRANSPORTATION & EXCHANGE		186	186	181	175	175	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

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

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

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

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 131 131 130 131 133

TABLE 3-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

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

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

LINE			2016	2017	2018	2019	2020	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		607	607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	607	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Out-of-State		351	357	346	342	338	5
6	TOTAL SUPPLY TAKEN		351	357	346	342	338	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		351	357	346	342	338	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	94	96	97	97	97	9
10		Commercial	47	49	48	47	47	10
11		Industrial	4	4	4	4	4	11
12		NGV	5	5	5	6	6	12
13		Subtotal-CORE	150	154	154	154	154	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	5	5	5	5	5	15
16		Electric Generation (EG)	186	188	177	173	169	16
17		Subtotal-NONCORE	198	200	189	185	181	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		351	357	346	342	338	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	15	15	15	15	20
21	NONCORE	Commercial/Industrial	13	12	12	12	12	21
22		Electric Generation (EG)	186	188	177	173	169	22
23	TOTAL TRANSPORTATION & EXCHANGE		213	215	204	200	196	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

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

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

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

4/ Core end-use demand exclusive of core aggregation

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

TABLE 4-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

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

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

LINE			2021	2022	2025	2030	2035	LINE
	CAPACITY AVAILABLE [1/ & 2/]							
1	California Source Gas		0	0	0	0	0	1
2	Southern Zone of SoCalGas [1/]		607	607	607	607	607	2
3	TOTAL CAPACITY AVAILABLE		607	607	607	607	607	3
	GAS SUPPLY TAKEN							
4	California Source Gas		0	0	0	0	0	4
5	Out-of-State		339	341	336	329	333	5
6	TOTAL SUPPLY TAKEN		339	341	336	329	333	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		339	341	336	329	333	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	97	98	99	101	103	9
10		Commercial	46	45	42	41	41	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	7	8	9	11	12
13		Subtotal-CORE	153	154	153	155	159	13
14	NONCORE	Commercial	7	7	7	7	8	14
15		Industrial	5	5	5	4	4	15
16		Electric Generation (EG)	171	172	168	160	159	16
17		Subtotal-NONCORE	183	184	180	171	171	17
18		Co. Use & LUAF	3	3	3	3	3	18
19	SYSTEM TOTAL THROUGHPUT		339	341	336	329	333	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	15	15	15	16	17	20
21	NONCORE	Commercial/Industrial	12	12	11	12	12	21
22		Electric Generation (EG)	171	172	168	160	159	22
23	TOTAL TRANSPORTATION & EXCHANGE		198	199	194	188	188	23
	CURTAILMENT							
24		Core	0	0	0	0	0	24
25		Noncore	0	0	0	0	0	25
26		TOTAL - Curtailment	0	0	0	0	0	26

NOTES:

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

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

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

4/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: 143 145 143 145 148

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2016 CALIFORNIA GAS REPORT

GLOSSARY

GLOSSARY

Average Day (Operational Definition)
Annual gas sales or requirements assuming average temperature year conditions divided by 365 days.

Average Temperature year
Long-term average recorded temperature.

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

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

CEC
California Energy Commission.

CNG (Compressed Natural Gas)
Fuel for natural gas vehicles, typically natural gas compressed to 3000 pounds per square inch.

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

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

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

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

Commercial (PG&E)

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

Company Use

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

Conversion Factor (Natural Gas)

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

Conversion Factor (Petroleum Products)

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

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

Conversion Factor (LNG)

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

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

Core Aggregator

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

Core customers (SoCalGas & SDG&E)

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

Core Customer (PG&E)

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

Core Subscription

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

CPUC

California Public Utilities Commission.

Cubic Foot of Gas

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

Curtailment

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

EG

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

Energy Service Provider (ESP)

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

Enhanced Oil Recovery (EOR)

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

Exchange

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

Exempt Wholesale Generators (EWG)

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

FERC

Federal Energy Regulatory Commission.

Futures (Gas)

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

Gas Accord

The Gas Accord is a multi-party settlement agreement, which restructured PG&E's gas transportation and storage services. The settlement was filed with the CPUC in August 1996, approved by the CPUC in August 1997 (D.97-08-055) and implemented by PG&E in March 1998. In D.03-12-061, the CPUC ordered the Gas Accord structure to continue for 2004 and 2005.

Key features of the Gas Accord structure include the following: unbundling of PG&E's gas transmission service and a portion of its storage service; placing PG&E at risk for transmission service and a portion of its storage service; placing PG&E at risk for transmission and storage costs and revenues; establishing firm, tradable transmission and storage rights; and establishing transmission and storage rates.

Gas Sendout

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

GHG

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

Heating Degree Day (HDD)

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

Heating Value

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

Industrial (SoCalGas & SDG&E)
Category of gas customers who are engaged in mining and in manufacturing durable goods.

Industrial (PG&E)

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

LDC
Local electric and/or natural gas distribution company.

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

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

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

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

MMCF/DAY
Million cubic feet of gas per day.

NGV (Natural Gas Vehicle)
Vehicle that uses CNG or LNG as its source of fuel for its internal combustion engine.

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

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

Off-System Sales
Gas sales to customers outside the utility's service area.

Out-Of-State Gas
Gas from sources outside the state of California.

Priority of Service (SoCalGas & SDG&E)
In the event of a curtailment situation, utilities curtail gas usage to customers based on the following end-use priorities:

1. Firm Service – All noncore customers served through firm intrastate transmission service, including core subscription service.
2. Interruptible – All noncore customers served through interruptible intrastate transmission service, including inter-utility deliveries.

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

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

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

PSEP
Pipeline Safety Enhancement Plan.

Purchase from Other Utilities
Gas purchased from other utilities in California.

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

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

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

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

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

Storage Banking

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

Storage Injection

Volume of natural gas injected into underground storage facilities.

Storage Withdrawal

Volume of natural gas taken from underground storage facilities.

Supplemental Supplies

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

System Capacity or Normal System Capacity (Operational Definition)

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

System Utilization or Nominal System Capacity (Operational Definition)

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

Take-or-Pay

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

Tariff

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

TCF

Trillion cubic feet of gas.

Therm

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

Total Gas Supply Available

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

Total Gas Supply Taken

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

Total Throughput

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

Transportation Gas

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

UEG
Utility electric generation.

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

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

WACOG
Weighted average cost of gas.

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

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

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2016 CALIFORNIA GAS REPORT

RESPONDENTS

RESPONDENTS

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

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

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

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

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

Working Committee

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

Observers

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

RESERVE YOUR SUBSCRIPTION

2017 CALIFORNIA GAS REPORT – SUPPLEMENT

Southern California Gas Company
2015 CGR Reservation Form
Box 3249, Mail Location GT14D6
Los Angeles, CA 90051-1249
or
Fax: (213) 244-4957
Email: Sharim Chaudhury
IChaudhury@semprautilities.com

- ❑ Send me a 2017 CGR Supplement
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Company Name: ____

C/O: ____

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Also, please visit our website at: www.socalgas.com
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San Francisco, CA 94177

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Email: IxG8@pge.com

- ❑ Send me a 2017 CGR Supplement
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- ❑ Change of address

Company Name: ______________________________________

C/O: ____

Address: ____

City: ________________ State: ____________ Zip: ________

Phone: (_____) _______________ Fax: (_____) _____________

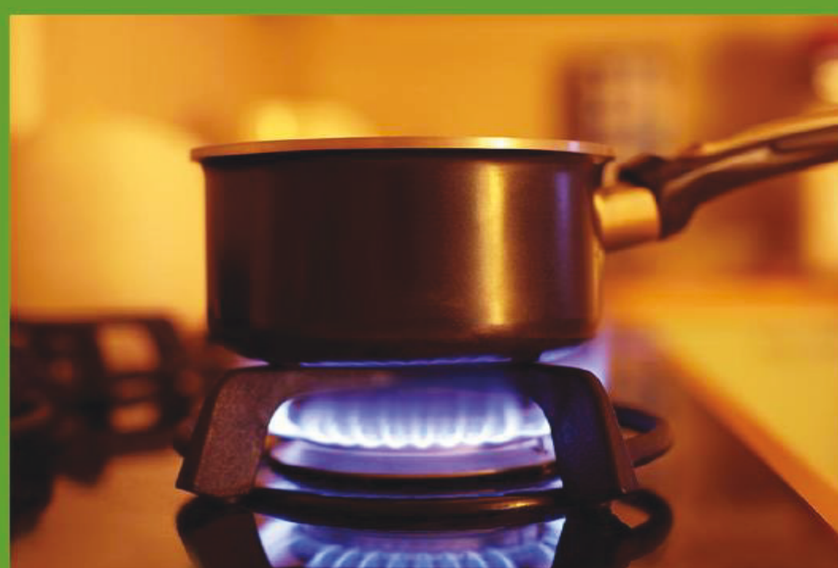
Please visit our website for digital copies of this and past reports:
http://www.pge.com/pipeline/library/regulatory/cgr_index.shtml

Malin
Oregon
Eureka
Redding
Sacramento
San Francisco
San Jose
Fresno
Bakersfield
Needles
Topock
Arizona
Santa Barbara
Los Angeles
Blythe
San Diego
S = Storage Fields

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.

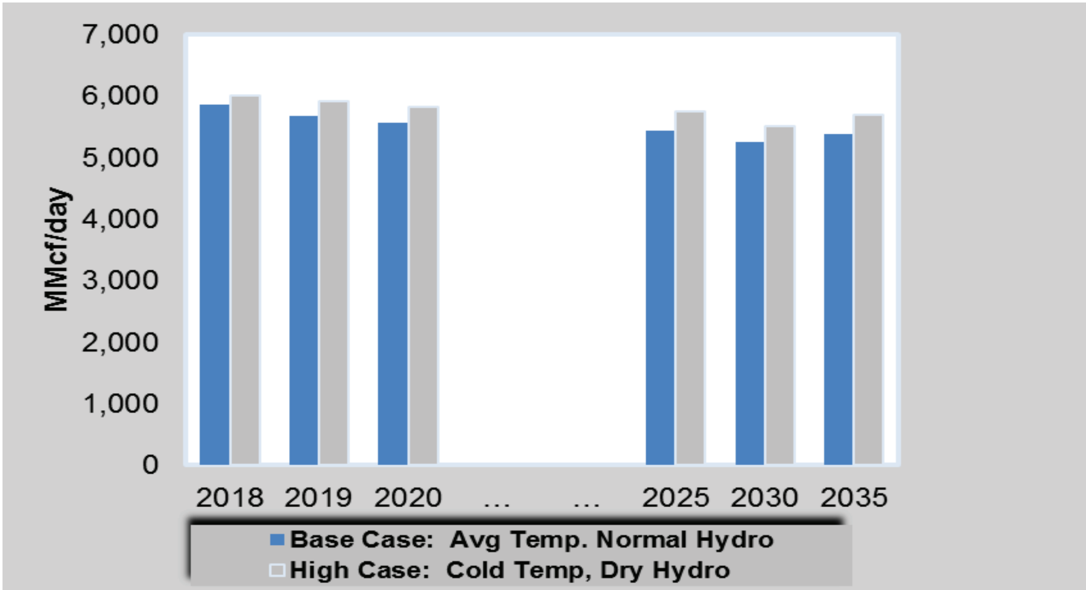
Residential gas demand is expected to decrease at an annual average rate of 1.4 percent. Demand in the commercial and industrial markets are expected to increase slightly at an annual rate of 0.2 percent. Stricter codes and standards coupled with more aggressive energy efficiency programs, in addition 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.

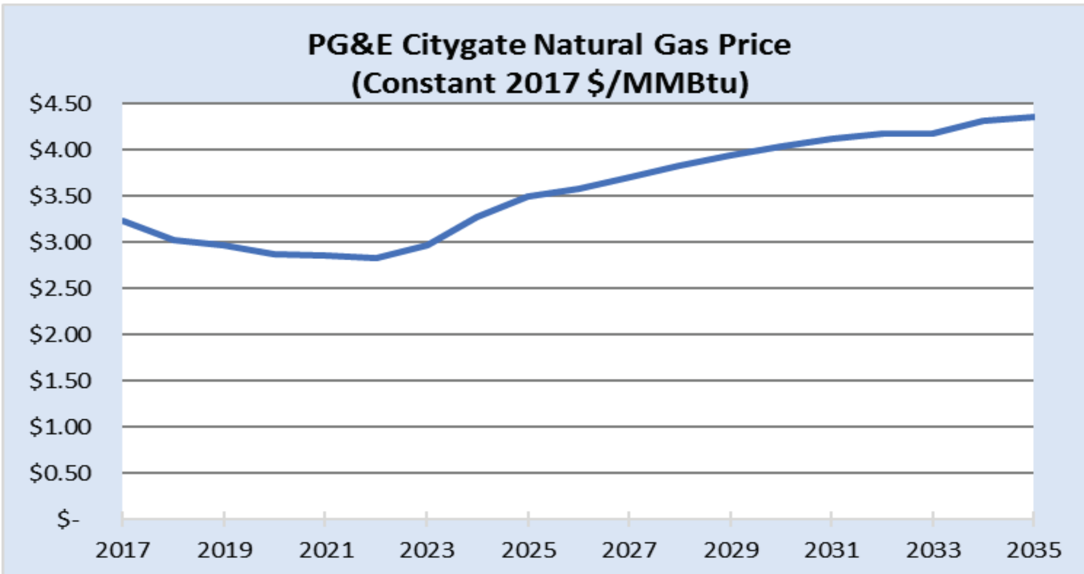
Mexico meets almost half of its natural gas demand with imports. Mexico's pipeline imports from the United States have increased significantly, and as of 2015, have accounted for approximately 80 percent of Mexico's natural gas imports. Mexico also imports natural gas from the Costa Azul LNG terminal, 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.

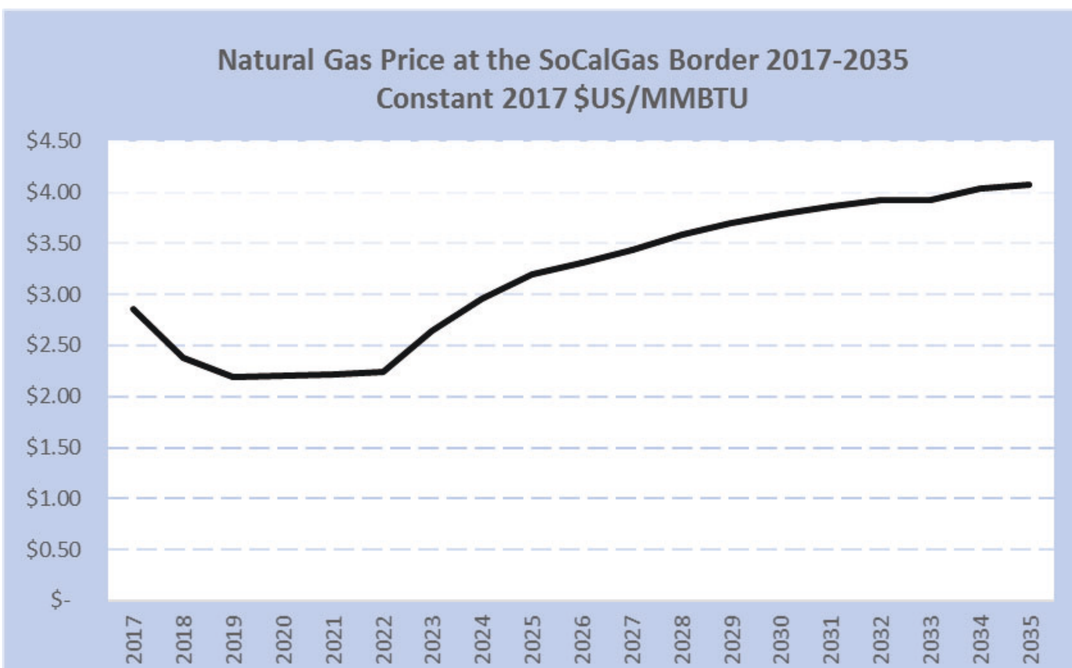
Industry experts currently forecast that North American gas supplies will be sufficient to meet expected demand growth, but at prices which are higher than recently low levels. While North American gas price increases will be somewhat tempered by renewable power generation additions both in the US and 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]

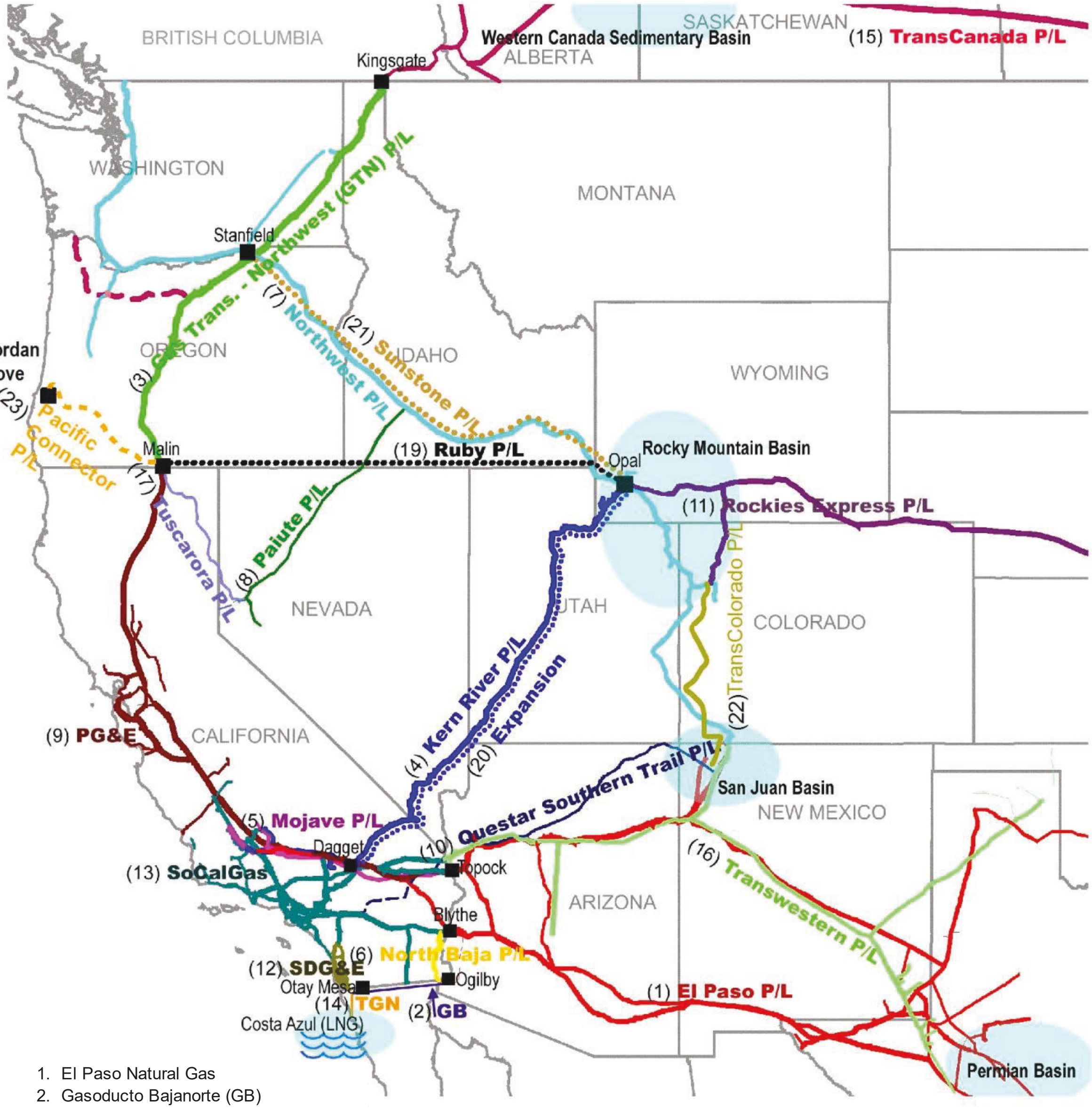
Supply Outlook/Pipeline Capacity

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.

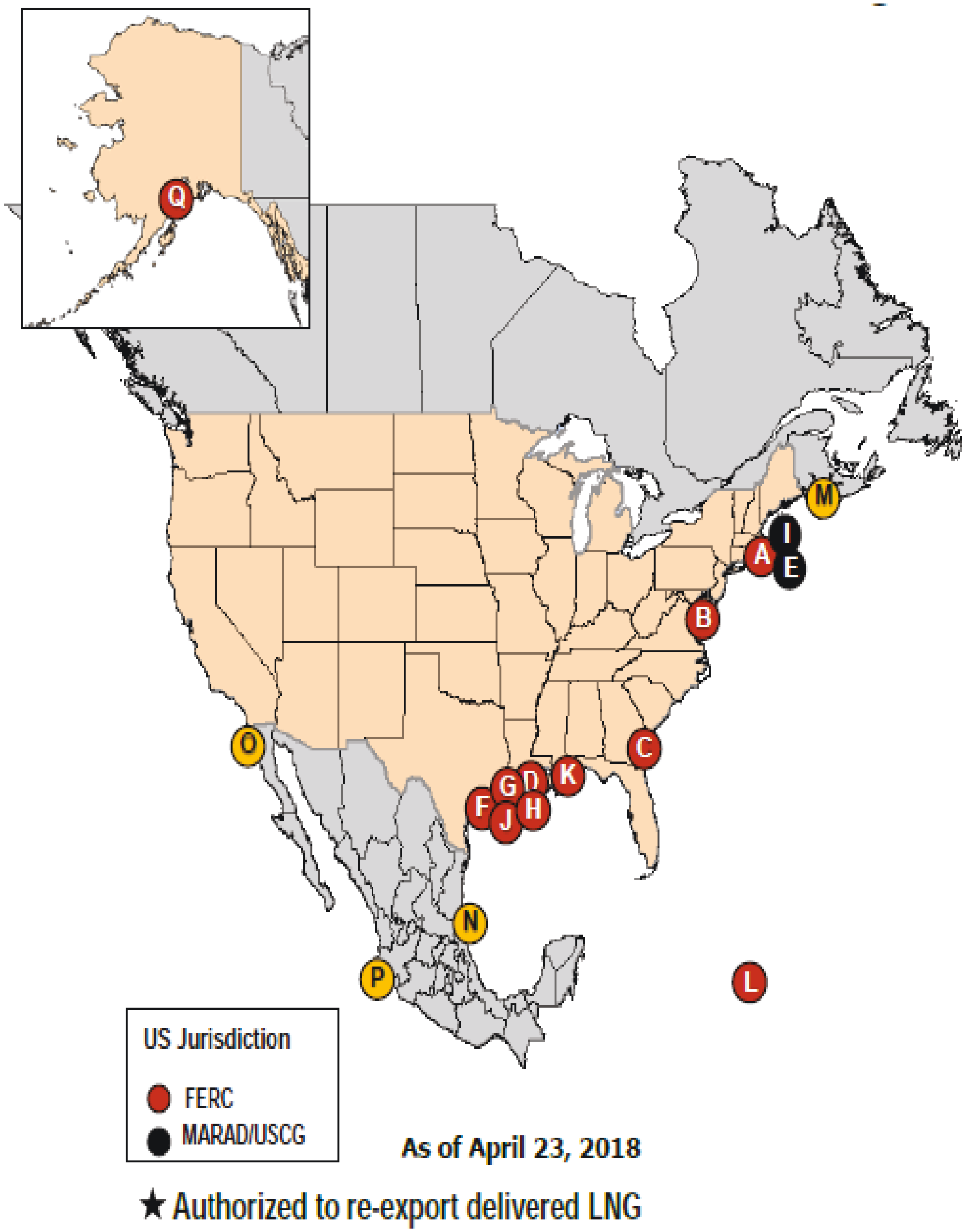
Details of the facilities are described in the table below.

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



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 Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.

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

	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 Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

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

	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 Calfornia Total excludes Off-System Deliveries to Southern California.
(4) Southern California Electric Generation includes commercial and industrial cogeneration, refinery-related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.
(5) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, EOR Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.
Source: CEC staff-provided forecast results from their own model simulations.
(6) Does not include off-system deliveries.
(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

STATEWIDE RECORDED SOURCES AND DISPOSITION

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

The information displayed in the following tables shows the composition of supplies from both out-of-state sources 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.

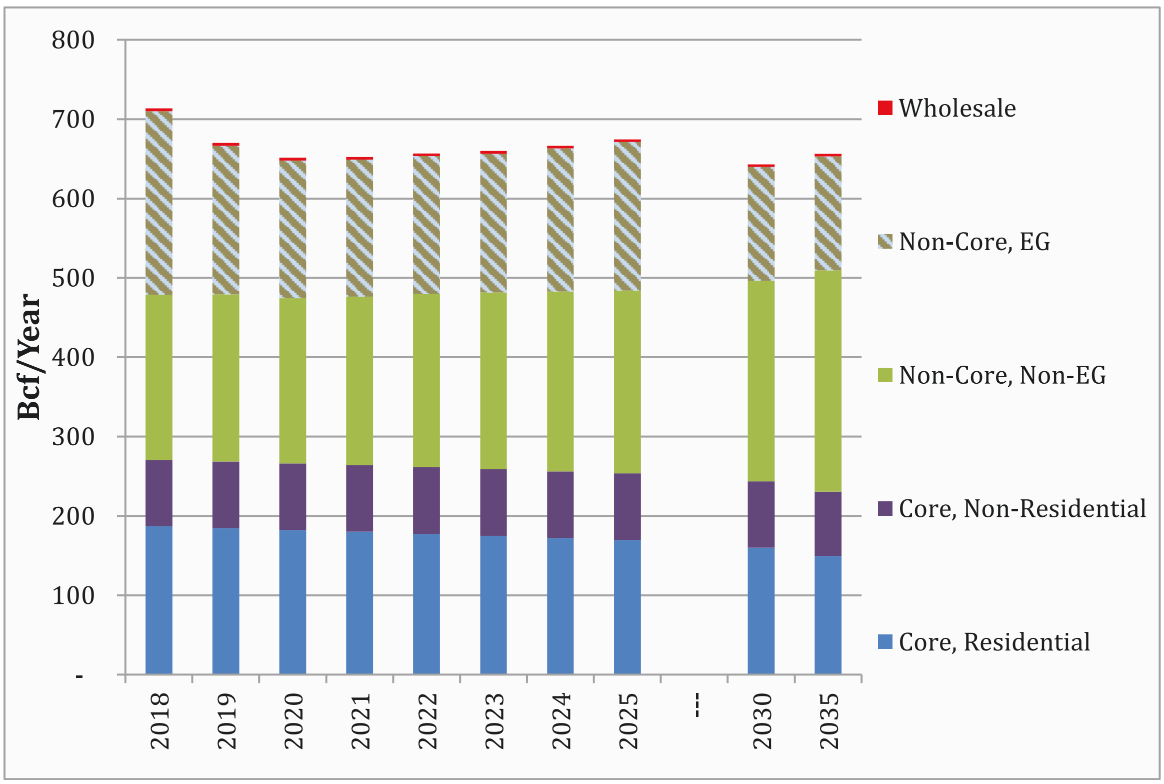
The forecast in this report covers the years 2018 through 2035. However, as a matter of convenience, the tabular data at the end of the section show only the years 2018 through 2025, and the years 2030, and 2035.

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 10º or 15º Fahrenheit above normal, which lead to peak electricity demands and drive up power plant gas demand; however, on a seasonal basis, temperatures seldom deviate more than 2º Fahrenheit from average.)

Hydro Conditions

In contrast to temperature deviations, annual water runoff for hydroelectric plants has varied by 50 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

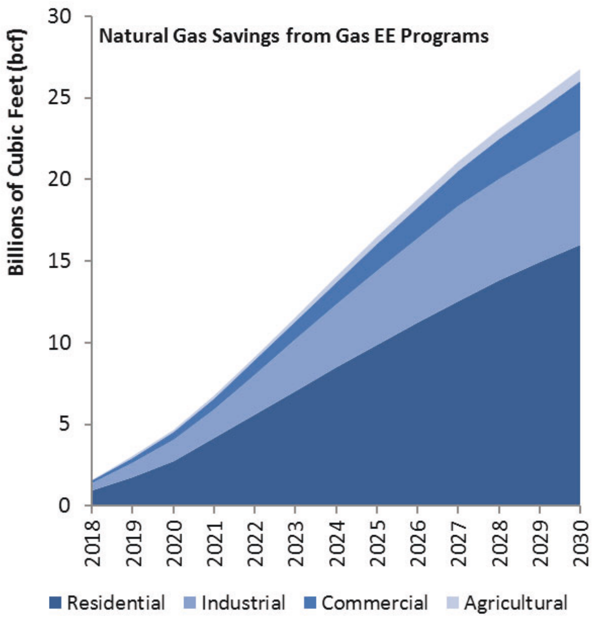
PG&E expects increased renewable electric generation due to current renewable portfolios standards and the Integrated Resource Planning Proceeding at the CPUC. While this increase in renewable generation will put downward pressure on the demand for generation from natural gas-fueled resources, the intermittent 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.

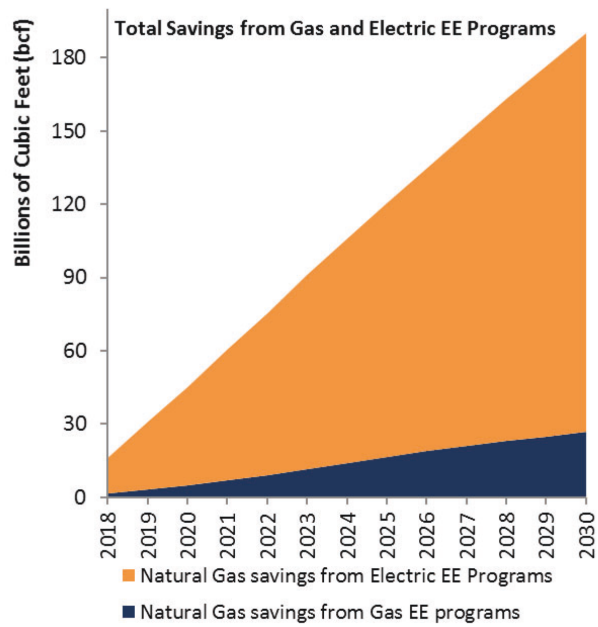
Energy Efficiency Programs

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.

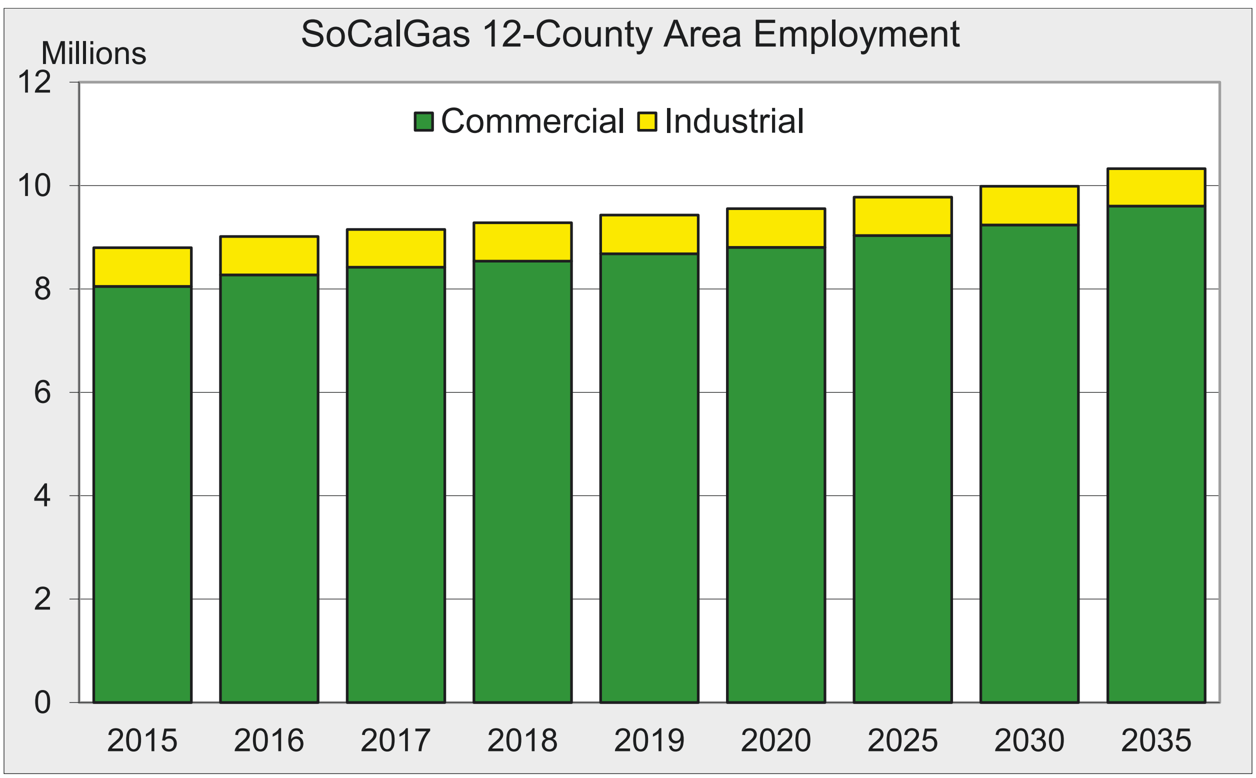
This report covers an 18-year demand and forecast period, from 2018 through 2035; only the consecutive years 2018 through 2022 and the point years 2023, 2024, 2025, 2030, and 2035 are shown in the tabular data in the next sections. These single point forecasts are subject to uncertainty, but represent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

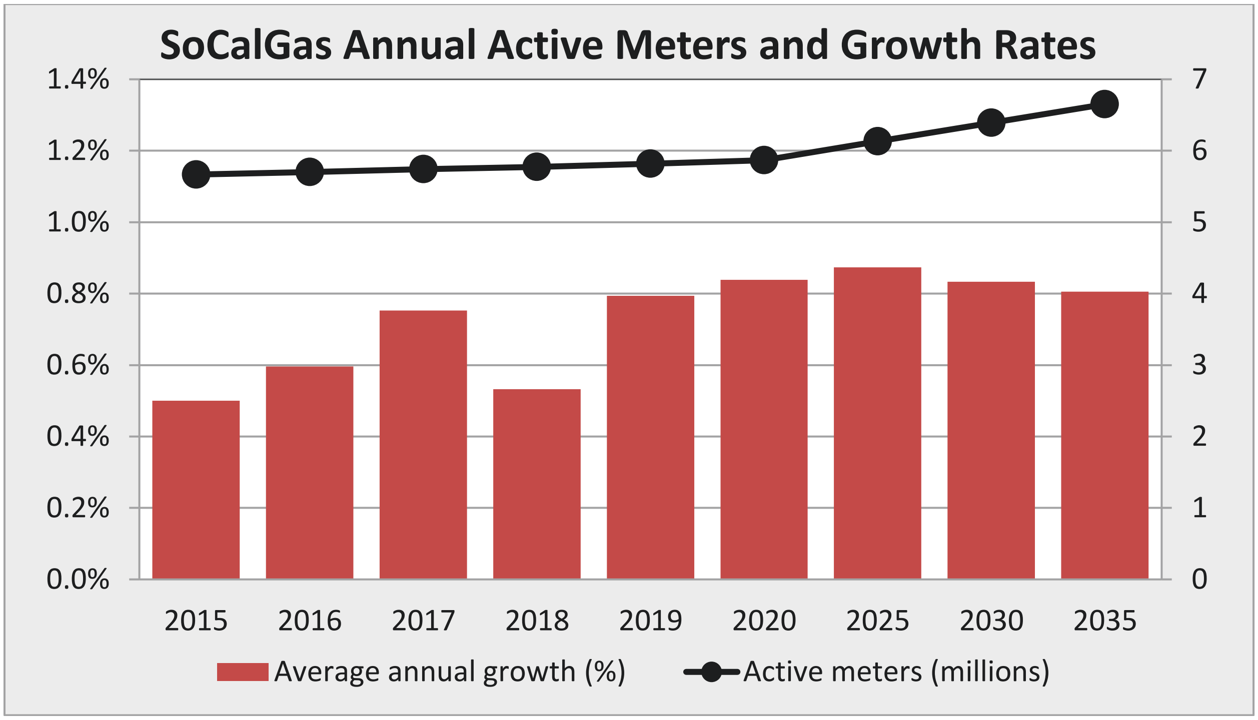
The gas demand projections are in large part determined by the long-term economic outlook for the SoCalGas service territory. As of mid-2018, southern California's economy is enjoying relatively strong growth after recovering from the 2007-to-2011 slump. Overall area jobs are expected to average modest 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.

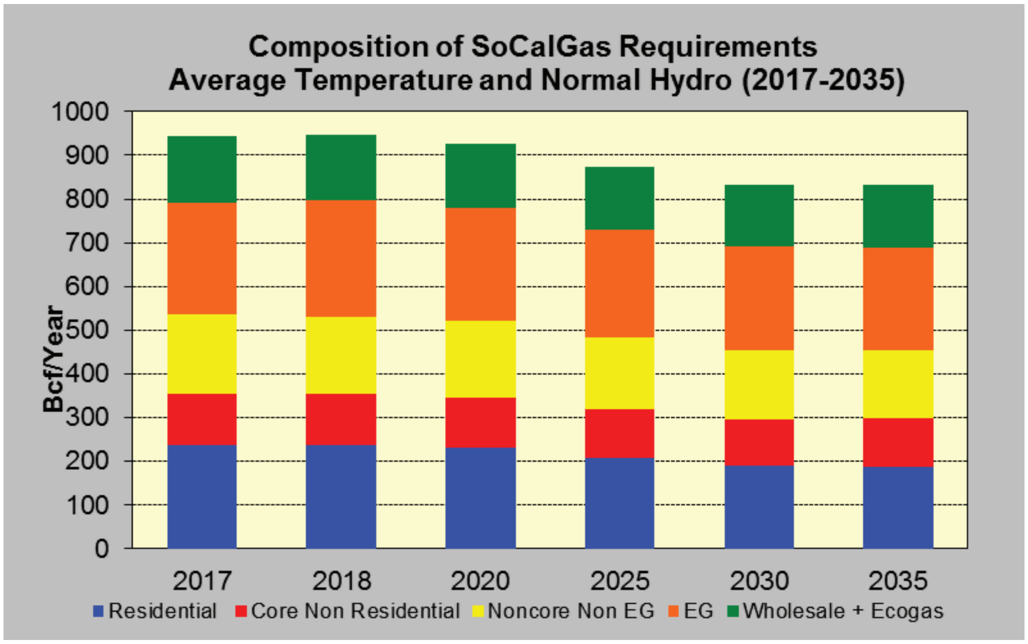


GAS DEMAND (REQUIREMENTS)

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.

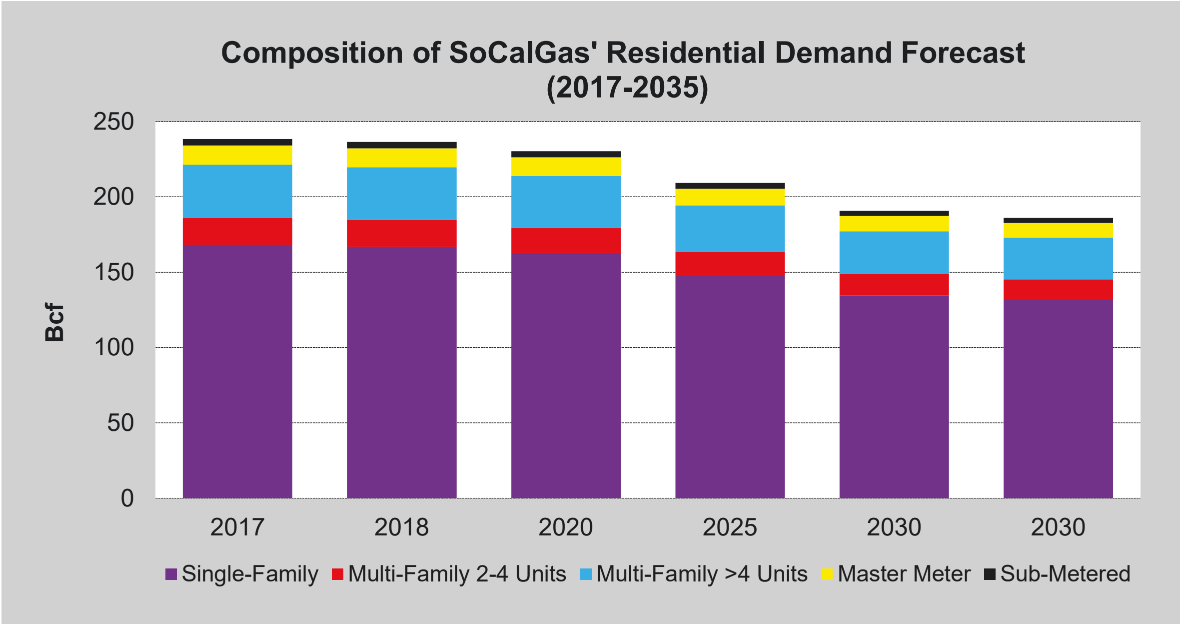
MARKET SECTORS

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

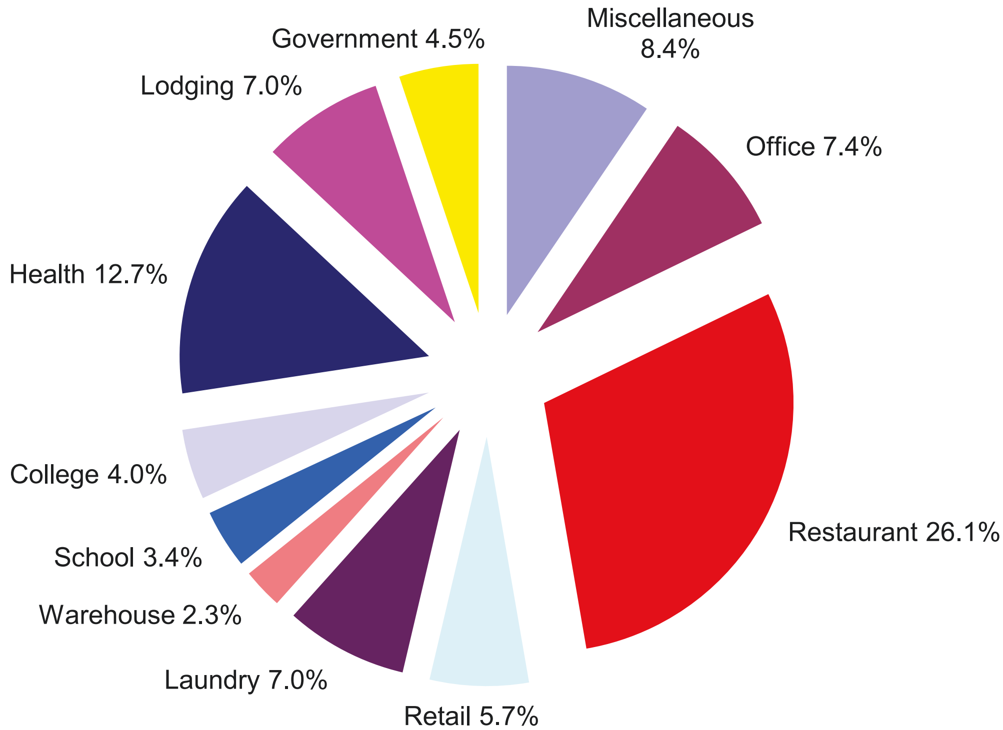


Commercial

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 CO2 emissions by effectively increasing the gas price for noncore commercial customers.

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

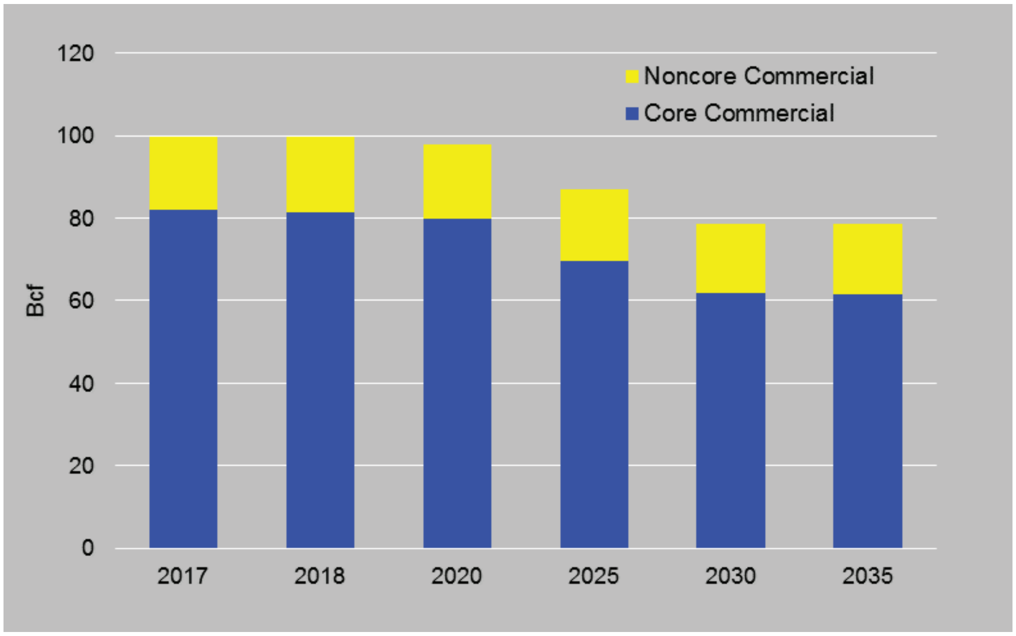


The commercial market consists of 14 business types identified by the customers' North American Industry Classification System (NAICS) codes. The restaurant business dominates this market with 26.1 percent of the usage in 2017, which represents usage in both core and noncore commercial market segments. 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

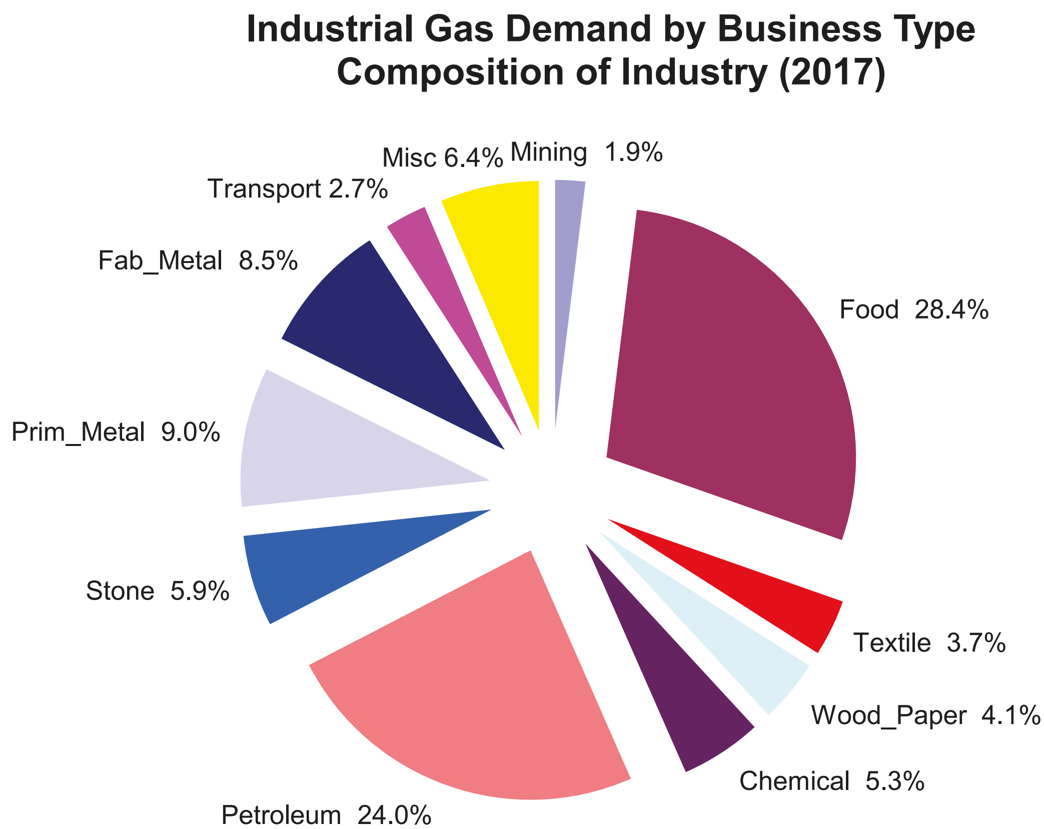


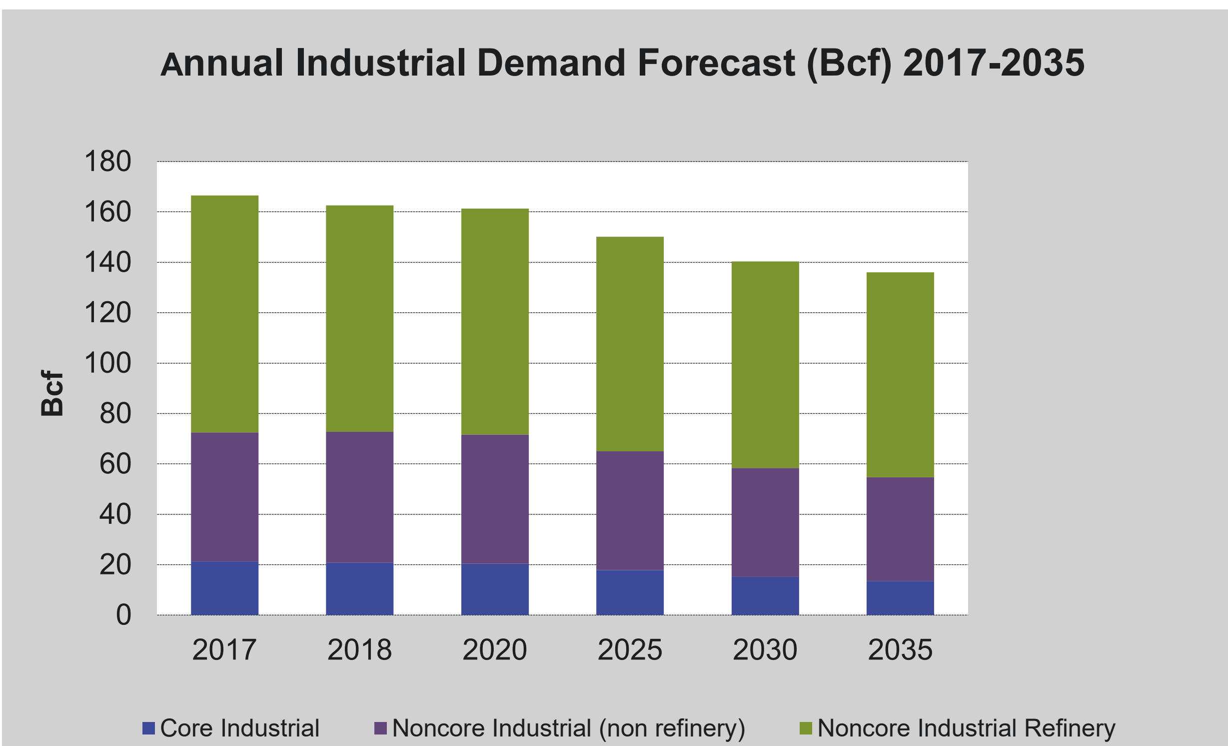
Industrial

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%

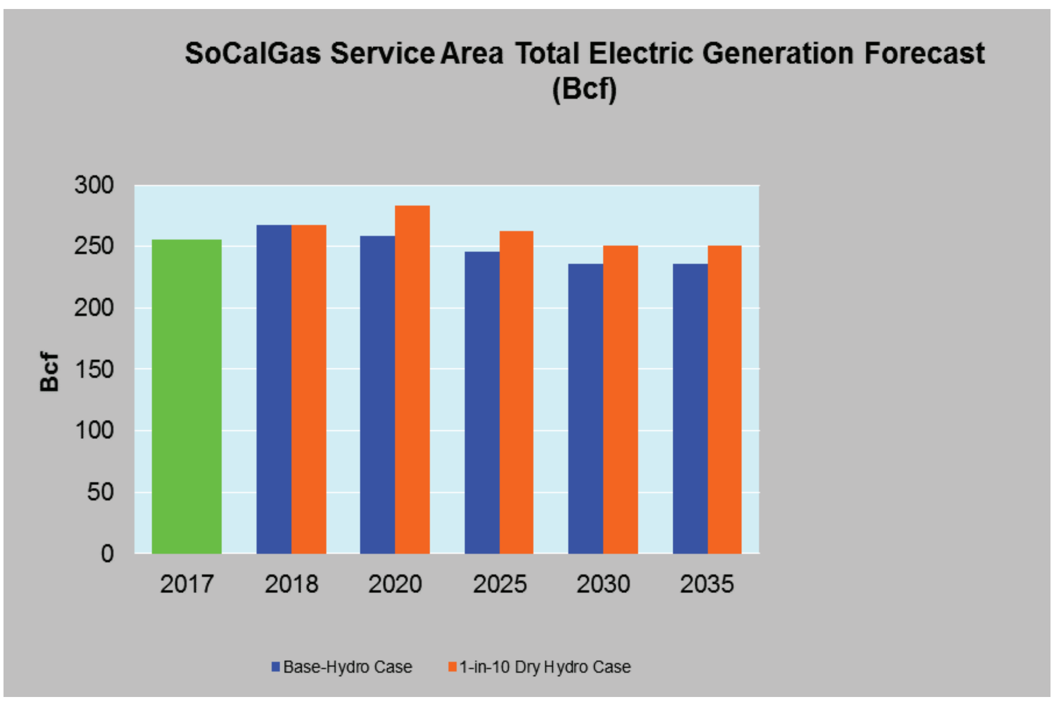

Annual Industrial Demand Forecast (Bcf) 2017-2035
Bcf
180
160
140
120
100
80
60
40
20
0
2017
2018
2020
2025
2030
2035
Core Industrial
Noncore Industrial (non refinery)
Noncore Industrial Refinery

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 CO2 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.

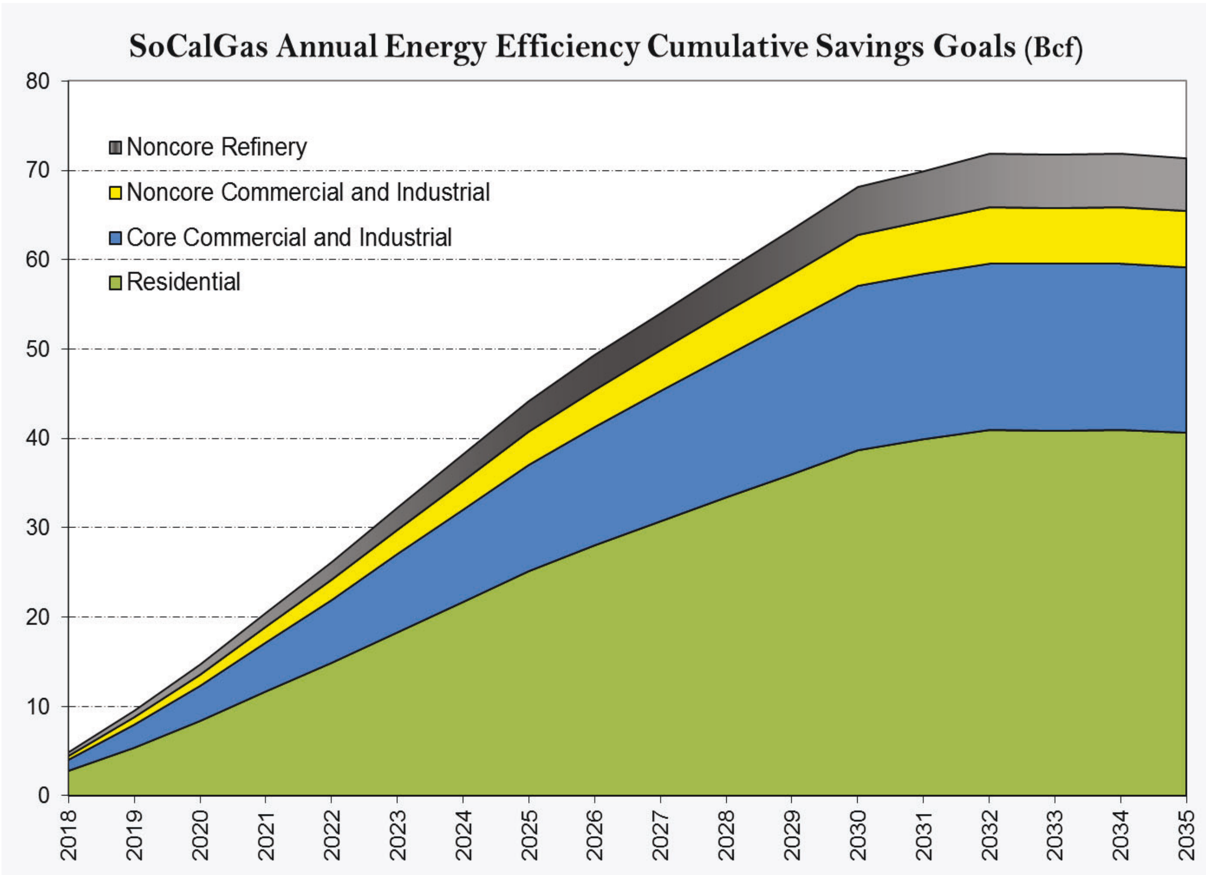
ENERGY EFFICIENCY PROGRAMS

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

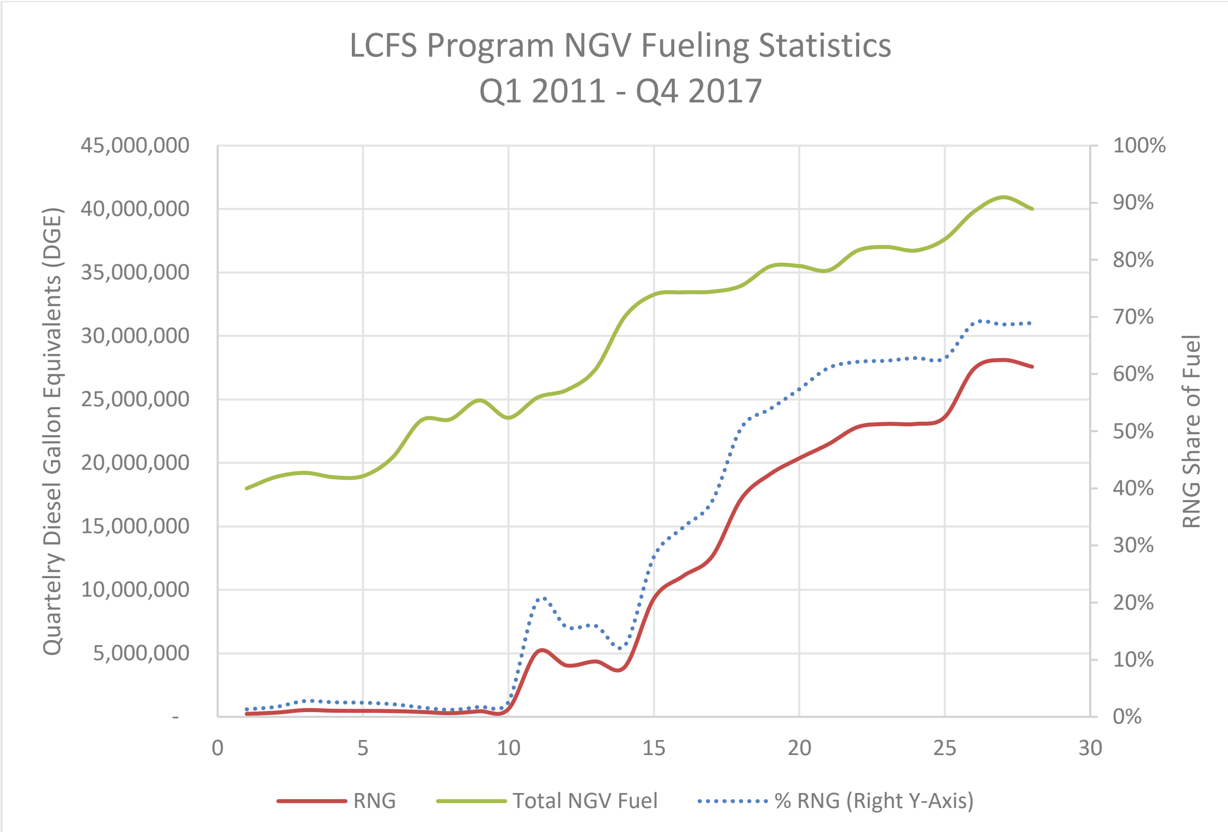


Figure 1 - RNG's growing role in California's transportation fuel market.

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

[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.

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[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 CO2 per MWh) and each state's unique generation mix.

On February 9, 2016, the U.S. Supreme Court issued a stay of the Environmental Protection Agency's (EPA's) Clean Power Plan, freezing carbon pollution standards for existing power plants while the rule 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^2e of emissions in three primary categories: combustion emissions at four compressor stations and two storage fields, where annual emissions exceed 10,000 mtCO^2e; 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			2013	2014	2015	2016	2017
	CAPACITY AVAILABLE						
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.
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 gas procurement by the City of Long Beach

	2018	2019	2020	2021	2022
6/	0.8	0.7	0.7	0.7	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:

	2018	2019	2020	2021	2022
8/	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.
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.
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.

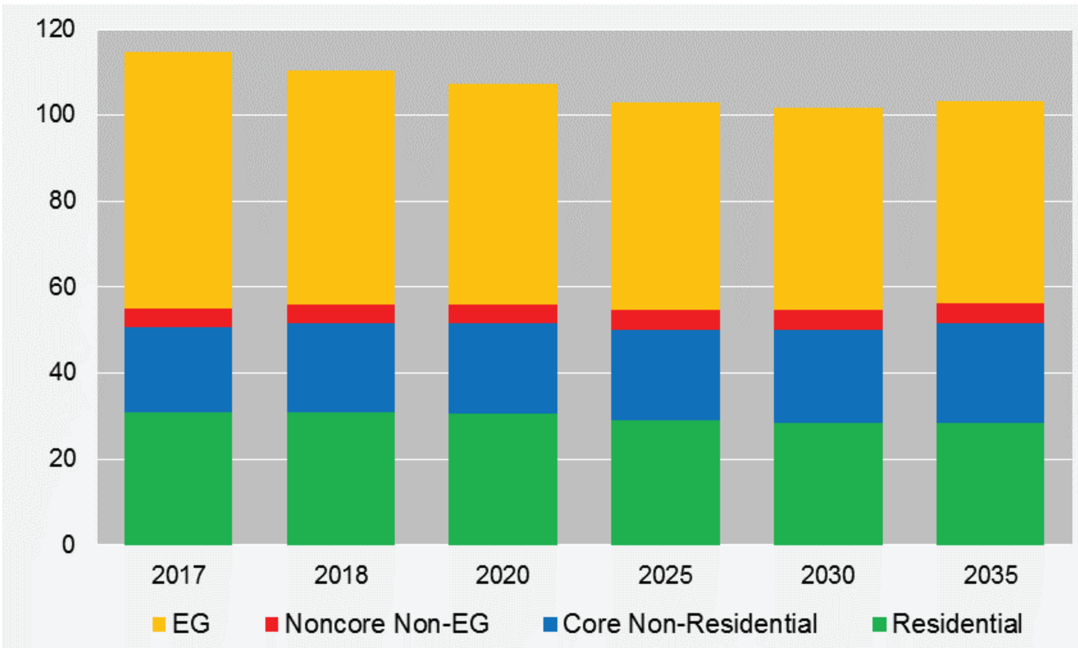
This projection of natural gas requirements, excluding electric generation (EG) demand, is derived from models that integrate demographic assumptions, economic growth, energy prices, energy efficiency programs, customer information programs, building and appliance standards, weather and other factors. 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.

Composition of Natural Gas Throughput
Average Temperature, Normal Year (2017-2035)
Bcf/Year



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

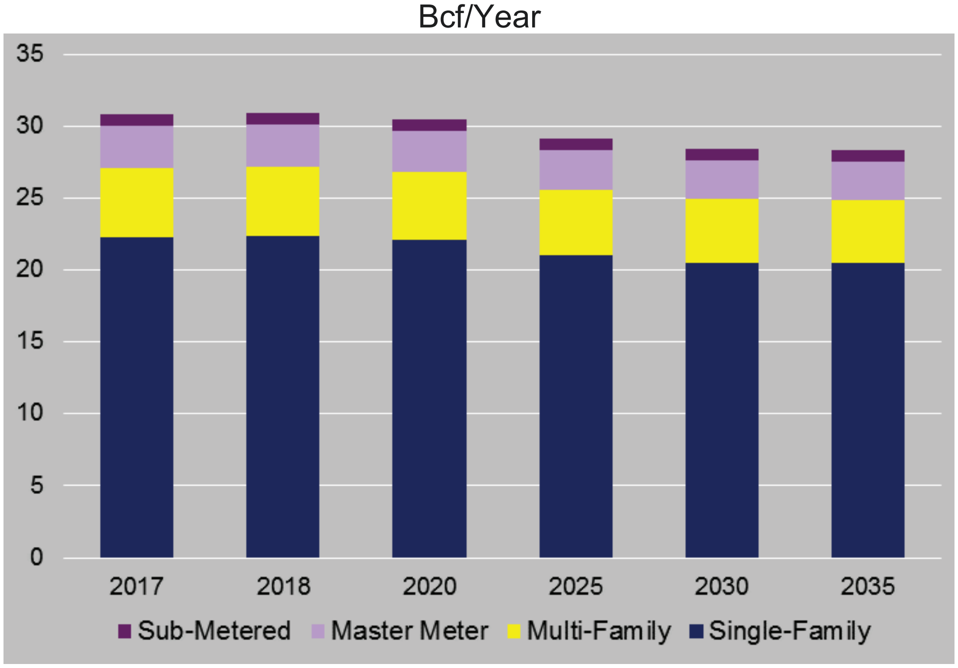
Residential

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.

Composition of SDG&E's Residential Demand Forecast
(2017-2035)
Bcf/Year

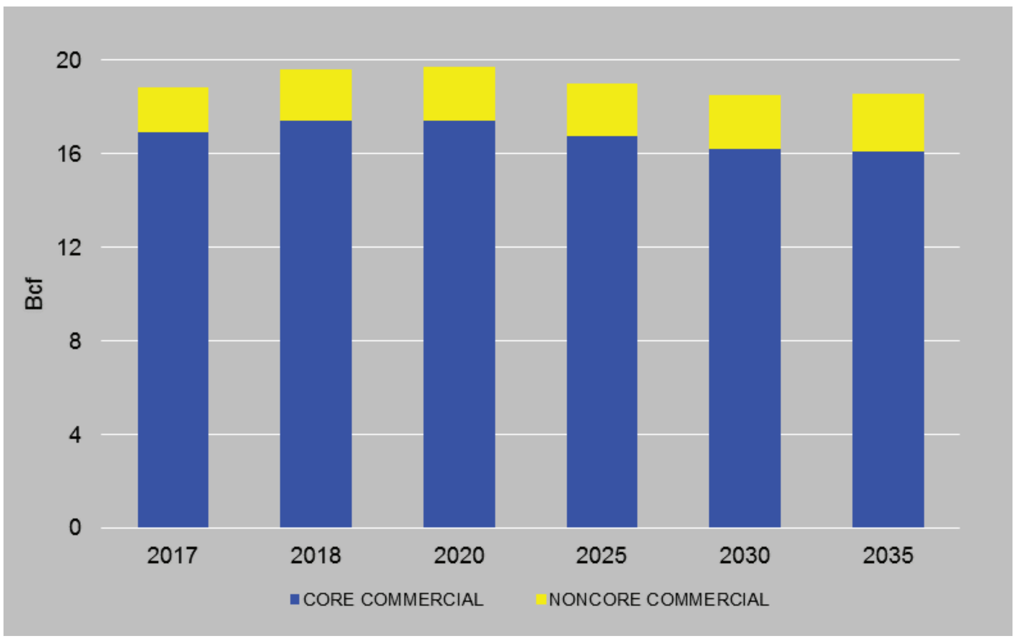


Commercial

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

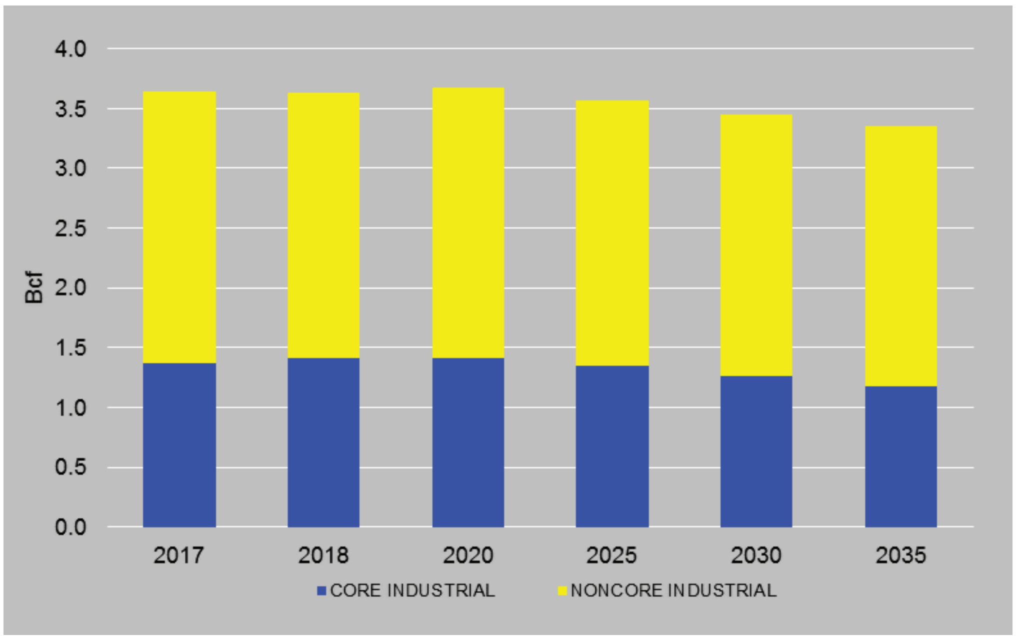
Commercial Sector's Natural Gas Demand Forecast
2017-2035
Bcf/year



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

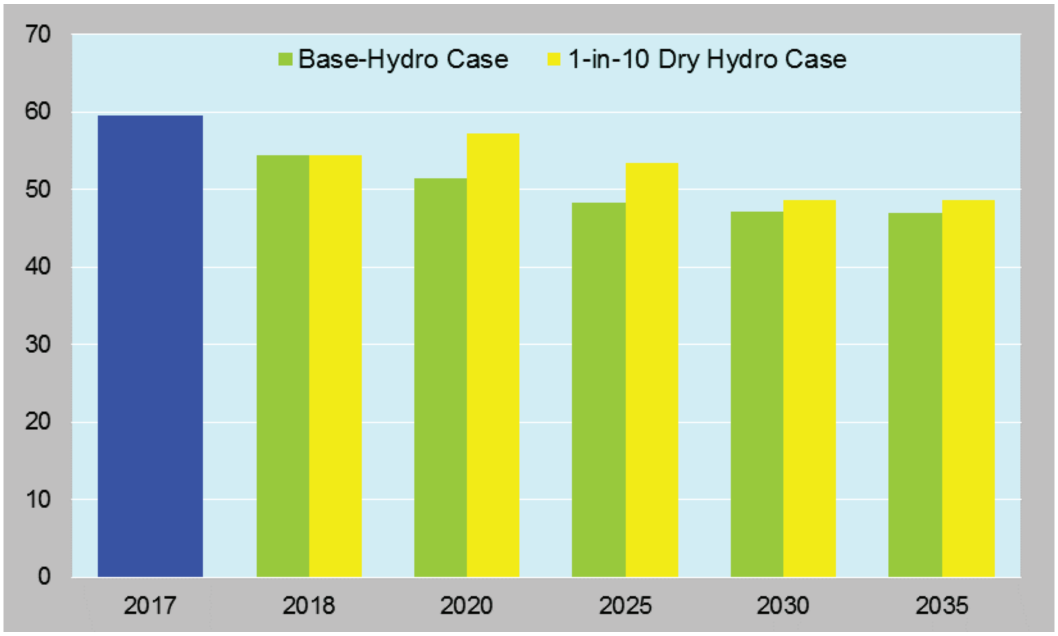


Non-core industrial load in 2017 was 2.3 Bcf and is expected to shrink about 0.2 percent per year to 2.2 Bcf by 2035. Demand-dampening effects of higher carbon-allowance fees will more than offset slight increases from economic growth.

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.

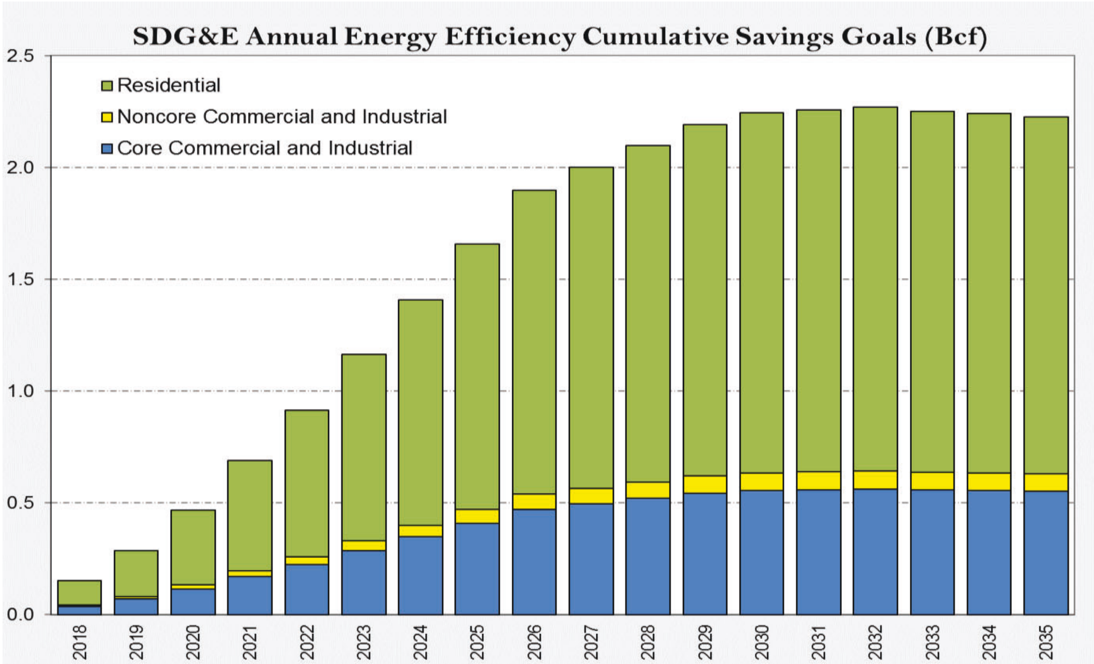
Natural Gas Vehicles (NGV)

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			2013	2014	2015	2016	2017
	Actual Deliveries by End-Use						
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

GLOSSARY

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 60º 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: 65ºF; PG&E 60ºF). A basis for computing how much electricity and gas are needed for space heating purposes. For example, for a 50ºF average temperature day, SoCalGas and SDG&E would accumulate 15 HDD, and PG&E would accumulate 10 HDD.

Heating Value

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

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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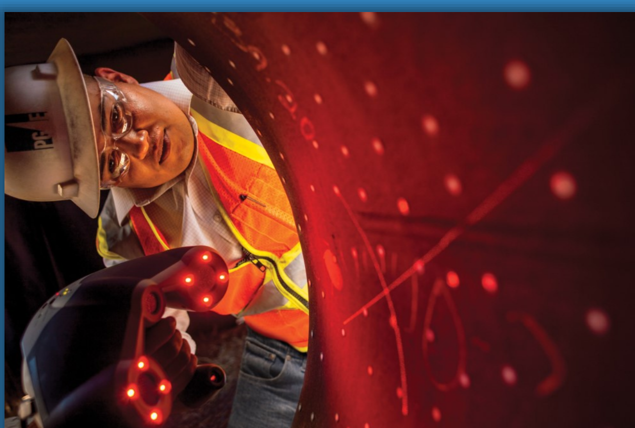



— Prepared by the California Gas and Electric Utilities —

Prepared in Compliance with California Public Utilities Commission Decision D.95-01-039

2020 CALIFORNIA GAS REPORT

PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES

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

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2020 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The *2020 California Gas Report* (CGR) 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 or Commission) Decision (D.) 95-01-039. The projections in the CGR 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 Energy Resources Department, Southwest Gas Corporation (SWG), and San Diego Gas & 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. Workpapers that document the assumptions and other forecast details are published separately by each of the utilities and the redacted versions are available upon request.

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.

2020 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

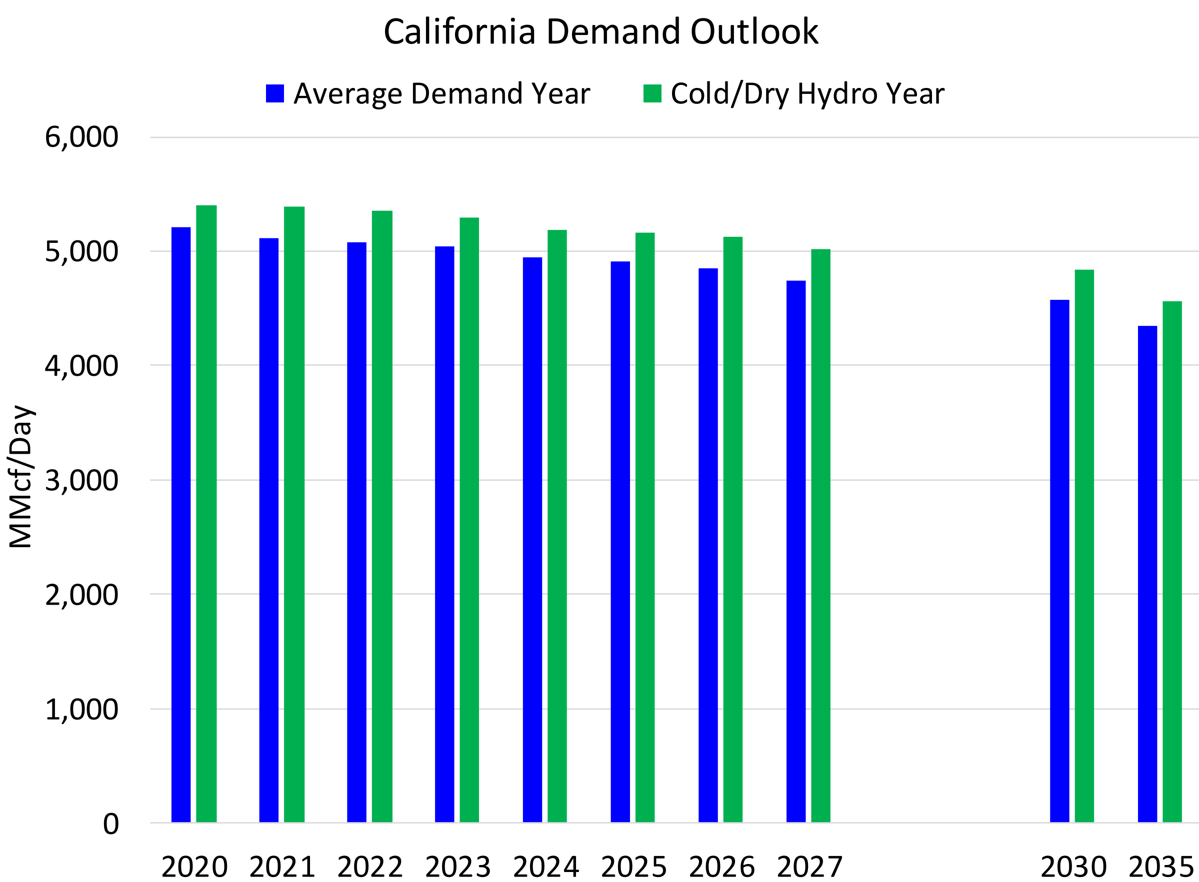
DEMAND OUTLOOK

Utility-driven, statewide natural gas demand[1] is projected to decline at an average rate of 1.0 percent each year through 2035. The decline comes from reduced gas demand in the major market segment areas of residential, electric generation (EG), commercial, and industrial. Statewide residential gas demand is projected to decrease at an average rate of 1.7 percent each year. EG gas demand is projected to decrease at an average annual rate of 1.5 percent each year. The Commercial segment gas demand, which includes both core and noncore commercial demand, is projected to decrease at an average annual rate of 1.5 percent each year. The Industrial gas demand segment is expected to decline at an average rate of 0.2 percent per year. Though the Natural Gas Vehicle (NGV) market shows moderate growth, it is not sufficient to offset the projected decrease in other market segments over the forecast horizon.

There are several drivers of these declines. Aggressive energy efficiency programs are dampening gas demand in these sectors. In addition, the statewide efforts to minimize greenhouse gas (GHG) emissions are reducing EG demand due to increase in demand side and supply side generation resources that produce few or no carbon emissions. Nevertheless, gas-fired generation and energy storage will continue to be primary technologies to support long-term increases in electricity usage and integrate increasing quantities of intermittent renewable electric generation into the electric grid.

1 Gas Demand served by PG&E, SoCalGas, SWG, City of Long Beach Energy Resources Department, and SDG&E.

FIGURE 1 – CALIFORNIA GAS DEMAND OUTLOOK



The graph above summarizes statewide gas demand under the Average Demand year (Average Demand) forecast and the Cold Temperature, Dry Hydroelectric Generation[2] scenario (Cold/Dry Hydro). The Average Demand refers to the gas demand projection for an average temperature year and normal hydroelectric generation (hydro) year, and the Cold/Dry Hydro refers to expected gas demand for a cold temperature year and dry hydro year conditions. Under an average-temperature condition and a normal hydro year, gas demand for the state is projected to average 5,205 million cubic feet of gas per day (MMcf/d) in 2020 decreasing to 4,343 MMcf/d by 2035, a decline of 1.2 percent per year.

In 2020, Northern California is projected to require an additional 5.0 percent of gas supply to meet demand for the Cold/Dry Hydro demand scenario, whereas Southern California is projected to require an additional 3.2 percent of supply to meet demand under this scenario. The

2 Dry Hydroelectric Generation scenario assumes dry hydro generation in the Western Electricity Coordinating Council (WECC).

weather for each year is an independent event and each event has the same likelihood of occurring.

FOCUS ON EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on Customer Energy Efficiency and other Demand-Side Management 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 valuable resource. Gas demand for electric power generation is expected to be moderated by CPUC mandated goals for electric energy efficiency programs and additional renewable power generation. The Average Year demand forecasts in this report assume that renewable power will meet 33 percent of the state's electric needs by 2020 and 60 percent by 2030 and beyond.

Passed in 2018, Senate Bill (SB) 100 increases and accelerates the Renewables Portfolio Standard (RPS) targets. The increase comes in 2030 with renewable power generation equal to 60 percent of retail electric sales. Previously, the target was 50 percent. The acceleration requires the RPS at 50 percent by 2026. An additional requirement mandated in 2018 establishes a statewide goal to achieve carbon neutrality by 2045 across all sectors of the California economy.

Enacted in 2015, 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. These targets must be cost-effective and feasible.

Additional California legislation and policy direction[3] provides directives and incentives to increase energy efficiency. Some of these efforts require access to building performance data, encouraging pay-for-performance incentive-based programs, and the use of energy management technology for use in homes and businesses. Moreover, legislation requires energy utilities to develop a plan to educate residential customers and small and medium business customers about the incentive programs.

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

3 For more information, see https://www.cpuc.ca.gov/egyefficiency/.

jurisdictional utilities. Gas savings from electric energy efficiency goals are based on a generic assumption of heat rate per megawatt-hour (MWh) of electricity produced at gas fired peaking and combined cycle power plants.

TABLE 1 – IMPACT OF RENEWABLE GENERATION AND ENERGY EFFICIENCY PROGRAMS ON GAS DEMAND

	2020	2021	2022	2023	2024	2025	2026	2027	2030	2035
California Energy Requirements by CPUC-Jurisdictional Utilities (CAISO) (1)										
Electricity Demand (GWh)	251,983	250,319	249,569	249,434	249,469	249,490	249,666	249,841	251,392	253,308
33% Renewables by 2020 & 60% Renewables by 2030										
Renewable Electric Generation (GWh/Yr) (2)	83,154	86,861	90,843	95,034	99,289	103,538	107,856	112,179	125,696	126,654
Increase over 2019 Level (GWh/Yr) (3)	23,415	27,121	31,104	35,295	39,549	43,799	48,116	52,439	65,957	66,915
Gas Savings over 2019 Level (Bcf/Yr) (4)	142	165	189	214	240	266	292	318	400	406
Electric Energy Efficieny Goals (5)										
Electricity Savings over 2019 Level (GWh/Yr)	1,256	2,402	3,452	4,690	6,160	7,829	9,659	11,711	18,823	31,410
Gas Savings over 2019 Level (Bcf/Yr) (4)	8	15	21	28	37	48	59	71	114	191
Energy Efficiency Goal for Natural Gas Programs (6)										
Gas Savings over 2019 Level (Bcf/Yr)	9	18	26	34	42	51	57	63	84	84
Total Gas Savings (Bcf/Yr) (7)	159	197	236	277	320	364	408	453	598	680

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 60% renewables by 2030.

(3) Increase reflects only the impacts of equipment installed after December 31, 2019.

(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 g 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 produ 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-

(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-

(7) Total gas savings are annual savings from equipment installed after December 31, 2019.

FUTURE GAS SYSTEM IMPACTS RESULTING FROM INCREASED RENEWABLE GENERATION AND ELECTRIFICATION

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. It is also expected that the increasing renewable generation will add to the daily and hourly load-forecast variance on the gas-fired EG fleet. Although the additional renewable energy will displace some of the natural gas currently being used to generate electricity in California, the intermittent nature of renewable generation will likely cause the electric system to rely on natural gas fired EG for providing the needed ancillary services (A/S) (ramping, voltage support, and quick starts) to balance the electric system in the short-term. In the long-term, this balancing may also come from the higher expected integration of energy storage devices e.g., batteries, fuel cells, and hydroelectric pumped storage.

The amount of gas consumed for integrating more renewables will fluctuate hourly. This is due to an increased need for rapid response from gas-fired generators to follow electric net load fluctuations. Since the gas-fired generation is expected to be the marginal resource in most hours, the gas system will need to be both robust and flexible to handle such fluctuations.

The expected growth in electrification poses considerable uncertainty on when, where, and how large will the impact be on gas demand throughout. In the building sector, electrification could decrease gas use. Recently, some California local jurisdictions[4] have forbidden the use of gas in new building construction. Moreover, it is possible for jurisdictions to require appliance substitution to electric from natural gas. Expected growth in electrification of vehicles and buildings would result in increasing electric load. This load increase could cause additional use of gas-fired generators.

4 See the following for more details for about 30 local jurisdictions implementing these requirements: https://www.sierraclub.org/articles/2020/03/californias-cities-lead-way-gas-free-future.

GAS PRICE FORECAST

MARKET CONDITION

The natural gas industry has seen its fair share of transformations over the last decade with the shale gas revolution, the first Liquefied Natural Gas (LNG) export cargo out of the United States (U.S.) Lower 48, and most recently the rise of associated supply from tight oil production growth. As a result, the North American gas supply portfolio contains a mix of conventional and unconventional natural gas supply sources. Moreover, improvements in fracking technology and horizontal drilling efficiencies in both dry and wet gas plays have resulted in the supply from unconventional shale resources increasing faster than conventional supplies.

The near-term gas price outlook continues to remain below $3.00/Million British Thermal Units (MMBtu) for most supply basins, in constant 2019 dollars. Production gains from the Permian Basin have been significant and are expected to remain strong for at least the next 5 years. Additionally, three Permian-area pipelines are expected to come online by late 2021. Supplies are expected to ramp up from the Permian production area and shale-sourced supplies continue to expand in the Marcellus, Utica, and Haynesville areas.

Natural gas prices will gain further support in most supply basins over the forecast period and move towards the $3.00-$4.00/MMBtu range in constant 2019 U.S. dollars by end of the decade as more demand and exports ramp up to expand the market size. Additionally, the challenges of building new pipeline projects in North America will have a material impact on the Henry Hub price outlook and where resources will be developed in the long term.

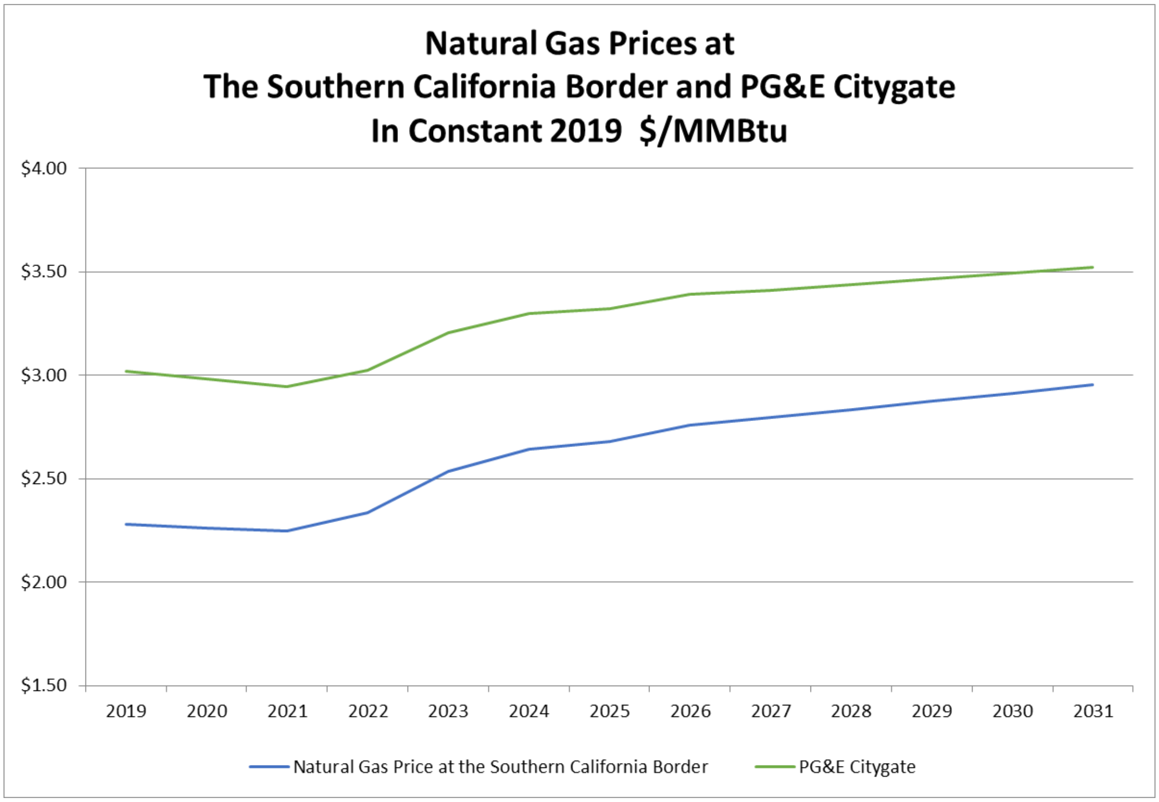
Industry experts continue to forecast that North American gas supplies will be sufficient to meet expected demand growth. North American gas price increases may be somewhat tempered by renewable power generation additions both in the U.S. and in Mexico. Continuing closures of coal-fired generation to meet environmental goals may provide price support but could be tempered by the softening of the global economy due to Coronavirus Disease 2019 (COVID-19) related impacts. Related uncertainties surrounding government policies are expected to create some headwinds for natural gas.

Development of the Gas Price Forecast

Natural gas prices at the SoCalGas border averaged $2.28/MMBtu in 2019. The inflation adjusted SoCalGas border price is expected to rise to $2.95/MMBtu by the year 2035. On average, the SoCalGas Border price is expected to be $2.56/MMBtu over the forecast horizon. For the PG&E Citygate, the natural gas price in 2019 averaged $3.52/MMBtu and is forecasted to decline to an average of $3.23/MMBtu over the forecast horizon.

Consistent with prior CGRs, the 2020 CGR gas price forecast was developed using a combination of market prices and fundamental long-term forecasts. The natural gas custom futures curve was extracted from Intercontinental Exchange and Chicago Mercantile Exchange for the 2020-2025 period. Fundamental price forecasts were used for 2028 and beyond. The forecasts for 2026 and 2027 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 2-year period. The fundamental gas price forecast represents an average of three forecasts developed by the California Energy Commission (CEC) and independent consultants Wood Mackenzie and S&P Global (formerly PIRA).

FIGURE 2 – NATURAL GAS PRICE CHART: SOCALGAS BORDER AND PG&E CITYGATE PRICES 2020-2035



It is important to recognize that the natural gas price forecast is inherently uncertain. PG&E, SoCalGas, and the respondents of the *2020 CGR*, separately and collectively, do not warrant the accuracy of the gas price projection. PG&E, SoCalGas, or the respondents of the *2020 CGR* shall not be liable or responsible for the use of or reliance on this natural gas price forecast.

NATURAL GAS PROJECTS

Over the past 5 years, the natural gas industry has made investments to improve the safety, accessibility, and reliability of natural gas supply. In addition, more projects have been proposed and some are under construction. The following describes the state of supply and regionally important projects.

GAS SUPPLY

California's existing gas supply portfolio is regionally diverse and ensures long-term supply availability. Gas supply to California includes sources from California (onshore and offshore), Southwestern U.S. (the Permian, Anadarko, and San Juan basins), the Rocky Mountains and Canada. Interstate pipelines currently serving California include Ruby Pipeline LLC, El Paso

Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission Northwest LLC (GTN), Transwestern Pipeline Company, Tuscarora Pipeline, and the Baja Norte/North Baja Pipeline. The map on the following page shows the locations of these supply sources and the natural gas pipelines serving California.

California benefits from substantial gas storage capacity in dedicated gas storage facilities across the state. In recent years, various regulations and standards[5] have been proposed and implemented to ensure safe, reliable operation of California gas storage facilities.

In addition to traditional sources of gas supply, multiple Renewable Gas (e.g., Renewable Natural Gas and hydrogen to name a couple) interconnection projects in California are beginning to come online. As further detailed in this CGR, gas utilities are taking significant steps to make RG interconnection easier and more transparent and see broad potential for RG in California. Currently, incentives (such as Low Carbon Fuel Standard (LCFS) and Renewable Identification Number (RIN) credits) are funneling RG towards use in the transportation sector. However, with the help of policy makers and thoughtful incentives, the energy sector hopes to utilize increasing amounts of future RG to meet customer needs and support electric grid reliability.

As California continues towards achieving low or zero emissions from energy, Green Hydrogen (H_2) will become an important fuel source in helping achieve the State's emissions goals. There is also great potential for generating Green[6] H_2 and storing it in existing gas utility infrastructure to help meet California's dynamic energy needs. No other storage technology has the capability for the long-term and large volume storage that H_2 does.

5 See Geologic Energy Management Division's Underground Natural Gas Storage for more details on regulations and standards at: https://www.conservation.ca.gov/calgem/Pages/UndergroundGasStorage.aspx.

6 Green Hydrogen is hydrogen produced from electricity that comes from renewable sources such as wind, solar or hydro.

FIGURE 3 – WESTERN NORTH AMERICAN NATURAL GAS PIPELINES

1. West Coast Pipeline
2. Woodfibre LNG Terminal
3. Terasen Sumas Gas Pipeline
4. TransCanada Pipeline
5. Alliance Pipeline
6. Northern Border Pipeline
7. Gas Transmission Northwest (GTN Pipeline
8. Northwest Pipeline
9. Jordan Cove LNG (Proposed)
10. Pacific Connector (Proposed)
11. Tuscarora Gas Transmission
12. Paiute Pipeline
13. Ruby Pipeline
14. Questar Pipeline
15. Rockies Express Pipeline
16. Southern Star Pipeline
17. TransColorado Pipeline
18. Kern River Pipeline
19. Pacific Gas and Electric Company
20. Southern California Gas Company
21. San Diego Gas and Electric Company
22. North Baja Pipeline
23. El Paso Natural Gas
24. TransWestern Pipeline
25. Rosarito Pipeline
26. Trasnportadora de Gas Natural (TGN)
27. Costa Azul LNG

WESTERN NORTH AMERICAN NATURAL GAS PIPELINES

LIQUEFIED NATURAL GAS

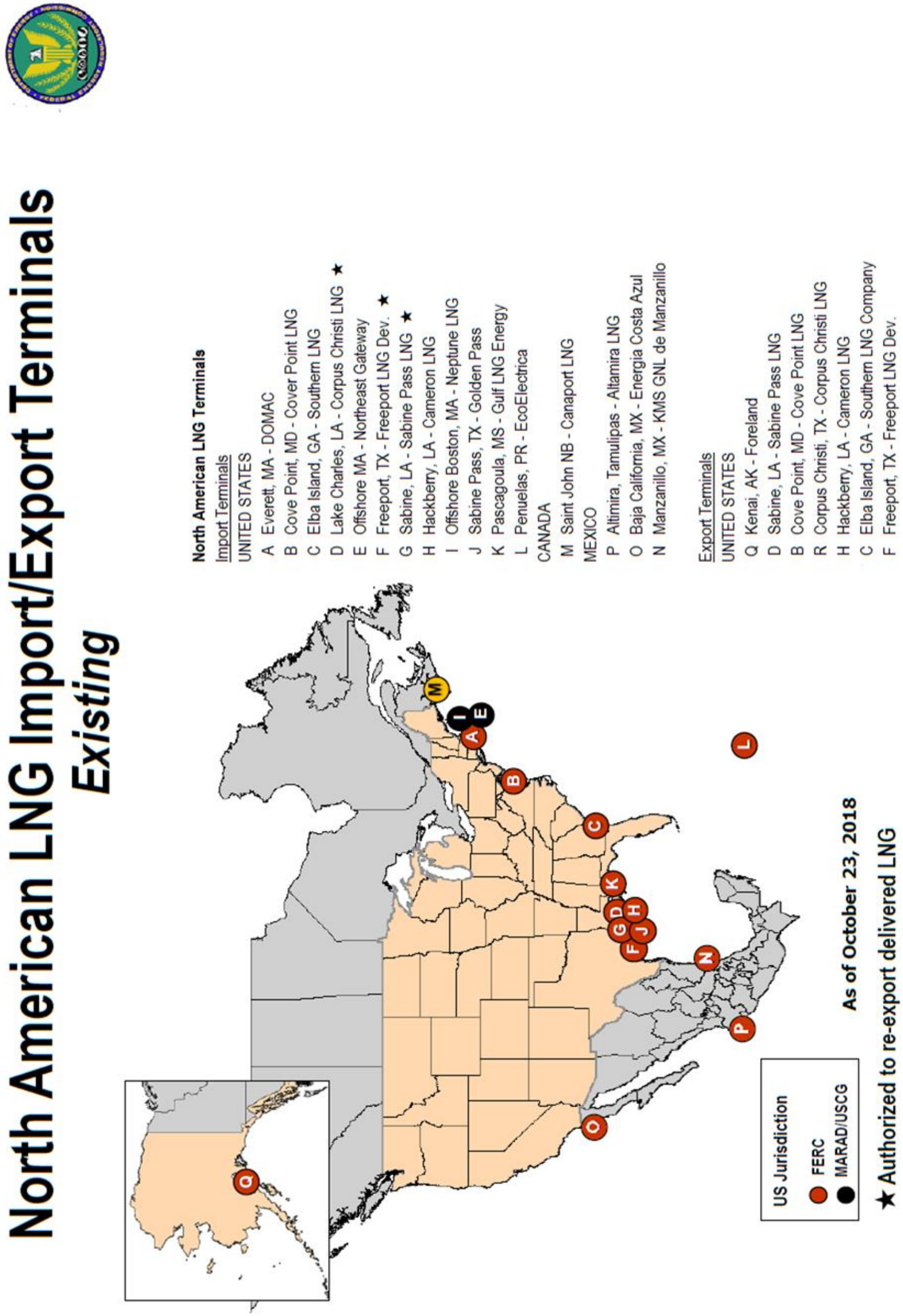
Currently, there are three Western U.S. LNG facilities, two operating in Mexico and one facility in Alaska. The two in Mexico are the Costa Azul terminal and the Altamira terminal operating as import facilities.

The abundance of shale gas has changed the paradigm for LNG in the West. Until the mid-2000s, LNG was thought as being a potential gas supply for California, but that has now changed. Currently, four companies plan on building export facilities. Two in Canada have decided to build these facilities. One in Oregon and one in Baja California, Mexico await final jurisdiction approvals and final investment decisions to begin construction.

TABLE 2 – POTENTIAL AND PROPOSED NORTH AMERICAN WEST COAST LNG TERMINALS AS OF SPRING 2020

Project	Location	Developer	Capacity (bcfd)
Jordan Cove	Oregon, United States	Pembina Pipeline Corporation	1.08
Costa Azul	Baja California, Mexico	Sempra Energy	1.00
LNG Canada	British Columbia, Canada	Shell, Petronas, Petrochinga, Mitsubishi, Korea Gas Corp.	3.50
Woodfibre LNG	British Columbia, Canada	Woodfibre LNG Limited	0.30

FIGURE 4 – NORTH AMERICAN IMPORT/EXPORT TERMINALS
EXISTING



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 2020-2035 for average temperature and normal hydro years and cold weather 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 Energy Resources Department, SDG&E, SWG, 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.

TABLE 3 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2020-2024

Line No.		2020	2021	2022	2023	2024
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	97	97	97	97	97
4	Out-of-State	4,357	4,274	4,270	4,206	3,984
5	Utility Total	4,454	4,371	4,367	4,303	4,081
6	*Non-Utility Served Load*[a]	1,011	1,007	978	983	969
7	**Statewide Supply Sources Total**	5,465	5,378	5,344	5,286	5,050
8	**California's Requirements**					
9	*Utility*					
10	Residential	1,139	1,130	1,106	1,090	1,069
11	Commercial	484	483	487	483	478
12	Natural Gas Vehicles	54	56	57	59	60
13	Industrial	998	997	1,000	997	998
14	Electric Generation[b]	1,166	1,093	1,104	1,076	1,018
15	Enhanced Oil Recovery Steaming	32	32	32	32	32
16	Wholesale/International + Exchange	251	251	252	251	251
17	Company Use and Unaccounted-for	71	69	69	69	68
18	Utility Total	4,194	4,111	4,107	4,057	3,974
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	633	635	638	640	643
21	EOR Cogeneration/Industrial	60	59	56	57	49
22	Electric Generation	318	313	284	286	278
23	Non-Utility Served Load[a]	1,011	1,007	978	983	969
24	**Statewide Requirements Total**[c]	5,205	5,118	5,084	5,040	4,943

(a) 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.

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

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

TABLE 4 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2025-2035

Line No.		2025	2026	2027	2030	2035
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	97	97	97	97	97
4	Out-of-State	3,857	3,813	3,737	3,580	3,497
5	Utility Total	3,954	3,910	3,834	3,677	3,594
6	*Non-Utility Served Load*[(a)]	953	936	908	897	750
7	**Statewide Supply Sources Total**	4,907	4,846	4,742	4,574	4,343
8	**California's Requirements**					
9	*Utility*					
10	Residential	1,053	1,033	1,014	959	884
11	Commercial	472	462	455	436	389
12	Natural Gas Vehicles	62	64	65	70	78
13	Industrial	998	995	983	977	968
14	Electric Generation[(b)]	1,019	1,008	968	890	927
15	Enhanced Oil Recovery Steaming	32	32	32	32	32
16	Wholesale/International + Exchange	251	250	249	249	250
17	Company Use and Unaccounted-for	68	66	66	64	65
18	**Utility Total**	3,954	3,910	3,834	3,677	3,594
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	645	648	650	658	672
21	EOR Cogeneration/Industrial	43	41	23	18	6
22	Electric Generation	265	246	235	220	72
23	Non-Utility Served Load[(c)]	953	936	908	897	750
24	**Statewide Requirements Total**[(c)]	4,907	4,846	4,742	4,574	4,343

(a) 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.

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

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

TABLE 5 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2020-2035

Line No.		2020	2021	2022	2023	2024
1	**Utility**					
2	*Northern California*					
3	California Sources[(a)]	34	34	34	34	34
4	Out-of-State	1,958	1,890	1,875	1,848	1,699
5	Northern California Total	1,992	1,924	1,909	1,882	1,733
6	*Southern California*					
7	California Sources[(b)]	63	63	63	63	63
8	Out-of-State	2,399	2,384	2,394	2,358	2,286
9	Southern California Total	2,462	2,447	2,457	2,421	2,349
10	**Utility Total**	4,454	4,371	4,367	4,303	4,081
11	**Non-Utility Served Load[(c)]**	1,011	1,007	978	983	969
12	**Statewide Supply Sources Total**	5,465	5,378	5,344	5,286	5,050
13						
14	**Utility**	2025	2026	2027	2030	2035
15	*Northern California*					
16	California Sources[(a)]	34	34	34	34	34
17	Out-of-State	1,578	1,559	1,539	1,512	1,457
18	Northern California Total	1,612	1,593	1,573	1,546	1,491
19	*Southern California*					
20	California Sources[(b)]	63	63	63	63	63
21	Out-of-State	2,279	2,254	2,198	2,069	2,040
22	Southern California Total	2,342	2,317	2,261	2,132	2,103
23	**Utility Total**	3,954	3,910	3,834	3,677	3,594
24	**Non-Utility Served Load[(c)]**	953	936	908	897	750
25	**Statewide Supply Sources Total**	4,907	4,846	4,742	4,574	4,343

(a) Includes utility purchases and exchange/transport gas.

(b) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.

(c) 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.

TABLE 6 – STATEWIDE ANNUAL GAS REQUIREMENTS[(a)]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2020-2024

Line No.		2020	2021	2022	2023	2024
1	**Utility**					
2	*Northern California*					
3	Residential	509	506	492	484	474
4	Commercial – Core	224	224	223	222	220
5	Natural Gas Vehicles – Core	8	8	9	9	10
6	Natural Gas Vehicles – Noncore	4	5	5	6	6
7	Industrial – Noncore	553	560	559	554	555
8	Wholesale	9	9	9	9	9
9	SMUD Electric Generation	117	117	117	117	117
10	PG&E Electric Generation[(b)]	267	196	196	196	196
11	Exchange (California)	1	1	1	1	1
12	Company Use and Unaccounted for	40	38	38	38	38
13	Northern California Total[(c)]	1,732	1,664	1,649	1,636	1,626
14	*Southern California*					
15	Residential	629	624	614	605	596
16	Commercial – Core	209	208	213	210	206
17	Commercial – Noncore	51	51	51	52	51
18	Natural Gas Vehicles – Core	42	43	43	44	45
19	Industrial – Core	54	52	52	51	50
20	Industrial – Noncore	391	386	389	391	393
21	Wholesale	240	241	241	241	240
22	SDG&E + Vernon Electric Generation	113	113	112	106	94
23	Electric Generation[(d)]	669	667	679	657	611
24	Enhanced Oil Recovery Steaming	32	32	32	32	32
25	Company Use and Unaccounted-for	31	31	31	31	30
26	Southern California Total	2,462	2,447	2,457	2,421	2,349
27	**Utility Total**	4,194	4,111	4,107	4,057	3,974
28	**Non-Utility Served Load[(e)]**	1,011	1,007	978	983	969
29	**Statewide Gas Requirements Total[(f)]**	5,205	5,118	5,084	5,040	4,943

Note:

(a) Includes transportation gas.

(b) 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.

(c) Northern California Total excludes Off-System Deliveries to Southern California.

(d) Southern California Electric Generation includes commercial and industrial cogeneration, refinery related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.

(e) 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.

(f) Does not include off-system deliveries.

TABLE 7 – STATEWIDE ANNUAL GAS REQUIREMENTS[(a)]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2025-2035

Line No.		2025	2026	2027	2030	2035
1	**Utility**					
2	*Northern California*					
3	Residential	464	453	443	413	341
4	Commercial – Core	219	215	212	202	167
5	Natural Gas Vehicles – Core	10	11	12	13	16
6	Natural Gas Vehicles – Noncore	6	7	7	8	10
7	Industrial – Noncore	553	551	545	554	560
8	Wholesale	9	9	9	9	9
9	SMUD Electric Generation	117	117	117	117	117
10	PG&E Electric Generation[(b)]	194	194	191	192	233
11	Exchange (California)	1	1	1	1	1
12	Company Use and Unaccounted for	38	37	37	37	38
13	Northern California Total[(c)]	1,612	1,593	1,573	1,546	1,491
14	*Southern California*					
15	Residential	589	580	572	547	543
16	Commercial – Core	201	196	192	182	171
17	Commercial – Noncore	52	51	51	51	51
18	Natural Gas Vehicles – Core	45	46	47	49	52
19	Industrial – Core	49	48	47	44	39
20	Industrial – Noncore	395	395	391	380	369
21	Wholesale	241	240	240	239	241
22	SDG&E + Vernon Electric Generation	94	91	84	78	78
23	Electric Generation[(d)]	614	607	577	503	499
24	Enhanced Oil Recovery Steaming	32	32	32	32	32
25	Company Use and Unaccounted-for	30	29	29	27	27
26	Southern California Total	2,342	2,317	2,261	2,132	2,103
27	**Utility Total**	3,954	3,910	3,834	3,677	3,594
28	**Non-Utility Served Load** [(e)]	953	936	908	897	750
29	**Statewide Gas Requirements Total** [(f)]	4,907	4,846	4,742	4,574	4,343

Note:

(a) Includes transportation gas.

(b) 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.

(c) Northern California Total excludes Off-System Deliveries to Southern California.

(d) Southern California Electric Generation includes commercial and industrial cogeneration, refinery related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.

(e) 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.

(f) Does not include off-system deliveries.

TABLE 8 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE(d) AND DRY HYDRO YEAR
(MMcf/d)
2020-2024

Line No.		2020	2021	2022	2023	2024
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	97	97	97	97	97
4	Out-of-State	4,522	4,501	4,489	4,406	4,176
5	Utility Total	4,619	4,598	4,586	4,503	4,273
6	*Non-Utility Served Load*(a)	1,045	1,043	1,033	1,038	1,025
7	**Statewide Supply Sources Total**	5,664	5,641	5,619	5,541	5,298
8	California's Requirements					
9	*Utility*					
10	Residential	1,235	1,226	1,202	1,186	1,166
11	Commercial	504	503	507	503	498
12	Natural Gas Vehicles	54	56	57	59	60
13	Industrial	1,000	1,000	1,002	999	1,001
14	Electric Generation(b)	1,196	1,184	1,187	1,140	1,076
15	Enhanced Oil Recovery Steaming	32	32	32	32	32
16	Wholesale/International + Exchange	264	265	265	265	264
17	Company Use and Unaccounted-for	73	73	73	71	70
18	Utility Total	4,359	4,338	4,326	4,257	4,166
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	633	641	639	636	636
21	EOR Cogeneration/Industrial	75	73	70	74	64
22	Electric Generation	338	335	325	324	318
23	Non-Utility Served Load(a)	1,045	1,048	1,034	1,034	1,018
24	**Statewide Requirements Total(c)**	5,404	5,387	5,360	5,290	5,184

Note:

(a) 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.

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

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

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

TABLE 9 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE[d] AND DRY HYDRO YEAR
(MMcf/d)
2025-2035

Line No.		2025	2026	2027	2030	2035
1	**California's Supply Sources**					
2	*Utility*					
3	California Sources	97	97	97	97	97
4	Out-of-State	4,049	4,013	3,931	3,756	3,684
5	Utility Total	4,146	4,110	4,028	3,853	3,781
6	*Non-Utility Served Load*[a]	1,021	1,013	989	980	777
7	**Statewide Supply Sources Total**	5,167	5,123	5,017	4,833	4,559
8	California's Requirements					
9	*Utility*					
10	Residential	1,149	1,129	1,110	1,055	978
11	Commercial	492	483	476	456	409
12	Natural Gas Vehicles	62	63	64	69	76
13	Industrial	1,000	997	985	980	970
14	Electric Generation[b]	1,077	1,073	1,029	933	984
15	Enhanced Oil Recovery Steaming	32	32	32	32	32
16	Wholesale/International + Exchange	264	264	263	262	264
17	Company Use and Unaccounted-for	70	70	68	66	67
18	Utility Total	4,146	4,110	4,028	3,853	3,781
19	*Non-Utility*					
20	Enhanced Oil Recovery Steaming	645	648	650	658	672
21	EOR Cogeneration/Industrial	60	59	39	32	10
22	Electric Generation	316	305	300	290	95
23	Non-Utility Served Load[a]	1,021	1,013	989	980	777
24	**Statewide Requirements Total[c]**	5,167	5,123	5,017	4,833	4,559

Note:

(a) 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.

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

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

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

TABLE 10 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
COLD TEMPERATURE (d) and DRY HYDRO YEAR
(MMcf/d)
2020-2035

Line No.		2020	2021	2022	2023	2024
1	**Utility**					
2	*Northern California*					
3	California Sources[a]	34	34	34	34	34
4	Out-of-State	2,045	1,967	1,939	1,908	1,759
5	Northern California Total	2,079	2,001	1,973	1,942	1,793
6	*Southern California*					
7	California Sources[b]	63	63	63	63	63
8	Out-of-State	2,477	2,534	2,550	2,497	2,417
9	Southern California Total	2,540	2,597	2,613	2,560	2,480
10	**Utility Total**	4,619	4,598	4,586	4,503	4,273
11	Non-Utility Served Load[c]	1,045	1,043	1,033	1,038	1,025
12	Statewide Supply Sources Total	5,664	5,641	5,619	5,541	5,298
13						
14	**Utility**	2025	2026	2027	2030	2035
15	*Northern California*					
16	California Sources[a]	34	34	34	34	34
17	Out-of-State	1,639	1,619	1,598	1,570	1,529
18	**Northern California Total**	1,673	1,653	1,632	1,604	1,563
19	*Southern California*					
20	California Sources[b]	63	63	63	63	63
21	Out-of-State	2,411	2,394	2,334	2,185	2,155
22	Southern California Total	2,474	2,457	2,397	2,248	2,218
23	**Utility Total**	4,146	4,110	4,028	3,853	3,781
24	Non-Utility Served Load[c]	1,021	1,013	989	980	777
25	**Statewide Supply Sources Total**	5,167	5,123	5,017	4,833	4,559

Notes:

(a) Includes utility purchases and exchange/transport gas.

(b) Includes utility purchases and exchange/transport gas and City of Long Beach "own-source" gas.

(c) 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.

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

TABLE 11 – STATEWIDE ANNUAL GAS REQUIREMENTS[a]
COLD TEMPERATURE[g] and DRY HYDRO YEAR
(MMcf/d)
2020-2024

Line No.		2020	2021	2022	2023	2024
1	Utility					
2	*Northern California*					
3	Residential	552	549	535	528	517
4	Commercial – Core	234	234	233	232	231
5	Natural Gas Vehicles – Core	8	8	9	9	10
6	Natural Gas Vehicles – Noncore	4	5	5	5	5
7	Industrial – Noncore	554	561	560	556	557
8	Wholesale	10	10	10	10	10
9	SMUD Electric Generation	117	117	117	117	117
10	Electric Generation[b]	297	216	204	199	199
11	Exchange (California)	1	1	1	1	1
12	Company Use and Unaccounted-for	41	40	40	39	39
13	Northern California Total[c]	1,819	1,741	1,713	1,696	1,686
14	*Southern California*					
15	Residential	683	677	667	658	648
16	Commercial – Core	218	217	222	219	215
17	Commercial – Noncore	52	52	52	53	52
18	Natural Gas Vehicles – Core	42	43	43	44	45
19	Industrial – Core	55	53	53	52	51
20	Industrial – Noncore	391	386	389	391	393
21	Wholesale	253	254	254	254	253
22	SDG&E + Vernon Electric Generation	113	124	126	118	106
23	Electric Generation[d]	669	727	740	706	654
24	Enhanced Oil Recovery Steaming	32	32	32	32	32
25	Company Use and Unaccounted-for	32	33	33	32	31
26	**Southern California Total**	2,540	2,597	2,613	2,560	2,480
27	**Utility Total**	4,359	4,338	4,326	4,257	4,166
28	Non-Utility Served Load[e]	1,045	1,043	1,033	1,038	1,025
29	**Statewide Gas Requirements Total[f]**	5,404	5,381	5,359	5,295	5,191

Note:

(a) Includes transportation gas.

(b) 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.

(c) Northern California Total excludes Off-System Deliveries to Southern California.

(d) Southern California Electric Generation includes commercial and industrial cogeneration, refinery related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.

(e) 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.

(f) Does not include off-system deliveries.

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

TABLE 12 – STATEWIDE ANNUAL GAS REQUIREMENTS[(a)]
COLD TEMPERATURE[(g)] AND DRY HYDRO YEAR
(MMcf/d)
2025-2035

Line No.		2025	2026	2027	2030	2035
1	Utility					
2	*Northern California*					
3	Residential	508	496	486	457	385
4	Commercial – Core	229	225	222	213	177
5	Natural Gas Vehicles – Core	10	11	12	13	16
6	Natural Gas Vehicles – Noncore	6	6	6	7	8
7	Industrial – Noncore	555	552	547	555	561
8	Wholesale	10	10	10	9	9
9	SMUD Electric Generation	117	117	117	117	117
10	Electric Generation[(b)]	199	197	193	194	249
11	Exchange (California)	1	1	1	1	1
12	Company Use and Unaccounted-for	39	39	38	38	39
13	Northern California Total[(c)]	1,673	1,653	1,632	1,604	1,563
14	*Southern California*					
15	Residential	641	632	623	598	593
16	Commercial – Core	210	205	201	191	180
17	Commercial – Noncore	53	52	52	52	52
18	Natural Gas Vehicles – Core	45	46	47	49	52
19	Industrial – Core	50	49	48	45	40
20	Industrial – Noncore	395	395	391	380	369
21	Wholesale	254	253	253	252	254
22	SDG&E + Vernon Electric Generation	107	104	98	85	85
23	Electric Generation[(d)]	654	655	621	537	533
24	Enhanced Oil Recovery Steaming	32	32	32	32	32
25	Company Use and Unaccounted-for	31	31	30	28	28
26	**Southern California Total**	2,474	2,457	2,397	2,248	2,218
27	**Utility Total**	4,146	4,110	4,028	3,853	3,781
28	Non-Utility Served Load[(e)]	1,021	1,013	989	980	777
29	**Statewide Gas Requirements Total[(f)]**	5,167	5,123	5,017	4,833	4,559

Note:

(a) Includes transportation gas.

(b) 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.

(c) Northern California Total excludes Off-System Deliveries to Southern California.

(d) Southern California Electric Generation includes commercial and industrial cogeneration, refinery related cogeneration, EOR-related cogeneration, and non-cogeneration electric generation.

(e) 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.

(f) Does not include off-system deliveries.

(g) 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 complements the existing 5-year recorded data tables included in the tabular data sections for each utility.

The information displayed in the following tables shows the composition of supplies from both out-of-state sources, as well as California sources. The data are based on the utilities' accounting records and on available gas nomination and preliminary gas transaction information obtained daily from customers or their appointed agents and representatives. It should be noted that data on daily gas nominations are frequently subject to reconciliation 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.

TABLE 13 – RECORDED 2015 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	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	849
Noncore Commercial/Industrial	45	142	75	41	106	27	(15)	0	421
EG (3)	86	273	143	79	203	52	(28)	0	808
EOR	5	16	8	5	12	3	(2)	0	47
Wholesale/Resale/International (4)	47	147	77	42	109	28	(15)	0	435
Total	122	1,024	379	207	655	110	62	0	2,559
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	269	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	478	0	0	0	873	36	0	0	1,387
TOTAL SUPPLIER	648	1,263	648	1,350	1,621	146	118	758	6,552
San Diego Gas & Electric Company									
Core	(8)	59	10	5	30	0	16	0	116
Noncore Commercial/Industrial	23	72	38	21	54	14	(8)	0	211
Total	15	132	48	26	84	14	9	0	327
Southwest Gas Corporation									
Core	21	0	0	0	0	0	11	0	37
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	23	0	0	0	0	0	11	0	39

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, and SDG&E, as shown.
(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.

TABLE 14 – RECORDED 2016 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	86	417	114	48	196	0	31	0	892
Noncore Commercial/Industrial	1	94	96	37	150	43	27	0	448
EG (3)	1	156	158	61	248	71	45	0	740
EOR	0	8	8	3	13	4	2	0	39
Wholesale/Resale/International (4)	1	82	83	32	130	37	24	0	390
Total	89	758	460	181	737	155	129	0	2,509
Pacific 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
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	418	0	0	0	792	43	0	0	1,253
TOTAL SUPPLIER	562	996	644	1,336	1,559	198	156	594	6,045
San Diego Gas & Electric Company									
Core	11	56	15	6	26	0	4	0	119
Noncore Commercial/Industrial	0	36	37	14	57	16	10	0	171
Total	12	92	52	20	83	16	14	0	290
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

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, and SDG&E, as shown.
(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.

TABLE 15 – RECORDED 2017 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	100	443	127	54	208	0	(27)	0	905
Noncore Commercial/Industrial	(4)	97	80	39	158	52	24	0	446
EG (3)	(4)	156	128	63	252	82	39	0	715
EOR	(0)	9	7	3	14	5	2	0	39
Wholesale/Resale/International (4)	(7)	88	72	35	142	46	22	0	398
Total	84	792	414	195	773	185	60	0	2,503
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)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	698	28	0	0	698	44	0	0	1,468
TOTAL SUPPLIER	833	1,046	578	1,354	1,504	229	84	599	6,227
San Diego Gas & Electric Company									
Core	14	61	17	7	28	0	(4)	0	124
Noncore Commercial/Industrial	(2)	38	31	15	62	20	10	0	175
Total	12	99	49	23	90	20	6	0	299
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

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, and SDG&E, as shown.
(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.

TABLE 16 – RECORDED 2018 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	158	439	103	37	173	0	(2)	0	908
Noncore Commercial/Industrial	(17)	99	35	57	207	61	7	0	448
EG (3)	(23)	136	48	78	283	83	10	0	615
EOR	(1)	8	3	5	18	5	1	0	38
Wholesale/Resale/International (4)	(13)	74	26	42	153	45	6	0	333
Total	104	756	214	218	834	194	22	0	2,342
Pacific Gas and Electric Company (5)									
Core	0	3	55	303	(4)	0	0	165	522
Noncore Industrial/Wholesale/EG (6)	28	212	221	966	16	0	0	355	1,798
Total	28	215	276	1,269	12	0	0	520	2,320
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	401	49	0	0	686	42	0	0	1,178
TOTAL SUPPLIER	555	1,020	490	1,487	1,532	236	34	520	5,874
San Diego Gas & Electric Company									
Core	22	61	14	5	24	0	(0)	0	127
Noncore Commercial/Industrial	(4)	25	9	14	52	15	2	0	112
Total	18	86	23	19	76	15	2	0	239
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

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, and SDG&E, as shown.
(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.

TABLE 17 – RECORDED 2019 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company (2)									
Core + UAF (3)	162	476	111	30	223	0	10	0	1,012
Wholesale/Resale/International (5)	(65)	368	47	118	674	213	19	0	1,374
Total	97	844	158	148	897	213	29	0	2,386
Pacific Gas and Electric Company (4)									
Core	0	0	58	286	(2)	0	0	172	514
Noncore Industrial/Wholesale/EG (5)	24	380	223	896	9	0	0	481	2,014
Total	24	380	281	1,182	7	0	0	653	2,528
Other Northern California									
Core (6)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (7, 8)									
Direct Sales/Bypass	388	29	0	0	664	71	0	0	1,152
TOTAL SUPPLIER	531	1,253	439	1,330	1,568	284	41	653	6,100
San Diego Gas & Electric Company									
Core	21	61	14	4	28	0	1	0	129
Noncore Commercial/Industrial	(4)	22	3	7	40	12	1	0	81
Total	17	83	17	11	68	12	2	0	210
Southwest Gas Corporation									
Core	25	0	0	0	0	0	0	0	25
Noncore Commercial/Industrial	3	0	0	0	0	0	0	0	3
Total	28	0	0	0	0	0	0	0	28

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) SoCalGas core volumes are accrued volumes.
(3) Includes NGV volumes
(4) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(5) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(6) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

STATEWIDE RECORDED HIGHEST SENDOUT

The tables below summarize the highest sendout days by the state in the summer and winter periods from the last 5 years. Daily sendout from SoCalGas, PG&E, and from customers not served by these utilities were used to construct the following tables.

TABLE 18 – CALIFORNIA HIGHEST SENDOUT DAYS (2015-2019)

ESTIMATED CALIFORNIA HIGHEST SUMMER SENDOUT (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
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
2018	07/24/2018	2,925	2,926	5,851	1,410	7,261
2019	09/04/2019	2,634	3,106	5,740	1,310	7,050

ESTIMATED CALIFORNIA HIGHEST WINTER SENDOUT (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
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
2018	02/20/2018	3,527	3,621	7,148	1,378	8,526
2019	02/05/2019	3,780	4,180	7,960	1,097	9,057

Notes:

(1) PG&E Pipe Ranger.

(2) SoCalGas Envoy.

(3) Source: Provided by the CEC. Data are from the California Division of Oil, Gas, and Geothermal Resources (DOGGR), Monthly Oil and Gas Production and Injection Report. Non-Utility Demand equals Kern-Mojave and California monthly average total flows less PG&E and SoCalGas peak day supply from Kern-Mojave and California in-state production.

(4) 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, Jul, Aug, Sep, and Oct.

2020 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

PG&E owns and operates an integrated natural gas transmission, underground storage, and distribution system across most of Northern and Central California. As of December 31, 2019, PG&E's natural gas system consists of approximately 42,800 miles of distribution pipelines, over 6,400 miles of backbone and local transmission pipelines, and three underground storage facilities. PG&E uses its backbone transmission system, composed primarily of Lines 300A, 300B, 400, and 401, to transport gas from its 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 4.3 million residential customers and over 200,000 commercial and industrial customers. PG&E also provides gas transportation and storage services to a variety of gas-fired EG plants in its service area and serves multiple NGV fleets, including utility owned facilities, with its publicly-accessible fueling stations throughout California. 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, including other regulated utilities, also utilize the PG&E system to meet their gas needs in Southern California.

The Northern California section of this report includes PG&E's gas demand forecast and discussions on gas supply, pipeline capacity, storage, and related policies, as well as the natural gas regulatory environment, including legislative developments and regulatory proceedings. Finally, the report includes PG&E's forecast of supply and demand for an Abnormal Peak Day (APD).

What follows is a summary of key takeaways from the Northern California sections of this report.

- **Gradual Decline in Forecasted Gas Demand:** PG&E's Average Demand[7] is projected to decline at an annual average rate of 1.0 percent between 2020 and 2035. The decline in forecasted gas demand is in response to the state's decarbonization policies and reflects reduced demand due to energy efficiency, building electrification resulting from fuel switching from natural gas appliances to electric, climate change, and an increase in GHG-free EG resources.
- **There Is High Uncertainty in Gas Demand Due to Building Electrification:** PG&E's Average Demand forecast reflects the impact of California's current policies for energy efficiency and the impact of existing and anticipated future policies around building decarbonization. Uncertainty around building electrification, especially retrofits, drives uncertainty in gas demand. In a high electrification scenario,[8] PG&E projects on-system gas demand to decline at an annual average rate of 1.3 percent between 2020 and 2035. In a low electrification scenario, PG&E projects gas on-system demand to decline at an annual average rate of 0.8 percent between 2020 and 2035. The rate of decrease for both scenarios is non-linear, with larger rates of decrease in the later years of the forecast.
- **Current Forecast Does Not Reflect Impact From COVID-19 pandemic on Gas Throughput:** When PG&E was preparing the gas throughput forecast for this report, economic shocks associated with the COVID-19 pandemic suddenly appeared. The lasting economic impacts from the COVID-19 pandemic are highly uncertain. As a result, this report does not attempt to forecast COVID-19 pandemic impacts on gas demand. As events unfold and reliable economic and policy forecasts become available, PG&E will consider such information.
- **Without Policy Solutions and a Managed Transition from Fossil Fuel to Other Energy Forms, Lower Forecasted Gas Demand Could Put Upward Pressure on Customer Gas Costs and Rates:** PG&E is committed to working with the regulators and other stakeholders to support the statewide GHG reduction policies and develop options to minimize rate increases. PG&E is doing this by safely reducing costs and maximizing utilization of existing infrastructure. To reduce costs, PG&E is pursuing opportunities to systematically retire infrastructure (where possible) and reduce capital and operating

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7 Gas demand projection for an average temperature year and normal hydroelectric generation (hydro) year representing on-system demand.

8 See "Gas Demand, Future Gas Demand Trends and Policy," section for details.

expenses through PG&E's Integrated Investment Planning. To increase utilization, PG&E is implementing programs to decarbonize existing gas throughput, supporting Renewable Gas (RG) adoption across new industries with existing gas system infrastructure, and adapting to utilize the gas system as a large-scale and long-duration storage mechanism for Green H2. There are broad opportunities for load growth that can help decarbonize the economy, such as marine, rail, and surface-transportation applications.

Regulatory bodies and investor-owned utilities (IOU) should work together to ensure that Californians continue to have access to clean, reliable, and affordable energy. In support of these important goals, PG&E is actively participating in the Biomethane Order Instituting Rulemaking (OIR) (Rulemaking (R.) 13-02-008) and the Gas System Planning OIR (R.20-01-007). Both OIRs address crucial topics that will impact the future of the California gas system. In addition to the efforts currently underway, additional steps need to be taken to adequately address:

- The possible impacts of climate change policies and laws on gas throughput and the cost structure of existing and future gas assets; and
- The barriers to Renewable Gas Standard[9] (RGS).[10]

The current investment and incentives for RG principally favor the transportation sector resulting in little RG available to establish a consistent RGS. If this is to change, California will have to balance the funding mechanisms between the transportation sector and a potential RGS so that RG project developers have opportunities to supply RG towards an RGS or the transportation sector.

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9 A carbon-based standard for California's gas supply.

10 An RGS does not currently exist. However, with implementation of SB 1440 through Phase IV of the Biomethane OIR and legislation that was proposed earlier this year (SB 1352), it is clear that there is some momentum to establishing an RGS that would require the utility to procure a certain percentage of RG for core gas customers (similar to the RPS on the electric side).

GAS DEMAND

OVERVIEW

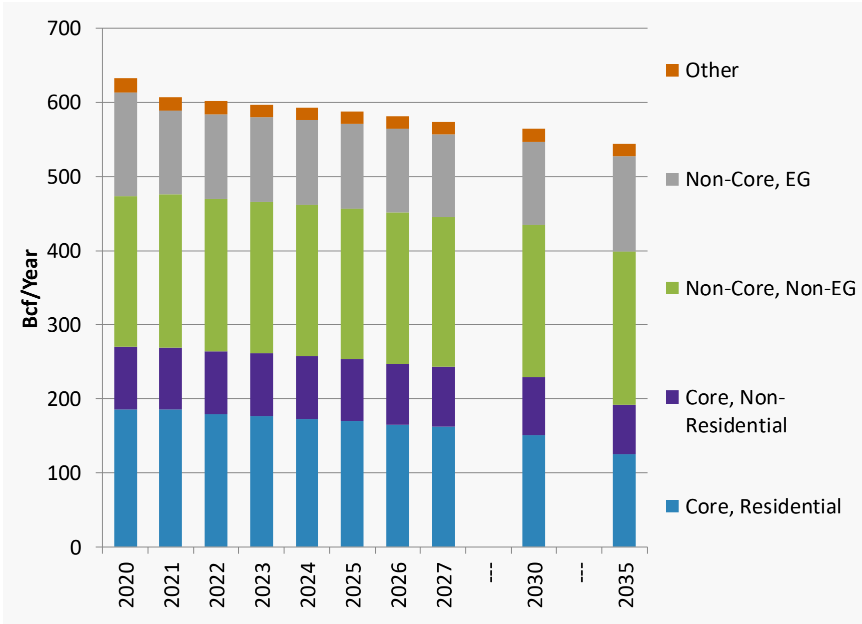
PG&E's 2020 CGR Average Demand forecast projects total on-system demand[11] to decline at annual average rate of 1.0 percent between 2020 and 2035. This is due to the combination of a projected annual decline of 2.3 percent in the core market and a projected annual decline of 0.2 percent in the noncore market.

Different factors drive the gas demand decline projection. This projected decline could result in gas system operating and maintenance costs spread over lower usage, causing customer gas rates to increase. Consequently, PG&E and statewide utility stakeholders will need to continue their involvement to mitigate customer rate increases. Additional gas throughput offsetting lower carbon intensive fuel uses could help spread costs more evenly.

This chapter includes PG&E's gas demand forecast and begins with a description of the forecast method, including assumptions driving the projection. After the methodology discussion, a sectorial forecast explanation follows for the Average Demand Year. To provide more robustness to the Average Demand Year forecast, scenarios show how demand looks under cold weather and dry hydroelectric conditions. The discussion finishes with gas demand policies, trends and impacts.

11 Excludes off-system sales.

FIGURE 5 – PG&E AVERAGE DEMAND YEAR GAS FORECAST



As shown in the above chart, total on-system gas demand for PG&E's gas system is projected to decline at an annual average rate of 1.0 percent between 2020 and 2035.[12] Core demand is projected to decline by an annual average rate of 2.3 percent over the 2020-2035 forecast horizon, driven by increasing energy efficiency, increasing building electrification, and a warming climate. Noncore non-EG demand is projected to remain relatively unchanged over the forecast horizon, as potential demand growth is offset by energy efficiency and increasing gas prices. Finally, the rate of growth of the noncore EG forecast decreases due to higher levels of renewable generation to meet the 60 percent requirement in 2030,[13] more electric storage, and higher burner-tip gas prices for Northern California electric generators. In this projection, total gas demand by electric generators[14] and cogenerators in Northern California[15] decreases at 0.6 percent per year from 2020 through 2035. This projection assumes average hydrological conditions.

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12 With the inclusion of off-system demand, the projection declines at an annual average rate of 1.9 percent between 2020 and 2035.

13 https://www.cpuc.ca.gov/rps/.

14 This gas demand forecast excludes gas delivered by non-utility 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.

15 Northern California electric generation gas demand consists of the generation fleet north of Path 26.

FORECAST METHOD

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed using econometric models as the foundation. These models are then modified to incorporate assumptions around future policy formation and technology adoption. Forecasts for NGVs and wholesale customers are developed based on market information and historical trends over the past five years. Forecasts of gas demand by power plants are developed by modeling the electricity market in the WECC using MarketBuilder software.

While variation in short-term gas use depends mainly on prevailing weather conditions and gas prices, longer-term projections 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;
- Forecasted prices;
- Growth in electricity demand;
- Growth of renewable generation;
- Efficiency profiles of residential and commercial buildings and the appliances within them; and
- Impacts from climate change.

In the 2020 CGR, the development of the forecasts comes at the same time as the initial impact of the global experience with the COVID-19 disease.[16] PG&E recognizes that COVID-19 will impact natural gas demand. However, there is considerable uncertainty around the economic impact from COVID-19. For example, it is uncertain how broadly, deeply, and for how long reduced economic activity will persist. It is also unclear whether the public response to the virus will change consumption behavior patterns. Forecasting the load impacts of these factors requires strong assumptions on the epidemiological and political course of the pandemic. Therefore, PG&E's current forecast relies on long-term forecast assumptions and tools to project gas demand and does not attempt to reflect the current and nearer-term impacts of COVID-19. What follows is an explanation of PG&E's forecast assumptions, as well as scenario analyses

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16 https://www.who.int/emergencies/diseases/novel-coronavirus-2019/technical-guidance.

that illustrate various potential outcomes from these assumptions. PG&E notes that these scenarios cannot capture all uncertainties.

ASSUMPTIONS

Temperature

Space heating accounts for a high percentage of use. Therefore, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's Average Demand year forecast assumes that temperatures in the forecast period will be equivalent to the average of observed temperatures during the past 20 years, with the addition of a temperature adjustment for climate change. Adding the climate change adjustment has little impact to the temperature assumptions in the early years of the forecast; however, the later years begin to show the effects of a warming climate. For example, by 2035 the total December/January heating degree days (HDD) are projected to be 8 percent below the 20-year average, lowering core throughput by approximately 6 percent.

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 2015 (This year represents the lowest hydroelectric generation over the past 20 years).

PG&E's EG gas throughput forecast uses an average temperature approach. The forecast does not capture peak day temperatures. Each summer typically contains a few heat waves with temperatures 10 to 15 degrees F above normal. This leads to peak electricity demands and drives up power plant gas demand. However, this forecast captures the seasonal variations on a monthly basis.

Hydroelectric Conditions Assumptions

In contrast to temperature deviations, annual water runoff for hydroelectric plants has varied by 50 percent above and below the long-term annual average. PG&E uses a vintage approach to WECC hydroelectric generation by assuming average generation for the most recent 20 historical years, 1998-2017, in the average year demand forecast. PG&E uses a cold/dry hydro conditions scenario to forecast impacts from extreme conditions impacting both Core space heating demand

and EG. PG&E uses the hydroelectric generation conditions for the calendar year 2015 to represent the dry hydroelectric condition.

Gas Price and Rate Assumptions

Inputs for gas prices and transportation rate assumptions are important for forecasting gas demand; this is especially true for market sectors that are particularly price sensitive, such as industrial or EG. PG&E used the gas commodity price forecast described in detail in the Southern California section. It combines current transportation rates with the gas commodity price forecast. PG&E's forecast assumes that changes to throughput do not directly impact rates. As a reminder, natural gas price forecasts are inherently uncertain and impact market sectors sensitive to price.

Electric Load Assumptions

PG&E's forecast relies on the mid-case electricity demand forecast from the CEC 2019 Integrated Energy Policy Report (IEPR). The IEPR captures the increasing load projected as electric vehicles become more commonplace. The electric demand forecast includes a component of building electrification as some local jurisdictions require new building construction to use electricity rather than natural gas.

Electric Generation Resource and Electric Transmission Assumptions

With increasing electric load and more stringent environmental requirements, California's portfolio of EG resources is expected to change significantly over the forecast horizon to 2035. Generation resources come from the 2019-2020 CPUC Integrated Resource Plan (IRP) Reference System Plan (RSP) from February 2020. The RSP proposes a target resource mix that includes new renewable resources, as well as energy storage resources. Renewable energy generation provides 33 percent of the state's retail sales in 2020 and is targeted to provide 60 percent by 2030. The gas-fired generation fleet in California will continue to change due to the California State Water Resources Control Board's (SWRCB) once-through cooling rules. Gas-fired plants that employ once-through cooling are assumed to retire by the compliance dates set by the SWRCB in conjunction with the CPUC direction,[17] with some re-powered by new gas-fired units. Lastly, modeled electric transmission import capacity aligns with the RSP.

This forecast does not include A/S impacts on gas demand. As intermittent renewable energy generation increases, more electric resources will be needed to provide A/S, such as regulation. A/S will likely be provided by energy storage resources and gas-fired power plants, thus, affecting gas demand to some extent. This impact requires a more granular forecasting methodology than used for this forecast.

For cogeneration gas demand, PG&E's forecast follows the RSP. Cogeneration gas demand mimics recent past usage throughout the forecast period. Most cogeneration plants are not strongly affected by prices in the wholesale electricity market. The electricity generated comes from some other industrial process, usually steam, and generation does not follow wholesale electric prices. Consequently, the cogeneration gas demand projection exhibits no variation throughout the forecast horizon.

MARKET SECTOR FORECASTS

RESIDENTIAL

Households in the PG&E service area are forecasted to grow 0.9 percent annually from 2020-2035. However, gas use per household has been dropping in recent years due to improvements in appliance and building-shell efficiencies. PG&E expects continued efficiency improvements, coupled with the following emerging trends, to decrease long-term residential gas demand.

1. As of April 2020, 30 cities in California passed local ordinance codes promoting the installation of all-electric appliances in new household construction. PG&E provides natural gas service to many of these cities. While the number of households are forecasted to grow at 0.9 percent annually, PG&E anticipates many of these households to install electric-only appliances.

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17 Final Recommended Compliance Date Extensions for Alamitos, Huntington Beach, Ormond Beach, and Redondo Beach Generation Stations SACCWIS Report, January 23, 2020: https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/final_report.pdf.

2. In addition to new construction building electrification, PG&E's forecast anticipates that existing households will begin to convert appliances from gas to electric driven by the formation of state or local policies, customer cost savings, or other mechanisms.

3. Finally, PG&E's forecast anticipates that the warming climate will gradually decrease residential gas sales.

Total annual residential demand is projected to continue declining, driven by efficiency gains, building and appliance electrification, and warming temperatures. By 2035, annual residential gas throughput is projected to be 33 *percent* lower than forecasted 2020 throughput, with most of this decrease occurring in the later years of the forecast.

COMMERCIAL

The number of commercial customers in the PG&E service area is projected to grow on average by 0.3 percent per year from 2020-2035. Similar to the residential customer class, PG&E expects new construction and retrofit building electrification, coupled with continuing energy efficiency and climate change, to lead to a long-term decline in commercial throughput. As a result, total commercial gas demand is projected to decline at 1.9 percent per year over the next 15 years.

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 declined 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 be relatively flat, with a projected 0.1 percent annual growth rate over the next 15 years as energy efficiency and future gas prices offset growth.[18]

ELECTRIC GENERATION

Gas demand from EG includes gas-fired cogeneration and power plants. Forecasts for this sector are subject to high uncertainty due to:

- Future gas prices, the combination of the commodity and transportation;
- Impact of electrification of appliances on electric load;
- Timing, location, and type of new generation, particularly renewable-energy facilities;
- Precipitation driving hydroelectric generation; and
- Impacts of GHG policies and regulations on generation.

These factors exhibit wide variation with unknown future policy direction that influences gas demand.

Historically, gas demand for EG varied due to these factors above. Over the past 5 years, 2015-2019, demand averaged 770 MMcf/d. In 2017, demand was 650 MMcf/d. One of the major drivers of this low demand came from a high hydroelectric generation period from ample precipitation in the Western U.S. For 2015, EG used about 1,000 MMcf/d. This year represented a low level of hydroelectric generation as drought conditions persisted in 2014 and 2015. For a good portion of 2019, gas prices were less in Northern California than Southern California causing more gas use in the PG&E service territory. The variation demonstrates that demand can be 30 percent higher than average or 15 percent lower than average over the past five years. As more renewable generation projects come online, the industry expects a decline in EG gas demand.

PG&E's forecast for gas use in cogeneration and power generation projects a decline. One of the leading factors to this decline in the near-term comes from the gas price forecast. The gas price forecast shows Northern California prices higher than Southern California. This places the Northern California gas-fired EG plants at a competitive disadvantage compared to plants farther south. The gas price forecast drives the near-term results with 2020 demand around

18 PG&E's industrial forecast includes impacts from California's Cap-and-Trade policies. Future GHG policies may impact industrial demand, adding uncertainty to the forecast.

400 MMcf/d that decreases to 313 MMcf/d in 2021. Consequently, southern-based units should see an uptick in generation based on this forecast.

As renewable generation and storage capacity increase throughout the forecast period, gas-fired generation further decreases. The RPS calls for renewable generation to be 33 percent of electric retail sales in 2020. By 2030, the RPS target percentage increases to 60 percent. Meanwhile, storage increases in the long-term coupled with capacity increases for renewable generation and the gas price forecast assumptions decrease the gas demand projection by 0.6 percent per year.

SMUD Electric Generation

SMUD is the sixth largest community-owned municipal utility in the U.S. 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 (MW). The peak gas load of these units is approximately 171 MMcf/d, and the average load is about 117 MMcf/d. This forecast assumes the average load of 117 MMcf/d, which is embedded in this forecast.

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 86 MMcf/d of capacity.

FORECAST SCENARIOS

The Average Demand year gas demand forecast presented above 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, decarbonization policies, appliance saturation, and efficiencies). Therefore, to capture uncertainties in gas demand, PG&E developed three alternative forecast scenarios of gas demand. The first scenario reflects a high gas demand situation. The second and third scenarios examine the impacts of low and high building electrification.

High Demand Scenario: Cold/Dry Hydro Year

For the high-demand scenario, PG&E relied on cold temperature conditions combined with dry hydro conditions. This forecast assumes that winter temperatures over the time horizon will have a 1-in-10 likelihood of occurrence. To represent dry hydroelectric conditions throughout the WECC, this forecast assumes the same hydroelectric generation conditions as those that prevailed during 2015.

The cold weather assumption increases electric load for space heating needs and impacts EG gas demand. The dry hydroelectric conditions show a need for incremental EG.

The gas demand impacts from this scenario project annual demand increasing 4 percent on average over the average year demand forecast. The cold weather impact represents the major driver in the gas throughput increase due to higher space heating. Winter monthly core throughput is projected to increase by 9 to 15 percent. The noncore industrial segment demonstrates little correlation to temperature leading to an insignificant demand increase over the average year demand forecast.

This scenario projects that EG gas demand increases by 1 to 8 percent. Hydroelectric resources in California represents 47 percent of the 20-year average. Broadly speaking, hydroelectric generation conditions in the rest of the WECC reflect near normal conditions. Electric imports from Southern California help meet the incremental electric load and hydroelectric generation decrement based on current projections for gas commodity prices and transportation rates. However, hydroelectric conditions vary widely. Dry hydroelectric conditions throughout the Western U.S. would raise the EG gas use on the PG&E gas system resulting in a different forecast.

SCENARIOS EVALUATING BUILDING ELECTRIFICATION

PG&E's Average Demand year forecast contains a projected level of new construction[19] and retrofit[20] building electrification; however, PG&E recognizes the uncertainty in this forecast. While a number of cities across California have demonstrated an interest in forming policies that incentivize building electrification or ban the installation of gas appliances in new residences, there has been very little historical adoption to inform a long-term forecast of building electrification. This is particularly true when forecasting the conversion of existing

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19 New construction building electrification applies to residences subject to new construction building codes and standards. This includes brand new homes and homes undergoing renovations large enough to trigger new construction building codes and standards.

20 Retrofit building electrification applies to the conversion of individual appliances from gas to electric in an existing residence that does not undergo a renovation large enough to be classified as new construction.

building appliance stock from gas to electric, which poses multiple barriers to adoption including the remaining lifecycle of existing appliances, the upfront cost of conversion, and the economics of consuming energy in the form of gas versus electricity. PG&E's Average Demand year forecast assumes these barriers are overcome to some extent as a result of state and local funding, technology development, and emerging policies, but recognizes the future could unfold in many different ways.

To illustrate the high degree of uncertainty in retrofit building electrification, PG&E has constructed two scenarios, in addition to the Average Demand year forecast, to analyze low and high levels of retrofit building electrification. To create these scenarios, adoption assumptions were modified in two ways. The first scenario, low electrification retrofit, modifies gas load by substituting 2 percent of residential gas water heater stocks to electric by 2030. This scenario assumes such substitution occurs for single family housing and does not occur for multifamily housing.. For the commercial sector, 3 percent of gas water heaters and space heaters are assumed to be electrified by 2030. The second scenario, high electrification retrofit, assumes higher levels of appliance substitution of water- and gas-heaters.

Table 19 below shows the percentage of existing gas fuel appliances to be replaced by electric appliances by the end of 2030 under different scenarios.

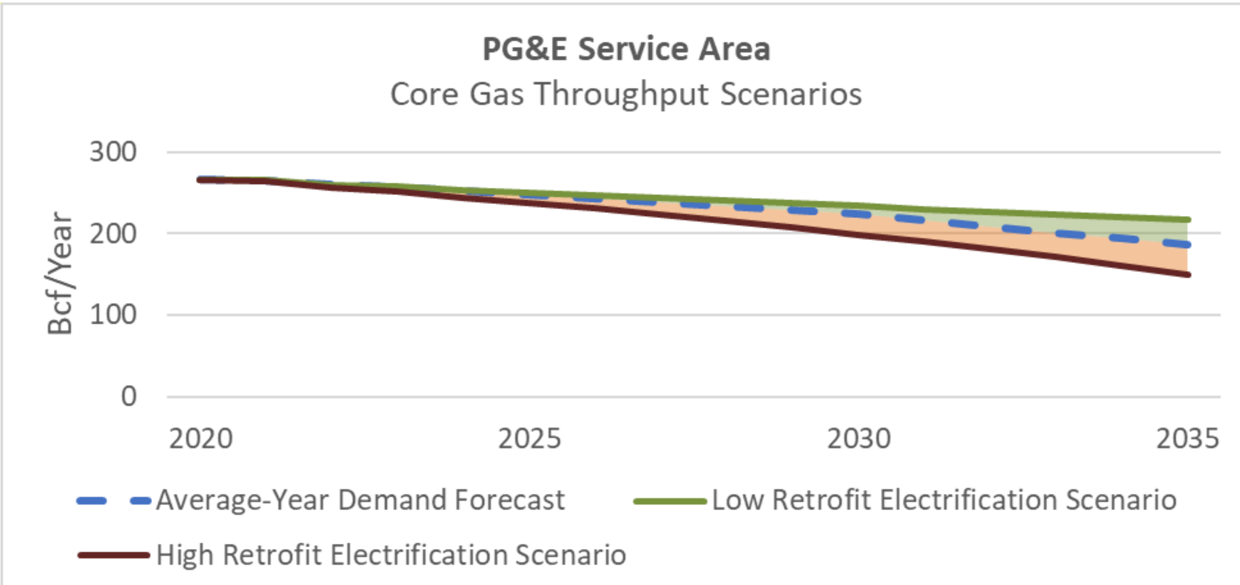
TABLE 19 – PG&E SERVICE AREA ASSUMPTION FOR PERCENTAGE OF GAS APPLIANCES REPLACED BY ELECTRIC APPLIANCES

Scenario	Residential		Commercial	
	Water Heater	Space Heater	Water Heater	Space Heater
Low Retrofit Scenario	2%	–	3%	3%
Base Retrofit Scenario*	6%	2%	10%	8%
High Retrofit Scenario	19%	6%	34%	29%

*The appliance replacement percentage is approximate since the Base Scenario is a weighted average of multiple retrofit scenarios.

The following figure shows the impact of the different levels of building electrification.

FIGURE 6 – PG&E SERVICE AREA: CORE GAS THROUGHPUT BUILDING ELECTRIFICATION RETROFIT SCENARIOS



As shown in the figure above, the level of retrofit building electrification significantly impacts the forecasted long-term trend of core gas throughput. Core throughput is projected to decline in all scenarios driven by energy efficiency, climate change, and building electrification for both new construction and building retrofits. The level of long-term decline varies significantly depending on the amount of building retrofits. The table below highlights the average annual percent decrease for the three forecasts, dividing the forecast horizon into three 5-year periods.

TABLE 20 – PG&E CORE THROUGHPUT AVERAGE ANNUAL GROWTH RATES

Forecast	2020-2025	2025-2030	2030-2035
Low Retrofit Electrification Scenario	-1.2%	-1.3%	-1.5%
Average Year Demand Forecast	-1.3%	-2.0%	-3.7%
High Retrofit Electrification Scenario	-2.2%	-3.5%	-5.4%

Although building electrification causes core gas throughput to decline, it may increase natural gas demand for EG. The forecast from 2030-2035 illustrates the projected impact. In PG&E's Average Demand year forecast, EG gas demand is forecasted to increase by 13 percent, mainly driven by transportation and building electrification.

However, uncertainties are not bounded within these scenarios. The impact of electrification could see no increase in natural gas demand or could grow by about 30 MMcf/d. The EG load may be at or near zero if the additional electric load is served by excess renewable generation. Absent this, the increase in gas-fired EG could be served by non-fossil natural gas, such as Renewable Natural Gas (RNG) or H2. Other factors could come into play, such as electric generators buying carbon offsets for the use of fossil-based natural gas or use technologies not yet commercialized, such as carbon capture and storage. How the future unfolds is uncertain.

POLICIES IMPACTING GAS DEMAND

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 (EO) 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. EO B-55-18 set a goal to achieve carbon neutrality by 2045. The Global Warming Solutions Act of 2006 (Assembly Bill (AB) 32) established the 2020 GHG emission reduction goal into law. SB 32 went further, calling for a 40 percent reduction in GHG emissions below 1990 levels by 2030. These goals are being accomplished by a suite of complementary policies, as well as the Cap-and-Trade Program, which was directly authorized through 2030 with the passage of AB 398.

GHG POLICIES

The gas demand forecast includes a GHG price projection.[21] The forecast incorporates complementary policies that aim to achieve California state GHG emissions reductions goals. (See below for further discussion of these policies.) Any trends embedded in historical demand patterns due to GHG goals and/or the compliance entities' participation in the Cap-and-Trade market translates to the forecast.

Since early 2019, several California local government jurisdictions have passed ordinances supporting all-electric new construction or explicitly limiting the expansion of the gas system. This increase in local government activity within PG&E's service territory could contribute to a decline in gas system throughput through the forecast horizon of the CGR and beyond.

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21 CEC Integrated Energy Policy Report mid-case forecast to 2030. Extrapolated to 2035 using the real adder to the floor price (5 percent rate).

The ongoing OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and perform Long-Term Gas System Planning (R.20-01-07) could also have a significant influence on future trends in gas system throughput. In particular, the second track of that proceeding will focus on long-term gas system planning and will warrant active participation from industry stakeholders.

Another uncertainty comes from how GHG policy implementation will be executed. SB 100 has a zero net GHG emissions goal. How this goal will be attained lacks clarity. If the zero net GHG emission goal is attained using more renewable generation and high levels of electric storage, for example, then EG gas demand may not increase in the long-term.

Given that the utilization of fossil natural gas emits GHGs, PG&E believes that RG must be part of the solution to reach California's GHG reduction goals. PG&E will continue to minimize GHG emissions by pursuing both demand-side reductions and acquisition of preferred resources, which produce little or no carbon emissions.

RENEWABLE ELECTRIC GENERATION

PG&E expects renewable EG to grow due to current RPS and the IRP 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 EG to cover forecast deviations and intra-day and intra-hour variability of intermittent generation.

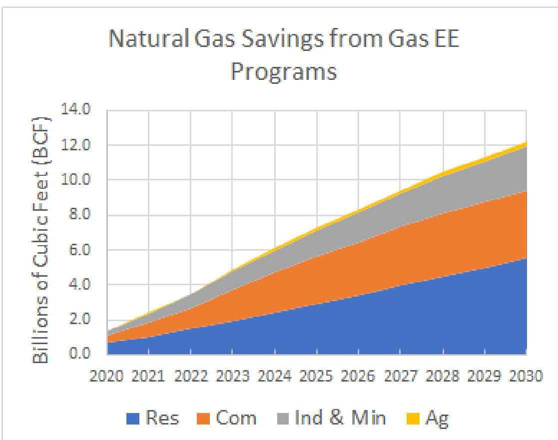
ENERGY EFFICIENCY PROGRAMS

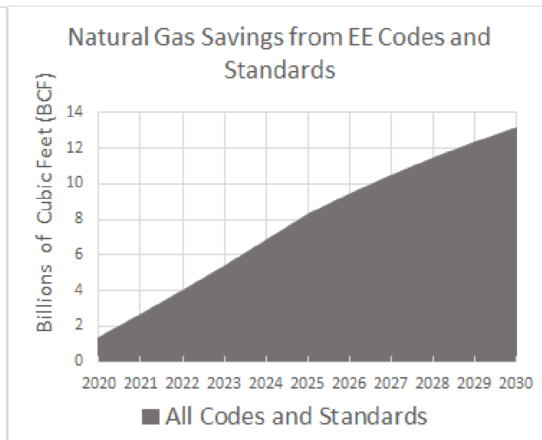
PG&E engages in many Energy Efficiency and conservation (EE) programs designed to help customers identify and implement ways to benefit environmentally and financially from EE investments. Programs administered by PG&E include services that help customers evaluate their EE options and adopt recommended 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 CPUC's Potential and Goal Study that informs Additional Achievable Energy Efficiency (AAEE) forecast in the CEC's California

Energy Demand 2020-2030 Revised Forecast.[22] 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. In the case of lighting, replacing a less efficient light bulb with a more efficient light bulb (e.g., replacing an incandescent with a light-emitting diode) that releases less heat leads to a lesser need for space cooling energy in summer and to a greater need for space heating energy in winter.

FIGURE 7 – PG&E SERVICE AREA: NATURAL GAS SAVINGS FROM EE PROGRAMS





Details of PG&E's 2018-2025 Energy Efficiency Portfolio can be found in Commission D.18-05-041, which authorized programs and budgets through 2025, and D.19-08-034, which adopted goals for these programs for 2020.

22 The California Energy Demand and the AAEE results are on the CEC's website: https://www.energy.ca.gov/sites/default/files/2019-12/AAEE%20Preliminary%20Results%2010-18-19_ada.pdf.

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.[23] The CEC issued its final report on SB 350 EE targets in October 2017,[24] and the CPUC incorporated higher levels of EE savings in their EE goals for 2018 and beyond. The CEC's final report suggests the state is on a path to meet or exceed the natural gas SB 350 doubling goal after accounting for IOU programs, POU programs, and codes and standards.[25]

IMPACT OF REACH CODES AND ELECTRIFICATION

In California, cities and counties have enacted reach codes that require a substitution away from natural gas appliances to electric appliances. This substitution from gas to electric is termed electrification. By February 2020, about 30 local jurisdictions have adopted reach codes.[26] This historical trend may continue its current projection or could change in other ways, either increasing or reversing at some unknown magnitude. Electrification, consequently, appears to be adding electric load in the long-term while removing sources of growth in gas demand.

The impact from electrification could be addressed in multiple ways. For example, the current RPS requirement states that 60 percent of system electric sales will be generated from renewable resources in 2030. As electrification increases load after 2030, the RPS requirement

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23 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."

24 Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. 2017. SB 350: Doubling Energy Efficiency Savings by 2030. CEC. Publication Number: CEC-400-2017-010-CMF.

25 See Figure 2 from the CEC report cited above.

26 https://www.sierraclub.org/articles/2020/03/californias-cities-lead-way-gas-free-future.

could increase and mitigate the use of natural gas for EG. The timing of the additional electric load within the day along with the intermittency characteristics of California's renewable resources will impact EG gas demand.

Even if EG gas demand increases, the effort to achieve the GHG emissions goal may come by differing gas supply options. The natural gas supply sources could be a clean version in the form of RNG or H2. The next chapter on natural gas supply will elaborate on these potential gas supplies.

FUTURE GAS DEMAND TRENDS AND POLICY

PG&E's gas demand forecast projects lower throughput over the long term (due to GHG policies, such as electrification and RPS) which would show a decline in revenues at current rates. At the same time, policies on safe utility operations have put upward pressure on costs. Investments into long lived assets, such as gas pipelines, are typically recovered over the assets' useful lives, which extend beyond this forecast. The combination of lower throughput and remaining investment in need of being recovered will put upward pressure on gas transportation rates. PG&E estimates that the declining throughput represented in the Average Demand year forecast and the scenarios could result in an increase to residential gas rates of approximately 60 percent to 100 percent by 2035 as compared to 2020. These estimates exclude changes to commodity costs, California GHG Emission Allowance costs, or authorized base revenue requirements.[27]

In addition, the transition from fossil fuel to other forms of energy usage needs to be carefully planned and managed. PG&E is committed to working with regulators and other stakeholders to support the statewide GHG reduction policies and develop options to minimize rate increase for the remaining gas customers.

Another high horsepower sector to consider for increasing gas throughput is rail transportation. Based on a study by the California Air Resource Board (CARB) from 2016, annual statewide locomotive diesel fuel consumption totals about 260 million gallons. Union Pacific Railroad (UP) and BNSF Railway Company (BNSF) combined interstate and intrastate

27 The increase of 60 percent to 100 percent is based on nominal dollars. The gas rate increase in real dollars is approximately 35 percent to 50 percent.

locomotives account for 93 percent of this fuel usage, California's passenger locomotives are 6 percent, and the remaining 1 percent is from military industrial locomotives.[28]

LNG as a fuel source has been considered by the rail industry, but thus far has been mostly limited to pilot studies. Based on conversations with representatives from UP, BNSF, and CARB, some of the key obstacles to LNG locomotive adoption include: few, if any, new locomotives are planned to be purchased in the near future, the high cost of converting the fueling infrastructure from diesel to LNG, and current emission standards don't adequately promote fuels cleaner than low sulfur diesel. Additionally, because LNG has an energy density of approximately 60 percent that of diesel, its use for long interstate routes would require increased fuel storage volume. This comes in the form of an LNG tender, which is an additional railcar that includes an insulated cryogenic tank and other equipment to convert LNG back to CNG. The added tender increases cost and complexity to the fuel transition.[29]

One possible path to greater LNG locomotive adoption is higher emissions standards. Locomotive emissions are governed by the U.S. EPA. Currently, their strictest emission level is Tier 4 and applies to locomotives manufactured in 2015 or later. In g/bhp-hr it limits nitrogen oxide (NO_x), particulate matter (PM), and hydrocarbon (HC) emissions to 1.3, 0.03, and 0.14 respectively.[30] In 2017, CARB petitioned to the U.S. EPA to consider adopting a new, stricter, Tier 5 standard with a proposed effective date of 2025. The Tier 5 standard would limit NO_x, PM, and HC emissions to 0.2, <0.01, and 0.02.[31] Thus far, there does not appear to be any movement by the U.S. EPA to adopt the proposed Tier 5 standard.

Without policy solutions and a managed transition from fossil fuel to other energy forms, the increase in residential rates would be even higher. Gridworks' most extreme estimate for their High Building Electrification – No Transition Strategy scenario could result in residential rates of $19/therm by 2050 (2018 dollars) compared to then-current residential rates near $1.37/therm.

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28 CARB. (2016). *Technology Assessment: Freight Locomotives.* Sacramento: California Air Resource Board.

29 *Ibid*.

30 CFR 1033.101 (https://www.ecfr.gov/cgi-bin/text-idx?SID=159ba6f126272ea1995c71a43b7af309&mc=true&node=pt40.36.1033&rgn=div5#se40.36.1033_1101).

31 https://ww2.arb.ca.gov/sites/default/files/2020-07/final_locomotive_petition_and_cover_letter_4_3_17.pdf.

The drivers to those higher rates come from lower projected gas throughput, higher GHG Emission Allowance costs, and the potential for added infrastructure investment costs.[32]

To minimize the rate increase for the remaining gas customers, PG&E is following a two-pronged approach while keeping safety as its top priority: (1) reduce cost and (2) maximize utilization. To reduce cost, PG&E is pursuing opportunities to systematically retire infrastructure (where possible) and reduce capital and operating expenses through PG&E's Integrated Investment Planning. To increase utilization of existing infrastructure, PG&E is actively planning for and implementing programs to decarbonize existing gas throughput, exploring new opportunities to support RG adoption across new industries, increase load on the natural gas system in areas that would replace less favorable hydrocarbon (e.g., marine, rail and transportation sectors) and seek opportunities to utilize the gas system as a long-term and large scale storage mechanism. Gridworks, with a mission to convene, educate and empower stakeholders working to decarbonize electricity grids, published its report[33] that shows these tactics may not be sufficient. Other avenues to explore include aligning financial recovery of gas infrastructure investment with their useful lives and adjusting ratemaking for effective cost recovery.

FUTURE OPPORTUNITIES

One recent development that could improve the outlook for throughput comes from the June 2020 California Air Resources Board (CARB) approval of the Advance Clean Truck (ACT) Regulation. This regulation requires increasing percentages of all new medium- and heavy-duty trucks sales in California to be zero-emission vehicles (ZEV)[34]. The regulation begins in 2024 with sales percentages ranging between 5 percent and 9 percent depending on truck or chassis type. By 2035, the percentages increase to a range of 40 percent to 75 percent.

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32 Then-current rate based on June 2020 G1 (Residential Service) tariff and $19/therm based on Gridworks' report California's Gas System In Transition, Equitable, Affordable, Decarbonized, and Smaller: https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

33 California's Gas System in Transition: Equitable, Affordable, Decarbonize and Smaller, Gridworks, 2019: https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf.

34 ZEVs are defined as either battery electric or hydrogen fuel cell vehicles.

Truck manufactures may choose hydrogen fuel cells as they decide how to meet this requirement. The hydrogen required for this could be transported via utility gas pipelines (under appropriate safety protocols) which could mitigate the potential for increasing customer costs.

Another potential growth area for gas throughput is the marine transportation sector which is increasingly looking at reducing its SOx and GHG emissions. This is orchestrated by The International Maritime Organization (IMO) which regulates global shipping emissions under Annex VI.[35] The IMO updated Annex VI on January 1, 2020 to target reductions in nitrogen oxides (NOx) and sulfur oxides (SOx). To reduce SOx, the Sulphur limit for all marine fuels was dropped from 3.50 percent m/m (mass by mass) to 0.50 percent m/m.

The consensus in the marine fuel industry is that the 0.50 percent Sulphur limit is only a stop on the way to a global 0.10 percent Sulphur limit, which currently exists in several Emissions Control Areas (ECA)[36] around the globe. Moving to 0.10 percent would necessitate using road grade diesel fuel as bunker fuel, therefore increasing fuel cost. Refining companies would need to further invest in hydrodesulfurization, which is costly to build and operate.

The push towards lowering SOx is driven by environmental groups, government regulations, and the shipping industry itself. Large European container companies are driving it as part of their corporate carbon strategies,[37] managing their fuel costs while doing so.

LNG is widely recognized as the best path forward to reduce SOx and GHG for marine purposes but has not seen much growth the previous decade. The updated IMO Annex VI are changing that, spurring investments in bunkering equipment[38] and vessels.[39] LNG is also seen as the most practical way to de-carbonize the shipping industry as the fuel can be made from Renewable Gas and, further out, Green Hydrogen.

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35 http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx.

36 http://www.imo.org/en/OurWork/Environment/SpecialAreasUnderMARPOL/Pages/Default.aspx.

37 https://www.maersk.com/news/articles/2019/06/26/towards-a-zero-carbon-future.

38 https://sea-lng.org/why-lng/bunkering/; https://www.ship-technology.com/news/west-coasts-lng-bunker-abs/.

39 https://www.cma-cgm.com/news/2749/world-premiere-launching-of-the-world-s-largest-lng-powered-containership-and-future-cma-cgm-group-flagship.

California marine fuel markets can be divided into ocean and coastal. The ocean market is the largest due to the fuel volumes vessels consume. California, with its large container ports in Oakland, Los Angeles, and Long Beach, may see demand for LNG in the future (which will require large investments). Some of the investments needed to meet this demand include storage terminals, bunker loading vessels, or liquefaction terminals.

This demand may come sooner rather than later as modern ship engines are flex-fuel capable in that they can run on either fuel oil or natural gas, thus optimizing fuel costs and environmental compliance.[40] To give an idea of the potential size of this market, in 2016 bunkers delivered across the ports of Los Angeles and Long Beach totaled 21.33 million barrels or 132 Bcf.[41]

Coastal market consists mostly of smaller vessels such as passenger ferries, tugs, fishing vessels etc. Already using an Ultra Low Sulphur Diesel under CARB regulations, they could see a cost reduction by switching to LNG powered fleets.[42] Small on-demand liquefaction terminals can bunker vessels at berth and have already been installed in Europe successfully.[43] They can be connected directly to the natural gas grid producing fuel on-demand.

NORTH AMERICAN GAS DEMAND TRENDS

Liquefied Natural Gas Imports/Exports

In years past, the U.S. imported LNG to supplement North American supplies to meet demand. However, U.S. imports of LNG have been declining since 2008. Over the past decade, the development of low-cost domestic shale gas supplies has largely eliminated the need for LNG imports and positioned the U.S. as a net exporter of LNG.

The U.S. began exporting LNG in 2016. For LNG projects proposing to export LNG, the U.S. Department of Energy (DOE) evaluates the impact of exports to countries without a Free Trade Agreement (FTA) with the U.S. The DOE grants approval if the project is deemed in the public interest. On the other hand, the U.S. Federal Energy Regulatory Commission (FERC),

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40 https://www.wartsila.com/twentyfour7/energy/taking-dual-fuel-marine-engines-to-the-next-level.

41 https://www.bunkerspot.com/americas/43523-americas-la-lb-annual-bunker-volumes-up-25-73-y-o-y.

42 https://www.mckinsey.com/industries/oil-and-gas/our-insights/imo-2020-and-the-outlook-for-marine-fuels#.

43 https://ec.europa.eu/energy/intelligent/projects/sites/iee-projects/files/projects/documents/magalog_lng_supply_chain.pdf.

focuses on evaluating the environmental impacts of proposed LNG projects, and authorizes the siting and construction of LNG facilities.

There are several proposed projects to export LNG to world markets. Many of the projects are "brownfield," using existing U.S. import terminals to export LNG, but some are "greenfield."

A brownfield project on North America's West Coast is the Energia Costal Azul (ECA) LNG export facility in Baja California, Mexico. ECA has received authorization from the DOE to liquify and re-export up to 1.7 billion cubic feet per day (Bcf/d) of U.S. produced natural gas.[44] This facility will have a 4.5 million metric tons (mmt) per annum of liquification capacity.[45] Construction of the project will occur in two phases. Phase 1 is a single LNG facility located adjacent to the existing LNG terminal. Phase 2 includes the addition of two trains and a storage tank. Transportation of gas for the planned ECA project is proposed to be over the expanded North Baja pipeline, subject to FERC approval. Construction and operation of the ECA export plant is contingent on commercial contracts, pertinent Mexican and U.S. government permitting, and financing. ECA anticipates construction to commence in the first half of 2021 with commercial operations beginning no later than 2025.

The ECA LNG export project, which would be the second on the North America's West Coast, is positioned to source gas off the El Paso Mainline System. Thus, it could divert gas supplies currently available to Northern California. ECA diversion of gas supplies from California is currently under consideration at the CPUC in the R.20-01-007 Proceeding.[46] This proceeding will investigate whether the demand from ECA could impact supply reliability to California, especially the southern portion, and put upward pressure on gas prices.

One greenfield project is the Jordan Cove Project in Oregon. Jordan Cove in early 2020 received authorization from the FERC to site, construct, and operate an LNG export facility. In order to supply the LNG facility with natural gas, FERC authorized the Pacific Connector Gas Pipeline. This pipeline would interconnect with the Ruby Pipeline and the GTN Pipeline. Additional work lies ahead to resolve issues of state and local approvals, financing, and facilities

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44 https://www.sempra.com/energia-costa-azul-lng-receives-us-non-fta-approval-liquefaction-export-infrastructure-project.

45 FE DOCKET NO. 18-145-LNG.

46 OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.

planning. The Jordan Cove LNG export project 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 U.S. remained a net exporter of natural gas in 2019.[47] Mexico, accounting for approximately 43 percent of total U.S. gas exports in 2019, 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 5.5 Bcf/d in 2019,[48] and pipeline exports are projected to reach 7.5 Bcf/d by 2025.[49] 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 15.5 Bcf/d of export capacity as of 2019, with an additional 0.6 Bcf/d expected to come online in 2020.

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.

47 Energy Information Administration (EIA), The U.S. exported more natural gas than it imported in 2017: https://www.eia.gove/todayinenergy/detail.php?id=35392.

48 EIA, U.S. Natural Gas Pipeline Exports to Mexico: https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_NUS-NMX_a.htm.

49 EIA, Annual Energy Outlook 2020 – Natural Gas Imports and Exports Table (Reference Case): https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2020&region=0-0&cases=ref2020&start=2019&end=2025&f=A&linechart=~~ref2020-d112119a.9-76-AEO2020~ref2020-d112119a.10-76-AEO2020&ctype=linechart&sourcekey=0.

GAS SUPPLY, CAPACITY, AND STORAGE

OVERVIEW

The Gas Supply, Capacity, and Storage section provides information about PG&E's current gas supply, natural gas pipelines, gas storage, and policies affecting these topics. The Gas Supply section includes information about current and anticipated developments regarding RG, as well as gas supply from sources throughout North America. The Pipeline section includes information about "upstream" inter-state pipelines, as well as intra-state pipelines. The Storage section gives an overview of PG&E's gas storage capacity and its gas storage facilities. The Policies section looks at a range of current policy developments and their impacts on PG&E's gas supply, including integration challenges for RG, as well as alternative fuel types, such as H2.

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990s. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity and storage capacity have provided all customers with direct access to gas supplies, intra- and inter-state transportation, and related services.

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

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. Supply can be delivered through a variety of sources, including any new and expanded interstate pipeline facilities and of PG&E's existing transmission facilities, or other storage facilities.

GAS SUPPLY

RENEWABLE GAS

There are seven Renewable Natural Gas (RNG) projects that are in the process of interconnecting with PG&E's gas system, with the first few expected to begin injecting pipeline quality gas in Q4 2020 and the rest expected to progress through 2021. These seven projects are expected to inject roughly 16,500 MCF/d into PG&E's pipeline system. Two of the projects are a result of the SB 1383 Dairy Pilot Program, highlighted below, and the other five are identified in the Biomethane Project Incentive Reservation Queue located on the CPUC website.[50]

SB 1383 Dairy Pilot Projects

On December 3, 2018, the CPUC, the California Air Resources Board (CARB), and the California Department of Food and Agriculture (CDFA) issued a joint press release announcing the selection of six dairy pilot projects in compliance with CPUC D.17-02-004 and SB 1383. Two of the pilot projects were awarded in PG&E's service territory: (1) the Merced Pipeline project sited at the Vander Woude Dairy in Merced (6 miles south of Merced); and (2) the J.G. Weststeyn Dairy project in Willows (5 miles west of Logandale).

50 https://www.cpuc.ca.gov/renewable_natural_gas/.

FIGURE 8 – PG&E SERVICE AREA: RENEWABLE NATURAL GAS PILOT PROJECTS LOCATION

PG&E is encouraged to see the first wave of RNG interconnection projects in its Northern California service territory.

Future California RNG Supply

A 2016 CARB-sponsored study by University of California (UC), Davis, "The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute" (the "STEPS study"), anticipated that as much as 82 Bcf per year of RNG supply could become available in California with appropriate policy development and investment.[51] The STEPS study identified that the largest opportunity for increasing the supply of RG would come from landfill sites, followed by dairy, municipal solid waste, and waste-water facilities.

A more recent assessment of in-state RNG supply for transportation, conducted by GNA,[52] projects that there will be roughly 16 BCF annually of RNG interconnected into gas pipelines in California by January 2024. Given the STEPS study results, the gas flowing from RNG sources by January 2024 is just the first wave of RNG expected to be eventually injected into the gas system.

Therefore, going forward, PG&E expects to see more RNG projects as developers realize the near and mid-term potential of this supply source.

Gas Absorption Capacity

To encourage effective development of RNG, PG&E created the Gas Supply Absorption Capacity Map.[53] This map is a high-level snapshot of PG&E's gas system that is designed to help contractors and developers find potential project sites by showing the relative ability (high to low) to accept new gas supply on PG&E transmission pipelines. Suppliers are encouraged to contact PG&E to discuss opportunities to bring on RNG supplies.

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

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51 STEPS Program Study, The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, prepared by Amy Myers Jaffe, available at: https://steps.ucdavis.edu/the-feasibility-of-renewable-natural-gas-as-a-large-scale-low-carbon-substitute/.

52 https://www.gladstein.org/gna_whitepapers/an-assessment-californias-in-state-rng-supply-for-transportation-2020-2024/

53 Available at: https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/interconnections-renewables/biomethane-map-overview.page

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 2019. While some of the 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 33 percent in 2019, 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.

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 towards California.

CALIFORNIA-SOURCED GAS

Northern California-sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2019, PG&E's customers obtained on average 26 MMcf/d of California sourced gas. PG&E does not anticipate a material change in this level of supply going forward.

U.S. SOUTHWEST GAS

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

PG&E's customers can purchase 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 GTN 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 GTN Pipeline interconnect at Stanfield, Oregon.

GAS PIPELINE CAPACITY

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, GTN, Paiute Pipeline Company, Ruby, 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, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 960 MMcf/d.

Canada and Rocky Mountains

PG&E's Redwood Path (Lines 400/401) is connected to GTN and Ruby at Malin, Oregon. The Redwood Path has a firm capacity of 2,060 MMcf/d.

IN-STATE PIPELINES

PG&E continues to accelerate the analysis of the existing pipeline system for opportunities to minimize rate increases for our customers by reducing our expenses, look for new opportunities for load growth and to decarbonize by increasing throughput of RG. PG&E is actively pursuing opportunities on radial feeds where several miles of pipe are in place to serve a small handful of customers. Electrifying these customers and decommissioning the pipeline will achieve greater cost savings in the short-term. These opportunities will also help inform PG&E's longer-term efforts, in partnership with cities, to strategize where to reduce our spending and predict long-term gas needs more accurately.

GAS STORAGE

Northern California is served by several gas storage facilities in addition to the long-standing PG&E fields at McDonald Island, Pleasant Creek, and Los Medanos. PG&E owns and operates 116 wells at these three natural gas storage fields located in California and is a 25 percent owner of a fourth storage field (Gill Ranch). PG&E's wholly owned storage facilities have a combined maximum capacity of 102.2 Bcf.

Other storage providers include Gill Ranch Storage, LLC (the 20 Bcf facility was co-developed with PG&E), 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 ample liquidity in the market both in Northern California and in other parts of the West.

In the past few years, the California Geologic Energy Management Division (CalGEM) (formerly, DOGGR) altered safety rules governing natural gas storage facilities. The CalGEM safety rules impact new investment in storage facilities and capacity throughout California while decreasing withdrawal capacity.

In PG&E's recent Gas Transmission and Storage Rate Case, the CPUC in D.19-09-025 adopted PG&E Natural Gas Storage Strategy (NGSS). As part of the strategy, PG&E is focusing the use of PG&E's gas storage facilities on system operations, including balancing supply and demand. Additionally, the strategy calls for the divestiture or decommissioning of the Los Medanos and Pleasant Creek storage facilities rather than investing the substantial amount money needed to make the facilities reliable and compliant with the new CalGEM regulations.

MCDONALD ISLAND

McDonald Island serves as the largest of PG&E's three facilities and is located on a man-made island in a scarcely populated agricultural area near the Sacramento-San Joaquin River Delta. McDonald Island is PG&E's largest gas storage field and has a maximum capacity of 82 Bcf. McDonald Island has 87 total wells; 81 wells operate for injection and withdrawal and 6 operate as observation wells. McDonald Island can provide 25 percent of Northern California's winter peak day gas demand.

LOS MEDANOS AND PLEASANT CREEK

Los Medanos is PG&E's second largest facility and has a maximum capacity of 17.9 Bcf. The facility is in Contra Costa County and contains 22 wells. Pleasant Creek is PG&E's smallest storage facility and has a maximum capacity of 2.0 Bcf. The facility is in Yolo County and contains seven wells. As reflected in the 2019 Gas Transmission and Storage (GT&S) Rate Case, NGSS,[54] PG&E will be selling or decommissioning the Pleasant Creek and Los Medanos storage facilities.

OTHER CALIFORNIA STORAGE FACILITIES

In addition to storage services offered by PG&E, there are four other storage providers in Northern California: Wild Goose Storage, LLC; Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. As of 2018, these facilities had an estimated total working gas capacity of roughly 239 Bcf.[55]

POLICIES IMPACTING FUTURE GAS SUPPLY AND ASSETS

OVERVIEW

California's policies to reduce the Carbon footprint and sources of GHGs, are expected to impact the gas supply and assets in the near future. PG&E is responding to these policies and actively planning for and implementing programs to decarbonize existing gas throughput, supporting RG adoption across new industries with existing gas system infrastructure, and adapting to utilize the gas system as a long-term storage mechanism.

RENEWABLE NATURAL GAS

As a result of various policy and regulatory changes, PG&E is seeing an influx of requests to interconnect RNG to utility pipelines in Northern California during 2020. RNG producers are leveraging available grants and incentives to encourage the production of RNG to reduce GHG emissions from the biogas sources to the environment and for use as an alternative fuel source for transportation and other end use customers. PG&E is engaged in the following efforts regarding RNG:

- Procuring RNG for all PG&E owned Compressed Natural Gas (CNG) fueling stations;
- Proposed a joint utility RNG Interconnection Rule, filed November 1, 2019;

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54 https://www.cpuc.ca.gov/General.aspx?id=10432.

55 Working gas capacity comes from providers of storage services websites.

- Proposed a joint utility RNG Interconnection and Operating Agreement, filed May 1, 2020; and
- Participation in various Research and Development (R&D) efforts to further understand and develop new methods and technologies to produce RNG that reduce the carbon intensity of the gas in the pipeline.

Chief Interconnection Barriers and Issues

The interconnection of RG projects to the utility pipeline system is critical in the effort to meet the state of California's GHG reduction goals and must be done first and foremost with consideration of public and employee safety.

The CPUC is continuing its work in R.13-02-008, establishing the process for the consistent interconnection of RNG across California, which should reduce the regulatory and incentive financing uncertainty that has slowed industry growth. At various points in the proceeding, interconnecting developers have indicated that interconnection costs are high, project timelines are long, and that utility gas quality and some contractual requirements are burdensome.

While there is significant potential for RNG to replace some portion of natural gas supply generally, the current investment and incentives for RNG principally favor the transportation sector. With the clear financial advantage towards transportation, there is comparatively little RNG available to establish a consistent RGS to meet PG&E's customer or third-party needs, should an RGS be established. If this is to change, California will have to balance the funding mechanisms between the transportation sector and a potential RGS so that RNG project developers have opportunities to supply RNG towards an RGS or the transportation sector.

Monetary Incentive Program

D.15-06-029 established a biomethane monetary included program authorizing $40 million to encourage biomethane producers to design, construct, and safely operate projects that interconnect and inject biomethane into California's natural gas utilities' pipeline systems.

D.19-12-009 implements an Incentive Reservation System for the biomethane monetary incentive program established in D.15-06-029. The Incentive Reservation System opened to applications on February 3, 2020 and the queue is published on the CPUC's RNG website.[56]

Based on information provided in D.19-12-009,[57] two projects have received a total of $8.18 million of funding under the incentive program, leaving $31.82 million remaining in the program. PG&E is unaware of any additional incentive awards being issued since December 2019.

Research and Development

PG&E's R&D RNG roadmap[58] further outlines PG&E's goals for incorporating RNG into the supply portfolio.

HYDROGEN

Green H2 is seen as a game changer in decarbonizing many sectors. To achieve the goals set forth in SB 100, California will likely need to incorporate Green H2 into the portfolio of green fuels for various sectors. Many other countries are already embracing H2 and fuel cell technology to reduce their carbon footprint. California is starting to see some movement on the legislative front to increase funding for furthering the use of Green H2. There is potential for Green H2 to be produced and then stored for future use or used to decarbonize the transportation sector. The California IOUs are working together on an action plan for incorporating Green H2 into the pipelines and will be filing an Application for a preliminary H2 injection standard in November 2020.

HYDROGEN STORAGE (CONVENTIONAL AND NEW TECH)

As mentioned above, Green H2 is seen as a game changer and has many potential applications. One such application is to produce Green H2 through electrolysis and stored in the pipeline system (or dedicated underground storage facilities) for later use, such as fuel for EG needed when the sun is not shining or the wind is not blowing. Green H2 storage has incredible

56 https://www.cpuc.ca.gov/renewable_natural_gas/.

57 D.19-12-009, p. 2.

58 https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/RNG_Roadmap_2020.pdf

potential for longer-term storage and at larger volumes for seasonal load shifting that would not be possible with batteries alone.

LNG AS MARINE FUEL

As mentioned above in the Gas Demand section, there is tremendous opportunity for growth in the marine market. The gas supply needed for this demand will need to come from cleaner sources of fuel such as RG and H2.

REGULATORY ENVIRONMENT

OVERVIEW

This section provides an overview of the existing and near-term regulatory policies and their effect on the Northern California gas system and its users.

Given the anticipated state and federal regulatory policies surrounding storage, transportation, inspection, and capacity requirements, the cost to safely and reliably operate PG&E's gas system will continue to rise. At the same time, a decline in throughput—which PG&E anticipates is a result of California's GHG goals and cities pushing for new electric reach codes—will mean those costs will be spread over fewer therms and possibly fewer customers, impacting the affordability of gas.

Furthermore, despite readily available domestic gas, operational innovation, and reaching a lower NOVA Gas Transmission Ltd (NGTL) rate for PG&E customers, the complex regulatory environment and evolving policies are likely to create price uncertainty in the medium/long-term.

FEDERAL AND CANADIAN REGULATORY MATTERS

PG&E actively participates in FERC ratemaking proceedings for interstate pipelines connected to PG&E's system since these proceedings can impact the cost of gas delivered and the services provided to the PG&E's gas customers. 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.

GTN AND CANADIAN PIPELINES

On March 10, 2020, GTN, submitted Advance Notification of Natural Gas Facilities Replacement for three compressor stations: Athol Compressor Station, Kent Compressor Stations, and Starbuck Compressor Station. PG&E is monitoring these construction projects as they may affect gas throughput and pipeline costs.

On March 25, 2020, the Commission of the Canada Energy Regulator has approved a rate design methodology and other terms and conditions of service settlement for the NGTL System.[59] This settlement will lower the NGTL rate for PG&E customers.

OTHER PIPELINES

There are currently no significant regulatory issues regarding El Paso Natural Gas Company, LLC (El Paso); Kern River Gas Transmission (Kern River); Ruby Pipeline, LLC (Ruby); or Transwestern Pipeline Company, LLC (Transwestern) pipelines.

FERC AND CAISO GAS-ELECTRIC COORDINATION ACTIONS

While there are no general inquiries or proceedings at FERC addressing gas-electric coordination, the California Independent System Operator (CAISO), which is FERC-jurisdictional, has ongoing policy initiatives that may impact gas demand, supply, and prices. These initiatives include:

- Resource Adequacy Enhancements;
- Flexible Ramping Product Refinements; and
- Flexible Capacity Needs Assessment Process.

These policy initiatives will need FERC approval before the proposed changes can be implemented.

STATE REGULATORY MATTERS

CALIFORNIA STATE SB 100 AND CARBON NEUTRALITY EXECUTIVE ORDER

On September 10, 2018, Governor Brown signed into law SB 100, which would further increase and accelerate the RPS targets and includes the following key requirements:

- Accelerates the RPS to 50 percent by 2026 and increases the RPS to 60 percent by 2030;
- Creates a separate state policy that requires 100 percent of all retail sales of electricity to serve end-use customers and 100 percent of electricity procured to serve state agencies to come from RPS-eligible or zero-carbon resources by 2045;

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59 *In re NGTL.*, Can. Energy Reg., Decision C05448 (March 25, 2020), available at: https://apps.cer-rec.gc.ca/REGDOCS/Item/Filing/C05448.

- Requires the CPUC, in consultation with the CAISO and other balancing authorities, to issue a joint report to the Legislature by January 1, 2021, and every 4 years thereafter, that evaluates the anticipated costs and benefits of the 100 percent clean policy to electric, gas, and water utilities, including customer rate impacts and benefits

Additionally, Governor Brown signed an EO on September 10, 2018 establishing a new statewide goal to achieve carbon neutrality by 2045 across all sectors of the California economy and to achieve and maintain net negative GHG emissions thereafter. Implementation of the order will require California to undertake additional decarbonization and negative emissions efforts. CARB plans to focus on carbon neutrality in its next Climate Change Scoping Plan, due in 2022.[60]

PIPELINE SAFETY

Since 2011, the CPUC and the California 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 16, 2020, PG&E filed its 2020 Gas Safety Plan with the CPUC. The Gas Safety Plan 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) semi-annual Gas Transmission & Storage Compliance Report; and (2) 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. Selected highlights from PG&E's 2019 reports, which further demonstrate PG&E's commitment to gas safety, include:

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60 CARB Scoping Plan Implementation Update (April 2020), available at: https://ww3.arb.ca.gov/board/books/2020/042320/20-4-2pres.pdf.

- **Asset Management System:** PG&E maintains an asset management system to help drive the business toward achieving its commitment to the safe, reliable, affordable management and operation of PG&E's gas assets, using the international Publicly Available Specification 55-1, International Organization for Standardization 55001, and American Petroleum Industry (API) Recommended Practice (RP) 1173 standards as guidance. Additionally, in November 2019, Lloyd's Register confirmed Gas Operations' continued compliance with API RP 1173.

- **Process Safety:** PG&E's commitment to implement process safety aligns with API RP 754 *Process Safety Performance Indicators for the Refining and Petrochemical Industries*. Process Safety and Gas Safety Excellence teams use a risk-sorting criterion to track and tabulate leading and lagging safety indicators. This helps identify emerging issues before incidents occur. In 2019, Gas Operations reached a key milestone in the journey of Process Safety Management maturity. Gas Operations was recognized, through a third-party assessment, for being in compliance with the intent of API RP 754, Process Safety Performance Indicators, insofar as it meets its business operations, demonstrating a commitment to incident prevention.

- **In-Line Inspection (ILI):** In 2019, PG&E increased piggability to roughly 36 percent of the approximately 6,600 miles of its Gas Transmission system. PG&E inspected a total of 478.1 miles, with 266.4 of those miles assessed with ILI for the first time. Approximately two-thirds of PG&E's transmission system (about 4,100 miles) has been or will be upgraded to accept ILI tools by the end of 2029.

- **Third-Party Dig-Ins:** In 2019, PG&E experienced 1.04 dig-ins per 1,000 Underground Service Alert (USA) tickets, out-performing its 2019 target of 1.23 dig-ins per 1,000 USA tickets.

- **Community Pipeline Safety Initiative**: A multi-year program designed to enhance safety by improving access to pipeline rights-of-way. The program was initially anticipated as a 5-year initiative ending in December 2017, but has been extended through December 2020 due to long-lead permitting and outstanding customer agreements. To date, the program has cleared approximately 1,542 vegetation miles and 359.72 structure miles. The remaining 9.27 miles of vegetation and 0.28 miles of structure clearing is expected to be completed in 2020.

STORAGE SAFETY

CalGEM (California Geologic Energy Management Division) finalized underground storage regulations in October 2018. Within the regulations, operators are required to increase monitoring and inspection practices and ensure well construction is in accordance with a dual barrier system by 2025. Implementation of the regulations to convert a targeted percentage of wells each year to dual barrier, tubing and packer completion, began in 2019 and impacts the available withdrawal capacity. PG&E, in its 2019 GT&S Rate Case application, included the impact of the proposed regulations in its NGSS, which includes the decommissioning or sale of the Pleasant Creek and Los Medanos storage facilities. The CPUC approved the NGSS in D.19-09-025, issued on September 23, 2019.

GAS QUALITY

Gas quality has received much less attention since 2010 due to the abundance of domestic gas supply. Domestic gas supply 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.

THE DOWNSTREAM EFFECTS OF INCREASED REGULATION: CITIES PURSUE ELECTRIFICATION

In response to California's firming GHG laws and strengthening public support, local governments have already begun taking significant steps towards electrification at the city level. As of February 2020, thirty cities have passed new electric reach codes, the majority of which fall within PG&E's territory.[61]

In fact, per the Building Decarbonization Coalition, as of March 2020, 13 California cities have passed reach codes for all-electric new construction.[62]

The spread of all-electric new construction would suggest a flattening demand for gas. However, as cited in the gas demand section, the full effect of these new reach codes has not yet been determined.

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61 "Forward-Looking Cities Lead the Way to a Gas-Free Future." Sierra Club, 6 Mar. 2020: https://www.sierraclub.org/articles/2020/07/californias-cities-lead-way-gas-free-future.

62 "*Active Code Efforts.*" The Building Decarbonization Coalition*, 30 Mar. 2020: www.buildingdecarb.org/active-code-efforts.html.*

KNOWN REGULATORY HURDLES

Federal regulation along with state and local climate action goals are set to create a challenging environment for gas utilities. To succeed in achieving these operational safety and climate action goals, the following hurdles need to be addressed:

- As regulations continue to strengthen, the cost of providing a safe and reliable gas system continues to rise. This increase in cost, paired with state and local GHG goals, which are expected to drive down gas throughput, will likely result in a higher cost per-therm for customers.
- Barriers to RGS: With the clear financial advantage towards transportation, there is comparatively little RG available to establish a consistent RGS to meet PG&E's customer or third-party needs should a RGS be established.

California's gas system is going though unprecedent changes. As we brace for the future, now, more than ever, it's important that regulatory bodies and IOUs work together to ensure that Californians continue to have access to clean, reliable and affordable energy.

OTHER REGULATORY MATTERS

OVERVIEW

This section includes PG&E's GHG and Cap-and-Trade reporting and discusses other regulatory matters that may impact Northern California's gas system.

PG&E is participating in a number of OIRs, which address crucial topics that will impact the California gas system. For example, the:

- Biomethane OIR (R.13-02-008) will help the utilities make RG interconnections more efficient and affordable across California; and
- Gas System Planning OIR (R.20-01-007) will allow the utilities to: (1) develop updated reliability standards that are in line with current and future operational challenges of gas system operators, (2) improve coordination between gas utilities and gas-fired generators, and (3) develop and implement a long-term strategy to work towards California's decarbonization goals.

GHG REPORTING AND CAP-AND-TRADE OBLIGATIONS

In March 2020, PG&E Gas Operations reported the GHG emissions to the U.S. Environmental Protection Agency (EPA) in accordance with 40 Code of Federal Regulations

(CFR) Part 98 in four primary categories: GHG emissions in reporting year 2019 resulting from combustion at seven compressor stations, where the annual emissions exceed 25,000 metric tons of carbon dioxide equivalent ($mtCO_2e$); the GHG emissions resulting from combustion of all customers except customers consuming more than 460 MMcf; certain vented and fugitive emissions from the seven compressor stations and natural gas distribution system; and GHG emissions from transmission pipeline blowdowns.

In April 2020, PG&E Gas Operations reported GHG emissions of approximately 42.9 million metric tons of carbon dioxide equivalent ($mmtCO_2e$) to the CARB in three primary categories for reporting year 2019: GHG emissions resulting from combustion at seven compressor stations and one underground gas storage facility, where the annual emissions exceed 10,000 $mtCO_2e$; the GHG emissions resulting from combustion of delivered gas to all customers; and vented and fugitive emissions from seven compressor stations, one underground gas storage facility and the natural gas distribution system.

PG&E's deliveries to small customers not directly covered by CARB's Cap-and-Trade program (i.e., PG&E's natural gas supplier function) create compliance obligations for PG&E under the CARB Cap-and-Trade Program. PG&E emissions from covered compressor stations also create compliance obligations for PG&E under Cap-and-Trade. In 2019, CARB determined that PG&E's compliance obligations as a natural gas supplier were approximately 18.3 $mmtCO_2e$ for reporting year 2018. CARB will determine PG&E's natural gas supplier compliance obligation for reporting year 2019 in October 2020. In June 2019, PG&E filed the 2018 Annual Natural Gas Leakage Abatement Report and reported 2.9 billion standard cubic feet of methane emissions from intentional and unintentional releases. The annual report is a partial fulfillment of 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 two-year Leak Abatement Compliance Plan in March 2020. 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 transitioning from the 3-year gas distribution leak survey cycle to risk-based leak surveys, continuing repair of its distribution system largest leaks, refining blowdown reduction strategies and beginning to expand the use of these strategies at compressor stations and storage facilities, and improving inventory of other devices that release gas to the atmosphere.

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. In April 2019, PG&E filed its Implementation Plan[63] for this program. The plan includes replacing high-bleed pneumatic devices, replacing rod packing, excavation damage data collection, and utilizing methods such as drafting and cross compression. More information can be found on the EPA's Methane Challenge Webpage.[64] In addition, PG&E is committed through its 1-million-ton challenge to reduce GHG emissions from company operations through 2022. PG&E's strategy to meet this goal includes increased leak survey and repair, removing high-bleed pneumatic devices, replacing vintage distribution main, and reducing transmission pipeline blowdowns.

BIOMETHANE OIR R.13-02-008 PHASE 3

On July 5, 2018, the CPUC reopened R.13-02-008 Phase 3 and ordered the joint California utilities to propose a joint RG interconnection tariff and interconnection agreements.

On November 1, 2019, the joint utilities filed a proposed RG interconnection rule. The CPUC held a workshop on November 13, 2019, to discuss the proposal, and parties filed comments thereafter.

On May 1, 2020, the joint utilities filed the proposed RG interconnection and operating agreement and related documents to be used with the RG rule. The CPUC held a workshop on May 18, 2020 to discuss the proposed agreement and parties filed comments thereafter.

The CPUC also instituted a Reservation System in D.19-12-009 that became effective as of February 3, 2020 for the biomethane incentive program implemented by D.15-06-029.

BIOMETHANE OIR R.13-02-008 PHASE 4

On November 21, 2019, the CPUC issued a Ruling to establish Phase 4 of the proceeding that will address injection of renewable H2 into gas pipelines and implementation of SB 1440 (RNG procurement).

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63 https://www.epa.gov/sites/production/files/2019-06/documents/pacific_gas_and_electric_mc_ip_webready_2019-05.pdf.

64 https://www.epa.gov/natural-gas-star-program/pacific-gas-electric-company-methane-challenge-partner-profile.

By November 21, 2020, the joint utilities are directed to file an application on a preliminary H2 injection standard. The joint gas utilities have hosted technical H2 working group sessions (the first on January 15, 2020 and the second on June 17, 2020) with reports filed by the joint utilities shortly thereafter.

GAS SYSTEM PLANNING OIR R.20-01-007

The CPUC opened a new Rulemaking to "Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning." This proceeding will be conducted in two phases and will: (1) develop and adopt as necessary updated reliability standards that reflect current and future operational challenges to gas system operators, (2) determine the regulatory changes to improve coordination between gas utilities and gas-fired generators, and (3) implement a long-term planning strategy to manage the transition away from natural gas-fueled technologies to meet California's decarbonization goals. Phase I of this proceeding is expected to conclude within 18 months.

- Reliability Standards - Phase 1 – Track 1A
- Market Structure and Regulations – Phase 1 – Track 1B
- Long-Term Natural Gas Policy and Planning – Phase 2

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 28.3 degree F system-weighted mean temperature across the PG&E gas system. The PG&E core demand forecast corresponding to a 28.3 degree F temperature is estimated to be approximately 3.0 Bcf/d. The PG&E load forecast shown here excludes all noncore demand and excludes all EG demand. PG&E estimates that total noncore demand served by pipeline and storage withdrawal capability during an APD event would be approximately 1.4 to 1.6 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 remaining balance of PG&E's core customers and have the same obligation as PG&E Core Gas Supply to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

In previous extreme-cold weather events, PG&E has observed a drop in flowing pipeline supplies. Supply from Canada is affected as the cold weather front drops south from Canada with a 2- to 3-day lag before hitting PG&E's service territory. There is also impact on supply from the Southwest. While prices can influence the availability of supply to our system, cold weather can affect producing wells in the basins, which in turn can affect the total supply to the PG&E system and others.

If core supplies are insufficient to meet core demand, PG&E can divert gas from noncore customers, including EG customers, to meet it. PG&E's tariffs contain diversion and Emergency Flow Order non-compliance charges that are designed to cause the noncore market to either reduce or cease its use of gas, if required. Since little, if any, alternate fuel-burn capability exists today, supply diversions from the noncore would necessitate those noncore customers to curtail operations. The implication for the future is that under supply-shortfall conditions—such as an APD—a significant portion of EG customers could be shut down with the impact on electric system reliability left as an uncertainty.

As mentioned above, PG&E projects that noncore demand served by pipeline and storage withdrawals, including gas-fired EG, on an APD would be approximately 1.4-1.6 Bcf/d in the near term. With the Wild Goose, Lodi, Gill Ranch, and Central Valley Gas storage facilities, more noncore demand will be satisfied in the event of an APD. The availability of supply for any given high-demand event, such as an APD, is dependent on a wide range of factors, including the availability of interstate flowing supplies and storage inventories.

TABLE 21 – FORECAST OF CORE GAS DEMAND AND SUPPLY ON AN APD (MMcf/d)

Line No.		2020-21	2021-22	2022-23
1	APD Core Demand (1)	3,031	3,043	3,055
2	Independent Storage Provider Withdrawal (2)	2,190	2,190	2,190
3	Firm Flowing Supply (3)	3,055	3,055	3,055
4	Total Resources to Meet Demands (4)	4,067	4,067	4,067

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 28.3 degrees F system composite temperature, corresponding to 1-in-90 year cold temperature event.1 PG&E uses a system composite temperature based on six weather sites.

(2) The Independent Storage Provider Withdrawal is based on information provided by the Independent Storage Providers to PG&E.

(3) The Firm Flowing Supply includes firm Redwood and Baja capacities and nominal amounts of California gas production. These values are those currently approved for use within PG&E.

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

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.

TABLE 22 – WINTER PEAK DAY DEMAND
(MMcf/d)

Year	Core (1)	Noncore Non-EG (2)	EG, Including SMUD (2)	Total Demand
2020	2,561	550	489	3,600
2021	2,571	565	425	3,561
2022	2,580	552	433	3,565
2023	2,589	556	428	3,573
2024	2,600	554	429	3,583
2025	2,612	553	439	3,604

Notes:
(1) Core demand calculated for 34.2 degrees F system composite temperature, corresponding to 1-in-10 year cold temperature event.
(2) Average daily winter (December) demand under 1-in-10 cold and dry conditions.

TABLE 23 – SUMMER PEAK DAY DEMAND
(MMcf/d)

Year	Core (1)	Noncore Non-EG(1)	EG, Including SMUD (1)	Total Demand
2020	384	672	489	1,545
2021	385	681	424	1,490
2022	372	675	386	1,433
2023	367	675	376	1,418
2024	359	675	372	1,406
2025	352	673	366	1,391

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

2020 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA – TABULAR DATA

TABLE 24 – ANNUAL GAS SUPPLY AND REQUIREMENTS (MMcf/d) – RECORDED SENDOUT

LINE		2015	2016	2017	2018	2019
GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS					
1	Core Purchases	0	0	0	0	0
2	Customer Gas Transport & Exchange	37	33	29	28	24
3	Total California Source Gas	37	33	29	28	24
	OUT-OF-STATE GAS					
	Core Net Purchases					
6	Rocky Mountain Gas	219	194	178	161	170
7	U.S. Southwest Gas	147	124	84	58	58
8	Canadian Gas	345	318	319	303	286
	Customer Gas Transport					
10	Rocky Mountain Gas	689	445	461	367	486
11	U.S. Southwest Gas	360	298	304	430	599
12	Canadian Gas	798	837	832	957	888
13	Total Out-of-State Gas	2,558	2,217	2,178	2,276	2,487
14	STORAGE WITHDRAWAL (2)	238	260	328	397	350
15	Total Gas Supply Taken	2,833	2,510	2,534	2,701	2,861
GAS SENDOUT						
	CORE					
19	Residential	450	461	483	489	503
20	Commercial	209	214	220	225	226
21	NGV	8	8	7	7	7
22	Total Throughput-Core	667	683	710	721	736
	NONCORE					
24	Industrial	534	544	543	562	534
25	Electric Generation (1)(2)	1,025	783	698	855	865
26	NGV	1	1	2	3	4
27	Total Throughput-Noncore	1,560	1,329	1,244	1,421	1,403
28	WHOLESALE	8	8	9	9	9
29	Total Throughput	2,235	2,020	1,963	2,151	2,148
30	OFF-SYSTEM DELIVERIES	251	217	233	264	224
31	CALIFORNIA EXCHANGE GAS	1	1	1	1	1
32	STORAGE INJECTION (3)	291	231	294	244	441
33	SHRINKAGE Company Use / Unaccounted for	56	42	44	41	47
34	Total Gas Send Out	2,833	2,510	2,534	2,701	2,861
	TRANSPORTATION & EXCHANGE					
38	CORE — ALL END USES	142	141	139	139	138
39	NONCORE — INDUSTRIAL	534	544	543	562	534
40	ELECTRIC GENERATION	1025	783	698	855	865
41	SUBTOTAL/RETAIL	1,701	1,469	1,380	1,557	1,538
43	WHOLESALE/INTERNATIONAL	8	8	9	9	9
45	TOTAL TRANSPORTATION AND EXCHANGE	1,709	1,477	1,389	1,566	1,547
	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 (4)	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) Recorded electric generation throughput is the residual of total noncore throughput less non-electric generation throughput.

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

(4) UEG curtailments include voluntary oil burns due to economic, operational, and inventory reduction reasons as well as involuntary curtailments due to supply shortages and capacity constraints.

TABLE 25 – ANNUAL GAS SUPPLY FORECAST
(MMcf/d)
AVERAGE DEMAND YEAR

LINE			2020	2021	2022	2023	2024
FIRM CAPACITY AVAILABLE							
1	California Source Gas		34	34	34	34	34
	Out of State Gas						
2	Baja Path(1)		960	960	960	960	960
3	Redwood Path(2)		2,060	2,060	2,060	2,060	2,060
3.a	SW Gas Corp. from Paiute Pipeline Comp.		41	41	41	41	41
4	Supplemental(3)		0	0	0	0	0
5	Total Supplies Available		3,095	3,095	3,095	3,095	3,095
GAS SUPPLY TAKEN							
6	California Source Gas		34	34	34	34	34
7	Out of State Gas (via existing facilities)		1,958	1,890	1,875	1,848	1,699
8	Supplemental		0	0	0	0	0
9	Total Supply Taken		1,992	1,924	1,909	1,882	1,733
10	Net Underground Storage Withdrawal		0	0	0	0	0
11	Total Throughput		1,992	1,924	1,909	1,882	1,733
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential(4)		509	506	492	484	474
13	Commercial		224	224	223	222	220
14	NGV		8	8	9	9	10
15	Total Core		741	738	724	716	704
	Noncore						
16	Industrial		553	560	559	554	555
17	SMUD Electric Generation(5)		117	117	117	117	117
18	PG&E Electric Generation(6)		267	196	196	196	196
19	NGV		4	5	5	6	6
20	Wholesale		9	9	9	9	9
21	California Exchange Gas		1	1	1	1	1
22	Total Noncore		952	888	888	882	884
23	Off-System Deliveries(7)		260	260	260	246	107
	Shrinkage						
24	Company use and Unaccounted for		40	38	38	38	38
25	TOTAL END USE		1,992	1,924	1,909	1,882	1,733
	TRANSPORTATION & EXCHANGE						
26	CORE	ALL END USES	139	139	137	136	134
27	NONCORE	COMMERCIAL/INDUSTRIAL	553	560	559	554	555
28		ELECTRIC GENERATION	384	313	313	313	313
29		SUBTOTAL/RETAIL	1,076	1,011	1,009	1,003	1,002
30		WHOLESALE/INTERNATIONAL	9	9	9	9	9
31		TOTAL TRANSPORTATION AND EXCHANGE	1,085	1,021	1,018	1,012	1,011
32	System Curtailment		0	0	0	0	0

NOTES:

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

TABLE 26 – ANNUAL GAS SUPPLY FORECAST
(MMcf/d)
AVERAGE DEMAND YEAR

LINE		2025	2026	2027	2030	2035
FIRM CAPACITY AVAILABLE						
1	California Source Gas	34	34	34	34	34
	Out of State Gas					
2	Baja Path[1]	960	960	960	960	960
3	Redwood Path[2]	2,060	2,060	2,060	2,060	2,060
3.a	SW Gas Corp. from Paiute Pipeline Comp.	41	41	41	41	41
4	Supplemental[3]	0	0	0	0	0
5	Total Supplies Available	3,095	3,095	3,095	3,095	3,095
GAS SUPPLY TAKEN						
6	California Source Gas	34	34	34	34	34
7	Out of State Gas (via existing facilities)	1,578	1,559	1,539	1,512	1,457
8	Supplemental	0	0	0	0	0
9	Total Supply Taken	1,612	1,593	1,573	1,546	1,491
10	Net Underground Storage Withdrawal	0	0	0	0	0
11	Total Throughput	1,612	1,593	1,573	1,546	1,491
REQUIREMENTS FORECAST BY END USE						
	Core					
12	Residential[4]	464	453	443	413	341
13	Commercial	219	215	212	202	167
14	NGV	10	11	12	13	16
15	Total Core	693	678	666	628	524
	Noncore					
16	Industrial	553	551	545	554	560
17	SMUD Electric Generation[5]	117	117	117	117	117
18	PG&E Electric Generation[6]	194	194	191	192	233
19	NGV	6	7	7	8	10
20	Wholesale	9	9	9	9	9
21	California Exchange Gas	1	1	1	1	1
22	Total Noncore	881	878	870	880	929
23	Off-System Deliveries[7]					
	Shrinkage					
24	Company use and Unaccounted for	38	37	37	37	38
25	TOTAL END USE	1,612	1,593	1,573	1,546	1,491
	TRANSPORTATION & EXCHANGE					
26	CORE ALL END USES	133	130	128	121	99
27	NONCORE COMMERCIAL/INDUSTRIAL	553	551	545	554	560
28	ELECTRIC GENERATION	311	311	308	309	350
29	SUBTOTAL/RETAIL	997	991	980	983	1,009
30	WHOLESALE/INTERNATIONAL	9	9	9	9	9
31	TOTAL TRANSPORTATION AND EXCHANGE	1,006	1,000	989	992	1,017
32	System Curtailment	0	0	0	0	0

NOTES:

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

TABLE 27 – ANNUAL GAS SUPPLY FORECAST
(MMcf/d)
HIGH DEMAND YEAR (1-IN-10 COLD YEAR)

LINE		2020	2021	2022	2023	2024
	FIRM CAPACITY AVAILABLE					
1	**California Source Gas**	34	34	34	34	34
	Out of State Gas					
2	Baja Path[1]	960	960	960	960	960
3	Redwood Path[2]	2,060	2,060	2,060	2,060	2,060
3.a	SW Gas Corp. from Paiute Pipeline Comp.	41	41	41	41	41
4	**Supplemental**[3]	0	0	0	0	0
5	**Total Supplies Available**	3,095	3,095	3,095	3,095	3,095
	GAS SUPPLY TAKEN					
6	**California Source Gas**	34	34	34	34	34
7	**Out of State Gas (via existing facilities)**	2,045	1,967	1,939	1,908	1,759
8	**Supplemental**	0	0	0	0	0
9	**Total Supply Taken**	2,079	2,001	1,973	1,942	1,793
10	**Net Underground Storage Withdrawal**	0	0	0	0	0
11	**Total Throughput**	2,079	2,001	1,973	1,942	1,793
	REQUIREMENTS FORECAST BY END USE					
	Core					
12	Residential[4]	552	549	535	528	517
13	Commercial	234	234	233	232	231
14	NGV	8	8	9	9	10
15	**Total Core**	793	791	777	769	758
	Noncore					
16	Industrial	554	561	560	556	557
17	SMUD Electric Generation[5]	117	117	117	117	117
18	PG&E Electric Generation[6]	297	216	204	199	199
19	NGV	4	5	5	5	5
20	Wholesale	10	10	10	10	10
21	California Exchange Gas	1	1	1	1	1
22	**Total Noncore**	984	910	897	888	889
23	**Off-System Deliveries**[7]	260	260	260	246	107
	Shrinkage					
24	Company use and Unaccounted for	41	40	40	39	39
25	**TOTAL END USE**	2,079	2,001	1,973	1,942	1,793
	TRANSPORTATION & EXCHANGE					
26	CORE — ALL END USES	147	147	145	144	142
27	NONCORE — COMMERCIAL/INDUSTRIAL	554	561	560	556	557
28	ELECTRIC GENERATION	414	333	321	316	316
29	SUBTOTAL/RETAIL	1,115	1,041	1,026	1,016	1,015
30	WHOLESALE/INTERNATIONAL	10	10	10	10	10
31	TOTAL TRANSPORTATION AND EXCHANGE	1,125	1,051	1,036	1,026	1,025
32	System Curtailment	0	0	0	0	0

NOTES:

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

TABLE 28 – ANNUAL GAS SUPPLY FORECAST (MMcf/d) HIGH DEMAND YEAR (1-IN-10 COLD YEAR)

LINE		2025	2026	2027	2030	2035
	FIRM CAPACITY AVAILABLE					
1	California Source Gas	34	34	34	34	34
	Out of State Gas					
2	Baja Path[1]	960	960	960	960	960
3	Redwood Path[2]	2,060	2,060	2,060	2,060	2,060
3.a	SW Gas Corp. from Paiute Pipeline Comp.	41	41	41	41	41
4	Supplemental[3]	0	0	0	0	0
5	**Total Supplies Available**	3,095	3,095	3,095	3,095	3,095
	GAS SUPPLY TAKEN					
6	California Source Gas	34	34	34	34	34
7	Out of State Gas (via existing facilities)	1,639	1,619	1,598	1,570	1,529
8	Supplemental	0	0	0	0	0
9	**Total Supply Taken**	1,673	1,653	1,632	1,604	1,563
10	Net Underground Storage Withdrawal	0	0	0	0	0
11	**Total Throughput**	1,673	1,653	1,632	1,604	1,563
	REQUIREMENTS FORECAST BY END USE					
	Core					
12	Residential[4]	508	496	486	457	385
13	Commercial	229	225	222	213	177
14	NGV	10	11	12	13	16
15	**Total Core**	747	732	720	683	579
	Noncore					
16	Industrial	555	552	547	555	561
17	SMUD Electric Generation[5]	117	117	117	117	117
18	PG&E Electric Generation[6]	199	197	193	194	249
19	NGV	6	6	6	7	8
20	Wholesale	10	10	10	9	9
21	California Exchange Gas	1	1	1	1	1
22	**Total Noncore**	886	882	873	883	946
23	Off-System Deliveries[7]					
	Shrinkage					
24	Company use and Unaccounted for	39	39	38	38	39
25	**TOTAL END USE**	1,673	1,653	1,632	1,604	1,563
	TRANSPORTATION & EXCHANGE					
26	CORE — ALL END USES	141	138	136	129	107
27	NONCORE — COMMERCIAL/INDUSTRIAL	555	552	547	555	561
28	ELECTRIC GENERATION	316	314	310	311	366
29	SUBTOTAL/RETAIL	1,011	1,004	992	995	1,034
30	WHOLESALE/INTERNATIONAL	10	10	10	9	9
31	TOTAL TRANSPORTATION AND EXCHANGE	1,021	1,013	1,002	1,004	1,044
32	System Curtailment	0	0	0	0	0

NOTES:

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

2020 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

SoCalGas is the principal distributor of natural gas in Southern California, providing retail and wholesale customers with transportation, exchange, 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 EG customers in Southern California. SDG&E, SWG, the City of Long Beach Energy Resources Department, and the City of Vernon are SoCalGas' four wholesale utility customers. SoCalGas also provides gas transportation services across its service territory to a border crossing point at the California-Mexico border at Mexicali to ECOGAS Mexico S. de R.L. de C.V which is a wholesale international customer located in Mexico.

This report covers a 16-year demand and forecast period, from 2020 through 2035; only the consecutive years 2020 through 2027 and the point years 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.

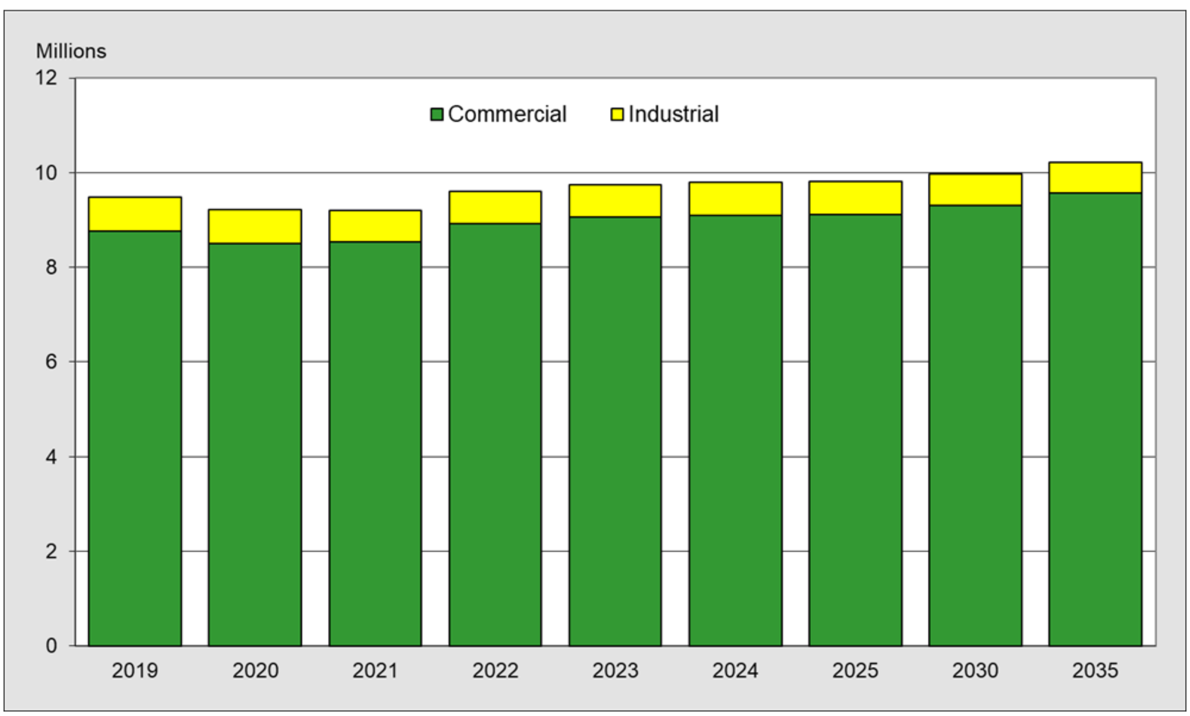
The Southern California section of the 2020 CGR begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The regulatory environment and GHG issues are also 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. After relatively steady growth from 2012-2019, in the first half of 2020 Southern California's economy plunged into recession with global impacts from the COVID-19 virus pandemic. The economy is likely to suffer substantially in 2020 and 2021 before recovering. Overall SoCalGas' area jobs are expected to average slow 0.6 percent annual growth from 2019 through 2025. Local manufacturing and mining industrial employment are projected to drop an average of 0.9 percent per year in the same period, with commercial jobs growing about 0.7 percent annually. Jobs in professional, business, health, and social services sectors should grow the fastest, averaging about 2 percent per year from 2019-2025.

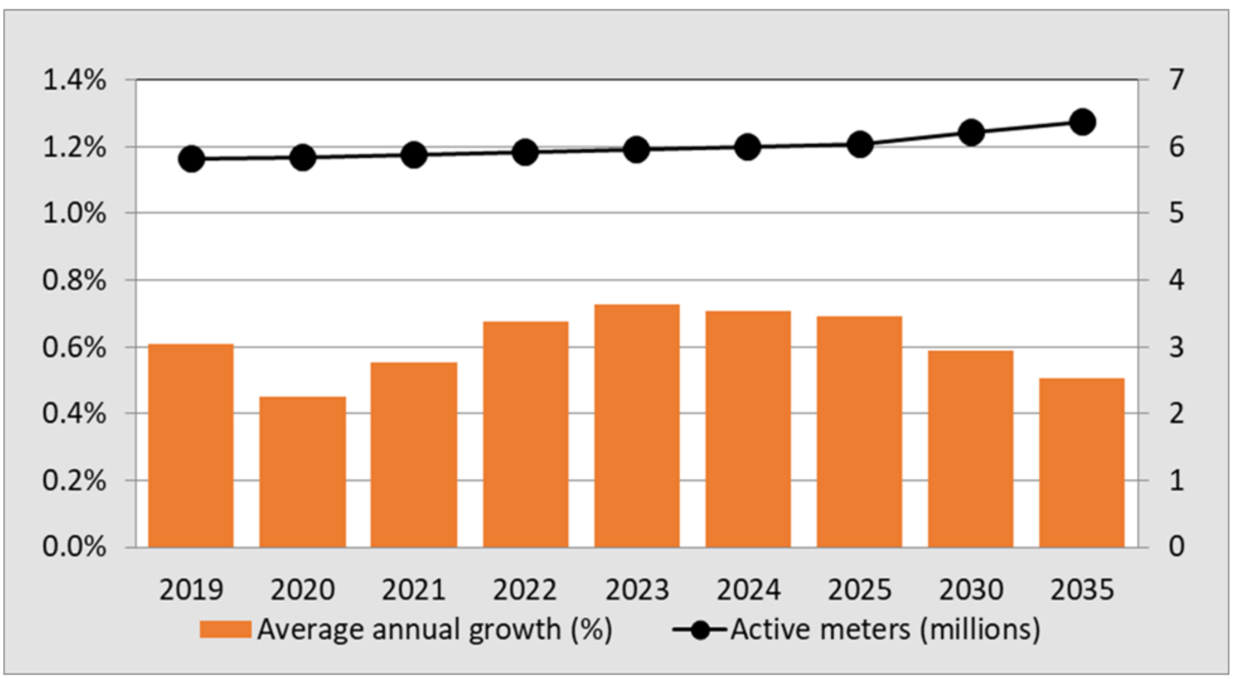
FIGURE 9 – SoCalGas 12-COUNTY AREA EMPLOYMENT



Longer term, SoCalGas' service-area employment is expected to increase slowly as the area population's average age gradually increases—part of a national demographic trend of aging and retiring Baby Boomers. From 2019 through 2035, total area job growth should average 0.5 percent per year. Area industrial jobs are forecasted to shrink an average of 0.7 percent per year through 2035; we expect the industrial share of total employment to fall from 7.7 percent in 2019 to 6.4 percent by 2035. Commercial jobs are expected to grow an average of 0.6 percent annually from 2019 through 2035.

From 2011-2019 SoCalGas' service area housing market gradually strengthened after its prior downturn. Starting in 2020, home building and meter hookups are expected to drop due to disruptions from the COVID-19 pandemic. Net active meter growth is projected to slow from 35,160 (+0.61 percent) in 2019 to 26,200 (+0.45 percent) in 2020 and 32,400 (+0.55 percent) in 2021. Longer term, SoCalGas expects active meters to average moderate 0.58 percent annual growth from 2019 through 2035.

FIGURE 10 – SoCalGas ANNUAL ACTIVE METERS AND GROWTH RATES



GAS DEMAND (REQUIREMENTS)

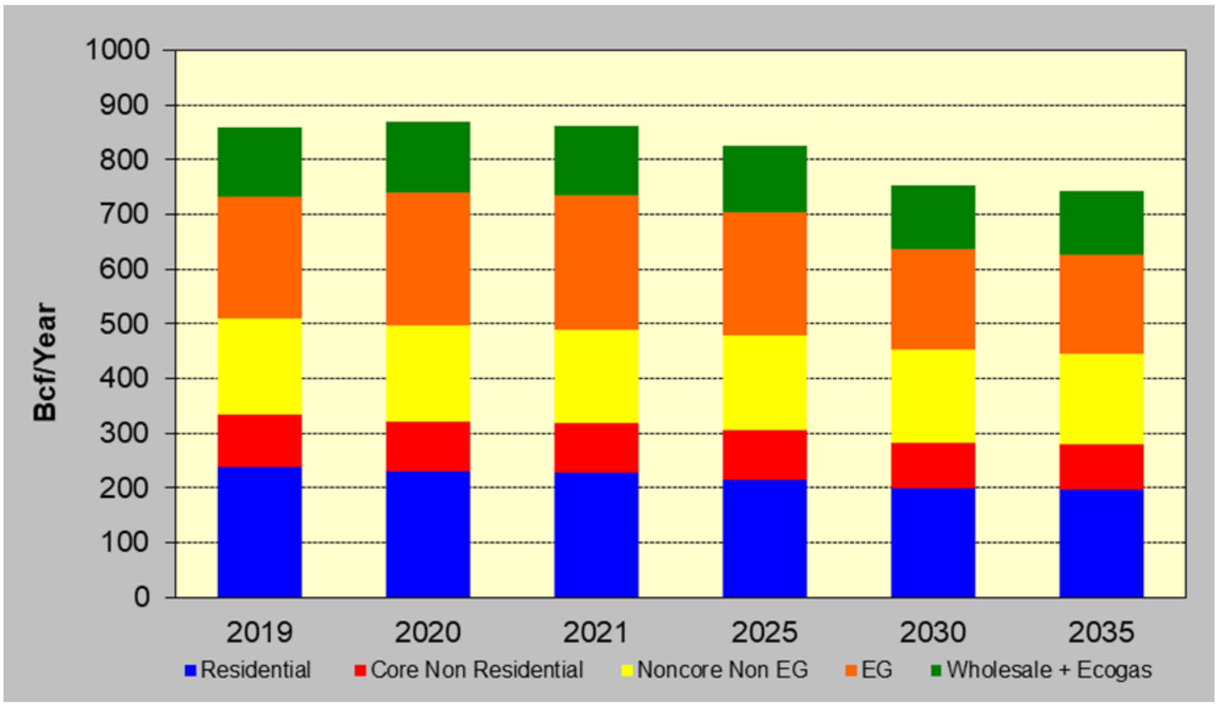
OVERVIEW

SoCalGas projects total gas demand to decline at an annual rate of 1 percent from 2020-2035. The decline in throughput demand is due to modest economic growth, and CPUC-mandated energy efficiency (EE) standards and programs and SB 350 goals. Other factors that contribute to the downward trend are tighter standards created by revised Title 24 Codes and Standards, renewable electricity goals, a decline in core commercial and industrial demand, and conservation savings linked to Advanced Metering Infrastructure (AMI). By comparison, the 2018 CGR projected an annual decline in demand of 0.74 percent over the forecast horizon.

From 2020-2035, residential demand is expected to decline from 230 Bcf to 198 Bcf. The decline is approximately 1 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 (comprising core commercial, core industrial and NGV) are expected to decline at an average annual rate of 1.0 percent or from 112 Bcf in 2020 to 96 Bcf by 2035. However, the NGV market is expected to grow 1.45 percent over the forecast horizon. The NGV market is expected to grow due to government (federal, state and local) incentives and regulations encouraging the purchase and operation of alternate fuel vehicles as well as the increased use of RNG that provides significant GHG emission reduction benefits. The noncore, non-EG markets are expected to decline 0.3 percent from 174 Bcf in 2020 to 165 Bcf by 2035. That decline is being driven by very aggressive energy efficiency goals and associated programs. Total EG load, including large cogeneration and non-cogeneration EG for a normal hydro year, is expected to decline from 245 Bcf in 2020 to 182 Bcf in 2035, a decrease of 2.0 percent per year.

The chart shows the composition of SoCalGas' throughput for the recorded year 2019 (with weather-sensitive market segments adjusted to average year HDD assumptions) and forecasts for the 2020-2035 forecast period.

FIGURE 11 – COMPOSITION OF SOCALGAS REQUIREMENTS AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR (2019-2035)



Notes:

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

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

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

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

ASSUMPTIONS REGARDING BUILDING DECARBONIZATION POLICY

Signed into law in September 2018, California AB 3232 calls on the CEC (working in consultation with the CPUC and other state agencies) to develop and articulate plans and projections, by year 2021, to reduce GHG emissions of California's residential and commercial buildings to 40 percent below 1990 levels by 2030. Much of the reduction will likely occur by replacing some buildings' gas end-use applications with electric ones. The CEC plans to develop and publish quantified projections of these electric-for gas substitutions in its 2021 IEPR. Since no state projections of AB 3232-driven fuel substitutions are yet available, the 2020

CGR and the ensuing gas demand forecasts do not include impacts from these policy changes. It is anticipated that state-projected impacts will be included in the 2022 CGR, assuming state projections are available by that time.

MARKET SENSITIVITY

TEMPERATURE

Core demand forecasts are prepared for two design temperature conditions—average year and cold year—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. 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 degrees F. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis.

In our 2020 CGR, SoCalGas and SDG&E have introduced a climate-change warming trend that gradually reduces HDD's over the forecast period. First, average temperature year values were computed as the simple average of annual HDD's for the calendar years 2000 through 2019: 1,273 HDD's for SoCalGas and 1,186 HDD's for SDG&E. Corresponding cold year HDD's were 1,518 for SoCalGas and 1,399 for SDG&E. For the forecast period, projected annual HDD's were reduced each year by 4 HDD's for SoCalGas and by 2 HDD's for SDG&E. For SoCalGas, projected average year and cold year HDD's both drop by 4 HDD annually: from 1,269 and 1,514 in year 2020, to 1,209 and 1,454 in year 2035. For SDG&E, projected average year and cold year HDD's drop by 2 HHD annually: from 1,184 and 1,397 in year 2020, to 1,154 and 1,367 in year 2035. The annual reductions are based on the latest 20-year trend in 20-year-averaged HDDs. That is, they are based on the observed trend in changes starting with average HDD's for years 1981-2000, then 1982-2001, 1983-2002...and ending with the average HDD's for years 2000-2019.

HYDRO CONDITIONS

The EG forecasts are prepared for two hydro conditions—average year and dry hydro. The Cold/Dry Hydro forecast refers to gas demand in a 1-in-10 dry hydro year.

MARKET SECTORS

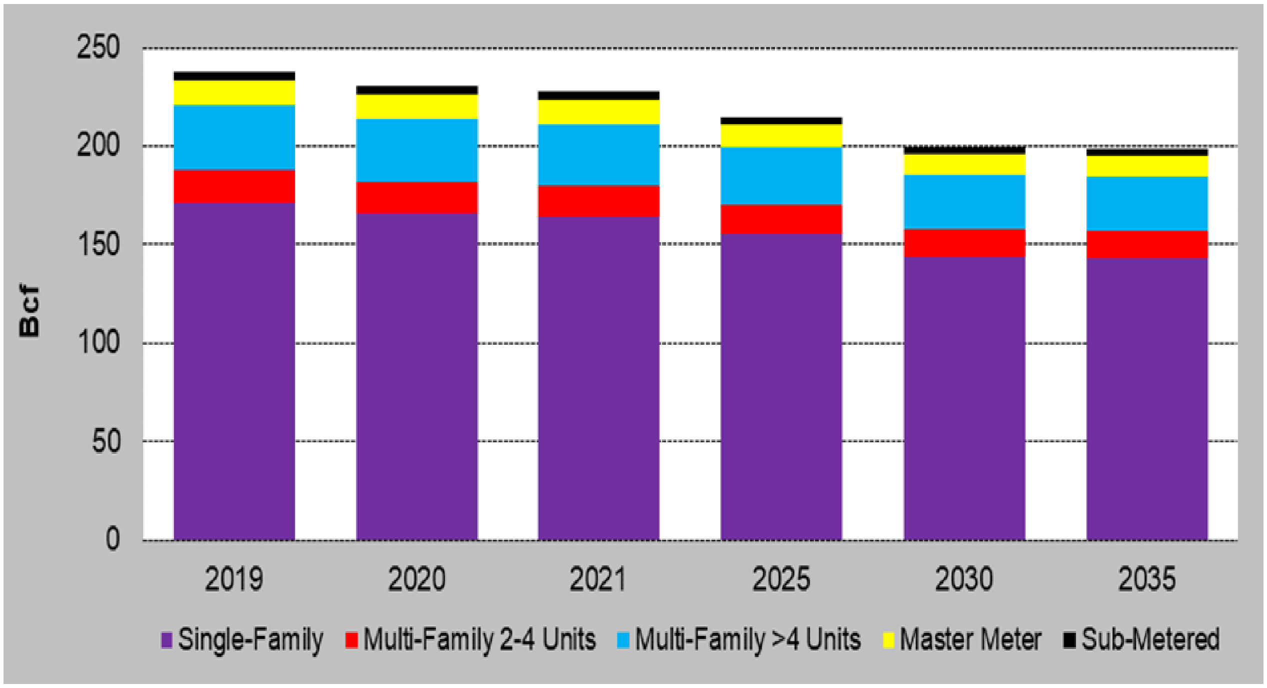
RESIDENTIAL

Residential demand adjusted for temperature totaled 237.5 Bcf in 2019. The residential load is expected to decline on average by 1.1 percent per year from 237.5 Bcf in 2019 to 198.3 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' 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 demand reductions in the residential sector by a total of 18.8 Bcf in year 2035.

The total residential customer count for SoCalGas consists of five residential segment types: (1) single family, (2) small multi-family, (3) large multi-family, (4) master meter, and (5) sub-metered customers. The active meters for all residential customer classes were 5.61 million at the end of 2019. This amount reflects a 68,331 increase in active meters between 2017 at year end and 2019 at year end. The 2020 CGR shows that in 2019, single family and overall multi-family temperature adjusted average annual use per meter was 468 therms and 292 therms, respectively. Over the forecast period, the demand is expected to decline to 442 therms/customer and 238 therms/customer, respectively. 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.

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.

FIGURE 12 – COMPOSITION OF SoCalGas' RESIDENTIAL DEMAND FORECAST (2019-2035)



COMMERCIAL

The core commercial market demand is expected to decline over the forecast period. On a temperature-adjusted basis, the 2019 core commercial market demand totaled 82.8 Bcf. By the year 2035, the load is anticipated to drop to approximately 62.5 Bcf. The average annual rate of decline from 2019-2035 is forecasted at 1.7 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.

In 2019, the noncore commercial temperature-adjusted usage was 18.3 Bcf. From 2019 through 2035, demand in this market is expected to rise slightly at approximate annual rate of 0.08 percent. By 2035, the noncore commercial load is expected to reach 18.6 Bcf.

FIGURE 13 – ANNUAL COMMERCIAL DEMAND FORECAST 2019-2035
BILLION CUBIC FEET PER YEAR (Bcf/y), AVERAGE YEAR WEATHER DESIGN

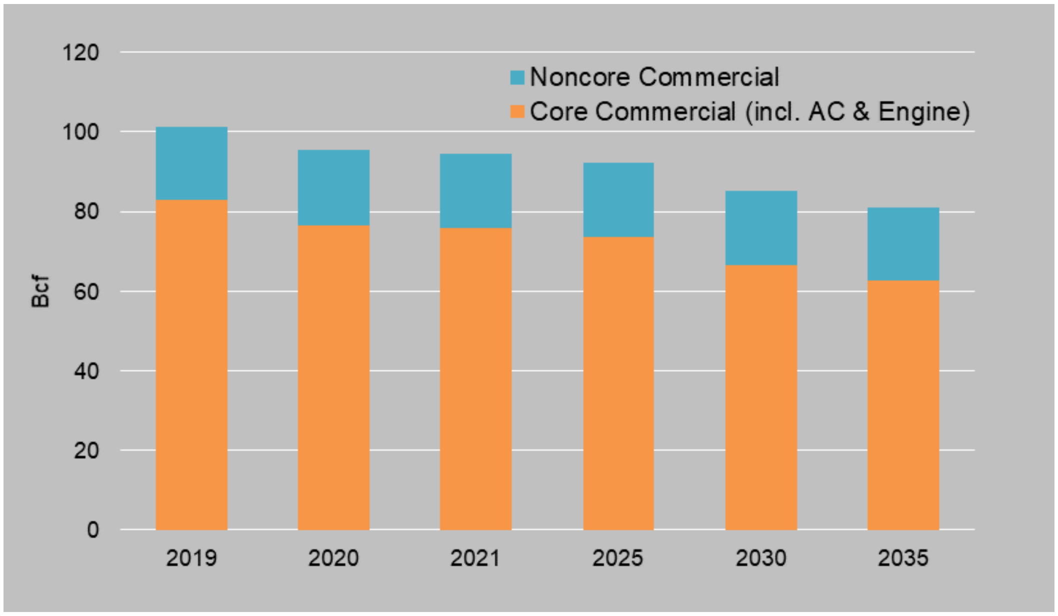
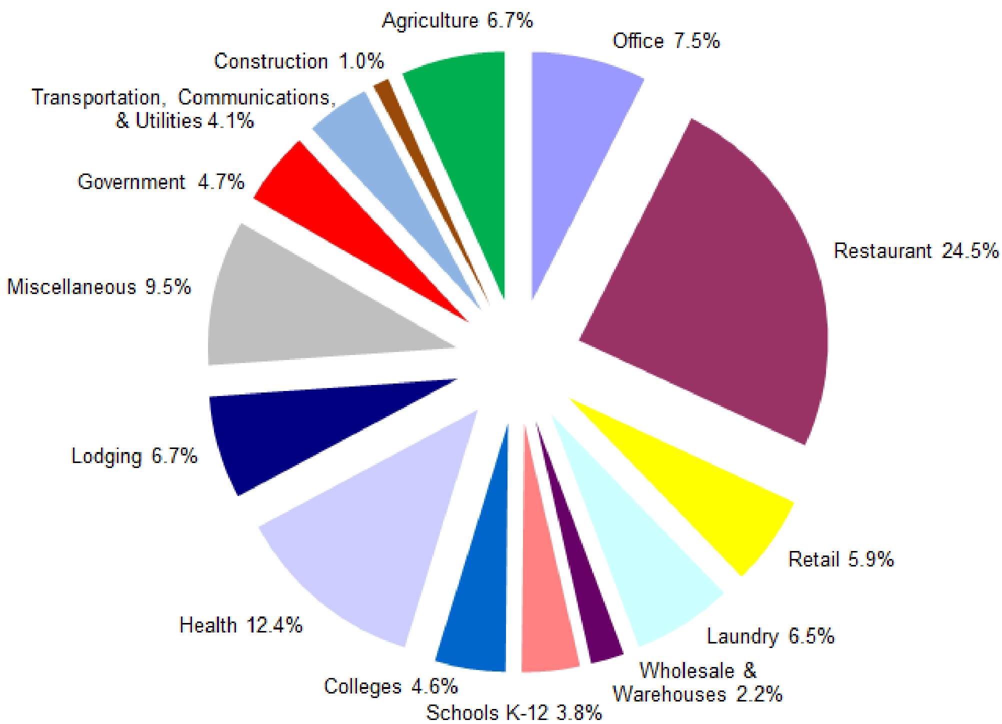


FIGURE 14 – COMMERCIAL GAS DEMAND BY BUSINESS TYPE
COMPOSITION OF INDUSTRY
(2019)



The commercial market consists of 14 business types identified by the customers' North American Industry Classification System codes. It represents includes both core and noncore usage. The restaurant business dominates this market with 24.5 percent of commercial usage in 2019, followed by the health services industry with a 12.4 percent share.

INDUSTRIAL

Non-Refinery Industrial Demand

In 2019, temperature-adjusted core industrial demand was 21.0 Bcf. Core industrial market demand is projected to drop by 2.3 percent per year from 21.0 Bcf in 2019 to 14.4 Bcf in 2035. This decrease results from a combination of factors: an annual 0.7 percent decrease in employment growth, a minor increase in marginal gas rates and CPUC-authorized energy efficiency programs.

The 2019 non-refinery industrial gas demand served by SoCalGas is shown below. Food and beverage manufacturing, with 36 percent of the total share, dominates this market. The graph below summarizes the composition of the core and noncore market by business type.

**FIGURE 15 – ANNUAL INDUSTRIAL DEMAND FORECAST (Bcf)
(2019-2035)**

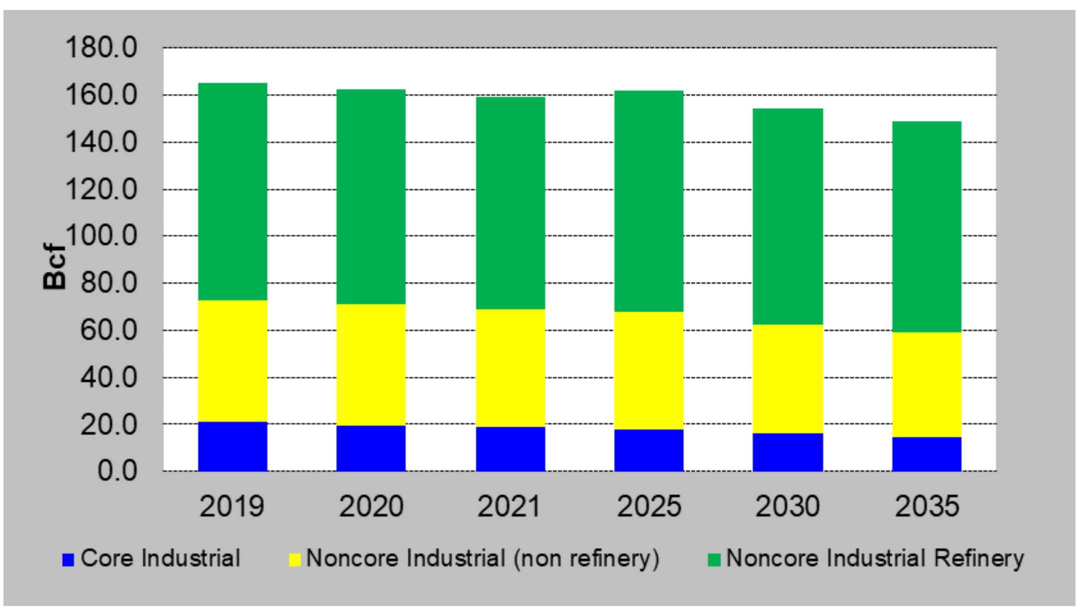
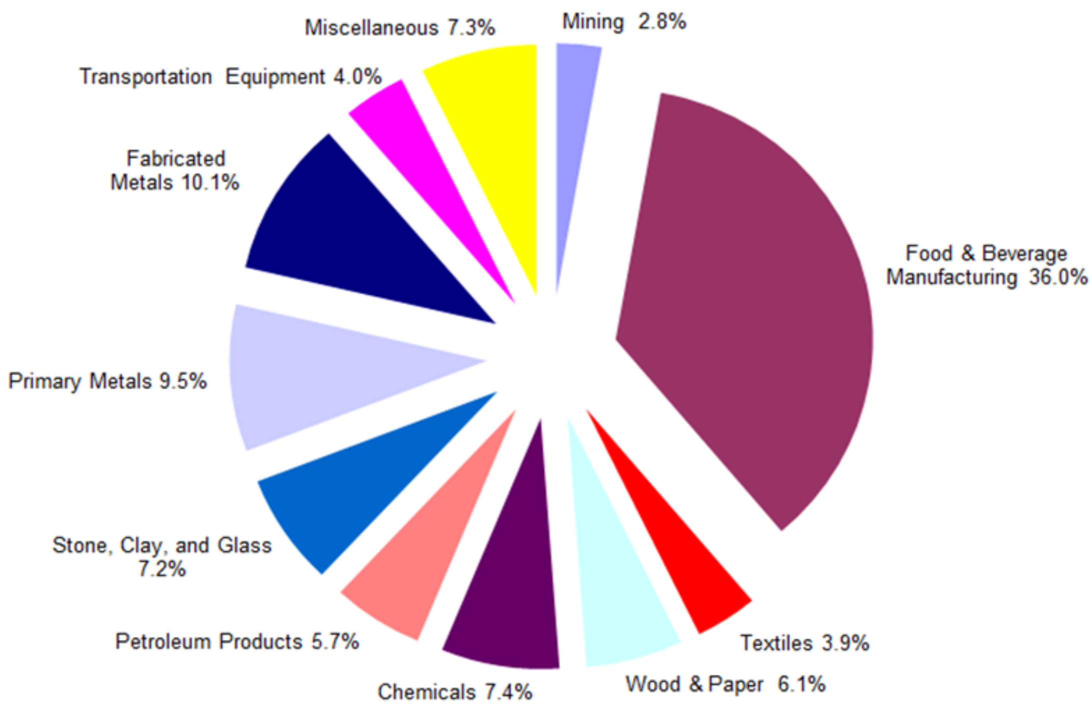


FIGURE 16 – INDUSTRIAL GAS DEMAND BY BUSINESS TYPE
COMPOSITION OF INDUSTRY
(2019)



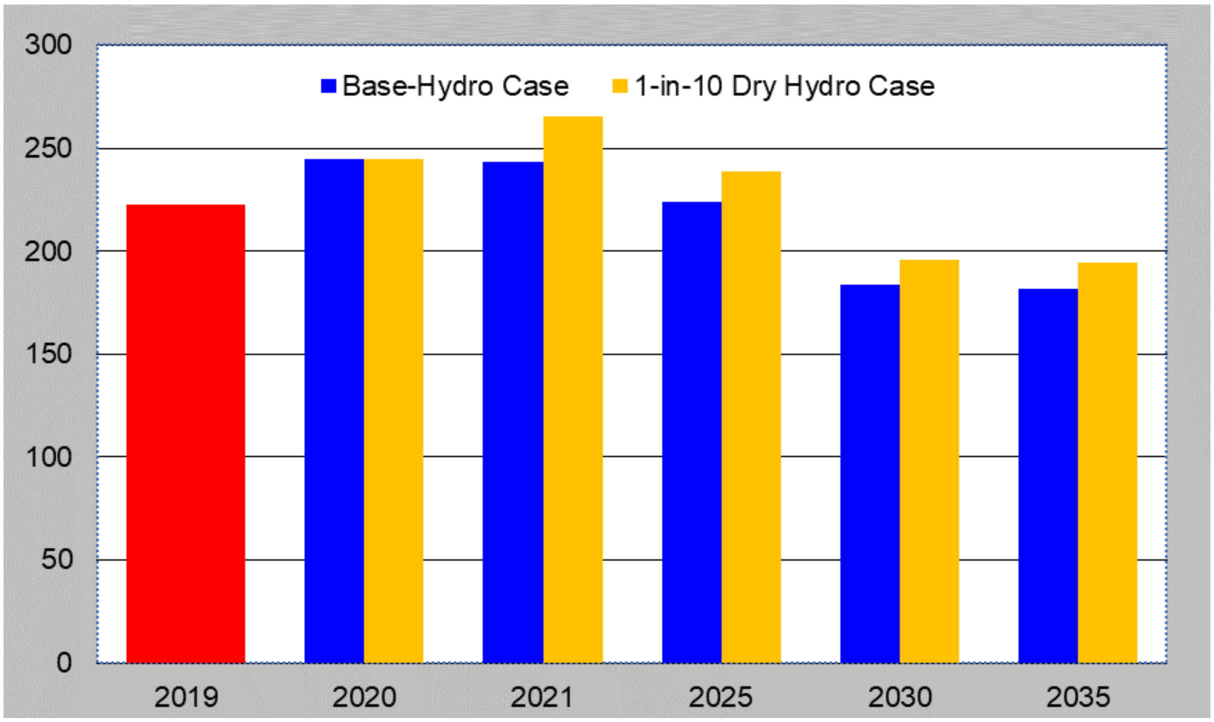
Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at an annual rate of 0.9 percent from 51 Bcf in 2019 to 45 Bcf by 2035. The reduced demand is primarily due to the CPUC-authorized energy efficiency programs, the departure of customers within the City of Vernon to wholesale service by the City of Vernon, and higher gas costs stemming from California's GHG carbon fees.

Refinery-Industrial Demand

Refinery-industrial demand is comprised of gas consumption by petroleum refining customers, H2 producers and refined petroleum product transporters. Gas demand in the refinery industrial market sector is forecasted to decline about 0.2 percent per year over the 2019-2035 forecast period, from 93 Bcf in 2019 to 90 Bcf in 2035. The decrease in the forecast period is primarily due to the estimated savings from CPUC-authorized energy efficiency programs.

ELECTRIC GENERATION

FIGURE 17 – SoCalGas SERVICE AREA TOTAL EG
(Bcf)



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, regional fuel price differences, the construction and retirement of power generating facilities (including thermal, renewable, and energy storage resources), the amount of California's import/export energy, and the state's overall long-term electricity demand growth. The EG gas throughput forecast can be higher or lower than the Average Demand forecast, depending on the factors mentioned above. Forecasted electricity demand is a major factor. If the electricity demand forecast is higher, the EG gas throughput forecast would also tend to be higher. Please refer to the California Energy Commission's (CEC) 2019 Integrated Energy Policy Report for high, mid, and low electricity demand scenarios. On the supply side, lower SoCalGas Citygate gas prices relative to other regions, less energy imported into California, and dry hydro conditions are also factors that would increase the EG gas throughput forecast.

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. There are several plants that are schedule to shut down by December 31, 2020. However, as of March 18, 2020, SWRCB has amended the OTC Policy to extend the compliance date for some of the power plants for an additional 1-3 years. These plants include Alamitos, Huntington Beach, Ormond Beach, and Redondo Beach generating stations.

The forecast uses a power market simulation for the period of 2020-2030. 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 Average Demand assumes that the state will reach its 60 percent RPS by 2030, as mandated in SB 100. The Average Demand also assumes the IOUs will meet D.13-10-040, or the energy storage procurement framework and design program. Furthermore, the Average Demand also includes additional energy storage as outlined in CPUC's "Revised 2019 Unified Resource Adequacy and Integrated Resource Plan Inputs and Assumptions – Guidance for Production Cost Modeling and Network Reliability Studies." 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 2019-2030 Managed Forecast, dated February 2020. SoCalGas selected the Mid Energy Demand scenario with the Mid AAEE. In their CEC forecast, the state-wide energy demand is lower than prior forecasts used in the 2018 CGR from years 2020-2028, and slightly higher for years 2029 and 2030. However, for Southern California, the energy demand is slightly higher for the years 2020-2030 than prior CEC electric demand forecasts.

Industrial/Commercial/Cogeneration <20 MW

The commercial/industrial cogeneration market segment is generally comprised of customers with generating capacity of less than 20 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 EG 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 2019, gas demand in the small cogeneration market was 28 Bcf. By 2035, cogeneration demand is projected to decline modestly to 27 Bcf (an average of 0.3 percent/year). The reduced demand is primarily due to higher gas costs due to California's GHG carbon fees.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. This market is forecasted to decline modestly at about 0.1 percent per year, decreasing from 23 Bcf in 2019 to 22 Bcf in 2035. The decline is mainly due to higher gas costs stemming from California's GHG carbon fees.

Enhanced Oil Recovery-Related Cogeneration

In 2019, recorded gas deliveries to the EOR-related cogeneration were 6.2 Bcf. EOR demand is forecasted to remain at 6.2 Bcf throughout the forecast period. Crude oil futures prices appear to be flat for the immediate future which is expected to result in California EOR operations staying steady going forward.

Electric Generation, Including Large Cogen

EG customers are comprised of utility electric generation (UEG) customers, various Exempt Wholesale Generator (EWG) customers and large cogeneration customers where usage exceeds 20 MW. For the Average Demand (average hydro condition), gas demand is forecasted to decrease from 188 Bcf in 2020 to 127 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 100 raised the RPS target level from 50 percent to 60 percent by 2030. SoCalGas' forecast includes the addition of approximately 1,382 MW of new, local, gas-fired combined cycle and peaking generating resources in its service area by summer 2020. However, the forecast also assumes 5,370 MW of local, gas-fired plants will be retired during the same time period as a result of the state's OTC 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 17 Bcf per year, on average.

For this forecast, SoCalGas followed CPUC's guideline for energy storage resources. In the model, a state-wide installed capacity of 754 MW was added starting in 2020. Storage capacity increases to 3,638 MW by 2030.

WHOLESALE AND INTERNATIONAL

SoCalGas provides wholesale transportation service to SDG&E, the City of Long Beach Energy Resources Department (Long Beach), 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 decrease from 39 Bcf in 2019 to 38.58 Bcf in 2035. The change reflects a 0.07 percent average annual decrease.

SDG&E

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 0.6 percent per year from 86.3 Bcf in 2019 to 78 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 Energy Resources Department. Long Beach's gas use is expected to decline slightly, from 9 Bcf in 2019 to 8 Bcf by 2035. Refer to the City of Long Beach Energy Resources Department for more information.

Southwest Gas Corporation

SoCalGas used the forecast prepared by Southwest Gas for this report. In 2019, SoCalGas delivered 10.3 Bcf to Southwest Gas and the total load is expected to remain flat at this level throughout the forecast horizon. Refer to SWG 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 8.5 Bcf in 2019 and increases to 9.24 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 remain steady at a level of 11.13 Bcf/y over the forecast horizon 2020-2035. Refer to Ecogas or IENova, Ecogas' parent company, for more information.

Enhanced Oil Recovery-Steam

In 2019, recorded gas deliveries to the EOR market were 11.76 Bcf. EOR demand is forecasted to remain at 11.76 Bcf throughout the forecast period. Crude oil futures prices appear to be flat for the immediate future which is expected to result in California EOR operations staying steady going forward.

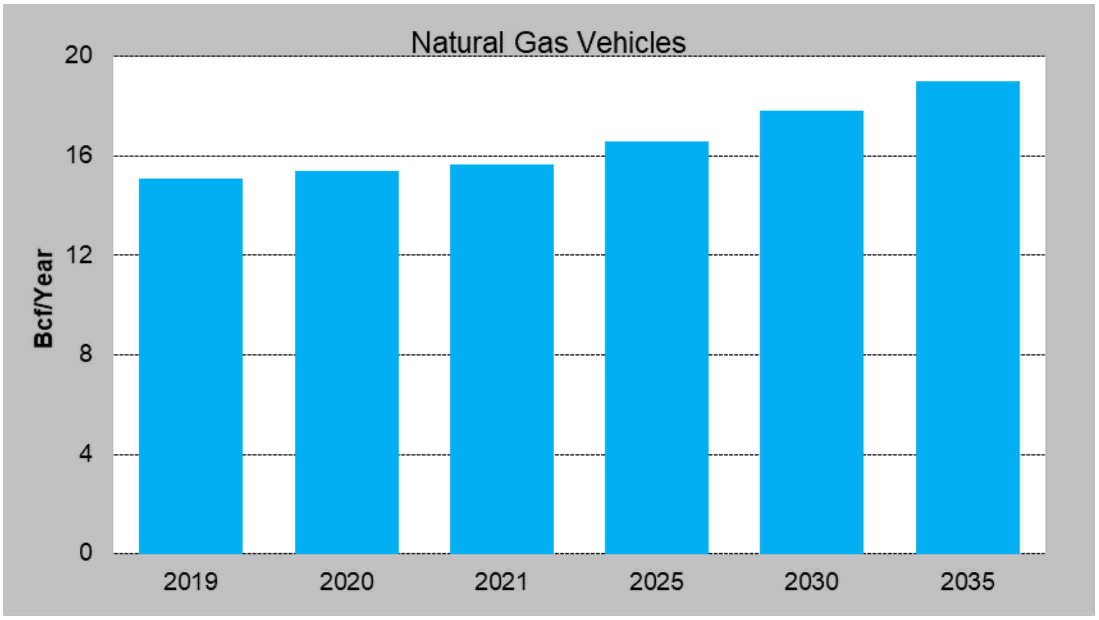
The EOR-related cogeneration demand is discussed in the EG section.

NATURAL GAS VEHICLES

The NGV market is expected to grow due to government (federal, state and local) incentives and regulations encouraging the purchase and operation of alternate fuel vehicles, as well as the increased use of RNG that provides significant GHG emission reduction benefits.

However, growth may be offset by competing technologies and fuels as well as the potentially lower cost differential between petroleum (gasoline and diesel) and natural gas. At the end of 2019, there were 335 CNG fueling stations delivering 15.1 Bcf of natural gas during the year. The NGV market is expected to grow 1.44 percent per year, on average. At the end of 2035, it is expected there will be 418 CNG fueling stations delivering 19 Bcf of natural gas during the year.

**FIGURE 18 – NGV DEMAND FORECAST
(2019-2035)**



ENERGY EFFICIENCY PROGRAMS

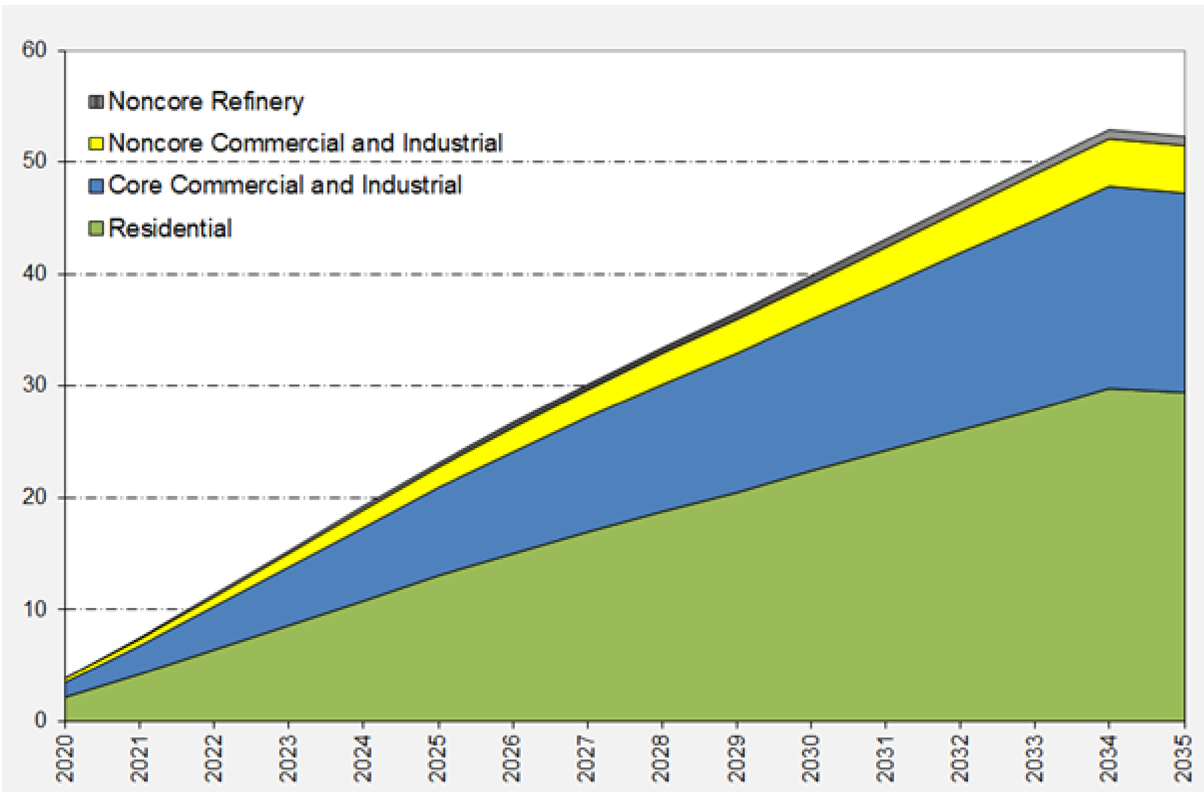
SoCalGas engages in a number of energy efficiency and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. Programs administered by SoCalGas include services that help customers evaluate their energy 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 EE portfolio combines the EE customer programs goals and the Title 24 Codes and Standards. SoCalGas' EE forecast is based on inputs from the 2020 energy efficiency annual budget advice letter (AL 5510-A), utilizing program level energy savings values forecasted for the 2020 program year. Forecasted savings for the 2021-2030 period are based on the 2020 EE forecast scaled to the goals approved in the recent EE proceeding goals decision, D.19-08-034, which set EE goals through 2030. Forecasted savings beyond 2030 are held constant based on 2030 forecasted values. Cumulative savings reflect the lifecycle EE program achievements from forecasted program savings starting in 2020 and do not include lifecycle savings from prior program years. SoCalGas currently uses a 15-year lifecycle for cumulative savings calculations.

COMBINED EE PORTFOLIO OF EE PROGRAMS AND CODES AND STANDARDS

FIGURE 19 – SoCalGas ANNUAL ENERGY EFFICIENCY CUMULATIVE SAVINGS GOALS (BCF)



Savings reported are for measures installed under SoCalGas' energy efficiency programs. Credit is only taken for measures that are installed as a result of SoCalGas' energy efficiency programs, and only for the 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.

GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

SoCalGas and SDG&E receive gas supplies from several sedimentary basins in the Western U.S. 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 2015 through 2019 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 97 MMcf/d in 2019.

SOUTH-WESTERN U.S. GAS

Traditional South-Western 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 pipeline with some volumes also on Transwestern pipeline. The San Juan Basin's gas supplies peaked in 1999 and have been declining at an annual rate of roughly 2 percent. The Permian Basin has experienced a major increase in gas production as a byproduct of the tremendous amount of oil development in the area. The increase positioned the Permian Basin as a preferred gas supply source of economical gas. Permian gas production increased over 100 percent during the period 2017-2019. In early 2020 Permian Basin oil and gas production began to decline due to sharply lower oil prices.

Mexican demand for South-Western U.S. gas along with East of California demand continue to steadily increase and compete for South-Western supplies. This increased demand, which has been more than offset by the recent increase in Permian gas production, will continue to compete with Southern California for South-West supplies.

ROCKY MOUNTAIN GAS

Rocky Mountain supply supplements traditional South-Western 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. Kern River Gas Transmissions volumes to Southern California have surpassed Transwestern pipeline's deliveries of South-Western supplies.

CANADIAN GAS

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

RENEWABLE NATURAL GAS

Since methane can come 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. Methane can also be produced by the combustion-free thermal conversion of agricultural crop residues, silvicultural residue, wood waste, and municipal sewage sludge or biosolids. 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 the University of California, Davis estimates that more than 20 percent of SoCalGas's current residential natural gas use can be provided by biogas derived from our state's existing organic waste alone.[65] 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,

65 *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*, prepared for the CARB and the California EPA by Amy Jaffe, Principal Investigator, STEPS Program, Institute of Transportation Studies, UC Davis.

the U.S. could produce up to 10 trillion cubic feet of biogas annually by 2030—that is more than five times California's projected natural gas consumption.[66]

A more recent study by ICF estimated a nation-wide potential range for RNG in 2040 of between 813-1,425 Bcf per year for RNG from Anaerobic Digestion, between 487-1,713 Bcf per year from Thermal Gasification and 265-695 BCF per year from Municipal Solid Waste.[67] The study also estimated a potential range for RNG in 2040 for the Pacific region[68] of 126-213 Bcf per year for RNG from Anaerobic Digestion, 22-51 Bcf per year from Thermal Gasification and 45-108 BCF per year from Municipal Solid Waste, for a total 'Pacific' region estimate of between 193-372 Bcf per year which would represent approximately 66 percent to 126 percent of SoCalGas' 2035 projected core natural gas consumption.

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, international and intrastate pipelines serving Southern and Central California include the El Paso, Mojave, Transwestern, Kern River, TGN, North Baja, and PG&E pipelines. These pipelines provide Southern and Central California with access to gas-producing regions in the U.S. Southwest and Rocky Mountain areas, Western Canada, California Production and Mexico LNG. Indicated firm capacities for each zone are specified in the SoCalGas G-BTS Rate Schedule.

SoCalGas' Southern Zone is connected to U.S. Southwest and Mexico pipeline systems at Ehrenberg, Blythe and Otay Mesa (El Paso, North Baja, and TGN). The Southern Zone has a firm capacity of 1210 MMcf/d.

SoCalGas' Northern Zone is connected to U.S. South-West and Rocky Mountain pipeline systems (Transwestern, El Paso, Kern River and Mojave) at Needles, west of Topock AZ, and

66 U.S. DOE: *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.

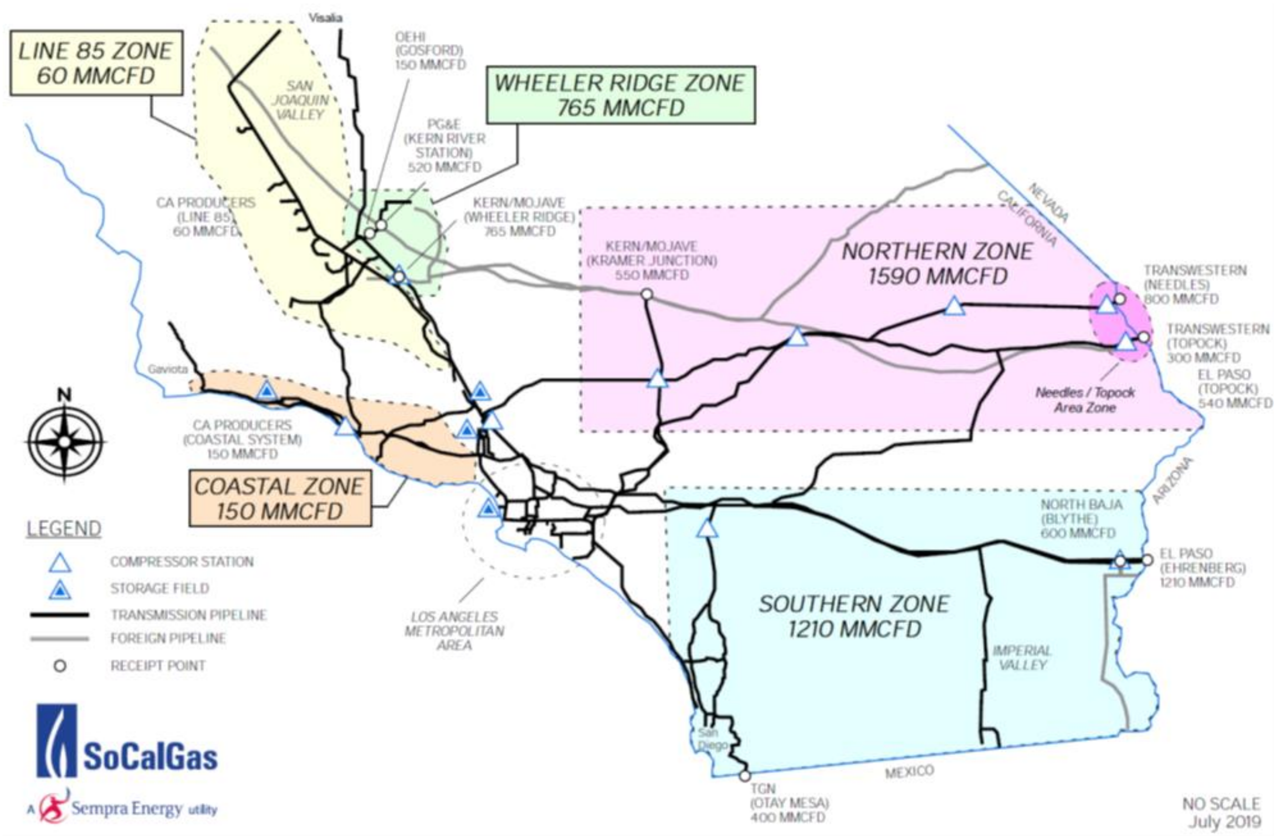
67 *Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment*, ICF, p. 13.

68 Pacific Region is defined as production in the states of Alaska, California, Oregon, Hawaii, and Washington.

Kramer Junction. The Northern Zone has a nominal firm capacity of 1590 MMcf/d, but is projected to be less than this through the CGR plan period, due to extended maintenance activity.

SoCalGas' Wheeler Zone is connected to Kern River/Mojave, OEHI Gosford, and PG&E that access supplies from the U.S. Southwest, Rocky Mountain, and Western Canada production areas and California production from Elk Hills. Wheeler Zone's firm capacity is 765 MMcf/d.

FIGURE 20 – RECEIPT POINT AND TRANSMISSION ZONE FIRM CAPACITIES



STORAGE

Underground storage of natural gas plays a vital role in balancing the region's energy supply and demand, and for system-wide reliability.[69] Natural gas storage is also used to meet peak

69 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.

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.[70] 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 more than 130 Bcf.[71] However, the combined working inventory for SoCalGas is reduced due to current working inventory regulatory restrictions imposed at Aliso Canyon.

Aliso Canyon historically has had a stated natural gas storage working inventory of 86.2 Bcf.[72] Since 2015,[73] the CPUC and CalGEM[74] have maintained restrictions on SoCalGas' use of Aliso Canyon. In July 2018, the CPUC approved a maximum working inventory of 34 Bcf for Aliso Canyon to support system reliability.[75] The CPUC and CalGEM may, in the future, authorize a different maximum inventory.

Since November 2017, the CPUC also developed a Withdrawal Protocol for Aliso Canyon, describing the process to be followed before making a withdrawal from the storage facility. In July 2019, in order to improve short-term reliability and price

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70 *Id.*, Conclusion 2.5 at 506.

71 SoCalGas 2019 General Rate Case (GRC) Filing, Exhibit SCG-10-R, p. NPN-3 and NPN-4.

72 As of July 19, 2017, CalGEM has authorized Aliso Canyon to operate with a working inventory of equivalently 68.6 Bcf.

73 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.

74 Formerly, DOGGR.

75 https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/715Report_Summer2018_Final.pdf.

stability in the Southern California region, the CPUC deemed that Aliso Canyon be used for withdrawals if certain conditions are met.[76]

In recognition of the safety enhancements SoCalGas has completed at Aliso Canyon and the importance of Aliso Canyon to southern California reliability,[77] SoCalGas continues to request that regulators lift withdrawal restrictions at Aliso Canyon.

STORAGE REGULATIONS

Since 2015, the CPUC, CalGEM, and Pipeline and Hazardous Materials Safety Administration (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.

Most recently, PHMSA issued their Final Rule for Underground Storage regulations, CFR Part 192.12, amending its minimum safety standards for underground natural gas storage facilities, effective March 13, 2020. The PHMSA Final Rule adopts API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, as published, modifies compliance timelines, formalizes integrity management practices, and clarifies the state's regulatory role.

CalGEM established 14 California Code of Regulations §1726 California Underground Gas Storage regulations effective October 1, 2018, which includes, among other things, mechanical testing mandates that require each well to be taken out-of-service as frequently as every

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76 https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/WithdrawalProtocol-Revised-April12020clean.pdf.

77 SoCalGas 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 CalGEM 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.

24 months, unless an alternative frequency is approved by CalGEM,[78] and semi-annual field shut-in tests for inventory verification.

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78 SoCalGas has submitted its Risk Management Plan to CalGEM, which proposes an alternative inspection frequency that would, among other things, reduce impacts to deliverability associated with a 24-month well re-assessment schedule.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

GENERAL RATE CASE

On September 26, 2019, CPUC unanimously approved a final 2019 GRC decision that adopts a TY 2019 revenue requirement of $2.770 billion for SoCalGas which is $166 million lower than the $2.937 billion that SoCalGas had requested in its Update testimony. The adopted revenue requirement represents an increase of $314 million or a 12.8 percent increase over 2018. The final decision adopts PTY revenue requirement adjustments for SoCalGas of $220 million for 2020 (7.9 percent increase) and $150 million for 2021 (5.0 percent increase).

In January 2020 the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SoCalGas was directed to file a Petition for Modification (PFM) to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional 5-year GRC period (2019-2023).

In April 2020 (then slightly revised in May), SoCalGas filed a PFM of its 2019 GRC decision requesting attrition year increases of $155 million (+4.95 percent) for 2022 and $137 million (+4.15 percent) for 2023. SoCalGas requested that a final decision be issued no later than October 1, 2020.

GAS RELIABILITY AND PLANNING OIR

The CPUC initiated a new rulemaking (R.20-01-007) to update gas reliability standards, determine the regulatory changes necessary to improve coordination between gas utilities and gas-fired electric generators, and implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals.

The rulemaking will be managed in two phases and Phase 1 will include two tracks. Track 1A will address reliability standards and focus on SoCalGas' and PG&E's system capabilities, the adequacy of existing gas reliability standards, whether slack capacity should be encouraged, whether transportation of gas to the planned Energía Costa Azul LNG export facility will impact reliability and prices, whether updated reliability standards will result in additional costs, and what cost recovery and allocation mechanisms should be used. Track 1B will address market structure and regulations, with a focus on interstate pipeline capacity, impacts on EG, and system operating procedures. A decision in Phase 1 is expected by May 2021. Phase 2 will address long-term planning and a schedule will be established after the completion of Phase 1. Preliminarily, Phase 2 is expected to address the appropriate gas infrastructure portfolio for gas utilities operating in California, the need to reconsider gas rate design and cost allocation methods, management of the natural gas transition indicated by the long-range portfolio modeling in the CPUC's IRP Program, and utility workforce consideration.

BUILDING DECARBONIZATION POLICY

In September 2018, former Governor Brown signed two bills into law related to reducing GHG emissions from buildings, SB 1477 and AB 3232. SB 1477 calls on the CPUC to develop, in consultation with the CEC, two programs (BUILD and TECH) aimed at reducing GHG emissions associated with buildings. AB 3232 calls on the Energy Commission by 2021 to develop plans and projections to reduce GHG emissions of California's residential and commercial buildings to 40 percent below 1990 levels by 2030, working in consultation with the CPUC and other state agencies.

In January 2019, the CPUC issued an OIR on building decarbonization (R.19-01-011). The proposed scope of the rulemaking includes: (1) implementing SB 1477; (2) potential pilot programs to address new construction in areas damaged by wildfires; (3) coordinating CPUC policies with Title 24 Building Energy Efficiency Standards and Title 20 Appliance Efficiency Standards developed at the CEC; and (4) establishing a building decarbonization policy framework. A final decision D.20-03-027 was issued on April 6, 2020, which establishes a framework for CPUC oversight of two building decarbonization pilot programs—the Building Initiative for Low-Emissions Development (BUILD Program) program and the Technology and Equipment for Clean Heating (TECH Initiative) initiative. These two pilot programs are designed to develop valuable market experience for the purpose of decarbonizing California's residential buildings in order to achieve California's zero-emissions goals. SB 1477 makes available $50 million annually for 4 years, for a total of $200 million, derived from the revenue generated from GHG emission allowances directly allocated to gas corporations and consigned to auction as part of the Air Resources Board's (ARB) Cap-and-Trade Program. Incentive eligibility for the BUILD Program shall be limited strictly to newly constructed all-electric building projects, without any hookup to the gas distribution grid.

AFFORDABILITY OIR

On July 12, 2018 the Commission instituted the OIR (R.18-07-006) to develop a common understanding, methods and processes to assess, the impacts on affordability of individual Commission proceedings and utility rate requests. This OIR includes gas, electric, water and communications utilities. On July16, 2020 the Commission issued its decision (D.20-07-032), which defines affordability as the degree to which a representative household is able to pay for an essential utility service, given its socioeconomic status. This decision also adopts three metrics and supporting methodologies to be used by the Commission for assessing the affordability of essential utility services, including: hours at minimum wage required to pay for essential utility services; vulnerability index of various communities; and ratio of essential utility service charges to non-disposable household income—known as the affordability ratio. The decision does not adopt an absolute definition of what constitutes affordable essential utility services; rather, the decision adopts metrics and methodologies for assessing affordability across utilities over time. The decision also authorizes a Phase 2 to the proceeding.

PIPELINE SAFETY

In 2011, the CPUC issued an OIR, R.11-02-019, 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, pursuant to D.11-06-017. 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 and Phase 2 covers less populated areas of SoCalGas' and SDG&E's service territories.

In June 2014, the CPUC issued D.14-06-007 approving the utilities' plan for implementing PSEP, subject to after-the-fact reasonableness review, established criteria to determine the costs that may be recovered from ratepayers, and authorized the establishment of balancing accounts to facilitate the recovery of costs for implementing Phase 1.

Subsequently, in D.16-12-063 the Commission approved SoCalGas' and SDG&E's joint application, (Application (A.) 14-12-016, requesting review and recovery of $33.2 million, which is a portion of the tracked PSEP costs incurred prior to June 12, 2014. Additionally, D.16-08-003, approved SoCalGas' and SDG&E's application (A.15-06-013) to establish Phase 2 memorandum accounts. The decision also authorized 50 percent interim cost recovery for Phase 1 actual revenue requirements booked to the regulatory accounts subject to refund, and a long-term procedural schedule for PSEP going forward. D.16-08-003 ordered SoCalGas and SDG&E to transition PSEP to the GRC starting with Test Year 2019 and that future GRC applications could include PSEP costs until implementation of the Plan is complete.

From 2011 through April 2020, SoCalGas and SDG&E have invested approximately $1.8 billion and $464 million, respectively, in PSEP, with additional expenditures planned.

In D,19-02-004, the Commission approved SoCalGas' and SDG&E's second PSEP Reasonableness Review application (A.16-09-005), which presented costs totaling $195 million (including certain costs for which the utilities are not seeking recovery) of pipeline safety projects completed by June 30, 2015. The Commission approved cost recovery of approximately $187 million ($172 million for SoCalGas and $15 million for SDG&E).

In D.19-03-025, the Commission also approved SoCalGas' and SDG&E's PSEP forecast application (A.17-03-021), finding $254.5 million associated with twelve SoCalGas Phase 1B and 2A pipeline projects reasonable and eligible for cost recovery. The decision directs SoCalGas and SDG&E to record costs to a one-way balancing account on an aggregate basis and balance to the authorized revenue requirements.

In December 2018, SoCalGas and SDG&E filed a third joint PSEP reasonableness review application (A.18-11-010) requesting cost review and rate recovery for 83 completed Phase 1 projects. The total costs submitted for review are approximately $941 million ($811 million for SoCalGas and $130 million for SDG&E). SoCalGas and SDG&E anticipate a decision from the Commission in 2020.

SAN JOAQUIN VALLEY OIR

In 2014, Governor Edmund G. Brown, Jr. signed into law AB 2672. This legislation added Public Utilities Code (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, 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. In December 2018, SoCalGas was approved to administer a natural gas pilot project in one community, California City, with a budget of $5.6 million.

MOBILE HOME PARK UTILITY UPGRADE PROGRAM

In February 2011, the Commission issued R.11-02-018 to examine what should be done to encourage mobile home parks (MHP) and manufactured housing communities to transfer to direct utility service. In March 2014, D.14-03-021 approved a three-year pilot program (January 1, 2015 through December 31, 2017) to incentivize voluntary conversions of master-metered service at MHPs at a target rate of 10 percent of the spaces within their service territories. In December 2014, the Commission approved Rule No. 44, establishing the MHP Upgrade Program, pursuant to D.14-03-021.

In September 2017, the CPUC issued Resolution (Res.) E-4878 approving SDG&E and SoCalGas' Advice Letters to continue converting 8,100 MHP spaces, or approximately an incremental 5 percent of MHP spaces through 2019. Subsequently, in March 2019, Res.E-4958 authorized an extension of the program through 2021, converting an additional 3.33 percent of spaces in years 2020 and 2021.

In April 2018, the CPUC opened R.18-04-018 to evaluate the existing MHP Pilot Program to determine whether to expand beyond the initial 3-year pilot into a permanent MHP Program. On April 16, 2020, the CPUC voted to establish a 10-year the Mobile Home Park Utility Conversion Program (MHP Program) with a goal of converting 50 percent of eligible MHP spaces, pursuant to D.20-04-004.

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

There has not been any significant activity in this area since the previous CGR was published, as reflected by the items noted below.

EL PASO

El Paso's rates have been the subject of extensive litigation at FERC in recent years. El Paso filed its third GRC in 5 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. A decision from the Court of Appeals is anticipated by the end of 2020.

KERN RIVER

A final ruling was issued in 2013 in Kern River's 2004 GRC. 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 GRC 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 GRC until July 2022. In the interim, the settlement agreement calls for separate proceedings to resolve issues related to capacity release procedures and gas quality.

GTN AND CANADIAN PIPELINES

SoCalGas acquires its Canadian natural gas supplies from the NGTL pipeline located in Alberta, Canada and transports these supplies through the NGTL pipeline in Alberta, to the

Foothills Pipelines 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.

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 6 years and be approximately 20 percent lower by 2021, relative to current 2014 levels.

GREENHOUSE GAS ISSUES

NATIONAL POLICY

The national GHG Program has been largely based on the Clean Power Plan adopted by the U.S. EPA, 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 carbon dioxide (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 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 EO 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 (AB 32) requires California to reduce GHG emissions to 1990 levels by 2020. AB 32 directed the CARB to adopt rules and regulations to achieve the "maximum technologically feasible and cost-effective GHG emission reductions."[79] The ARB 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 the ARB 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.

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

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 the ARB 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 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 SB 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 RPS 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 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, ARB, and CAISO—to implement the bill. SoCalGas has been engaged with these agencies throughout the process, and has been providing input.

SENATE BILL 1383

SB 1383 was signed into law on September 19, 2016, establishing methane emissions reduction targets in a statewide effort to reduce emissions of Short-Lived Climate Pollutants (SLCP) in various sectors of California's economy.[80] SB 1383 requires a 40 percent reduction in methane, a 40 percent reduction on hydrofluorocarbon gases and a 50 percent reduction in

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80 http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.

anthropogenic black carbon by 2030, relative to 2013 baseline levels and requires the ARB, the CPUC, and the CEC to undertake various actions related to reducing SLCPs in the state. SB 1383 also establishes targets to achieve a 50 percent reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and a 75 percent reduction by 2025. The law grants CalRecycle the regulatory authority required to achieve the organic waste disposal reduction targets and establishes an additional target that not less than 20 percent of currently disposed edible food is recovered for human consumption by 2025. The bill mandates the ARB, in consultation with the Department of Food and Agriculture, to adopt regulations to reduce methane emissions from livestock and dairy manure operations. SB 1383 also requires state agencies to consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of RG.

Pursuant to SB 1383, the ARB formed a Dairy and Livestock GHG Reduction Working Group in 2017 to help understand ways to reduce dairy and livestock methane emissions by 40 percent from 2013 levels by 2030. The working group's assignment was to identify and address technical, market, regulatory, and other barriers to development of methane reduction projects. SoCalGas actively participated in the working group and its three sub-groups including SoCalGas staff serving as co-chair of the Fostering Markets for Digester Projects sub-group whose task was to establish a roadmap, attentive to the SB 1383 statute dates of July 1, 2020 and January 1, 2024, to significantly expand the number of livestock digester projects in California that support the state's climate and air quality goals.

SoCalGas has participated in the CDFA Dairy Digester Research and Development Program (DDRDP), which provides financial assistance for the installation of dairy digesters in California, which will result in reduced GHG emissions. SoCalGas staff in SJV attended and presented at CDFA DDRDP workshops, webinars and listening sessions held in environmental justice (also known as disadvantaged communities) areas near dairies. We also provide education and assist customers who are interested in the CDFA Program, as well as on other topics related to RNG, such as alternative fuel vehicles. A specific example is our promotion of RNG in our marketing materials especially those developed and displayed at the International Ag Expo held every year in Tulare, California. CDFA also includes a link on their DDRDP website to SoCalGas' RG website.

SENATE BILL 100 AND EXECUTIVE ORDER B-55-18

The 100 Percent Clean Energy Act of 2019, or SB 100, was signed into law on September 10, 2018. SB 100 sets a state policy that eligible renewable energy and zero-carbon resources supply 100 percent of all retail sales of electricity in California by 2045. The bill also accelerates California's RPS, which, pursuant to a 2016 bill by the same author (SB 350), already mandates that load-serving entities procure at least 50 percent of retail sales from eligible renewable energy resources by 2030; under SB 100, the 2030 target will be increased to 60 percent, and the 50 percent target will be advanced to 2026, in recognition that California retail sellers are well on their way to achieving the target in advance of the existing deadlines. EO B-55-18 establishes a new statewide goal to achieve economy-wide carbon neutrality no later than 2045.

ASSEMBLY BILL 3232

The zero-emissions buildings and sources-of-heat energy bill requires the CEC to assess the potential for the state to reduce the emissions of GHGs from the state's residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030. Their report is due January 2021.

GHG RULEMAKING

Beginning on January 1, 2015, the ARB'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 mtCO_2e equivalent per year have a direct obligation to the ARB 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.[81] 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'

81 CPUC D.15-10-032.

transportation rates beginning April 1, 2016. Customers with a direct obligation to the ARB 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 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 (3) 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

The ARB publishes total, covered and non-covered emissions because total emissions are used to calculate California's GHG emissions inventory and covered emissions are used to determine a facility's Cap-and-Trade obligation. At the time of the writing of the 2020 CGR, the 2019 GHG numbers have not been verified by the independent third party. The 2018 numbers are the most recent verified numbers for the reporting category. As of 2018, SoCalGas reported to the ARB *verified* GHG emissions of approximately 41.4 mmtCO_2e in three primary categories: (1) combustion emissions at five compressor stations and two storage fields, where annual emissions exceed 10,000 mtCO_2e; (2) vented and fugitive emissions from three compressor stations, two storage fields and the natural gas distribution system; and (3) the GHG emissions resulting from combustion of natural gas delivered to all customers.

In 2018, GHG emissions for gas delivered to all customers was 39.9 mmtCO_2e, but 20.7 mmtCO_2e for gas delivered to non-covered customers. Non-covered customers consist of smaller customers with emissions of less than 25,000 mtCO_2e. For Cap-and-Trade obligation, 20.7 mmtCO_2e is the appropriate Cap-and-Trade value. Large, covered customers pay their own Cap-and-Trade bill.

Four of the five facilities subject to the EPA's mandatory reporting regulation are also subject to ARB's 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 ARB's Cap-and-Trade Program). More recently, SoCalGas estimated that its GHG emissions compliance obligation as a natural gas supplier to be approximately 22.0 mtCO_2e for 2019. ARB will issue final 2019 GHG emissions compliance obligations for natural gas suppliers in November 2020.

The adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipelines consistent with Pub. Util. Code Section 961 (d), § 192.703 (c) of Subpart M of Title 49 of the CFR, and the Commission's General Order 112-F are covered under R.15-01-008. 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 2020, SoCalGas reported 2.2 Bcf of methane emissions from intentional and unintentional releases for the year 2019. These emissions were reported in the SB 1371 report. Only some intentional emissions are subject to the ARB Cap-and-Trade Program.

MOTOR VEHICLE EMISSIONS REDUCTIONS

National GHG policymakers 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 the EPA's Mandatory Reporting of GHGs rule, all vehicle and engine manufacturers outside of the light-duty sector must report emission rates of CO_2, nitrous oxide, and methane from their products.

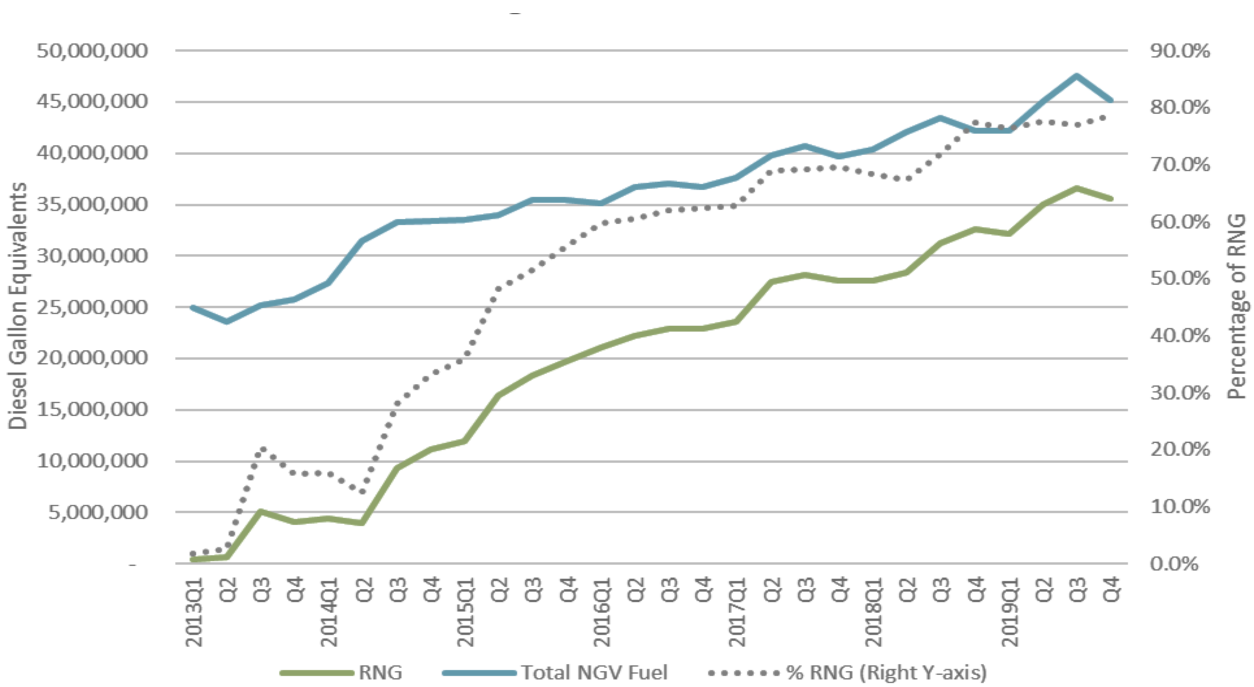
LOW CARBON FUEL STANDARD

Established by EO, signed by then Governor Arnold Schwarzenegger in 2007, the LCFS requires a 10 percent carbon intensity reduction by 2020 in the transportation sector. In 2019, the LCFS was updated and now requires a 20 percent carbon intensity by 2030 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 CO_2 equivalent grams per unit of fuel energy sold. As stated above, the transition to cleaner fuels will increase the demand for natural gas, H2 and natural gas-generated electricity in order to meet the needs of a cleaner state transportation fleet. Further, the CPUC has authorized the utilities to sell LCFS credits generated both by their use of low-carbon fuel vehicles and those generated by utility-owned public refueling stations. The revenue generated by the sale of these credits is being 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 began generating credits from utility-owned 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. In 2018, the CPUC approved a SoCalGas Advice Letter to initiate a Voluntary RNG Procurement Pilot program. The program enables SoCalGas to procure and dispense 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. On April 1, 2019, SoCalGas began procuring 100 percent RNG at all utility-owned CNG stations. SoCalGas anticipates the Pilot will result in more value returned to its CNG customers while supporting the development of the RNG market.

To date, there is a significant amount of RNG being used in California NGVs. The most recent data from the LCFS Program shows that approximately 78 percent of fuel delivered to NGVs in 2019 was RNG. The chart below shows how RNG's role in this important program has grown over time. Since 2013, RNG has delivered more than 3.9 mmt of carbon reductions and displaced more than 560 million gallons of diesel fuel.[82]

FIGURE 21 – LCFS PROGRAM NGV FUEL STATISTICS
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 EIA forecasts a 5.3 percent annual growth rate for NGV volumes in the Pacific region through 2050.[83]

82 LCFS Reporting Tool Quarterly Summaries: https://www.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

83 EIA 2018 Annual Energy Outlook: https://www.eia.gov/outlooks/aeo/.

PROGRAMMATIC EMISSIONS REDUCTION: CALIFORNIA GHG REDUCTION STRATEGIES

The ARB has the responsibility to develop the broad strategies to achieve California's GHG emissions reduction targets. The 2017 Scoping Plan Update identified several strategies to achieve the 2030 target to reduce emissions by 40 percent from 1990 levels: double building efficiency; 50 percent renewable power; cleaner transportation; and reduce SLCPs and Cap emissions from various sectors. The SLCP includes targets to reduce methane emissions from organic sources of methane and methane leakage from the oil and gas industry.

The CPUC has an on-going 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 26 Best Practices for emission mitigation. This proceeding is led by the CPUC in consultation with the ARB. The first phase will develop the overall policies and guidelines for a natural gas leak abatement program consistent with SB 1371. The second phase will develop ratemaking and performance-based financial incentives associated with the natural gas leak abatement program determined through Phase 1 of the proceeding. Energy efficiency and renewables are considered fundamental to GHG emission reduction in the electric sector. As a result, integration of additional renewables will require quick-start peaking capacity for firming and shaping of intermittent power, which in the foreseeable future will be gas-fired combustion turbines.

RENEWABLE NATURAL GAS

Biomethane, or 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.

In March of 2019, SoCalGas announced a plan to replace 20 percent of its traditional natural gas supply with RNG by 2030 as part of SoCalGas' vision to be the cleanest gas utility in North America, delivering affordable and increasingly renewable energy to its customers. To kickstart the plan, SoCalGas will pursue regulatory authority to implement a broad RNG procurement program with a goal of replacing 5 percent of its natural gas supply with RNG by

2022. SoCalGas also recently filed a request with the CPUC to allow customers to purchase RNG for their homes. SoCalGas aims to have CPUC approval of its voluntary program by the end of 2020.

SoCalGas is currently procuring 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. Approximately 90 percent of Californians use natural gas for space and water heating, and for delivering RNG to these appliances through existing natural gas infrastructure has the potential to seamlessly decarbonize these end-uses without disrupting customer behavior or preferences.

When biogas is conditioned/upgraded to pipeline quality specifications, commonly referred to as "biomethane" or "renewable natural gas," it can be interconnected to a gas utility's pipeline and nominated for a specific end-use customer.[84] Biogas may also be consumed onsite for a variety of uses, including electrical power generation from internal combustion engines, fuel cells, and turbines, or as a fuel source for NGVs. 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 AB 32 and SB 1383, whereas captured and processed RNG injected into a gas pipeline system can ultimately count towards satisfying AB 32 and SB 1383 emission reduction goals. In light of this, the legislature established SB 1440 which would require the CPUC, in consultation with the ARB, to consider adopting biomethane procurement targets or goals for each of the state's gas corporations.[85]

AB 1900 (2012, Gatto) required that the Commission open a rulemaking to ensure that each gas corporation provide non-discriminatory open access to its gas pipeline system to any party for the purposes of physically interconnecting with the gas pipeline system and effectuating the

84 SoCalGas' Tariff Rule 30 (https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf) must be met in order to qualify for pipeline injection into SoCalGas' gas pipeline system.

85 SB 1440 (Hueso, 2018): https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB1440.

safe delivery of gas.[86] On February 13, 2013, the Commission opened R.13-02-008, OIR to Adopt Biomethane Standard and Requirement, Pipeline Open Access Rules, and Related Enforcement Provisions (Biomethane OIR). In collaboration with and the Office of Environmental Health Hazard Assessment, the Commission determined that biomethane could be safely injected into the natural gas pipeline system in D.14-01-034 (adopted January 16, 2014).[87] D.14-01-034 adopted Pipeline injection standards for 17 "constituents of concern" potentially found in biomethane. H2 is one of the 17 "constituents of concern, and an injection standard of 0.1 percent of H2 was adopted for biomethane injected into gas pipelines. The statute directs that the pipeline injection standards shall be revisited every 5 years.[88] The establishment of biomethane injection standards is Phase 1 of the Biomethane OIR. Phase 2 of the Biomethane OIR resulted in D.15-06-029, which adopted a biomethane interconnector monetary incentive program. The objective of the program is to encourage the development of biomethane projects that are interconnected to the utilities' gas pipeline systems. Initially, the incentive program authorized a total of $40 million for incentives, up to $1.5 million per project, for projects that successfully interconnect and operate by June 11, 2020. The incentives are paid by the gas utility that operates the pipeline system where the facility interconnects. Pub. Util. Code § 399.19[89] extended the monetary incentive program to December 31, 2021 and increased the incentives to $3 million for non-dairy clusters and $5 million for dairy clusters.

In October 2019 Governor Newsom signed into law SB 457, which extends the program until December 31, 2026, or until all available program funds are expended, whichever occurs first. In accordance with SB 457, CPUC D.19-12-009[90] extends the date for awarding pipeline interconnection incentives. This Decision also implements an Incentive Reservation System for the biomethane monetary incentive program established in D 15-06-029. The Incentive

86 AB 1900 (Gatto 2012): https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201120120AB1900.

87 D.14-01-034: Decision Regarding the Biomethane Implementation Tasks in AB 190: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M086/K466/86466318.PDF.

88 See Health and Safety Code, §§ 25421(a) and 25421(e).

89 AB 2313 (Williams 2016): https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB2313.

90 D.19-12-009: Decision Establishing a Reservation System for the Biomethane Incentive Program, Extending Date and Addressing Rate Recovery for Pipeline Interconnection Infrastructure: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M321/K901/321901043.PDF.

Reservation System allows project developers to reserve incentive funds during the development phase of a project and receive the funds once the project is interconnected and operating. Applications for the Incentive Reservation System are designed to ensure that only viable projects can secure a spot on the reservation list. The Commission maintains the Incentive Reservation System and makes it publicly available to promote the transparency of the use of funds. As of the time of this writing, all $40 million for incentives have been reserved by 11 biomethane projects currently in development, while an additional 8 projects are on a waiting list for possible incentive funding.[91]

Phase 3 of the Biomethane OIR addresses the need for a standard statewide RG interconnection tariff and interconnection agreement. An August 22, 2019 Ruling established a schedule to develop the standard tariff and required SoCalGas, SDG&E, Southwest Gas, and PG&E to file a standard RG Interconnection Tariff (Rule) and Agreement.[92] The proposed joint utility RG Interconnection Rule was filed on November 1, 2019, and the proposed RG Interconnection Agreement was filed on May 1, 2019.

Phase 4 of the Biomethane OIR was opened November 21, 2019.[93] It will address two issues: (1) standards for injection of renewable H2 into gas pipelines; and (2) implementation of SB 1440 to consider adopting biomethane procurement targets or goals for each gas corporation.

One of the primary policy drivers of California RNG development is SB 1383 (as discussed above). SB 1383 required, among other things, that the CPUC implement "at least 5 dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system."[94] 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. The pilot

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91 https://www.cpuc.ca.gov/renewable_natural_gas/.

92 Assigned Commissioner's Ruling on Joint Motion Regarding Further Procedural Schedule for a Standard Renewable Gas Interconnection Tariff and Agreements: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M311/K290/311290174.PDF.

93 Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of R.13-02-008: http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M320/K307/320307147.PDF.

94 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383.

project Selection Committee consisted of staff members and attorneys from the CPUC, the ARB, and the CDFA. On December 3, 2018 the Selection Committee identified the selected six Dairy Biomethane Pilot Projects.[95] Four of these are in SoCalGas' service territory: CalBioGas Buttonwillow LLC; CalBioGas North Visalia LLC; CalBioGas South Tulare LLC; and Lakeside Pipeline LLC. (The other two projects are in PG&E's service territory: Maas Energy Works in Merced; and DVO's Weststeyn Dairy in Willows.)

HYDROGEN

Hydrogen is the simplest and most abundant element, making up approximately 75 percent of the observable universe. Hydrogen can be utilized as a fuel to generate energy. With its abundance and simple chemical structure, hydrogen can be manufactured from feedstock such as methane, or water and electricity, using scalable, sustainable, and renewable methods. Hydrogen has favorable emissions characteristics because it does not contain carbon or produce GHG when it is consumed. For this reason, hydrogen can play an important role in the transition to a clean, low-carbon energy system in California.[96]

As part of the State of California's climate strategy, hydrogen can provide important GHG emissions reductions, and can also play a key role in enabling the use of zero-emissions fuel cell electric vehicles, which can reduce criteria emissions from on-road diesel, the largest and hardest to electrify contributors to the State's black carbon and nitrogen oxides (NOx) inventories.[97] California has also been at the forefront of developing hydrogen fueling stations to demonstrate the feasibility of hydrogen-fueled transportation and the potential that such a network creates for deployment of light duty fuel-cell electric vehicles (FCEVs).

Hydrogen fuel for transportation was adopted in California through the policy framework by Assembly Bill (AB) 8, which provided certainty for hydrogen fueling station deployment.[98] In addition, new programs and policies have been developed and initiated to ensure that some of the most ambitious public-private goals are met as projected. The Low Carbon Fuel Standard's (LCFS) Hydrogen Refueling Infrastructure (HRI) credit provisions took effect, predicated on the

95 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M246/K748/246748640.PDF.

96 http://hydrogencouncil.com.

97 https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm.

98 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB8.

goal of reaching 200 hydrogen stations by 2025 as described by Governor Brown's Executive Order B-48-18 (EO B-48-18).[99]

Globally, hydrogen is widely seen as a pivotal component of the future clean energy economy. The two primary technological processes used today to produce hydrogen are electrolysis and reformation, including steam methane reformation (SMR) and autothermal reformation (ATR). Hydrogen is also produced when organic mass is gasified, but this "syngas," consisting of mainly carbon monoxide (CO) and hydrogen, is typically an intermediate product often used to generate methane or electricity. Reforming is a mature technology and is the most economical way to produce hydrogen, supplying 95 percent or more of the hydrogen used in the United States today.[100] The electrolysis process uses renewable electricity to split water (H_2O) into H_2 and oxygen (O_2).

As a gaseous fuel, hydrogen can help decarbonize the gas grid and be used in a variety of end use applications, beyond transportation. The hydrogen can either be stored directly, or methanated and injected into the natural gas grid to be stored and delivered to a variety of end uses, supplementing or displacing traditional natural gas. Storing hydrogen from electrolysis is a scalable and versatile energy storage pathway.

99 https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html.

100 The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology, Institute of Transportation Studies, UC Davis (March 2017), available at https://steps.ucdavis.edu/wp-content/uploads/2017/05/2017-UCD-ITS- RR-17-04-1.pdf

PEAK DAY DEMAND

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's bundled 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 foreach utility's service area. This criteria correlates to a system average temperature of 40.5 degrees F for SoCalGas' service area and 43.0 degrees F 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.

TABLE 29 – CORE 1-IN-35 YEAR EXTREME PEAK DAY DEMAND (MMcf/d)

Year	SoCalGas Core Demand (1)	SDG&E Core Demand (2)	Other Core Demand (3)	Total Demand
2020	2,912	425	123	3,460
2021	2,892	424	124	3,440
2022	2,878	425	125	3,427
2023	2,856	423	126	3,405
2024	2,834	422	126	3,382
2025	2,809	420	127	3,357
2026	2,782	419	128	3,329

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 SWG, 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.

TABLE 30 – WINTER 1-IN-10 YEAR COLD DAY DEMAND CONDITION (MMcf/d)

Year	SoCalGas Core (1)	SDG&E Core (2)	Other Core (3)	Noncore Non-EG (4)	EG (5)	Total Demand
2020	2,752	400	103	661	1,068	4,983
2021	2,732	399	104	659	1,072	4,967
2022	2,718	400	105	664	1,105	4,992
2023	2,698	398	105	668	1,106	4,975
2024	2,676	397	106	671	1,089	4,940
2025	2,652	395	107	674	1,119	4,948
2026	2,626	394	108	674	1,101	4,902

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 SWG, City of Long Beach, and City of Vernon.
(4) Noncore-Non-EG includes noncore Non-EG end-use customers of SoCalGas, SDG&E, SWG, City of Long Beach, City of Vernon, and all end-use customers of Ecogas.
(5) EG includes UEG/EWG Base Hydro, large cogeneration, industrial and commercial cogeneration (<20 MW), refinery-related cogeneration, and EOR-related cogeneration.

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.

TABLE 31 – SUMMER HIGH SENDOUT DAY DEMAND
(MMcf/d)

Year	High-Demand Month (1)	SoCalGas Core (2)	SDG&E Core (3)	Other Core (4)	Noncore Non-EG (5)	EG (6)	Total Demand
2020	Sep	620	94	28	536	1,928	3,206
2021	Sep	613	94	28	531	1,894	3,160
2022	Sep	612	94	28	536	1,936	3,206
2023	Sep	605	94	28	538	1,952	3,217
2024	Sep	598	93	29	540	1,631	2,891
2025	Sep	589	93	29	542	1,646	2,899
2026	Sep	580	92	29	541	1,626	2,868

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 SWG, City of Long Beach, and City of Vernon.

(5) Average daily summer Noncore-Non-EG demand. Noncore-Non-EG includes noncore Non-EG end-use customers of SoCalGas, SDG&E, SWG, City of Long Beach, City of Vernon, and all end-use customers of Ecogas.

(6) Highest demand during the high-demand month under 1-in-10 dry hydro conditions, except year 2020, when the EG highest demand is based on 2020 hydro condition.

Highest demand during the high-demand month under 1-in-10 dry hydro conditions, except year 2020, when the EG highest demand is based on 2020 hydro condition.

2020 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY – TABULAR DATA

TABLE 32 – SoCalGas
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2015-2019

Line	CAPACITY AVAILABLE		2015	2016	2017	2018	2019
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		122	89	84	104	97
	Out-of-State Gas						
11	Other Out-of-State		2,397	2,342	2,434	2,246	2,305
12	Total Out-of-State Gas		2,397	2,342	2,434	2,246	2,305
13	TOTAL SUPPLY TAKEN		2,519	2,431	2,518	2,350	2,402
14	Net Underground Storage Withdrawal		40	80	(14)	(8)	7
15	TOTAL THROUGHPUT (1)(2)		2,559	2,511	2,504	2,342	2,409
	DELIVERIES BY END-USE						
16	Core	Residential	548	557	565	569	645
17		Commercial	207	213	214	217	226
18		Industrial	58	55	55	57	61
19		NGV	35	36	38	40	41
20		Subtotal	848	861	872	883	973
21	Noncore	Commercial	52	57	56	59	58
22		Industrial	362	391	389	389	357
23		EOR Steaming	46	39	39	38	51
24		Electric Generation	795	740	713	615	589
25		Subtotal	1,255	1,228	1,198	1,102	1,055
26	Wholesale/International		428	390	401	333	342
27	Co. Use & LUAF		28	31	33	25	39
28	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,559	2,511	2,504	2,342	2,409
	TRANSPORTATION AND EXCHANGE						
29	Core	All End Uses	52	56	62	71	74
30	Noncore	Commercial/Industrial	414	449	446	448	415
31		EOR Steaming	46	39	39	38	51
32		Electric Generation	795	740	713	622	589
33		Subtotal-Retail	1,307	1,284	1,260	1,181	1,129
34	Wholesale/International		428	390	401	333	342
35	TOTAL TRANSPORTATION & EXCHANGE		1,735	1,674	1,660	1,513	1,471
36	CURTAILMENT (3)						
37	REFUSAL						
38		Total BTU Factor (Dth/Mcf)	1.0353	1.0345	1.0343	1.0319	1.0336

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 33 – SoCalGas: TABLE 1-SCG
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
RECORDED YEARS 2020-2024
AVERAGE TEMPERATURE YEAR

LINE			2020	2021	2022	2023	2024	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/		990	990	990	1,250	1,250	5
6	Total Out-of-State Gas		2,965	2,965	2,965	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,175	3,175	3,175	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		63	63	63	63	63	8
9	Out-of-State		2,399	2,384	2,394	2,358	2,286	9
10	TOTAL SUPPLY TAKEN		2,462	2,447	2,457	2,421	2,349	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,462	2,447	2,457	2,421	2,349	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	629	624	614	605	596	13
14		Commercial	209	208	213	210	206	14
15		Industrial	54	52	52	51	50	15
16		NGV	42	43	43	44	45	16
17		Subtotal-CORE	934	926	922	911	896	17
18	NONCORE	Commercial	51	51	51	52	51	18
19		Industrial	391	386	389	391	393	19
20		EOR Steaming	32	32	32	32	32	20
21		Electric Generation (EG)	669	667	679	657	611	21
22		Subtotal-NONCORE	1,143	1,136	1,152	1,132	1,088	22
23	WHOLESALE &	Core	187	188	188	188	187	23
24	INTERNATIONAL	Noncore Excl. EG	53	53	53	54	54	24
25		Electric Generation (EG)	113	113	112	106	94	25
26		Subtotal-WHOLESALE & INTL.	353	353	353	347	335	26
27		Co. Use & LUAF	31	31	31	31	30	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,462	2,447	2,457	2,421	2,349	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	70	70	71	71	70	29
30	NONCORE	Commercial/Industrial	442	437	441	443	444	30
31		EOR Steaming	32	32	32	32	32	31
32		Electric Generation (EG)	669	667	679	657	611	32
33		Subtotal-RETAIL	1,213	1,206	1,222	1,203	1,158	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	353	353	353	347	335	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,566	1,560	1,575	1,550	1,493	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 2019 recorded California Source Gas; production less than capacity due to reservoir performance and economics.
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach: 0.6 | 0.6 | 0.6 | 0.5 | 0.5
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: 894 | 885 | 880 | 868 | 854

TABLE 34 – SoCalGas: TABLE 2-SCG
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
RECORDED YEARS 2025-2035
AVERAGE TEMPERATURE YEAR

LINE			2025	2026	2027	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/		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		63	63	63	63	63	8
9	Out-of-State		2,279	2,254	2,198	2,069	2,040	9
10	TOTAL SUPPLY TAKEN		2,342	2,317	2,261	2,132	2,103	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,342	2,317	2,261	2,132	2,103	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	589	580	572	547	543	13
14		Commercial	201	196	192	182	171	14
15		Industrial	49	48	47	44	39	15
16		NGV	45	46	47	49	52	16
17		Subtotal-CORE	885	871	858	822	806	17
18	NONCORE	Commercial	52	51	51	51	51	18
19		Industrial	395	395	391	380	369	19
20		EOR Steaming	32	32	32	32	32	20
21		Electric Generation (EG)	614	607	577	503	499	21
22		Subtotal-NONCORE	1,093	1,086	1,051	966	951	22
23	WHOLESALE &	Core	187	186	186	185	187	23
24	INTERNATIONAL	Noncore Excl. EG	54	54	54	54	54	24
25		Electric Generation (EG)	94	91	84	78	78	25
26		Subtotal-WHOLESALE & INTL.	334	331	323	317	319	26
27		Co. Use & LUAF	30	29	29	27	27	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,342	2,317	2,261	2,132	2,103	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	70	69	69	68	68	29
30	NONCORE	Commercial/Industrial	447	447	442	431	419	30
31		EOR Steaming	32	32	32	32	32	31
32		Electric Generation (EG)	614	607	577	503	499	32
33		Subtotal-RETAIL	1,162	1,155	1,119	1,034	1,018	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	334	331	323	317	319	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,497	1,486	1,443	1,351	1,337	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 2019 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2025	2026	2027	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.5	0.5	0.4	0.4	0.4

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

	2025	2026	2027	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	843	829	816	779	763

TABLE 35 – SoCalGas: TABLE 3-SCG
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2020-2024
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

LINE			2020	2021	2022	2023	2024	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/]		990	990	990	1,250	1,250	5
6	Total Out-of-State Gas		2,965	2,965	2,965	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE [4/]		3,175	3,175	3,175	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas [5/]		63	63	63	63	63	8
9	Out-of-State		2,477	2,534	2,550	2,497	2,417	9
10	TOTAL SUPPLY TAKEN		2,540	2,597	2,613	2,560	2,480	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [6/]		2,540	2,597	2,613	2,560	2,480	12
	REQUIREMENTS FORECAST BY END-USE [7/]							
13	CORE [8/]	Residential	683	677	667	658	648	13
14		Commercial	218	217	222	219	215	14
15		Industrial	55	53	53	52	51	15
16		NGV	42	43	43	44	45	16
17		Subtotal-CORE	998	989	985	974	959	17
18	NONCORE	Commercial	52	52	52	53	52	18
19		Industrial	391	386	389	391	393	19
20		EOR Steaming	32	32	32	32	32	20
21		Electric Generation (EG)	669	727	740	706	654	21
22		Subtotal-NONCORE	1,144	1,197	1,214	1,183	1,131	22
23	WHOLESALE &	Core	200	201	201	200	200	23
24	INTERNATIONAL	Noncore Excl. EG	53	53	54	54	54	24
25		Electric Generation (EG)	113	124	126	118	106	25
26		Subtotal-WHOLESALE & INTL.	366	378	381	372	359	26
27		Co. Use & LUAF	32	33	33	32	31	27
28	SYSTEM TOTAL THROUGHPUT [6/]		2,540	2,597	2,613	2,560	2,480	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	72	72	73	73	72	29
30	NONCORE	Commercial/Industrial	443	438	442	444	445	30
31		EOR Steaming	32	32	32	32	32	31
32		Electric Generation (EG)	669	727	740	706	654	32
33		Subtotal-RETAIL	1,216	1,269	1,287	1,255	1,204	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	366	378	381	372	359	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,582	1,647	1,668	1,628	1,563	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 2019 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2020	2021	2022	2023	2024
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.7	0.7	0.6	0.6	0.5

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

	2020	2021	2022	2023	2024
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	957	948	943	931	916

TABLE 36 – SoCalGas: TABLE 4-SCG
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2025-2035
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

LINE			2025	2026	2027	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/		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		63	63	63	63	63	8
9	Out-of-State		2,411	2,394	2,334	2,185	2,155	9
10	TOTAL SUPPLY TAKEN		2,474	2,457	2,397	2,248	2,218	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,474	2,457	2,397	2,248	2,218	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	641	632	623	598	593	13
14		Commercial	210	205	201	191	180	14
15		Industrial	50	49	48	45	40	15
16		NGV	45	46	47	49	52	16
17		Subtotal-CORE	948	933	920	883	866	17
18	NONCORE	Commercial	53	52	52	52	52	18
19		Industrial	395	395	391	380	369	19
20		EOR Steaming	32	32	32	32	32	20
21		Electric Generation (EG)	654	655	621	537	533	21
22		Subtotal-NONCORE	1,134	1,135	1,096	1,000	985	22
23	WHOLESALE &	Core	200	199	199	198	199	23
24	INTERNATIONAL	Noncore Excl. EG	54	54	54	54	54	24
25		Electric Generation (EG)	107	104	98	85	85	25
26		Subtotal-WHOLESALE & INTL.	361	358	350	337	339	26
27		Co. Use & LUAF	31	31	30	28	28	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,474	2,457	2,397	2,248	2,218	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	72	71	71	70	70	29
30	NONCORE	Commercial/Industrial	448	448	443	432	420	30
31		EOR Steaming	32	32	32	32	32	31
32		Electric Generation (EG)	654	655	621	537	533	32
33		Subtotal-RETAIL	1,206	1,206	1,167	1,070	1,055	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	361	358	350	337	339	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,567	1,564	1,518	1,408	1,394	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 2019 recorded California Source Gas; production less than capacity due to reservoir performance and economics.
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach: 0.5 | 0.5 | 0.5 | 0.5 | 0.5
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: 905 | 891 | 877 | 840 | 823

2020 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT

CITY OF LONG BEACH
ENERGY RESOURCES DEPARTMENT

The annual gas supply and forecast requirements prepared by the Long Beach Energy Resources Department (Long Beach) are shown on the following tables for the years 2020 through 2035.

Long Beach operates the fifth largest municipally owned natural gas utility in the country and is one of only three in the State. The gas utility provides safe and reliable natural gas services to about 500,000 residents and businesses via approximately 150,000 connected gas meters, delivered through more than 1,800 miles of gas pipelines. 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 gas use is split at 53 percent residential and 47 percent commercial/industrial.

Long Beach serves core and noncore customers from three incremental supply sources: (1) interstate supplies delivered into the SoCalGas' intrastate pipeline system; (2) gas storage withdrawals; and (3) local gas delivered directly to Long Beach Energy Resources Department's pipeline system from gas fields within the city. Currently, local production supplies about 5 percent of Long Beach's gas use. Long Beach purchases most of its gas supplies from producers in the South-Western U.S. As a Wholesale customer, Long Beach contracts with SoCalGas for intrastate transmission service to deliver that gas from the California border to its service area.

The City of Long Beach is the only municipal government in the State of California that manages oil operations. Through its Energy Resources Department, the City operates the Wilmington Oil Field and has various financial interests in smaller oil fields throughout the City, such as the Signal Hill East and West Units, Recreation Park, and City Wasem.

As a municipal utility, Long Beach's gas 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.

2020 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT – TABULAR DATA

TABLE 37 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT: TABLE 1-LB ANNUAL GAS SUPPLY AND SENDOUT – MMCF/D RECORDED YEARS 2015-2019 FOR THE 2020 CGR REPORT

LINE	GAS SUPPLY AVAILABLE	2015	2016	2017	2018	2019	LINE
	California Source Gas						
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	4
	Out-of-State Gas						
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	0.7	0.9	0.6	0.6	1.1	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	0.7	0.9	0.6	0.6	1.1	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	16
	Out-of-State Gas						
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	21.9	22.8	24.6	23.9	25.2	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	21.9	22.8	24.6	23.9	25.2	21
22	Subtotal	22.5	23.7	25.2	24.5	26.3	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	22.5	23.7	25.2	24.5	26.3	24

TABLE 37 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d RECORDED YEARS 2009-2019 FOR THE 2020 CGR REPORT (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2015	2016	2017	2018	2019	LINE
1	CORE	Residential	11.9	11.9	11.8	12.1	12.9	1
2	CORE/NONCORE	Commercial	5.4	5.8	6.0	5.9	6.1	2
3	CORE/NONCORE	Industrial	3.7	3.9	4.7	4.3	4.7	3
4		Subtotal	20.9	21.6	22.5	22.3	23.8	4
5	NON CORE	Non-EOR Cogeneration	1.2	1.9	2.2	1.9	1.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	1.2	1.9	2.2	1.9	1.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.4	0.2	0.5	0.2	0.8	13
14		Subtotal-END USE	22.5	23.7	25.1	24.5	26.3	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		22.5	23.7	25.1	24.5	26.3	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	2.3	2.6	2.9	3.0	3.1	18
19		Non-EOR Cogeneration	1.1	1.8	2.0	1.9	1.5	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	3.4	4.3	5.0	4.9	4.7	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		3.4	4.3	5.0	4.9	4.7	24
	ACTUAL CURTAILMENT							
25		Residential	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	32

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

TABLE 38 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
AVERAGE YEAR FORECAST FOR THE 2020 CGR REPORT

LINE	GAS SUPPLY AVAILABLE	2020	2021	2022	2023	LINE
	California Source Gas					
1	Regular Purchases	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	4
	Out-of-State Gas					
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.1	1.1	1.1	1.1	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.1	1.1	1.1	1.1	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	16
	Out-of-State Gas					
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	25.2	25.2	25.2	25.2	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	25.2	25.2	25.2	25.2	21
						22
22	Subtotal	26.3	26.3	26.3	26.3	
						23
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	
						24
24	TOTAL Gas Supply Taken & Transported	26.3	26.3	26.3	26.3	

TABLE 38 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d AVERAGE YEAR FORECAST FOR THE 2020 CGR REPORT (CONTINUED)

LINE	GAS SUPPLY AVAILABLE	2024	2025	2030	2035	LINE
	California Source Gas					
1	Regular Purchases	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	4
	Out-of-State Gas					
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.1	1.1	1.1	1.1	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.1	1.1	1.1	1.1	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	16
	Out-of-State Gas					
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	25.2	25.2	25.2	25.2	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	25.2	25.2	25.2	25.2	21
22	Subtotal	26.3	26.3	26.3	26.3	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	26.3	26.3	26.3	26.3	24

**TABLE 39 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1A-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
AVERAGE YEAR FORECAST FOR THE 2020 CGR REPORT**

LINE	ACTUAL DELIVERIES BY END-USE		2020	2021	2022	2023	LINE
1	CORE	Residential	12.9	12.9	12.9	12.9	1
2	CORE/NONCORE	Commercial	6.1	6.1	6.1	6.1	2
3	CORE/NONCORE	Industrial	4.7	4.7	4.7	4.7	3
4		Subtotal	23.8	23.8	23.8	23.8	4
5	NON CORE	Non-EOR Cogeneration	1.7	1.7	1.7	1.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	7
8		Subtotal	1.7	1.7	1.7	1.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.8	0.8	0.8	0.8	13
14		Subtotal-END USE	26.3	26.3	26.3	26.3	14
15		Storage Injection	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		26.3	26.3	26.3	26.3	16
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.1	3.1	3.1	3.1	18
19		Non-EOR Cogeneration	1.5	1.5	1.5	1.5	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	4.7	4.7	4.7	4.7	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		4.7	4.7	4.7	4.7	24
	ACTUAL CURTAILMENT						
25		Residential	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	32

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

TABLE 39 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1A-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d AVERAGE YEAR FORECAST FOR THE 2020 CGR REPORT (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2024	2025	2030	2035	LINE
1	CORE	Residential	12.9	12.9	12.9	12.9	1
2	CORE/NONCORE	Commercial	6.1	6.1	6.1	6.1	2
3	CORE/NONCORE	Industrial	4.7	4.7	4.7	4.7	3
4		Subtotal	23.8	23.8	23.8	23.8	4
5	NON CORE	Non-EOR Cogeneration	1.7	1.7	1.7	1.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	7
8		Subtotal	1.7	1.7	1.7	1.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.8	0.8	0.8	0.8	13
14		Subtotal-END USE	26.3	26.3	26.3	26.3	14
15		Storage Injection	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		26.3	26.3	26.3	26.3	16
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.1	3.1	3.1	3.1	18
19		Non-EOR Cogeneration	1.5	1.5	1.5	1.5	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	4.7	4.7	4.7	4.7	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		4.7	4.7	4.7	4.7	24
	ACTUAL CURTAILMENT						
25		Residential	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	32

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

TABLE 40 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2020 CGR REPORT

LINE	GAS SUPPLY AVAILABLE	2020	2021	2022	2023	LINE
	California Source Gas					
1	Regular Purchases	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	4
	Out-of-State Gas					
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.3	1.3	1.3	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.3	1.3	1.3	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	16
	Out-of-State Gas					
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	29.4	29.4	29.4	29.4	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	29.4	29.4	29.4	29.4	21
22	Subtotal	30.8	30.8	30.8	30.8	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	30.76	30.8	30.8	30.8	24

TABLE 40 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
COLD YEAR FORECAST FOR THE 2020 CGR REPORT
(CONTINUED)

LINE	GAS SUPPLY AVAILABLE	2024	2025	2030	2035	LINE
	California Source Gas					
1	Regular Purchases	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	4
	Out-of-State Gas					
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN					
	California Source Gas					
13	Regular Purchases	1.3	1.3	1.3	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.3	1.3	1.3	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	16
	Out-of-State Gas					
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	29.4	29.4	29.4	29.4	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	29.4	29.4	29.4	29.4	21
22	Subtotal	30.8	30.8	30.8	30.8	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	30.8	30.8	30.8	30.76	24

TABLE 41 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1A-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
COLD YEAR FORECAST FOR THE 2020 CGR REPORT

LINE	ACTUAL DELIVERIES BY END-USE		2020	2021	2022	2023	LINE
1	CORE	Residential	15.1	15.1	15.1	15.1	1
2	CORE/NONCORE	Commercial	7.2	7.2	7.2	7.2	2
3	CORE/NONCORE	Industrial	5.6	5.6	5.6	5.6	3
4		Subtotal	27.8	27.8	27.8	27.8	4
5	NON CORE	Non-EOR Cogeneration	2.0	2.0	2.0	2.0	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	7
8		Subtotal	2.0	2.0	2.0	2.0	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	30.8	30.8	30.8	30.8	14
15		Storage Injection	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		30.8	30.8	30.8	30.8	16
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.6	3.6	3.6	3.6	18
19		Non-EOR Cogeneration	1.8	1.8	1.8	1.8	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.4	5.4	5.4	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.4	5.4	5.4	5.4	24
	ACTUAL CURTAILMENT						
25		Residential	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	32

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

TABLE 41 – CITY OF LONG BEACH-ENERGY RESOURCES DEPARTMENT : TABLE 1A-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2020 CGR REPORT (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2024	2025	2030	2035	LINE
1	CORE	Residential	15.1	15.1	15.1	15.1	1
2	CORE/NONCORE	Commercial	7.2	7.2	7.2	7.2	2
3	CORE/NONCORE	Industrial	5.6	5.6	5.6	5.6	3
4		Subtotal	27.8	27.8	27.8	27.8	4
5	NON CORE	Non-EOR Cogeneration	2.0	2.0	2.0	2.0	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	7
8		Subtotal	2.0	2.0	2.0	2.0	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	30.8	30.8	30.8	30.8	14
15		Storage Injection	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		30.8	30.8	30.8	30.8	16
	ACTUAL TRANSPORTATION AND EXCHANGE						
17		Residential	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.6	3.6	3.6	3.6	18
19		Non-EOR Cogeneration	1.8	1.8	1.8	1.8	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.4	5.4	5.4	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.4	5.4	5.4	5.4	24
	ACTUAL CURTAILMENT						
25		Residential	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	32

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

2020 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 890,818 customers in San Diego County in 2019, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2019 were approximately 86 billion cubic feet (Bcf), which is an average of 235 MMcf/d.

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.

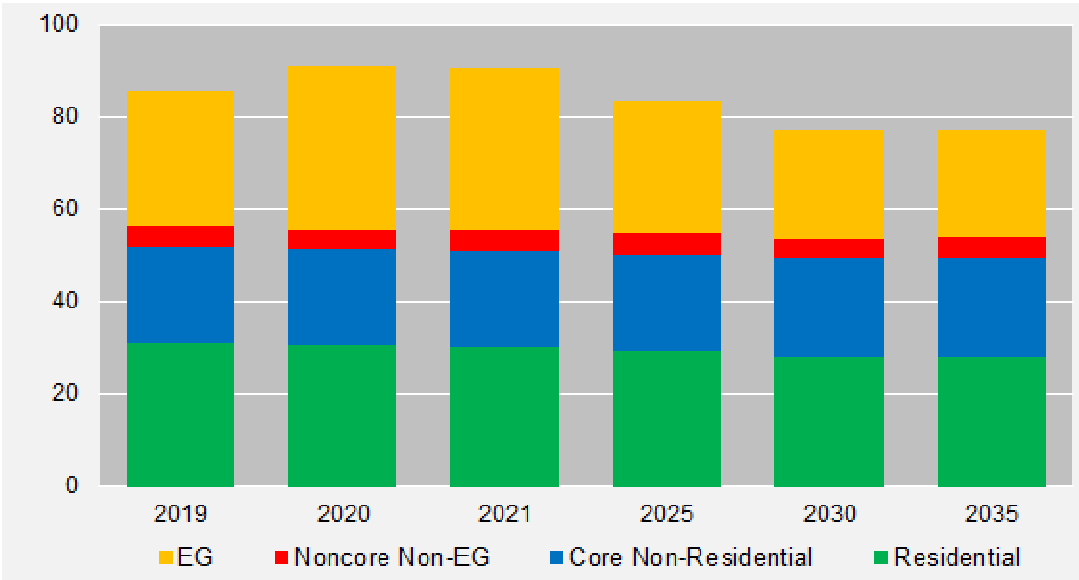
This projection of natural gas requirements, excluding EG demand, is derived from models that integrate demographic assumptions, economic growth, energy prices, energy efficiency programs, customer information programs, building and appliance standards, weather and other factors. Weather-normalized non-EG gas demand is projected to drop slightly from 57 Bcf in 2019 to 54 Bcf in 2035. Including EG, overall demand adjusted for average temperature conditions totaled 86 Bcf in 2019 and is expected to drop about 0.6 percent per year to 77 Bcf by 2035.

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 0.7 percent annually from 2019-2035; the subset of industrial (mining and manufacturing) jobs is projected to shrink an average of 0.3 percent per year during the same period. The number of SDG&E gas meters is expected to increase an average of 0.73 percent annually from 2019 through 2035.

FIGURE 22 – SDG&E'S COMPOSITION OF NATURAL GAS THROUGHPUT AVERAGE TEMPERATURE, NORMAL YEAR (2019-2035) (Bcf/y)



From 2019 through 2035, SDG&E's forecasted gas demand is expected to decline at an average annual rate of 0.6 percent. The decline is driven by future projected reductions in the EG load. Additional factors reducing the load forecast are energy efficiency programs and new requirements on Title 24 building codes and standards.

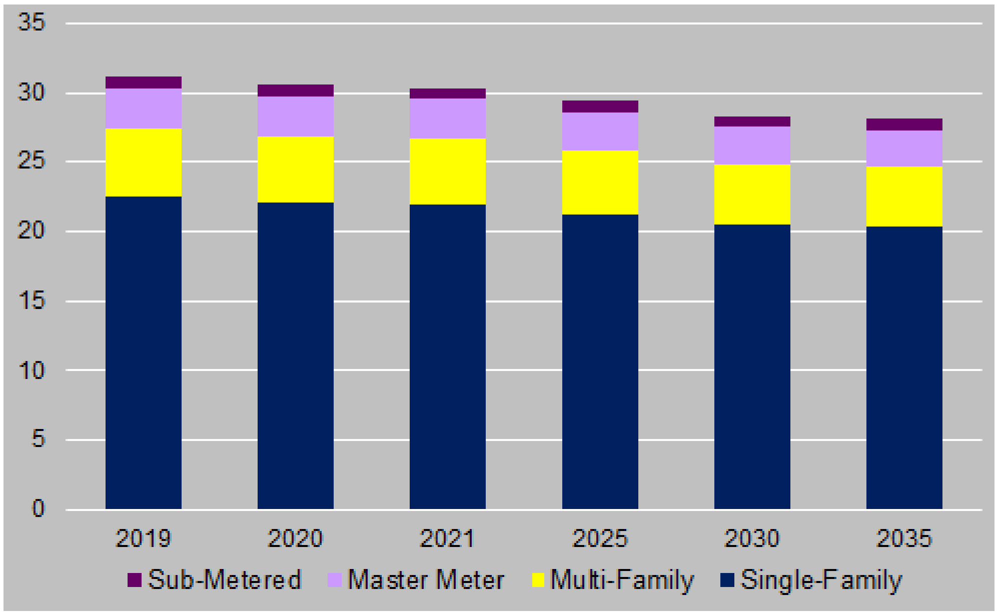
MARKET SECTORS

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. Residential demand adjusted for average temperature conditions totaled 31 Bcf in 2019. By the year 2035, the residential demand is expected to drop to 28 Bcf. The change reflects a 0.53 percent average annual rate of decline.

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

**FIGURE 23 – COMPOSITION OF SDG&E'S RESIDENTIAL DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN, 2019-2035
(Bcf/y)**

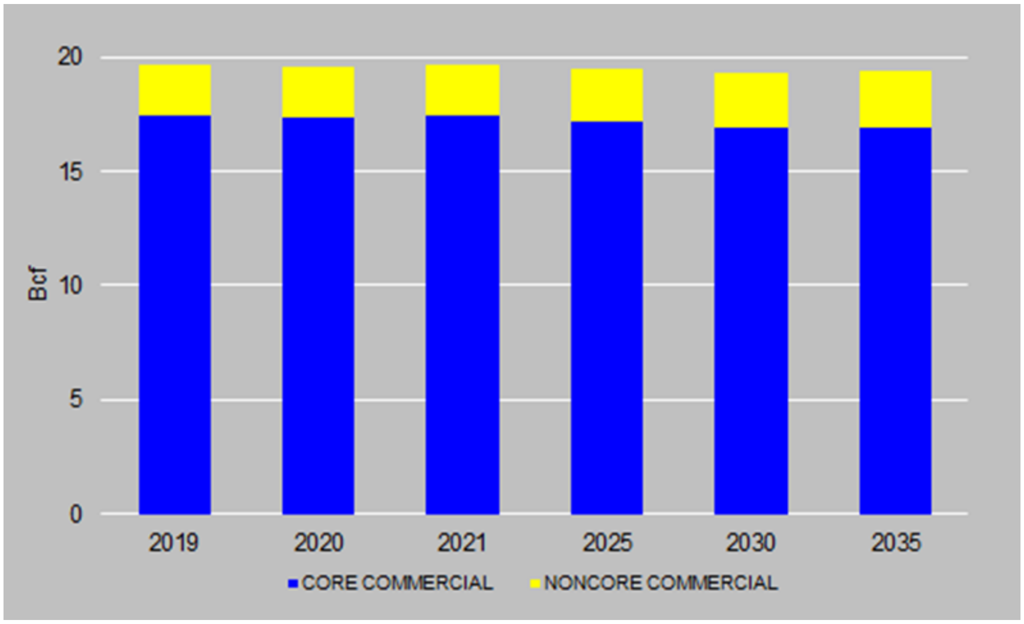


COMMERCIAL

On a temperature-adjusted basis, SDG&E's core commercial demand in 2019 totaled 17.4 Bcf. By the year 2035, the core commercial load is expected to decline slightly to 16.9 Bcf.

SDG&E's non-core commercial load in 2019 was 2.3 Bcf. Over the forecast period, gas demand in this market is projected to grow an average of 0.6 percent per year to 2.5 Bcf by 2035, driven by increased economic activity and employment.

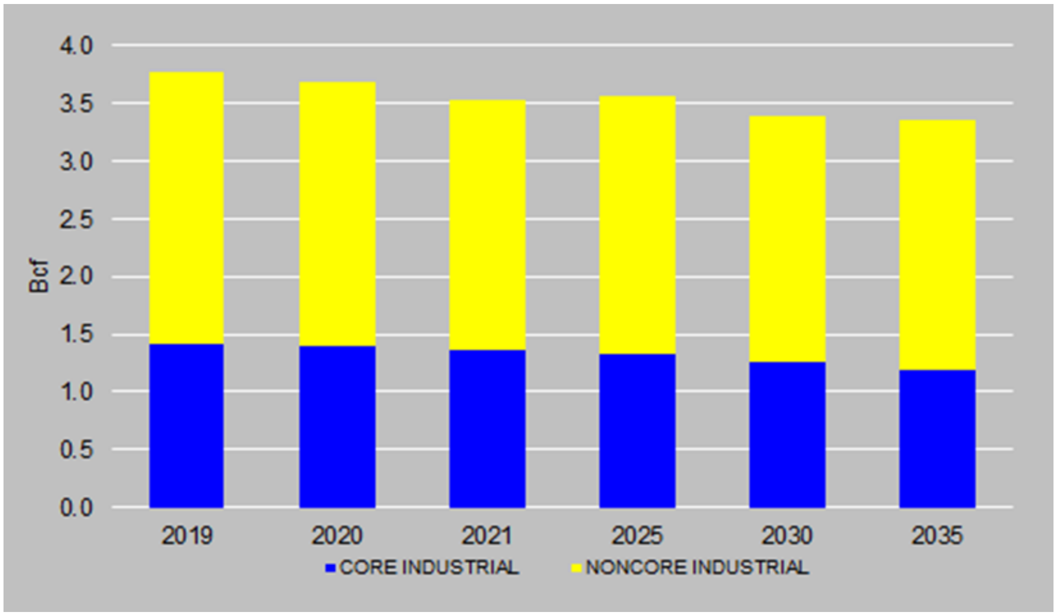
FIGURE 24 –SDG&E COMMERCIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN
(2019-2035)



INDUSTRIAL

Temperature-adjusted core industrial demand was 1.41 Bcf in 2019 and is expected to decline to 1.19 Bcf by 2035, an average decrease of 1.1 percent per year. This result is due to slightly lower employment growth and the impact of savings from CPUC-authorized energy efficiency programs in the industrial sector.

**FIGURE 25 –SDG&E INDUSTRIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN
(2019-2035)**

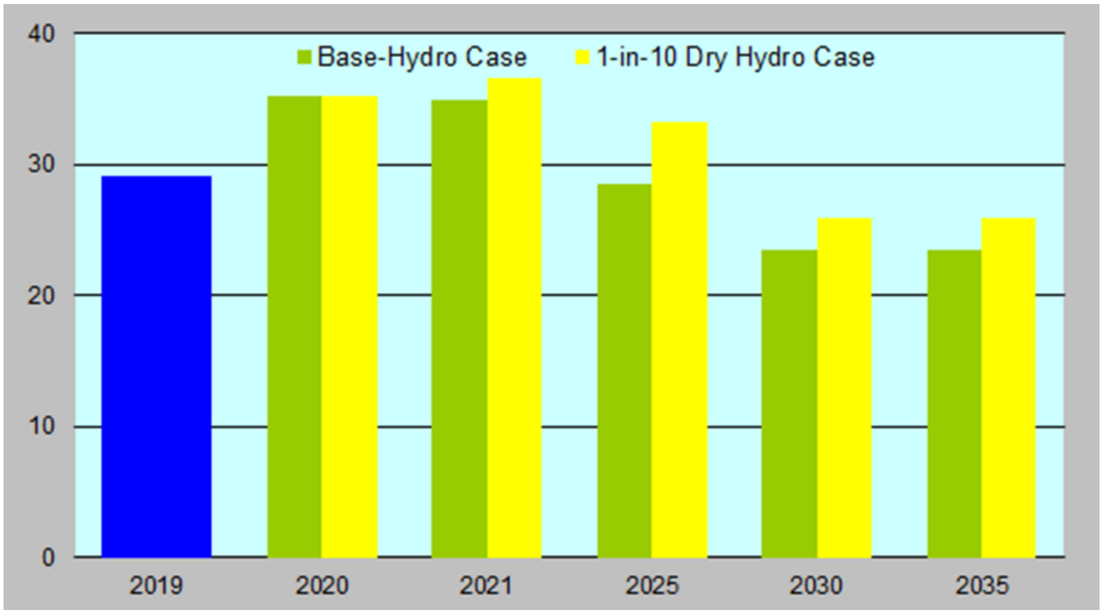


Non-core industrial load in 2019 was 2.4 Bcf and is expected to shrink about 0.6 percent per year to 2.2 Bcf by 2035. Demand-dampening effects of higher energy efficiency and higher carbon-allowance fees will more than offset slight increases from economic growth.

ELECTRIC GENERATION

Total EG, including cogeneration and non-cogeneration EG, was 29 Bcf in 2019. From 2019, EG load is expected to decline an average of 1.35 percent per year to 23 Bcf by 2035. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.

FIGURE 26 – SDG&E'S TOTAL EG GAS DEMAND: BASE HYDRO AND 1-IN-10 DRY HYDRO DESIGN, 2019-2035
(Bcf/y)



Small Cogeneration (<20 MW)

Small EG load from self-generation totaled 7.0 Bcf in 2019. By 2035, small EG load is expected to drop to 5.8 Bcf – dropping an average of 1.2 percent per year. Demand-dampening effects of higher carbon-allowance fees will more than offset slight increases from economic growth.

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 29 Bcf in 2020 to 18 Bcf in 2030. This forecast includes no additional thermal generating resources in its service area, and it assumes no retirement during the same time period. The EG forecast is held constant at 2030 levels through 2035, as previously explained.

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

NATURAL GAS VEHICLES

Natural gas is a clean-burning alternative vehicle fuel that offers several advantages to users when compared to diesel. According to the Clean Cities Guide to Alternative Fuel and Advanced Medium- and Heavy-Duty Vehicles by the U.S. DOE,[101] a switch from conventional diesel vehicles to NGVs has the potential to result in lower levels of emissions, including NOx and particulate matter. In 2019 alone, SDG&E's NGVs displaced the equivalent of 17 million gallons of gasoline and prevented around 75 thousand metric tons of emissions. Additionally, natural gas is generally less expensive than diesel or gasoline, which can become an attractive option for buyers in the heavy-duty vehicle industry.

SDG&E customers benefit from the LCFS credits generated from the gas consumed at utility owned CNG stations. The revenue from the sales is distributed to consumers as a price reduction at those fueling stations.

The clean vehicle market is expected to grow due to strong economic fundamentals, increased vehicle options, the continuation of government (federal, state and local) incentives, additional regulations encouraging alternative fuel vehicle adoption, and regional collaboration for the deployment of necessary infrastructure. Additionally, since April 2019 SDG&E has been procuring 100 percent renewable natural gas (RNG) at all utility-owned CNG stations, which provides significant GHG emission reduction benefits.

However, growth may be offset by competing technologies and fuels, as well as the potentially lower cost differential between petroleum (gasoline and diesel) and natural gas. In 2019, SDG&E served 33 compressed natural gas (CNG) fueling stations located throughout the service territory and delivered approximately 2 Bcf of natural gas. The SDG&E NGV market is expected to grow at an average annual rate of 3 percent over the forecast horizon.

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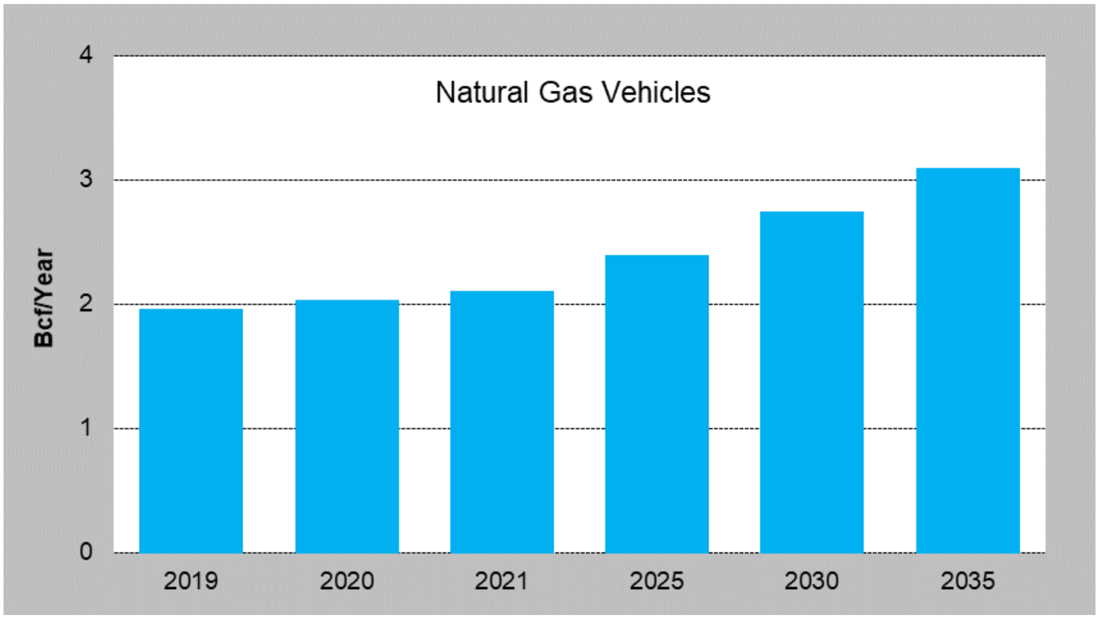
[101] U.S. DOE | Energy Efficiency & Renewable Energy: *Clean Cities Guide to Alternative Fuel and Advanced Medium- and Heavy-Duty Vehicles*.

FIGURE 27 – ANNUAL NGV DEMAND FORECAST

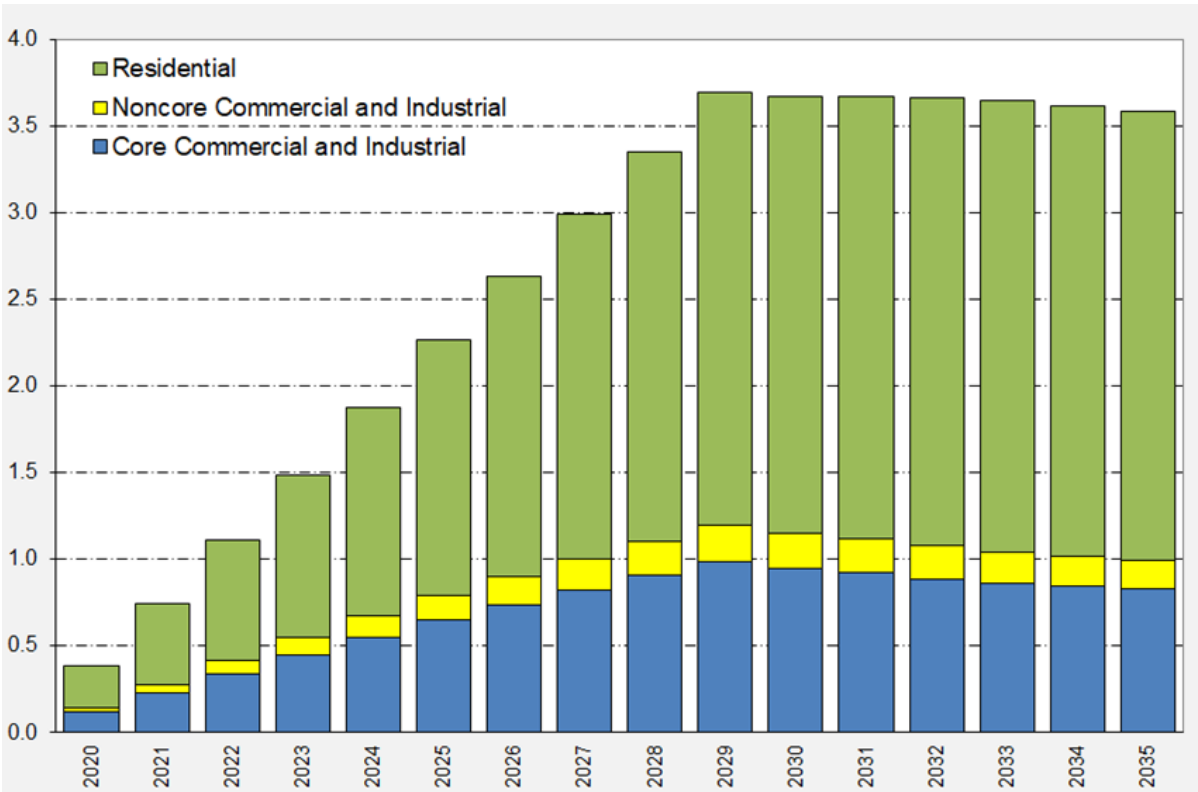


ENERGY EFFICIENCY PROGRAMS

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 2020 and occurring through the year 2035 in addition to the Title 24 Codes and Standards expected over the 2020-2035 horizon. Savings and goals for these programs are based on the program goals authorized by the Commission in D.19-08-034.

FIGURE 28 – SDG&E ANNUAL ENERGY EFFICIENCY CUMULATIVE SAVING GOALS (Bcf)



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.[102] 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.

102 "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 in 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 of December 6, 2007. For more information, refer above to the "Gas Supply, Capacity, and Storage" section in the Southern California part of this report.

REGULATORY ENVIRONMENT

GENERAL RATE CASE

On September 26, 2019, CPUC unanimously approved a final 2019 GRC decision that adopts a TY 2019 revenue requirement of $1.990 billion for SDG&E's combined operations ($1.590 billion for electric, $0.400 billion for gas) which is $213 million lower than the $2.203 billion (including OMEC) that SDG&E had requested in its Update testimony. The adopted revenue requirement represents an increase of $107 million or a 5.7 percent increase over 2018. The final decision adopts PTY revenue requirement adjustments for SDG&E of $134 million for 2020 (6.7 percent increase) and $102 million for 2021 (4.8 percent increase).

In January 2020 the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SDG&E was directed to file a PFM to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional five-year GRC period (2019-2023).

In April 2020 (then slightly revised in May), SDG&E filed a PFM of its 2019 GRC decision requesting attrition year increases of $94 million (+4.24 percent) for 2022 and $96 million (+4.13 percent) for 2023. SDG&E requested that a final decision be issued no later than October 1, 2020.

OTHER REGULATORY MATTERS

For more information on non-GRC regulatory matters, refer above to the "Regulatory Environment" section in the Southern California part of this report, which generally applies to SDG&E's gas business as well.

PEAK DAY DEMAND

Gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio that contains 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 and SDG&E) retail core peak day demand.

2020 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY – TABULAR DATA

TABLE 42 – SDG&E
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2015-2019

LINE			2015	2016	2017	2018	2019
	Actual Deliveries by End-Use						
1	**CORE**	Residential	67	71	72	70	81
2		Commercial	49	51	52	54	57
3		Industrial	0	-	-	-	-
4	*Subtotal -*	*CORE*	116	122	124	124	138
5	**NONCORE**	Commercial	0	-	-	-	-
6		Industrial	11	12	11	12	13
7		Non-EOR Cogen/EG	74	60	71	51	43
8		Electric Utilities	126	99	92	49	33
9	*Subtotal -*	*NONCORE*	211	171	174	112	89
10	**WHOLESALE**	All End Uses	0	-	-	-	-
11	*Subtotal -*	*Co Use & LUAF*	9	(3)	1	3	4
12	**SYSTEM TOTAL THROUGHPUT**		336	290	299	239	230
	Actual Transport & Exchange						
13	**CORE**	Residential	1	1	1	1	1
14		Commercial	12	13	13	14	14
15	**NONCORE**	Industrial	11	12	11	12	13
16		Non-EOR Cogen/EG	74	60	71	51	43
17		Electric Utilities	126	99	92	49	33
18	*Subtotal -*	*RETAIL*	224	185	188	127	103
19	**WHOLESALE**	All End Uses	0	-	-	-	-
20	**TOTAL TRANSPORT & EXCHANGE**		224	185	188	127	103
	Storage						
21		*Storage Injection*	0	-	-	-	-
22		*Storage Withdrawal*	0	-	-	-	-
	Actual Curtailment						
23		Residential	0	-	-	-	-
24		Com/Indl & Cogen	0	-	-	-	-
25		Electric Generation	0	-	-	-	-
26	**TOTAL CURTAILMENT**		0	-	-	-	-
27	**REFUSAL**		0	-	-	-	-
	ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes						
		MMbtu/Mcf:	1.040	1.036	1.040	1.038	1.032

TABLE 42 – SDG&E
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2015-2019
(CONTINUED)

LINE		2015	2016	2017	2018	2019
	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	2015	2016	2017	2018	2019
	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	112	105	111	112	127
18	Out-of-State Transport-Others	224	185	188	127	103
19	**Total Out-of-State Gas**	336	290	299	239	230
20	**TOTAL Gas Supply Taken & Transported**	336	290	299	239	230
	(MMCFD)					

TABLE 43 – SDG&E: TABLE 1-SDGE
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2020-2024
AVERAGE TEMPERATURE YEARS

LINE			2020	2021	2022	2023	2024	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		250	251	250	243	231	5
6	TOTAL SUPPLY TAKEN		250	251	250	243	231	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		250	251	250	243	231	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	83	83	83	82	81	9
10		Commercial	47	48	48	48	47	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	140	141	141	140	138	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	96	96	95	89	79	16
17		Subtotal-NONCORE	108	108	107	101	91	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		250	251	250	243	231	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	14	14	14	14	20
21	NONCORE	Commercial/Industrial	12	12	12	12	12	21
22		Electric Generation (EG)	96	96	95	89	79	22
23	TOTAL TRANSPORTATION & EXCHANGE		121	122	121	115	105	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 valu based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 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:

	2020	2021	2022	2023	2024
	131	131	131	130	128

TABLE 44 – SDG&E: TABLE 2-SDGE
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2025-2035
AVERAGE TEMPERATURE YEARS

LINE			2025	2026	2027	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	Southern Zone of SoCalGas		231	227	220	212	213	5
6	TOTAL SUPPLY TAKEN		231	227	220	212	213	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		231	227	220	212	213	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	81	80	79	77	77	9
10		Commercial	47	47	47	46	46	10
11		Industrial	4	4	4	3	3	11
12		NGV	7	7	7	8	8	12
13		Subtotal-CORE	139	138	137	134	134	13
14	NONCORE	Commercial	6	6	6	6	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	78	75	69	64	64	16
17		Subtotal-NONCORE	90	87	81	76	77	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		231	227	220	212	213	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	14	14	15	16	20
21	NONCORE	Commercial/Industrial	12	12	12	12	13	21
22		Electric Generation (EG)	78	75	69	64	64	22
23	TOTAL TRANSPORTATION & EXCHANGE		104	101	95	91	93	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 val based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 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:

	2025	2026	2027	2030	2035
transportation (CAT) in MDth/d:	129	128	127	123	122

TABLE 45 – SDG&E: TABLE 3-SDGE
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2020-2024
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

LINE			2020	2021	2022	2023	2024	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		260	270	271	263	251	5
6	TOTAL SUPPLY TAKEN		260	270	271	263	251	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		260	270	271	263	251	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	91	91	90	90	89	9
10		Commercial	49	49	49	49	49	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	150	150	149	149	148	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	96	106	108	100	89	16
17		Subtotal-NONCORE	108	118	120	112	101	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		260	270	271	263	251	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	14	14	14	14	14	20
21	NONCORE	Commercial/Industrial	12	12	12	12	12	21
22		Electric Generation (EG)	96	106	108	100	89	22
23	TOTAL TRANSPORTATION & EXCHANGE		122	132	134	126	115	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 val
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).
2/ For 2020 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:

	2020	2021	2022	2023	2024
transportation (CAT) in MDth/d:	140	140	139	139	138

TABLE 46 – SDG&E: TABLE 4-SDGE
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2025-2035
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

LINE			2025	2026	2027	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	Southern Zone of SoCalGas		253	248	242	230	229	5
6	TOTAL SUPPLY TAKEN		253	248	242	230	229	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		253	248	242	230	229	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	88	87	87	85	84	9
10		Commercial	49	48	48	48	48	10
11		Industrial	4	4	4	4	3	11
12		NGV	7	7	7	8	8	12
13		Subtotal-CORE	148	146	146	145	143	13
14	NONCORE	Commercial	6	6	6	6	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	91	88	82	71	71	16
17		Subtotal-NONCORE	103	100	94	83	84	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		253	248	242	230	229	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	15	15	15	15	16	20
21	NONCORE	Commercial/Industrial	12	12	12	12	13	21
22		Electric Generation (EG)	91	88	82	71	71	22
23	TOTAL TRANSPORTATION & EXCHANGE		118	115	109	98	100	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 val
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 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:

	2025	2026	2027	2030	2035
transportation (CAT) in MDth/d:	137	135	135	134	131

2020 CALIFORNIA GAS REPORT

GLOSSARY

GLOSSARY

A.
Application.

AAEE
Additional Achievable Energy Efficiency.

AB
Assembly Bill.

AMI
Advanced Metering Infrastructure.

APD
Abnormal Peak Day.

API
American Petroleum Institute.

A/S
Ancillary services.

Average Day (Operational Definition)
Annual gas sales or requirements assuming average temperature year conditions divided by 365 days.

Average Temperature Year
Long-term average recorded temperature.

Bcf
Billion cubic feet.

Bcf/d
Billion cubic feet per day.

Bcf/y
Billion cubic feet per year.

Btu (British thermal unit)
Unit of measurement equal to the amount of heat energy required to raise the temperature of one pound of water 1-degree F. This unit is commonly used to measure the quantity of heat available from complete combustion of natural gas.

CAISO
California Independent System Operator.

CalGEM
California Geologic Energy Management Division (formerly, DOGGR).

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

CARB
California Air Resources Board.

CCST
California Council on Science and Technology.

CDFA
California Department of Food and Agriculture.

CEC
California Energy Commission.

CFR
Code of Federal Regulations.

CGR
California Gas Report.

CNG (Compressed Natural Gas)
Fuel for NGVs, typically natural gas compressed to 3000 pounds per square inch.

CO_2
Carbon dioxide.

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 EG resource.

Commercial (SoCalGas and 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 EG, EOR, or gas resale activities with usage less than 20,800 therms per month.

Commission
California Public Utilities Commission (see also CPUC).

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

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

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 (MMBtu 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

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.

Core Customer (PG&E)
All customers with average usage less than 20,800 therms per month.

Core Customers (SoCalGas and 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 Subscription
Noncore customers who elect to use the LDC as a procurement agent to meet their commodity gas requirements.

COVID-19
Coronavirus Disease 2019.

CPUC
California Public Utilities Commission (see also Commission).

Cubic Foot of Gas
Volume of natural gas, which, at a temperature of 60 degrees 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.

D.
Decision.

DDRDP
Dairy Digester Research and Development Program.

DOE
Department of Energy.

DOGGR
California Division of Oil, Gas, and Geothermal Resources (now CalGEM).

ECA
Energia Costal Azul.

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

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

EO
Executive Order.

EOR (Enhanced Oil Recovery)
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.

EWG (Exempt Wholesale Generator)
A category of customers consuming gas for the purpose of generating electric power.

F
Fahrenheit.

FERC
Federal Energy Regulatory Commission.

FTA
Free Trade Agreement.

Futures (Gas)
Unit of natural gas futures contract trades in units of 10,000 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 (Green House Gas)
GHGs 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 GHGs are, in order of relative abundance are water vapor, CO_2, methane, nitrous oxide, ozone and CFCs.

GRC
General Rate Case.

GT&S
Gas Transmission and Storage.

GTN
Gas Transmission Northwest LLC.

H2
Hydrogen.

HDD (Heating Degree Day)
A HDD is accumulated for every degree F the daily average temperature is below a standard reference temperature (SoCalGas and SDG&E: 65 degrees F; PG&E 60 degrees F). A basis for computing how much electricity and gas are needed for space heating purposes. For example, for a 50 degrees 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 60 degrees F and a pressure base of 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 7 pounds or less per one million cubic feet, the natural gas shall be considered dry.

IEPR
Integrated Energy Policy Report.

ILI
In-Line Inspection.

Industrial (PG&E)
Non-residential customers not engaged in EG, EOR, or gas resale activities using more than 20,800 therms per month.

Industrial (SoCalGas and SDG&E)
Category of gas customers who are engaged in mining and in manufacturing.

IOU
investor-owned utility.

IRP
CPUC SB350 Integrated Resource Plan.

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 degrees F (-162 degrees C) and condensed into a liquid that takes up 600 times less space than in its gaseous state.

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

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

MHP
Mobile Home Park.

MMBtu
Million British thermal units. One MMBtu is equals to 10 therms or one dekatherm.

MMcf/d
Million cubic feet per day.

mmt
million metric tons.

mmtCO_2e
million metric tons of carbon dioxide equivalent.

mtCO_2e
metric tons of carbon dioxide equivalent.

MW
Megawatt.

MWh
Megawatt-hour.

NGSS
Natural Gas Storage Strategy.

NGTL
NOVA Gas Transmission Ltd.

NGV (Natural Gas Vehicle)
Vehicle that uses CNG or LNG as its source of fuel for its internal combustion engine.

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

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

Off-System Sales
Gas sales to customers outside the utility's service area.

OIR
Order Instituting Rulemaking.

OTC
once-through-cooling.

Out-of-State Gas
Gas from sources outside the state of California.

PFM.
Petition for Modification.

PG&E
Pacific Gas and Electric Company.

PHMSA
Pipeline and Hazardous Materials Safety Administration.

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); and
5. Market Center Services.

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 EG load;
- Up to 100 percent of non-EG noncore except for refineries;
- Up to 100 percent of refineries and up to 100 percent of the remaining dispatched EG load;
- Non-Residential Core customers; and
- Residential Core customers.

PSEP
Pipeline Safety Enhancement Plan.

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

Pub. Util. Code
Public Utilities Code.

Purchase from Other Utilities
Gas purchased from other utilities in California.

R.
Rulemaking.

R&D
Research and Development.

RIN
Renewable Identification Number.

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

Res.
Resolution.

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.

RG
Renewable Gas.

RGS
Renewable Gas Standard.

RNG
Renewable Natural Gas.

RP
Recommended Practice.

RPS
Renewables Portfolio Standard.

RSP
CPUC SB350 IRP Reference System Plan.

SB
Senate Bill.

SDG&E
San Diego Gas & Electric Company.

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

SLCP
Short-Lived Climate Pollutants.

SMUD
Sacramento Municipal Utility District.

SoCalGas
Southern California Gas Company.

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.

SWG
Southwest Gas Corporation.

SWRCB
State Water Resources Control Board.

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.

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.

UC
University of California.

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.

U.S.
United States.

USA
Underground Service Alert.

WACOG
Weighted average cost of gas.

WECC
Western Electricity Coordinating Council.

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.

2020 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 Energy Resources 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

- Eric Semelius - Statewide Chair- PG&E
- Todd Peterson - PG&E
- Anupama Pandey - PG&E
- Rose-Marie Payan - SoCalGas/SDG&E
- Sharim Chaudhury - SoCalGas/SDG&E
- Scott Wilder - SoCalGas/SDG&E
- Nasim Ahmed - SoCalGas
- Jeff Huang – SoCalGas/SDG&E
- Michelle Clay-Ijomah - SDG&E
- Gary Lenart - SoCalGas
- Preston Miller - Kern River

Observers

- Jean Spencer - CPUC
- Renee Guild - CPUC
- Munir Fellahi - CPUC
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Wild Goose
Sacramento
Pleasant Creek
Lodi Gas Storage
Los Medanos
McDonald Island
San Francisco
San Jose
Gill Ranch Storage
Fresno
Bakersfield
Needles
Topock
La Goleta
Honor Rancho
Santa Barbara
Los Angeles
Aliso Canyon
Blythe
Playa Del Rey
San Diego

2020 California Gas Report

Decision D.95-01-039

2022 California Gas Report

Prepared in Compliance with California Public Utilities Commission Decision

D.95-01-039

2022 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 Energy Resources Department
Southern California Edison Company

2022 CALIFORNIA GAS REPORT

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2022 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The *2022 California Gas Report* (CGR) 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 or Commission) Decision (D.) 95-01-039. The projections in the CGR 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), Southwest Gas Corporation (SWG), Wild Goose Storage, LLC., Central Valley Gas Storage, LLC., Gill Ranch 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 & 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.

2022 CALIFORNIA GAS REPORT

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

CALIFORNIA ENERGY MARKETS ARE EVOLVING

Serving the needs of customers and providing safe, reliable, and affordable services are top priorities among the participating investor owned utilities (IOUs). As we meet these needs, there is a growing realization that California energy markets are evolving. Though still undergoing transformation, the economic drivers, customer preferences, climate change, technological innovation, and policy will point out the road forward for our energy system.

The joint IOUs are committed to achieving our state's carbon goals and are taking steps to reduce the energy system carbon footprint, while continuing to serve the energy needs of our customers. More traditional solutions to reduce these emissions include, but are not limited to, conservation measures such as adjusting thermostats to lower baselines, where possible, and energy efficiency measures such as building and appliance improvements. Additional efforts are becoming increasingly important as well, such as efforts to diversify and decarbonize energy portfolios and sources by incorporating low-carbon and renewable fuels. Accelerating the adoption of these low-carbon and renewable energy sources will be critical to meeting carbon neutrality goals and will also be transformational for California's energy system.

Reducing reliance on traditional fuels (fossil fuels) comes with significant tradeoffs. From an economic standpoint it may be costly and is certainly not expected to be rapid or easy. Nonetheless, the push to find ways forward and to provide energy solutions to customers in a clean and affordable way is an imperative.

What is required is a concerted and sustained effort in addition to active participation across multiple sectors, alongside dialogue with all stakeholders with an interest in energy security. Clear communication between governments, industry, consumers and utility service providers is an essential focal point for successful implementation. Through open-minded dialogue, we can ensure a secure and sustainable energy future.

EXECUTIVE SUMMARY

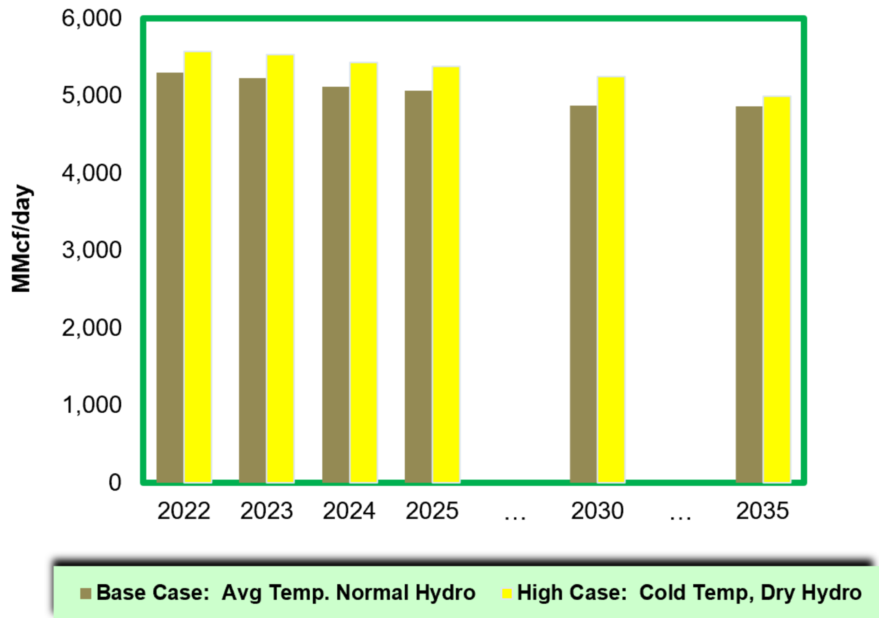
DEMAND OUTLOOK

Utility-served, statewide natural gas demand is projected to decrease at an annual average rate of 1.1 percent per year through 2035. The decline is 0.1 percent faster than what had been projected in the 2020 California Gas Report (CGR). More aggressive energy efficiency and fuel substitution have accelerated the decline in forecasted throughput for the 2022 CGR relative to the 2020 findings. In this Report, fuel substitution refers to the conversion of all or a portion of existing energy uses from one fuel type to another with the goal of reducing greenhouse gas emissions such as replacing a gas water heater with an electric water heater.

The projected decline comes from less gas demand in the major market segment areas of residential, electric generation (EG), commercial and wholesale markets. Total Statewide residential gas demand is projected to decrease at an annual average rate of 2.4 percent per year, a faster decline than the 1.7 percent annual rate of decline that had been forecasted in the 2020 Report. EG demand is projected to decrease at an annual rate of 1.1 percent per year, which is a slightly less rapid rate than the 1.5 percent annual decline that had been forecasted in 2020. The statewide commercial demand is projected to decrease at an annual average rate of 1.8 percent per year, which is slightly more accelerated than the 1.5 percent annual decline from the 2020 CGR. The aggregate statewide wholesale market segment is expected to decline at an annual average rate of 0.25 percent per year. The segments where growth in demand is expected are the natural gas vehicle (NGV) sector and the industrial market segments. The industrial market segment and the NGV sectors are expected to grow at an annual average rate of 0.16 percent and 2.3 percent per year over the forecast period.

There are several drivers of these declines across many of the key energy sectors. Aggressive energy efficiency programs and fuel substitution are expected to dampen gas demand in these sectors. Statewide efforts to minimize greenhouse gas (GHG) emissions are depressing EG demand through aggressive programs that pursue demand side reductions and the acquisition of preferred power generation resources that produce few or no carbon emissions. Nevertheless, for the foreseeable future, gas-fired generation and gas storage will continue to be important technologies that support long-term electric demand growth and growing integration of intermittent renewable resource generation.

FIGURE 1 – CALIFORNIA GAS DEMAND OUTLOOK: 2022-2035



The graph above summarizes statewide gas demand under the Average Demand case (base case) and the Cold Weather, Dry Hydroelectric Generation[1] case (high case). The base case refers to the expected gas demand for an average temperature year and normal hydroelectric generation (hydro) year, and the high case refers to expected gas demand for a cold temperature year and dry hydro conditions. Under the base case, gas demand for the entire state is projected to average 5,298 million cubic feet of gas per day (MMcf/d) in 2022 decreasing to 4,857 MMcf/d by 2035, a decline of 0.67 percent per year.

Compared to the Average Year forecast, the Northern California high demand scenario is 3.3 percent higher in year 2022 while the Southern California demand is 3.0 percent higher for the same year.

[1] Hydroelectric generation refers to generation within the Western Electricity Coordinating Council (WECC).

EXECUTIVE SUMMARY

FOCUS ON ENERGY EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on conservation and energy efficiency. The IOUs are committed to helping their customers make the best possible energy decisions and helping customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. An important role of the energy efficiency programs includes services, administered by the respective utilities, to help customers evaluate their energy efficiency options and adopt recommended solutions, as well as equipment-retrofit improvements, such as rebates for new hot water heaters and space heaters.

Gas demand for electric power generation is expected to be dampened by statewide GHG reduction goals and electric energy efficiency programs and additional renewable power generation. Both demand forecasts assume that renewable power will meet the CPUC 2021 Integrated Resource Plan Preferred System Plan (IRP PSP).

Renewable power capacity additions are driven, in part, by Senate Bill (SB) 100. Passed in 2018, SB 100 increased and accelerated the Renewables Portfolio Standard (RPS) targets and established the policy goal that zero carbon energy resources supply 100 percent of electric retail sales to end-use customers by the year 2045. One major milestone will occur by 2030, when renewable power generation will generate at least 60 percent of retail electric sales. The currently approved IRP PSP helps the state move towards attainment of this goal.

Additional California legislation and policy direction[2] provides directives and incentives to increase energy efficiency. Some of these efforts require access to building performance data, encouraging pay-for-performance incentive-based programs, and the use of energy management technology for use in homes and businesses. Moreover, legislation requires energy utilities to develop a plan to educate residential customers and small and medium business customers about the incentive programs. The programs and targets must meet three requirements: (1) they must be cost-effective; (2) they must be feasible; and (3) they should not adversely impact the environment. In recent years, California has increasingly focused on the potential for fuel substitution to address GHG emission reduction goals. The Commission has developed a

[2] For more information, see https://www.cpuc.ca.gov/energyefficiency/.

baseline for analyzing and evaluating energy efficiency and fuel substitution using a code baseline, industry standard practice and existing conditions. So far, the Commission standard requires that the fuel substitution measure must both save energy and not harm the environment as measured by GHG emissions.

EXECUTIVE SUMMARY

CALIFORNIA'S LONG-TERM CLIMATE GOALS AND THE ENERGY TRANSITION: FUTURE GAS SYSTEM IMPACTS

California is facing the ambitious goal of economy-wide carbon neutrality by 2045 or sooner and has adopted a suite of policies that begin to move the State towards this goal. Many of these policies are discussed more specifically elsewhere in this Report, but there are still many unknowns about the exact timing and path of the energy transition. The current policy landscape does suggest that there will be significant changes to the way Californians use energy. California natural gas utilities are actively participating in, studying and monitoring this evolution.

While much uncertainty remains about the exact path California will take, the gas utilities recognize it is probable that two segments of natural gas customers in particular may potentially face substantial change – natural gas-fired electric generation (EG) and core (mainly residential and commercial buildings), as discussed above. Today, California relies on gas-fired EG, hydroelectric generation, and growing battery resources to balance its electric grid – a role that will likely persist through the energy transition. This role will evolve, however, as fuel-based electric generation is displaced by increasing amounts of solar and wind to meet energy decarbonization goals. While this is likely to result in less natural gas being used by the EG segment, gas fired EG is forecasted to be an important resource for providing electricity when intermittent renewables or variable hydroelectric generation are not available. This means that peak EG load could persist or grow while usage pattern will become more volatile and less predictable. This could have a greater influence over peak natural gas system design conditions and, accordingly, costs.

At the same time, decarbonization goals will accelerate energy efficiency and support fuel substitution for natural gas end-uses in the core building segment. This is likely to result in declining core gas use over time. The core segment currently contributes the majority of the gas utilities' revenue requirements. These issues combined, among other trends and factors, create the impetus for an evolved approach to natural gas and clean fuels in California – from perspectives of system design, financial, and rate reform. These issues are highlighted in this Report and the subject of the Long-term Gas Reliability and Planning Proceeding (R.20-01-007) currently in Track 2 at the CPUC.

One element of the energy transition and attaining the State's decarbonization goals is building electrification also known as fuel substitution. The gas utilities' forecasts have incorporated these evolving forecasts, including collaborating with the CEC developed fuel substitution scenarios. The state is in the early stages of the energy transition. Forecasts around the timing and degree of these changes are highly uncertain. These forecasts will improve over time as trends are observed in the real world and as policy and market drivers mature. The gas utilities will be actively monitoring these trends and expect that each update of the biannual California Gas Report will further refine these factors and their impacts on resultant gas demand forecasts.

It is important to note that the California Gas Report is relied upon for system planning purposes to help benchmark investment and operating policies that impact natural gas system capacity and reliability. The gas utilities recognize the need to evolve with the government-mandated energy transition. The utilities also recognize the necessity of maintaining flexibility during the energy transition to ensure California gas customers have safe, clean, reliable, and affordable sources of energy.

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. One challenge with renewable resources is that while they provide energy, the amounts are not always predictable and are not always immediately dispatchable.

The increase in future renewable generation in the state will reduce the total amount of natural gas usage. It is also expected that the increasing and intermittency of renewable generation will add to the daily and hourly load forecast variance on the gas-fired EG fleet. In the long-term, balancing electric supply and demand may come through the higher expected integration of energy storage devices (e.g., batteries, fuel cells, and hydroelectric pumped storage).

Due to the expansion of intermittent renewable resources, there may be an increased need for rapid response, gas-fired generators to follow electric net load fluctuations. 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 and continue to support electric reliability.

The expected growth in electrification poses considerable uncertainty on when, where, and how large the impacts will be on gas demand. In the building sector, electrification could decrease gas use. Recently, some California local jurisdictions have forbidden the use of gas in new building construction. Moreover, there are some indications that jurisdictions may actively pursue appliance substitution away from natural gas and to the electric alternative(s). The expected growth in electrification of vehicles and buildings would result in increasing electric load that could create a need for additional use of gas-fired generators.

Further adding to gas demand variance is the impact of natural gas burner-tip prices. Burner-tip gas prices represent what gas utility customers pay at their premises. For EG, relative geographic burner-tip prices impact generation dispatch economics. If prices in one portion of the state are higher or lower than another portion, gas demand can vary accordingly.

GAS PRICE FORECAST

MARKET CONDITIONS

The natural gas industry has experienced multiple changes over the past two decades. Gas supply rapidly grew on the back of the shale gas revolution. More recently, gas supply growth has come from the rise of associated gas production from tight oil supply growth. Additionally, Liquefied Natural Gas (LNG) export demand has grown rapidly. Since the end of 2021, the European Union (EU) and United Kingdom (UK) imported record-high LNG volumes because of low natural gas inventories and interrupted gas pipeline supplies. As a result, the North American gas market has seen gas prices fluctuate. To exemplify this price variation, the U.S. EIA[3] reported the national benchmark price at Henry Hub was about $3/Million British thermal units (MMBtu) in early June 2021. One year later, the gas price was about $8.50/MMBtu.

Natural gas prices have risen, relative to the 2020 outlook, mainly because of five factors. First, the North American natural gas inventories have fallen below the five-year average. Second, there has been steady demand in U.S. LNG exports due to European natural gas shortages, which have been exacerbated by the war in Ukraine. Europe has become the main destination for U.S. LNG exports and accounted for 74 percent of total U.S. LNG exports during the first 4 months of 2022. Third, the current U.S. Administration is restricting licensing and drilling for traditional fuels including natural gas. Fourth, high demand for natural gas being driven by the growing needs of the electric power sector in the U.S. as a whole. Lastly, natural gas production investment has lagged behind the rapid growth of gas demand over the past year.

For the 2022 CGR, the gas price outlook[4] reflects market conditions in early 2022. The 2022 near term gas price average at the California city-gates[5] is a little above $5.00/MMBtu. During the mid-2020s, gas prices are projected to decline to approximately $4.00/MMBtu.

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[3] U.S. Energy Information Administration https://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm.

[4] Nominal dollars.

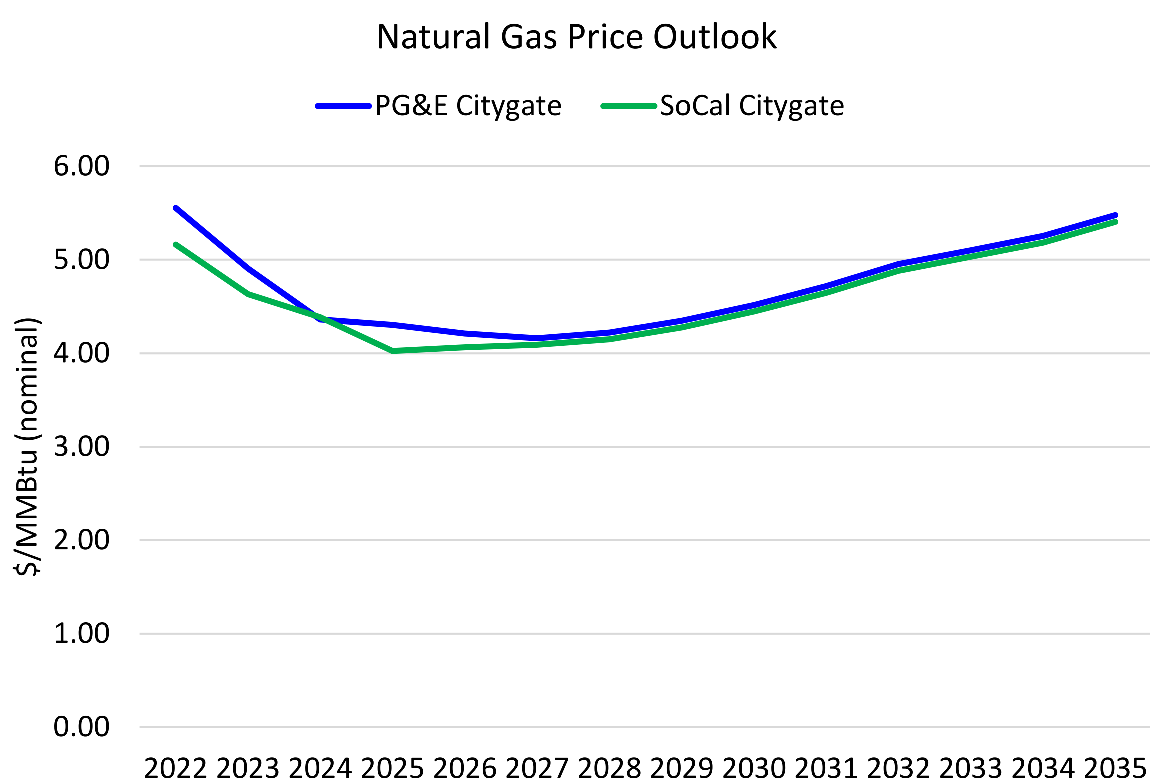
[5] The two Citygate price hubs are the Southern California Gas Company Citygate (SoCal Citygate) and the Pacific Gas and Electric Citygate (PG&E Citygate).

Industry experts forecast that gas prices will increase about $1.50/MMBtu thereafter to average approximately $5.50/MMBtu by year 2035.

Development of the Gas Price Forecast

The 2022 CGR gas price forecast was developed using a combination of market prices and fundamental long -term forecasts. For the 2022 through 2027 period, the gas prices represent a blend of contract futures prices from the Chicago Mercantile Exchange and S&P Global[6] basis differentials to Henry Hub. For 2030 and beyond, S&P Global fundamental price forecasts were used. The forecasts for 2028 and 2029 reflect a blending of futures prices and fundamental prices.

FIGURE 2 – FORECASTED NATURAL GAS PRICES



[6] S&P Global Commodity Insights North American Gas Regional Short-Term Forecast, March 22, 2022.

It is important to recognize that natural gas price forecasts are inherently uncertain. The price forecast used in the Report were developed in early 2022. The prices seen in much of the first half of 2022 have been materially higher than the prices in the forecast. Additionally, gas prices have seen significant volatility.

PG&E, SoCalGas, and the respondents of the 2022 CGR, separately and collectively, do not warrant the accuracy of the gas price projections. PG&E, SoCalGas, or the respondents of the 2022 CGR shall not be liable or responsible for the use of or reliance on this natural gas price forecast.

GAS SUPPLY

California's existing gas supply portfolio is regionally diverse and provides long -term supply availability. Gas production that California has access to includes California (onshore and offshore), Southwestern U.S. (the Permian, Anadarko, and San Juan basins), the Rocky Mountains, and Canada.

California natural gas utilities and customers gain access to this diverse supply portfolio using an extensive pipeline system. Interstate pipelines serving California include Ruby Pipeline LLC, El Paso Natural Gas Company, Kern River Transmission Company, Mojave Pipeline Company, Gas Transmission Northwest LLC (GTN), Transwestern Pipeline Company, Tuscarora Pipeline, and the Baja Norte/North Baja Pipeline. The map on the following page shows the locations of these supply sources and the natural gas pipelines serving California.

FIGURE 3 – WESTERN NORTH AMERICAN NATURAL GAS PIPELINES

1. West Coast Pipeline
2. Woodfibre LNG Terminal
3. Terasen Sumas Gas Pipeline
4. TransCanada Pipeline
5. Alliance Pipeline
6. Northern Border Pipeline
7. Gas Transmission Northwest (GTN Pipeline
8. Northwest Pipeline
9. Jordan Cove LNG (Proposed)
10. Pacific Connector (Proposed)
11. Tuscarora Gas Transmission
12. Paiute Pipeline
13. Ruby Pipeline
14. Questar Pipeline
15. Rockies Express Pipeline
16. Southern Star Pipeline
17. TransColorado Pipeline
18. Kern River Pipeline
19. Pacific Gas and Electric Company
20. Southern California Gas Company
21. San Diego Gas and Electric Company
22. North Baja Pipeline
23. El Paso Natural Gas
24. TransWestern Pipeline
25. Rosarito Pipeline
26. Trasnportadora de Gas Natural (TGN)
27. Costa Azul LNG

California benefits from substantial gas storage capacity in dedicated gas storage facilities across the state. These gas storage facilities supplement pipeline gas supply during high demand periods and also provide supply reliability. Additionally, storage allows gas customers to take advantage of low prices and store gas for use in periods with higher prices. Various regulations and standards[7] have been implemented to ensure safe and reliable operations of California gas storage facilities. The table below gives the current status of gas storage capacity in California.

Table 1: California Natural Gas Storage Capacities

Recorded Year 2021

	Inventory (Bcf)	Injection (MMcf/d)	Withdrawal (MMcf/d)	Cite
Northern California				
Independent Storage Providers				1
Lodi Gas Storage	31	552	750	
Wild Goose Storage	75	525	950	
Gill Ranch	15	165	162	
Central Valley	11	300	300	
Pacific Gas & Electric Company-Utility Storage***	35	315	1,144	2
Northern California Total	167	1,857	3,306	
Southern California				
Southern California Gas Company-Utility Storage	137	790	2,660	3
California Total	375	3,432	7,995	

Citations

1) Capacities derived from information provided by Independent Storage Providers
2) ***Firm maximum inventory level
3) Per the current active Triennial Cost Allocation Proceeding, D 20-02-045

[7] See Geologic Energy Management Division's Underground Natural Gas Storage for more details on regulations and standards at: https://www.conservation.ca.gov/calgem/Pages/UndergroundGasStorage.aspx.

In addition to traditional sources of gas supply, multiple Renewable Natural Gas (RNG) interconnection projects in California have come online in recent years. As further detailed in this CGR, gas utilities see broad potential for RNG in California and are taking significant steps to make RNG interconnection easier and more transparent. As policies evolve and new programs are created, such as California's recently approved Renewable Gas Standard, we expect RNG to play a growing role in serving customers' energy needs beyond the transportation sector. Currently, incentive programs such as California's Low Carbon Fuel Standards (LCFS) and the federal Renewable Fuel Standard (RFS) are successfully supporting the use of RNG in the transportation sector.

As California continues towards achieving a decarbonized energy system, hydrogen (H_2) will become an important fuel source in achieving the State's emissions goals. There is growing potential for generating renewable H_2[8] and storing and delivering it using existing gas utility infrastructure to help meet California's dynamic energy needs. Hydrogen pathways can provide exceptional and important value, such as long-duration, high capacity and high energy storage capabilities relative to other clean energy storage technologies.

LIQUEFIED NATURAL GAS

In years past, the U.S. imported LNG to supplement North American supplies. Since the mid-2010s, LNG imports have primary been used to serve peak winter load. However, U.S. imports of LNG have been declining since 2008. Since this time, the development of low-cost domestic shale gas supplies largely eliminated the need for LNG imports. Since 2016, the U.S. has been exporting LNG.

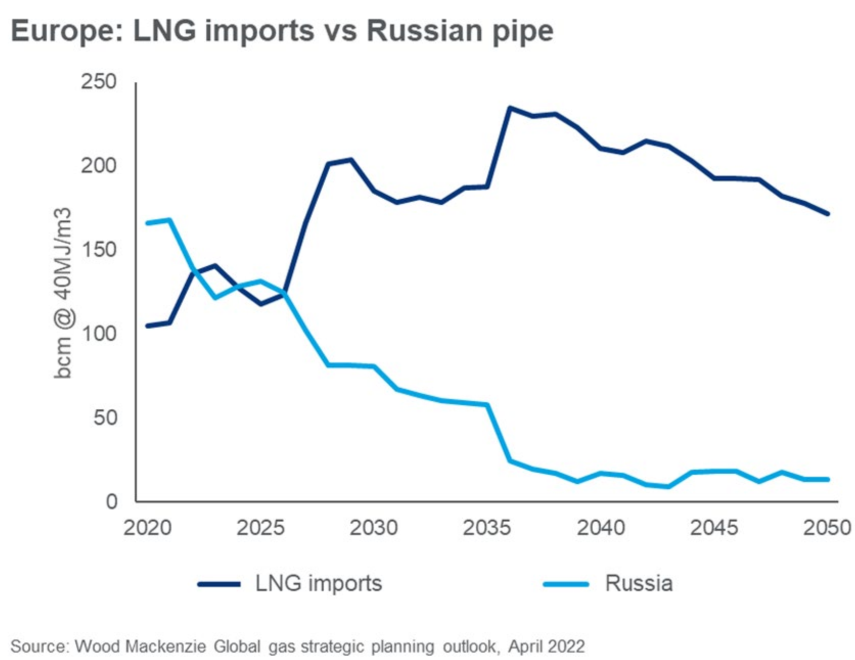
LNG exports are expected to continue growing. Current economic conditions and the sanctions imposed on Russia in response to its invasion of Ukraine have exacerbated natural gas shortages, primarily in Europe. The outlook suggests that LNG will continue to expand and grow because world needs are expanding.

[8] Renewable hydrogen is hydrogen produced by renewable electricity, hydrogen derived from biomethane, or hydrogen derived from biomass using a thermal conversion process.

LNG is expected to help meet European heating load needs as well as its gas fired EG demand. Published studies have found that although the average CO_2 emissions have declined over the last decade, marginal emissions have not decreased, but rather increased slightly due primarily to countries' reliance on coal to satisfy marginal electricity use.[9] Flowing LNG supplies to Europe may mitigate the environmental impact of the forecasted energy shortage in Europe. The chart below illustrates the outlook that industry experts are projecting to sustain LNG demand growth in the European countries including the UK and Turkey for the next twelve years, with demand subsiding somewhat after 2034.

Worldwide LNG demand is expected to almost double from current levels by the year 2040. According to industry experts, the U.S. is expected to become the largest LNG exporter in 2022, leap-frogging Australia and Qatar. Industry surveys of global LNG developers have indicated plans to accelerate the expansion of operations to meet the growth in overseas demand over the long-term**.**

Figure 4 - LNG Outlook



[9] "Why are Marginal CO_2 Emissions Not Decreasing for Electricity? Estimates and Implications for Climate Policy," by Stephen Hallard, Matthew Kotchen, Erin Mansur and Andrew Yates. Presented at the 2022 American Economic Association annual meetings.

EXECUTIVE SUMMARY

In the next few years, LNG export facilities will begin operations in Western Canada and Western Mexico. In the US, exports are expected to increase as global demand for LNG grows. The following maps illustrate (1) Existing U.S. LNG export terminals; (2) U.S. export terminals approved but not yet built; and (3) U.S. LNG export terminals proposed and being evaluated whose application status is in the process of being reviewed.

Figure 5

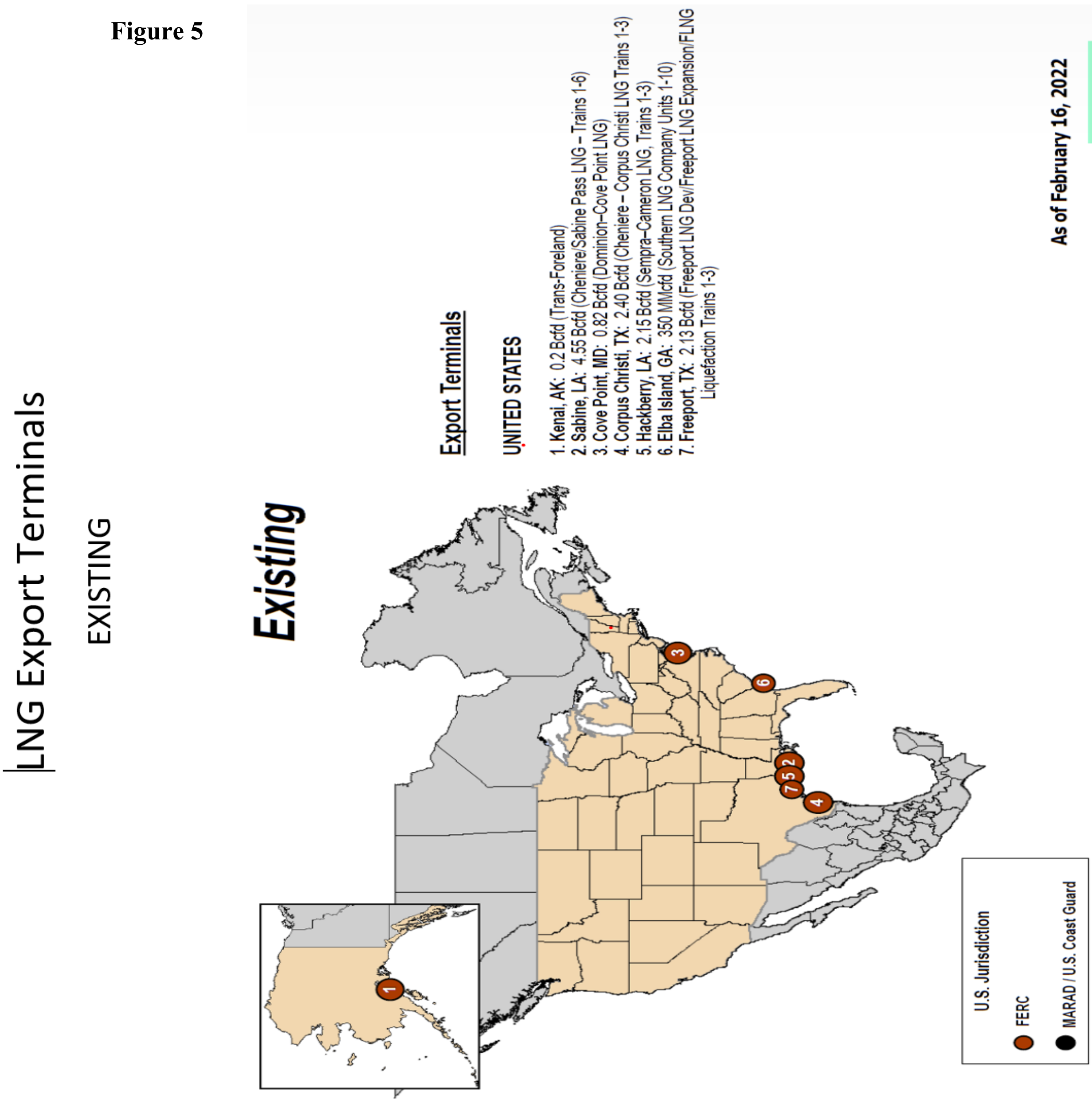
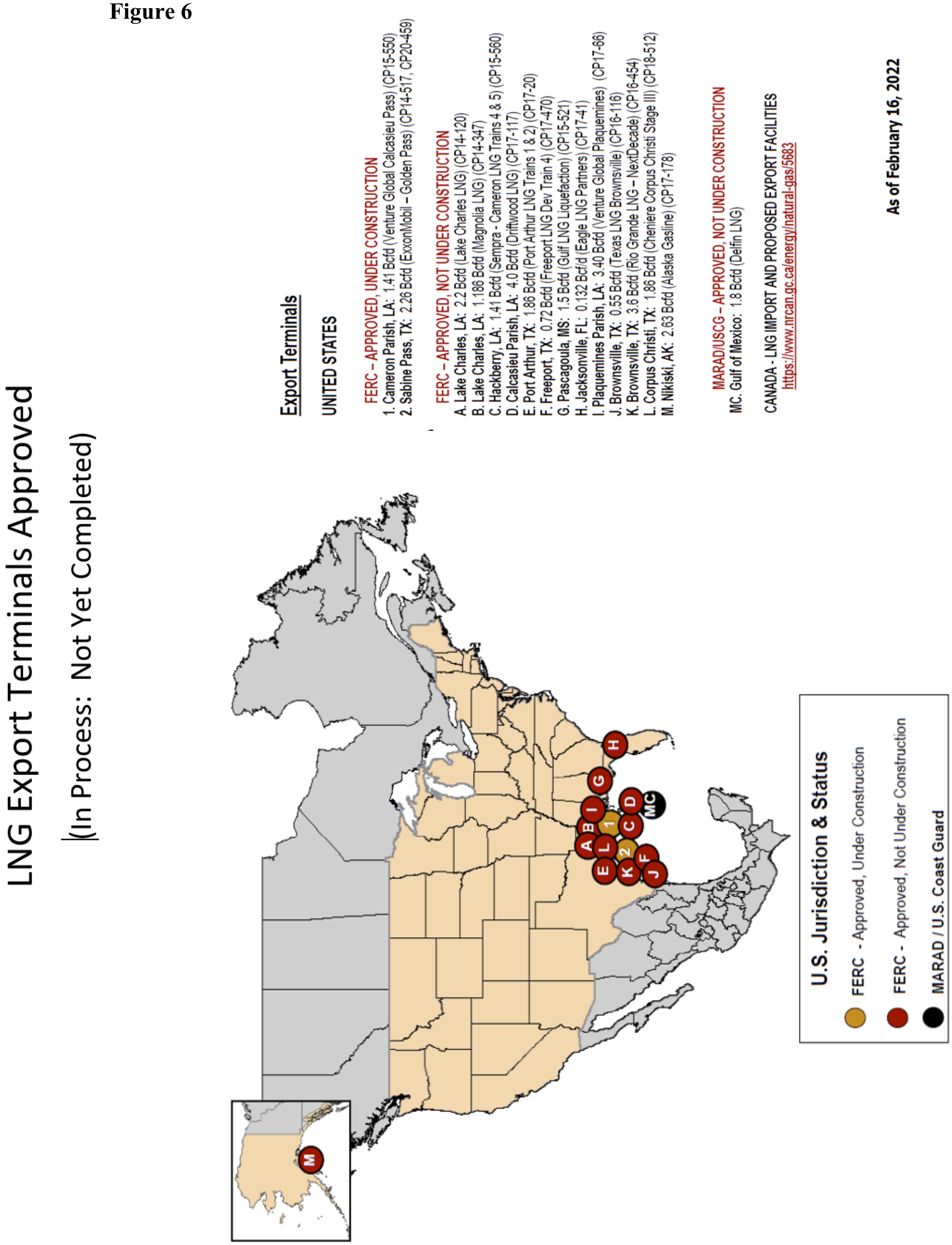

LNG Export Terminals
EXISTING
Existing
Export Terminals
UNITED STATES
1. Kenai, AK: 0.2 Bcfd (Trans-Foreland)
2. Sabine, LA: 4.55 Bcfd (Cheniere/Sabine Pass LNG – Trains 1-6)
3. Cove Point, MD: 0.82 Bcfd (Dominion–Cove Point LNG)
4. Corpus Christi, TX: 2.40 Bcfd (Cheniere – Corpus Christi LNG Trains 1-3)
5. Hackberry, LA: 2.15 Bcfd (Sempra–Cameron LNG, Trains 1-3)
6. Elba Island, GA: 350 MMcfd (Southern LNG Company Units 1-10)
7. Freeport, TX: 2.13 Bcfd (Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction Trains 1-3)
As of February 16, 2022
U.S. Jurisdiction
FERC
MARAD / U.S. Coast Guard

Figure 6


LNG Export Terminals Approved
(In Process: Not Yet Completed)
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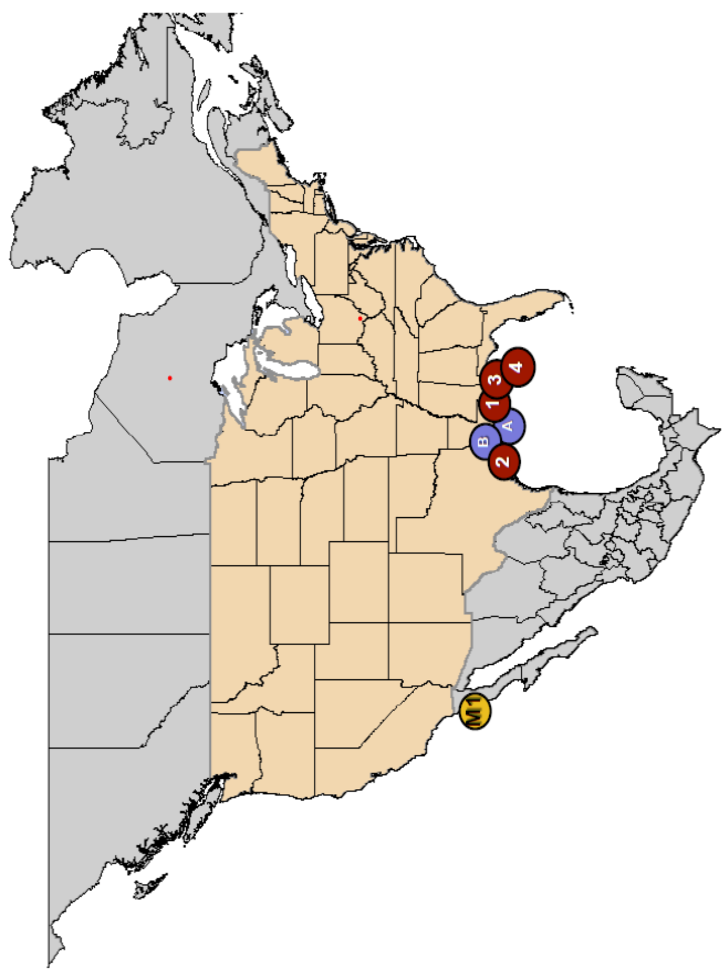
U.S. Jurisdiction & Status
FERC - Approved, Under Construction
FERC - Approved, Not Under Construction
MARAD / U.S. Coast Guard
Export Terminals
UNITED STATES
FERC – APPROVED, UNDER CONSTRUCTION
1. Cameron Parish, LA: 1.41 Bcfd (Venture Global Calcasieu Pass) (CP15-550)
2. Sabine Pass, TX: 2.26 Bcfd (ExxonMobil – Golden Pass) (CP14-517, CP20-459)
FERC – APPROVED, NOT UNDER CONSTRUCTION
A. Lake Charles, LA: 2.2 Bcfd (Lake Charles LNG) (CP14-120)
B. Lake Charles, LA: 1.186 Bcfd (Magnolia LNG) (CP14-347)
C. Hackberry, LA: 1.41 Bcfd (Sempra - Cameron LNG Trains 4 & 5) (CP15-560)
D. Calcasieu Parish, LA: 4.0 Bcfd (Driftwood LNG) (CP17-117)
E. Port Arthur, TX: 1.86 Bcfd (Port Arthur LNG Trains 1 & 2) (CP17-20)
F. Freeport, TX: 0.72 Bcfd (Freeport LNG Dev Train 4) (CP17-470)
G. Pascagoula, MS: 1.5 Bcfd (Gulf LNG Liquefaction) (CP15-521)
H. Jacksonville, FL: 0.132 Bcf/d (Eagle LNG Partners) (CP17-41)
I. Plaquemines Parish, LA: 3.40 Bcfd (Venture Global Plaquemines) (CP17-66)
J. Brownsville, TX: 0.55 Bcfd (Texas LNG Brownsville) (CP16-116)
K. Brownsville, TX: 3.6 Bcfd (Rio Grande LNG – NextDecade) (CP16-454)
L. Corpus Christi, TX: 1.86 Bcfd (Cheniere Corpus Christi Stage III) (CP18-512)
M. Nikiski, AK: 2.63 Bcfd (Alaska Gasline) (CP17-178)
MARAD/USCG – APPROVED, NOT UNDER CONSTRUCTION
MC. Gulf of Mexico: 1.8 Bcfd (Delfin LNG)
CANADA - LNG IMPORT AND PROPOSED EXPORT FACILITIES
https://www.nrcan.gc.ca/energy/natural-gas/5683
As of February 16, 2022

Figure 7

LNG Export Terminals
PROPOSED & Under Evaluation



UNITED STATES

PROPOSED TO FERC
Pending Applications:
1. Cameron Parish, LA: 1.18 Bcfd (Commonwealth, LNG) (CP19-502)
2. Port Arthur, TX: 1.86 Bcfd (Sempra - Port Arthur LNG Trains 3 & 4) (CP20-55)
3. Cameron Parish, LA: 1.45 Bcfd (Venture Global CP2 Blocks 1-9) (CP22-21)
4. Cameron Parish, LA: .057 Bcfd (Venture Global Calcasieu Pass) (CP22-25)

Projects in Pre-filing:
A. LaFourche Parish, LA: 0.65 Bcfd (Port Fourchon LNG) (PF17-9)
B. Plaquemines Parish, LA: 2.76 Bcfd (Delta LNG - Venture Global) (PF19-4)

CANADA
For Canadian LNG Import and Proposed Export Facilities:

https://www.nrcan.gc.ca/energy/natural-gas/5683

MEXICO (Projects in advanced planning/development stages)
M1. Baja California, MX: 0.4 Bcfd (Sempra – Energía Costa Azul Phase 1)

As of February 16, 2022

EXECUTIVE SUMMARY

Along the western North American coast, there are two LNG facilities. These include the LNG export terminal in Kenai Alaska owned and operated by Foreland and the LNG facility in Baja California/Mexico owned by Energia Costa Azul, a Sempra-owned subsidiary.

The Kenai plant in Nikiski, Alaska was once the only LNG export terminal in the U. S. but has not exported LNG since Fall 2015. In winter 2020, the FERC voted to approve Trans-Foreland's project to make modifications and reactivate portions of the plant. The project will bring the plant out of "warm idle status" and would enable the transfer of gas to an adjacent refinery.

Energia Costa Azul is a liquified natural gas joint venture between Sempra LNG and IEnova. It is the first and only LNG export project in Mexico. The project connects gas supplies from Texas and the northern U.S. directly to markets in Mexico and countries across the Pacific Basin.

Figure 8 LNG Infrastructure Map in Baja California and Mexico

More locally, in January 2022, under a grant agreement, Sysco Riverside developed a publicly accessible liquefied natural gas station to fuel their expanding fleet of natural gas-powered goods movement vehicles in Riverside, California. The new station established natural gas fueling infrastructure to support its fleet and others operating along one of the busiest stretches of highway in the nation. At the time of application, Sysco operated 35 trucks. This initial fleet is expected to grow to 125 liquefied natural gas trucks during the project life, thus creating a strong need for infrastructure to fuel its vehicles.

Sysco' s contractor, Fullmer Construction, was responsible for the construction of the liquefied natural gas fueling station. Sysco' s objective in constructing this station is to provide the additional necessary infrastructure needed to make alternative fuels like natural gas a commercially available and preferable fueling option. Natural gas contains less carbon than any other traditional fuel, and thus produces lower carbon dioxide and greenhouse gas emissions per year. In fact, natural gas vehicles produce up to 20-30 percent fewer greenhouse gas emissions than comparable diesel vehicles. Natural gas is also typically less expensive than diesel, costing less per unit of energy.

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 2022-2035 for Average Temperature and Normal Hydro years (base case) in addition to the Cold Temperature and Dry Hydro (high case).

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 Energy Resources Department, SDG&E, Southwest Gas (SWG), 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.

TABLE 2 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	4,428	4,408	4,310	4,257	4,252
Utility Total	4,545	4,525	4,427	4,374	4,369
Non-Utility Served Load (1)	1,024	1,010	990	995	999
Statewide Supply Sources Total	**5,570**	**5,535**	**5,416**	**5,368**	**5,369**
California's Requirements					
Utility					
Residential	1,101	1,077	1,054	1,031	1,008
Commercial	463	462	455	449	442
Natural Gas Vehicles	52	53	54	56	57
Industrial	906	920	933	938	937
Electric Generation (2)	1,377	1,327	1,252	1,219	1,245
Enhanced Oil Recovery Steaming	27	27	27	27	27
Wholesale/International+Exchange	283	283	282	282	281
Company Use and Unaccounted-for	65	65	64	63	62
Utility Total	4,273	4,215	4,122	4,064	4,059
Non-Utility					
Enhanced Oil Recovery Steaming	640	637	638	634	631
EOR Cogeneration/Industrial	54	52	49	52	45
Electric Generation	330	321	303	309	323
Non-Utility Served Load (1)	1,024	1,010	990	995	999
Statewide Requirements Total (3)	**5,298**	**5,225**	**5,111**	**5,058**	**5,059**

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.

TABLE 3 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2027-2035

	2027	2028	2029	2030	2035
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	3,909	3,844	3,802	3,731	3,594
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility Served Load (1)	995	979	1,006	1,025	1,147
Statewide Supply Sources Total	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**
California's Requirements					
Utility					
Residential	988	964	944	921	804
Commercial	435	425	417	408	366
Natural Gas Vehicles	59	60	62	63	70
Industrial	937	936	935	933	925
Electric Generation (2)	1,240	1,210	1,198	1,162	1,193
Enhanced Oil Recovery Steaming	26	25	24	24	20
Wholesale/International+Exchange	281	280	279	278	274
Company Use and Unaccounted-for	61	61	60	59	58
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility					
Enhanced Oil Recovery Steaming	628	627	672	712	878
EOR Cogeneration/Industrial	40	39	19	14	0
Electric Generation	327	313	316	299	269
Non-Utility Served Load (1)	995	979	1,006	1,025	1,147
Statewide Requirements Total (3)	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**

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.

TABLE 4 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2022-2035

Utility	2022	2023	2024	2025	2026
Northern California					
California Sources (1)	56	56	56	56	56
Out-of-State	2,049	2,054	2,043	2,038	2,063
Northern California Total	2,105	2,110	2,099	2,094	2,119
Southern California					
California Sources (2)	61	61	61	61	61
Out-of-State	2,379	2,354	2,266	2,219	2,190
Southern California Total	2,440	2,415	2,327	2,280	2,251
Utility Total	4,545	4,525	4,427	4,374	4,369
Non-Utility Served Load (3)	1,024	1,010	990	995	999
Statewide Supply Sources Total	**5,570**	**5,535**	**5,416**	**5,368**	**5,369**

Utility	2027	2028	2029	2030	2035
Northern California					
California Sources (1)	56	56	56	56	56
Out-of-State	1,749	1,738	1,722	1,698	1,681
Northern California Total	1,805	1,794	1,778	1,754	1,737
Southern California					
California Sources (2)	61	61	61	61	61
Out-of-State	2,160	2,106	2,080	2,034	1,912
Southern California Total	2,221	2,167	2,141	2,095	1,973
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility Served Load (3)	995	979	1,006	1,025	1,147
Statewide Supply Sources Total	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**

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) Cogen, EOR steaming and powerplant customers, and gas consumption at Elk Hills powerplant.

Source: CEC staff-provided forecast results from their own model simulations.

TABLE 5 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
Utility					
Northern California					
Residential	491	473	460	445	432
Commercial - Core	208	214	213	210	208
Natural Gas Vehicles - Core	7	7	8	8	8
Natural Gas Vehicles - Noncore	4	4	4	4	4
Industrial - Noncore	462	477	492	497	498
Wholesale	9	9	9	9	9
SMUD Electric Generation	96	96	96	96	96
Electric Generation (2)	484	448	441	442	481
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	34	34	34	34	34
Northern California Total (3)	1,833	1,800	1,794	1,784	1,809
Southern California					
Residential	610	604	594	585	575
Commercial - Core	206	200	194	190	185
Commercial - Noncore	48	49	49	49	49
Natural Gas Vehicles - Core	41	42	43	44	45
Industrial - Core	54	54	53	52	51
Industrial - Noncore	389	390	389	389	388
Wholesale (excluding EG)	236	236	235	235	234
SDG&E, Vernon & Ecogas EG	127	117	104	97	97
Electric Generation (EG) (4)	670	667	612	584	571
Enhanced Oil Recovery Steaming	27	27	27	27	27
Company Use and Unaccounted-for	31	30	29	29	28
Southern California Total	2,440	2,415	2,327	2,280	2,251
Utility Total	4,273	4,215	4,122	4,064	4,059
Non-Utility Served Load (5)	1,024	1,010	990	995	999
Statewide Gas Requirements Total (6)	**5,298**	**5,225**	**5,111**	**5,058**	**5,059**

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.

TABLE 6 – STATEWIDE ANNUAL GAS REQUIREMENTS (1)
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR
(MMcf/d)
2027-2035

	2027	2028	2029	2030	2035
Utility					
Northern California					
Residential	423	412	402	391	338
Commercial - Core	205	200	195	189	163
Natural Gas Vehicles - Core	8	8	9	9	10
Natural Gas Vehicles - Noncore	4	5	5	5	5
Industrial - Noncore	499	499	499	498	496
Wholesale	9	9	9	9	9
SMUD Electric Generation	96	96	96	96	96
Electric Generation (2)	489	493	493	486	549
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	33	33	33	33	33
Northern California Total (3)	1,805	1,794	1,778	1,754	1,737
Southern California					
Residential	565	552	542	530	466
Commercial - Core	181	177	174	170	155
Commercial - Noncore	49	49	49	49	48
Natural Gas Vehicles - Core	46	47	48	50	54
Industrial - Core	50	49	48	47	44
Industrial - Noncore	388	388	388	387	385
Wholesale (excluding EG)	234	233	232	231	228
SDG&E, Vernon & Ecogas EG	96	92	92	88	87
Electric Generation (EG) (4)	558	529	516	493	461
Enhanced Oil Recovery Steaming	26	25	24	24	20
Company Use and Unaccounted-for	28	27	27	26	25
Southern California Total	2,221	2,167	2,141	2,095	1,973
Utility Total	4,026	3,961	3,919	3,848	3,711
Non-Utility Served Load (5)	995	979	1,006	1,025	1,147
Statewide Gas Requirements Total (6)	**5,021**	**4,940**	**4,926**	**4,874**	**4,857**

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.

TABLE 7 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE (4) AND DRY HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	4,561	4,581	4,487	4,438	4,443
Utility Total	4,678	4,698	4,604	4,555	4,560
Non-Utility Served Load (1)	1,159	1,144	1,130	1,129	1,152
Statewide Supply Sources Total	**5,837**	**5,842**	**5,734**	**5,684**	**5,713**
California's Requirements					
Utility					
Residential	1,186	1,165	1,142	1,118	1,094
Commercial	488	481	473	467	460
Natural Gas Vehicles	52	53	54	55	57
Industrial	911	924	935	940	939
Electric Generation (2)	1,378	1,374	1,307	1,278	1,315
Enhanced Oil Recovery Steaming	27	27	27	27	27
Wholesale/International+Exchange	297	297	295	295	295
Company Use and Unaccounted-for	67	67	66	65	64
Utility Total	4,406	4,388	4,299	4,245	4,250
Non-Utility					
Enhanced Oil Recovery Steaming	639	635	638	629	628
EOR Cogeneration/Industrial	48	50	50	50	41
Electric Generation	472	460	442	450	484
Non-Utility Served Load (1)	1,159	1,144	1,130	1,129	1,152
Statewide Requirements Total (3)	**5,565**	**5,532**	**5,429**	**5,374**	**5,403**

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.

TABLE 8 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE (4) AND DRY HYDRO YEAR
(MMcf/d)
2027-2035

	2027	2028	2029	2030	2035
California's Supply Sources					
Utility					
California Sources	117	117	117	117	117
Out-of-State	4,116	4,043	4,000	3,925	3,792
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility Served Load (1)	1,143	1,147	1,209	1,204	1,077
Statewide Supply Sources Total	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**
California's Requirements					
Utility					
Residential	1,073	1,049	1,028	1,004	884
Commercial	453	443	434	425	382
Natural Gas Vehicles	58	60	61	63	70
Industrial	939	938	937	935	927
Electric Generation (2)	1,326	1,290	1,277	1,239	1,279
Enhanced Oil Recovery Steaming	26	25	24	24	20
Wholesale/International+Exchange	294	293	293	292	288
Company Use and Unaccounted-for	64	63	62	62	60
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility					
Enhanced Oil Recovery Steaming	625	627	719	756	906
EOR Cogeneration/Industrial	37	37	21	17	6
Electric Generation	481	483	470	431	165
Non-Utility Served Load (1)	1,143	1,147	1,209	1,204	1,077
Statewide Requirements Total (3)	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**

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.

**TABLE 9 – STATEWIDE TOTAL SUPPLY SOURCES-TAKEN
COLD TEMPERATURE [4] and DRY HYDRO YEAR
(MMcf/d)
2022-2026**

Utility	2022	2023	2024	2025	2026
Northern California					
California Sources [1]	56	56	56	56	56
Out-of-State	2,109	2,149	2,144	2,141	2,177
Northern California Total	2,165	2,205	2,200	2,197	2,233
Southern California					
California Sources [2]	61	61	61	61	61
Out-of-State	2,452	2,432	2,343	2,298	2,267
Southern California Total	2,513	2,493	2,404	2,359	2,328
Utility Total	4,678	4,698	4,604	4,555	4,560
Non-Utility Served Load [3]	1,159	1,144	1,130	1,129	1,152
Statewide Supply Sources Total	**5,837**	**5,842**	**5,734**	**5,684**	**5,713**

Utility	2027	2028	2029	2030	2035
Northern California					
California Sources [1]	56	56	56	56	56
Out-of-State	1,876	1,863	1,844	1,821	1,800
Northern California Total	1,932	1,919	1,900	1,877	1,856
Southern California					
California Sources [2]	61	61	61	61	61
Out-of-State	2,239	2,180	2,156	2,104	1,992
Southern California Total	2,300	2,241	2,217	2,165	2,053
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility Served Load [3]	1,143	1,147	1,209	1,204	1,077
Statewide Supply Sources Total	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**

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) 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.

TABLE 10 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
COLD TEMPERATURE [7] and DRY HYDRO YEAR
(MMcf/d)
2022-2026

	2022	2023	2024	2025	2026
Utility					
Northern California					
Residential	527	512	500	485	472
Commercial - Core	224	224	222	220	217
Natural Gas Vehicles - Core	7	7	8	8	8
Natural Gas Vehicles - Noncore	3	4	4	4	4
Industrial - Noncore	467	480	493	499	499
Wholesale	10	10	10	10	10
SMUD Electric Generation	96	96	96	96	96
Electric Generation [2]	485	490	490	493	543
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	36	35	35	35	35
Northern California Total [3]	1,893	1,895	1,895	1,887	1,923
Southern California					
Residential	660	653	642	632	622
Commercial - Core	214	208	202	197	193
Commercial - Noncore	49	49	49	50	50
Natural Gas Vehicles - Core	41	42	43	44	45
Industrial - Core	55	55	53	52	51
Industrial - Noncore	389	390	389	389	388
Wholesale (excluding EG)	249	249	248	248	247
SDG&E, Vernon & Ecogas EG	127	118	105	98	98
Electric Generation (EG) [4]	670	671	616	591	578
Enhanced Oil Recovery Steaming	27	27	27	27	27
Company Use and Unaccounted-for	32	31	30	30	29
Southern California Total	2,513	2,493	2,404	2,359	2,328
Utility Total	4,406	4,388	4,299	4,245	4,250
Non-Utility Served Load [5]	1,159	1,144	1,130	1,129	1,152
Statewide Gas Requirements Total [6]	**5,565**	**5,532**	**5,429**	**5,374**	**5,403**

(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.

TABLE 11 – STATEWIDE ANNUAL GAS REQUIREMENTS [(1)]
COLD TEMPERATURE [(7)] AND DRY HYDRO YEAR
(MMcf/d)
2025-2035

	2027	2028	2029	2030	2035
Utility					
Northern California					
Residential	463	452	441	431	378
Commercial - Core	214	209	204	199	172
Natural Gas Vehicles - Core	8	8	9	9	10
Natural Gas Vehicles - Noncore	4	4	4	4	5
Industrial - Noncore	500	500	500	500	497
Wholesale	10	9	9	9	9
SMUD Electric Generation	96	96	96	96	96
Electric Generation (2)	565	567	564	557	616
Exchange (California)	38	38	38	38	38
Company Use and Unaccounted-for	35	35	34	34	35
Northern California Total (3)	1,932	1,919	1,900	1,877	1,856
Southern California					
Residential	610	597	586	573	506
Commercial - Core	189	184	181	177	161
Commercial - Noncore	50	49	49	49	49
Natural Gas Vehicles - Core	46	47	48	50	54
Industrial - Core	51	50	49	48	45
Industrial - Noncore	388	388	388	387	385
Wholesale (excluding EG)	247	246	245	244	241
SDG&E, Vernon & Ecogas EG	98	93	94	89	92
Electric Generation (EG) (4)	567	534	524	496	474
Enhanced Oil Recovery Steaming	26	25	24	24	20
Company Use and Unaccounted-for	29	28	28	27	26
Southern California Total	2,300	2,241	2,217	2,165	2,053
Utility Total	4,233	4,160	4,117	4,042	3,909
Non-Utility Served Load (5)	1,143	1,147	1,209	1,204	1,077
Statewide Gas Requirements Total (6)	**5,376**	**5,307**	**5,326**	**5,246**	**4,987**

(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.

EXECUTIVE SUMMARY

STATEWIDE RECORDED SOURCES AND DISPOSITION

The Statewide Sources and Disposition Summary complements the existing 5-year recorded data tables included in the tabular data sections for each utility.

The information displayed in the following tables shows the composition of supplies from both out-of-state sources, as well as California sources. The data are based on the utilities' accounting records and 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 reconciliation 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.

TABLE 12– RECORDED 2017 STATEWIDE SOURCES AND DISPOSITION SUMMARY
(MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	100	443	127	54	208	0	(27)	0	905
Noncore Commercial/Industrial	(4)	97	80	39	158	52	24	0	446
EG (3)	(4)	156	128	63	252	82	39	0	715
EOR	(0)	9	7	3	14	5	2	0	39
Wholesale/Resale/International (4)	(7)	88	72	35	142	46	22	0	398
Total	84	792	414	195	773	185	60	0	2,503
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)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	698	28	0	0	698	44	0	0	1,468
TOTAL SUPPLIER	833	1,046	578	1,354	1,504	229	84	599	6,227
San Diego Gas & Electric Company									
Core	14	61	17	7	28	0	(4)	0	124
Noncore Commercial/Industrial	(2)	38	31	15	62	20	10	0	175
Total	12	99	49	23	90	20	6	0	299
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

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, and SDG&E, as shown.
(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.

TABLE 13 – RECORDED 2018 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	158	439	103	37	173	0	(2)	0	908
Noncore Commercial/Industrial	(17)	99	35	57	207	61	7	0	448
EG (3)	(23)	136	48	78	283	83	10	0	615
EOR	(1)	8	3	5	18	5	1	0	38
Wholesale/Resale/International (4)	(13)	74	26	42	153	45	6	0	333
Total	104	756	214	218	834	194	22	0	2,342
Pacific Gas and Electric Company (5)									
Core	0	3	55	303	(4)	0	0	165	522
Noncore Industrial/Wholesale/EG (6)	28	212	221	966	16	0	0	355	1,798
Total	28	215	276	1,269	12	0	0	520	2,320
Other Northern California									
Core (7)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	401	49	0	0	686	42	0	0	1,178
TOTAL SUPPLIER	555	1,020	490	1,487	1,532	236	34	520	5,874
San Diego Gas & Electric Company									
Core	22	61	14	5	24	0	(0)	0	127
Noncore Commercial/Industrial	(4)	25	9	14	52	15	2	0	112
Total	18	86	23	19	76	15	2	0	239
Southwest Gas Corporation									
Core	22	0	0	0	0	0	12	0	34
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	24	0	0	0	0	0	12	0	36

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, and SDG&E, as shown.
(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.

TABLE 14 – RECORDED 2019 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company (2)									
Core + UAF (3)	162	476	111	30	223	0	10	0	1,012
Wholesale/Resale/International (5)	(65)	368	47	118	674	213	19	0	1,374
Total	97	844	158	148	897	213	29	0	2,386
Pacific Gas and Electric Company (4)									
Core	0	0	58	286	(2)	0	0	172	514
Noncore Industrial/Wholesale/EG (5)	24	380	223	896	9	0	0	481	2,014
Total	24	380	281	1,182	7	0	0	653	2,528
Other Northern California									
Core (6)	22	0	0	0	0	0	12	0	34
Non-Utilities Served Load (7, 8)									
Direct Sales/Bypass	388	29	0	0	664	71	0	0	1,152
TOTAL SUPPLIER	531	1,253	439	1,330	1,568	284	41	653	6,100
San Diego Gas & Electric Company									
Core	21	61	14	4	28	0	1	0	129
Noncore Commercial/Industrial	(4)	22	3	7	40	12	1	0	81
Total	17	83	17	11	68	12	2	0	210
Southwest Gas Corporation									
Core	25	0	0	0	0	0	0	0	25
Noncore Commercial/Industrial	3	0	0	0	0	0	0	0	3
Total	28	0	0	0	0	0	0	0	28

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) SoCalGas core volumes are accrued volumes.
(3) Includes NGV volumes
(4) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(5) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(6) Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

TABLE 15 – RECORDED 2020 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company (2)									
Core + UAF (3)	132	406	151	9	245	0	0	0	943
Noncore	(45)	532	64	169	613	139	38	0	1,510
Total	87	938	215	178	858	139	38	0	2,453
Pacific Gas and Electric Company (4)									
Core	0	8	33	379	(7)	0	0	165	578
Noncore Industrial/Wholesale/EG (5)	26	294	214	936	9	0	0	411	1,890
Total	26	302	247	1,315	2	0	0	576	2,468
Other Northern California									
Core (6)	14	0	0	0	0	0	0	0	14
Non-Utilities Served Load (7,8)									
Direct Sales/Bypass	334	37	0	0	621	60	0	0	1,052
TOTAL SUPPLIER	461	1,277	462	1,493	1,481	199	38	576	5,987
San Diego Gas & Electric Company									
Core	18	56	21	1	34	0	0	0	131
Noncore Commercial/Industrial	(4)	49	6	15	56	13	3	0	138
Total	14	105	27	16	90	13	3	0	269
Southwest Gas Corporation - Southern California Division									
Core	25.4	0	0	0	0	0	0	0	25
Noncore Commercial/Industrial	2.0	0	0	0	0	0	0	0	2
Total	27.4	0	0	0	0	0	0	0	27

Notes:

(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) SoCalGas core volumes are accrued volumes.
(3) Includes NGV volumes
(4) Kern River supplies include net volume flowing over Kern River High Desert interconnect.
(5) Includes UEG, COGEN, industrial and deliveries to PG&E's wholesale customers.
(6) Includes Southwest Gas Coproration and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

TABLE 16 – RECORDED 2021 STATEWIDE SOURCES AND DISPOSITION SUMMARY (MMcf/d)

	California Sources	El Paso	Trans western	PG&E/GTN	Kern River	Mojave	Other (1)	Ruby	Total
Southern California Gas Company									
Core + UAF (2)	132	406	151	9	245	0	0	0	943
Noncore Commercial/Industrial/EG/EOR/Wholesale/Resale/International	-46	432	206	217	583	85	3	0	1,480
Total	86	838	357	226	828	85	3	0	2,423
Pacific Gas and Electric Company (5)									
Core	0	29	0	410	-2	0	0	159	597
Noncore Industrial/Wholesale/EG (6)	23	356	186	942	6	0	0	32	1,840
Total	23	386	186	1,352	4	0	0	485	2,437
Other Northern California									
Core (7)	13	0	0	0	0	0	0	0	13
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	295	49	0	0	631	42	0	0	1,017
TOTAL SUPPLIER	417	1,273	543	1,578	1,463	127	3	485	5,890

Notes:
(1) Includes storage activities, volumes delivered on North Baja and 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	Other (1)	Ruby	Total
San Diego Gas & Electric Company									
Core	19	59	22	1	36	0	0	0	137
Noncore Commercial/Industrial	-4	37	18	19	50	7	0	0	128
Total	15	91	40	20	86	7	0	0	265
SouthWest Gas									
Core	24	0	0	0	0	0	13.00	0.000	37.00
Noncore Commercial/Industrial	2	0	0	0	0	0	0.17	0.000	2.17
Total	26	0	0	0	0	0	13.17	0.000	39.17

Notes

(1) **Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.**
(2) **SoCalGas core volumes are accrued volumes.**
(3) **Includes NGV volumes.**
(4) **Kern River supplies include net volume flowing over Kern River High Desert interconnect.**
(5) Includes UEG, Cogen, industrial load and deliveries to PG&E's wholesale customers.
(6) Includes Great Basin Gas Transmission Company and Tuscarora Deliveries in the Lake Tahoe and Susanville areas.
(7) Deliveries to end-users by non-CPUC jurisdictional pipelines.
(8) California production is preliminary.

STATEWIDE RECORDED HIGHEST SENDOUT

The tables below summarize the highest sendout days by the state in the summer and winter periods from the last 5 years. Daily sendout from SoCalGas, PG&E, and from customers not served by these utilities were used to construct the following tables.

Table 17: Estimated California Highest *SUMMER* Sendout (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2017	08/28/2017	2,602	3,484	6,086	1,416	7,502
2018	07/24/2018	2,925	2,926	5,851	1,410	7,261
2019	09/04/2019	2,606	2,907	5,7513	1,310	6,823
2020	08/18/2020	2,792	3,143	5,935	1,270	7,205
2021	09/09/2021	2,909	2,827	5,736	1,080	6,816

Table 18: Estimated California Highest *WINTER* Sendout (MMcf/d)

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2017	12/21/2017	3,665	3,456	7,121	1,259	8,380
2018	02/20/2018	3,527	3,621	7,148	1,378	8,526
2019	02/05/2019	3,751	3,913	7,664	1,097	8,761
2020	02/04/2020	3,230	3,881	7,111	1,261	8,372
2021	12/14/2021	3,470	3,837	7,307	935	8,242

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. Nonutility Demand equals Kern-Mojave and California monthly average total flows less PG&E and SoCal Gas peak day supply from Kern-Mojave and California in-state production.

(4) PG&E and SoCalGas sendout(s) are reported for the day on which the *combined* two utilities' 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, Jul, Aug, Sep and Oct.

2022 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA

INTRODUCTION

PG&E owns and operates an integrated natural gas transmission, underground storage, and distribution system across most of Northern and Central California. As of December 31, 2021, PG&E's natural gas system consists of approximately 42,000 miles of distribution pipelines, over 6,400 miles of backbone and local transmission pipelines, and three fully owned underground storage facilities and a 25 percent interest in Gill Ranch Storage. PG&E uses its backbone transmission system, composed primarily of Lines 300A, 300B, 400, and 401, to transport gas from its 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 4.3 million residential customers and over 200,000 commercial and industrial customers. PG&E also provides gas transportation and storage services to a variety of gas-fired Electric Generation (EG) plants in its service area and serves multiple Natural Gas Vehicle (NGV) fleets, including utility owned facilities, with its publicly-accessible fueling stations throughout California. 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 southeast 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, including other regulated utilities, also utilize the PG&E system to meet their gas needs in Southern California.

The Northern California section of this report includes PG&E's gas demand forecast and discussions on gas supply, pipeline capacity, storage, and related policies, as well as the natural gas regulatory environment, including legislative developments and regulatory proceedings. Finally, the report includes PG&E's forecast of supply and demand for an Abnormal Peak Day (APD) and demand for a 1-in-10 Peak Day during the winter and summer. What follows is a summary of key takeaways from the Northern California sections of this report.

PG&E Forecasts a Gradual Decline in Future Gas Demand: PG&E's average year demand is forecasted to decline at an annual average rate of 0.5 percent between 2022 and 2035. The decline in forecasted gas demand is in response to the state's decarbonization policies and reflects reduced demand due to energy efficiency, building electrification resulting from fuel switching from natural gas appliances to electric, and climate change.

The Forecasted Demand is Subject to Significant Uncertainties: Forecast uncertainties are significant including the impacts from Northern and Southern California gas price differentials, impact of climate change on forecasted gas and electric load and hydroelectric generation, planned electric generation buildout, and the level of building electrification.

PG&E is Taking Actions to Evolve the Natural Gas System to be an Affordable Energy Delivery Platform Consistent with Decarbonization Goals. PG&E's work is guided by the following four pillars:

1. Reduce the carbon footprint of the gas system by greening the gas supply, leveraging electrification, facility conversion from dirtier fuel sources, efficiency, and methane abatement.

2. Decrease costs by limiting system expansion, strategically reducing capital and operational expenses, strategically pruning the gas system, and focusing on targeted and zonal electrification.

3. Identify alternative revenue sources through opportunities to 1) convert dirtier fuel sources to cleaner natural gas through investment in compressed natural gas, 2) switch facilities (including backup generation) from dirtier fuel sources, and 3) invest in the rail and marine sectors.

4. Leverage innovative financial mechanisms such as changes to depreciation, rate design, and external funding to help close the gap between costs and revenues.

Policy and Regulatory Solutions and a Managed Transition Plan Are Needed to Keep Customers' Bills Affordable. PG&E is committed to working with regulators and other stakeholders to support statewide GHG reduction policies and develop options to minimize customer bill impacts. PG&E is doing this by safely reducing costs and maximizing utilization of existing infrastructure. In order to successfully implement the State's environmental goals, issues such as obligation to serve, treatment of capital versus expense dollars, and non-traditional funding need to be addressed and resolved.

Regulatory bodies and investor-owned utilities (IOU) should work together to ensure that Californians continue to have access to clean, reliable, and affordable energy. In support of these important goals, PG&E is actively participating in the Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning (Gas System Planning OIR) (R.20-01-007), which addresses crucial topics that will impact the future of the California gas system.

PG&E is accelerating its work on the use of Renewable Natural Gas (RNG) to contribute towards access to clean, reliable, and affordable energy. The current investment and incentives for Renewable Natural Gas (RNG) principally favor the transportation sector resulting in little RNG available to comply with the recently enacted Renewable Gas Standard (RGS). If this is to change, California will have to balance the funding mechanisms between the transportation sector and the RGS so that RNG project developers have opportunities to supply RNG towards the RGS or the transportation sector.

GAS DEMAND

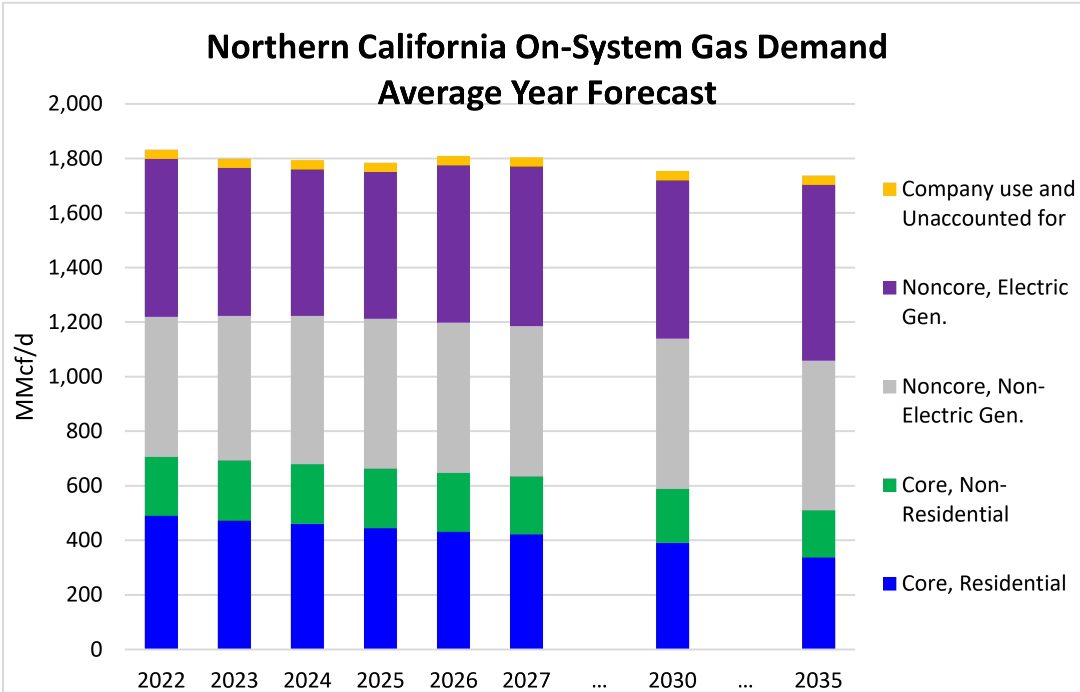
OVERVIEW

PG&E's 2022 CGR Average Year (also known as Average Temperature and Normal Hydro Year) demand forecast projects total on-system demand to decline at an annual average rate of 0.5 percent between 2022 and 2035. The core sectors are forecasted to decline at an average annual rate of 2.5 percent. The noncore sectors increase at a rate of 0.6 percent annually, driven in part by an increase in throughput for electric generation.

This projected decline in total demand could result in gas system operating and maintenance costs allocated over lower usage, causing customer gas rates to increase. Consequently, PG&E and statewide utility stakeholders will need to continue their work to mitigate customer rate increases. In future, additional gas throughput could come from the substitution of higher carbon intensive fuels, such as high sulfur marine shipping fuels, to help allocate transmission costs over a larger customer base.

This chapter includes PG&E's gas demand forecast and begins with a description of the forecast method, including a discussion of important assumptions. After the methodology discussion, the report presents information on the average demand forecast by customer sector. To provide more information about gas throughput under stressed conditions, the Cold Temperature and Dry Hydro Year forecast presents demand under cold temperature and dry hydroelectric conditions. This is followed by a discussion of gas demand policies, trends, and impacts. The chapter concludes with a presentation of abnormal peak day demand.

FIGURE 9



Changes in the major components of on-system gas demand are illustrated in Figure 9 above. Core demand declines, driven by increasing energy efficiency, increasing building electrification, and a warming climate. Noncore, non-EG demand is forecasted to remain largely flat over the forecast horizon, as potential demand growth is partly limited by energy efficiency and increasing gas prices. The Noncore EG demand forecast increases from 2022 to 2035.

The EG demand forecast is largely a function of electric energy demand, the future CAISO generation portfolio, transmission constraints, and gas prices. PG&E's forecast incorporates the higher levels of renewable generation and electric storage from the 2021 California Public Utilities Commission Integrated Resource Plan[10] and reflects higher burner-tip gas prices for Northern California electric generators relative to Southern California. The forecast for gas demand by electric generators[11] and co-generators in Northern California[12] increases at 0.9

[10] https://www.cpuc.ca.gov/irp/.

[11] This gas demand forecast excludes gas delivered by non-utility 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.

[12] Northern California electric generation gas demand consists of the generation fleet north of Path 26.

percent per year from 2022 through 2035[13]. The increase is driven in part by Northern California electric reliability needs due to transmission constraints in some hours.

FORECAST METHOD AND ASSUMPTIONS

PG&E's gas demand forecasts for the residential, commercial, and industrial sectors are developed using econometric models as the foundation. These models are then modified to incorporate assumptions around future policy formation and technology adoption. Forecasts for NGVs and wholesale customers are developed based on market information and historical trends over the past five years. To address the impact of COVID, PG&E developed a simplified approach. The first order COVID impacts are assumed to occur between March 2020 and ramping down after the introduction of vaccines to mid-2023, after which COVID effects are considered to be subsumed into economic and population variables. This general profile is consistent with estimates and discussion from our economic forecasting data source, Moody's. This dummy variable[14] approach models the increases in residential load and the decreases in commercial load which are then ramped down to zero in mid-2023. Effects beyond that time period are limited to those explicitly produced by economic and population variables or reflected in the historical time series apart from a simple dummy variable. Such a simplified approach is necessitated by the very limited amount of historical data from the COVID time period as well as the idiosyncratic nature of the COVID response over location and time. The simplified approach could introduce uncertainty on the duration and scale of impacts from COVID.

Forecasts of gas demand by power plants are developed by modeling the electricity market in the Western Electricity Coordinating Council (WECC) using PLEXOS software. PLEXOS is a production cost modeling tool that estimates the consumption of all fuels used for power generation on an economic basis. The tool determines the least cost dispatch of generating resources to meet a given power demand.

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[13] EG demand forecast uses common modeling assumptions developed jointly by the IOUs. Since the forecast is dependent on several factors including gas price differential between northern and southern California, future resource additions and retirements, and hydro-electric generation, actual EG demand in future may vary from the forecast.

[14] A dummy variable is a variable that takes on the values 1 and 0; 1 means something is true. https://www.stata.com/support/faqs/data-management/creating-dummy-variables/.

While variation in short-term gas use depends mainly on prevailing weather conditions and gas prices, longer term projections 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;
- Forecasted prices;
- Growth in electricity demand;
- Growth of renewable generation;
- Efficiency profiles of residential and commercial buildings and the appliances within them; and
- Impacts from climate change.

TEMPERATURE ASSUMPTIONS

Space heating accounts for a high percentage of use. Therefore, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's Average Year demand forecast assumes that temperatures in the forecast period will be equivalent to the average of observed temperatures during the past 19 years, with the addition of a temperature adjustment for climate change. Adding the climate change adjustment has little impact to the temperature assumptions in the early years of the forecast; however, the later years begin to show the effects of a warming climate. For example, by 2035 the total December/January heating degree days (HDD) are projected to be 16 percent lower than the 19-year average, reducing core throughput by approximately 6 percent.

Actual temperatures in the forecast period will be higher or lower than the assumption including climate change. Temperature variation impacts gas use. PG&E's Cold, Dry Hydro demand forecast assumes that winter temperatures in the forecast horizon will have a 1-in-10 likelihood of occurrence.

PG&E's EG gas throughput forecast uses an average temperature approach. The forecast does not capture peak day temperatures. Each summer typically contains a few heat waves with temperatures 10 to 15 degrees F above normal. This leads to peak electricity demands and drives up power plant gas demand. This forecast captures the seasonal variations on a monthly basis.

HYDROELECTRIC CONDITIONS ASSUMPTIONS

In contrast to temperature deviations, annual water runoff for hydroelectric plants has varied by 50 percent above and below the long-term annual average. PG&E uses a vintage approach to WECC hydroelectric generation by assuming average generation for the most recent 15 historical years, 2005-2019, in the Average Year demand forecast. PG&E uses the Cold, Dry Hydro forecast to illustrate the impacts from extreme conditions impacting both core space heating demand and EG. PG&E uses the hydroelectric generation conditions for the calendar years 2014 and 2015 to represent the dry hydroelectric condition.

GAS PRICE AND RATE ASSUMPTIONS

Inputs for gas prices and transportation rate assumptions are important for forecasting gas demand. This is especially true for market sectors that are particularly price sensitive, such as the industrial or EG sectors. PG&E used the gas commodity price forecast described in detail in the Executive Summary. It combines transportation rates with the gas commodity price forecast. PG&E's forecast assumes that changes to throughput do not directly impact rates. As a reminder, natural gas price forecasts are inherently uncertain and impact market sectors sensitive to price.

GAS LOAD ASSUMPTIONS

As described above, PG&E's base forecast is developed from econometric regression models. This forecast is modified by forecasts of policy and technology adoption. The major modifiers are building electrification (BE) and energy efficiency (EE). The EG forecast is based on the mid case electricity demand forecast from the CEC 2021 Integrated Energy Policy Report (IEPR). This demand forecast includes the Additional Achievable Fuel Substitution (AAFS 2) scenario building electrification information as described under "Electric Load Assumptions" and the forecast building electrification quantities have accompanying consistent gas reduction quantities. These gas reductions are included in the forecast as a modifier to the base models.

PG&E also includes the impact of EE in its gas forecast. PG&E's model requires the inputs of two categories of energy efficiency, "Additional Achievable Energy Efficiency" (AAEE) savings and "Committed" savings. AAEE represents savings from programs that had not yet been funded and new codes and standards (C&S). Committed represents savings from measures resulting from codes & standards already on the books but implemented during the forecast period. The AAEE forecast used by PG&E is the CEC's 2019 IEPR Mid AAEE case[15]. PG&E also utilizes the Committed savings forecast from the CEC 2019 IEPR to avoid double-counting. Committed savings are provided separately by the CEC since they are embedded in the IEPR baseline. Since committed savings for the 2021 IEPR were not available in time for use in this forecast, PG&E opted to use the previous vintage (2019 IEPR) to avoid introducing overlap between the two categories.

Finally, there is a smaller adjustment that tends to increase gas sales. There is a group of customers who intend to use natural gas as a cleaner alternative to current fuels. A few of these customers have already signed agreements and the remainder are assumed to sign at a 30% conversion rate. These customers are classified as industrial because they are predominately industrial gas users.

ELECTRIC LOAD ASSUMPTIONS

PG&E's forecast relies on the mid case electricity demand forecast from the CEC 2021 Integrated Energy Policy Report (IEPR). The IEPR captures the increasing electric load as electric vehicles become more commonplace as projected. The electric demand forecast also includes building electrification from the CEC IEPR AAFS 2 forecast[16 & 17]. The AAFS 2 scenario is the CEC's mid-low scenario for electrification.

Finally, the electric load forecast incorporates the CEC IEPR Additional Achievable Energy Efficiency (AAEE) 3 forecast, the mid case[18]. IOU savings are informed by the CPUC's recent 2021 Potential & Goals Study (P&G). Savings for publicly owned utility (POU) utilize the

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15 California Energy Commission, Adopted 2019 Integrated Energy Policy Report https://efiling.energy.ca.gov/getdocument.aspx?tn=232922.

16 The "AAFS" here stands for Additional Achievable Fuel Substitution, so the scenarios include reductions for gas consumption that are "substituted out" through electrification.

17 California Energy Commission https://www.energy.ca.gov/media/6102.

18 California Energy Commission, ADOPTED Final 2021 Integrated Energy Policy Report Volume IV California Energy Demand Forecast https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581.

California Municipal Utilities Association's (CMUA) 2020 Energy Efficiency Potential Forecast for POU program savings. Additionally, the CEC conducts additional studies to assess the impact of codes & standards as well as savings "Beyond Utility" contributions not accounted for in other categories.

ELECTRIC GENERATION AND ELECTRIC TRANSMISSION ASSUMPTIONS

With increasing electric load and more stringent environmental requirements, California's portfolio of EG resources is expected to change significantly over the forecast horizon to 2035. Generation resource addition and retirement assumptions are from the 2021 CPUC Integrated Resource Plan (IRP) Preferred System Plan (PSP). The PSP proposes a target resource mix that includes new renewable and energy storage resources. Gas-fired plants that employ once-through cooling are assumed to retire by the compliance dates set by the California State Water Resources Control Board (SWRCB) in conjunction with the CPUC direction[19] with some re-powered by new gas-fired units. Lastly, modeled CAISO import capability also aligns with the PSP.

For cogeneration gas demand, the forecast for all years reflects recent past cogeneration usage. Most cogeneration plants are not strongly affected by prices in the wholesale electricity market. The electricity generated comes from some other industrial process, usually steam, and generation does not follow wholesale electric prices. Consequently, the cogeneration gas demand projection exhibits no variation throughout the forecast horizon.

All of these assumptions are subject to uncertainty and puts the forecasted demand at significant uncertainty. The forecasted gradual decline in future gas demand is in response to the state's decarbonization policies and reflects reduced demand due to energy efficiency, building electrification resulting from fuel switching from natural gas appliances to electric, and climate change. Furthermore, the trajectory of gas prices may change dramatically as well. The following four factors have the most impact to the forecasted demand.

[19] California State Water Resources Control Board policy effective December 23, 2021 https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/policy.html.

- **Gas Prices**: Gas prices impact retail customer usage and the extent to which thermal resources are used to meet electric demand. Over the past year, California and the world have been experiencing high and volatile gas prices. Moreover, the relative north-to-south gas burner-tip price differential has a significant impact on which thermal generation resources will dispatch. This forecast assumes a nominal Southern California price advantage.

- **Climate Change:** Changes in climate impacts both core and electric generation gas demand. It also significantly impacts hydroelectric generation which affects the need for gas generation. Although this forecast attempts to use methodologies that best reflects climate change (e.g., use of a 15-year hydroelectric generation average), the impacts and pace of change are not fully understood and will be different than the assumptions used in this forecast.

- **Generation Resource Policy and Buildout:** PG&E's forecasts assume California will invest in generation resources in accordance with the California Public Utilities Commission's 2021 Integrated Resource Plan Preferred System Plan. The Plan is ambitious with over 26,000 megawatts of added resources[20]. Deviation from the plan in either resource mix or timing will impact the gas demand forecast.

- **Building Electrification Policy:** PG&E's Average Year and Cold, Dry Hydro Year demand forecasts reflect the impact of existing building decarbonization policies as reflected in the California Energy Commission's 2021 Integrated Energy Policy Report. The CEC has developed multiple forecasts for building electrification growth, reflecting the uncertainty.

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[20] Nameplate capacity.

NORTHERN CALIFORNIA

MARKET SECTOR FORECASTS

RESIDENTIAL

Northern California residential demand is forecasted to decrease from 491 MMcf/d in 2022 to 338 MMcf/d in 2035. Residential households in the PG&E service area are forecasted to be flat to slightly declining from 2022 to 2035. This is the result of continued mild growth until about 2029, after which households with gas service use begins to decline. More importantly, gas use per household has been dropping in recent years due to improvements in appliance and building shell efficiencies. PG&E expects continued efficiency improvements, coupled with the following emerging trends, to decrease long-term residential gas demand.

1. As of June 16, 2022, 57[21] jurisdictions in the state of California have adopted ordinances that require or give preference to all-electric new construction. Around 40 of these jurisdictions used Reach Codes (beyond Title 24, Part 6, of the Energy Code) as a policy tool; these are local ordinances which must be approved by the California Energy Commission (CEC). The remaining jurisdictions adopted local ordinances which do not require further approvals[22]. Not all construction types are covered by these ordinances and there is regional variation (residential versus non-residential). While the number of households are forecasted to grow at 0.9 percent annually, the CEC building electrification outlook indicates that many of these households will install electric-only appliances as new planning cycles comply with these new ordinances.

2. In addition to new construction building electrification, this forecast anticipates that existing households will begin to convert appliances from gas to electric driven by the formation of state or local policies, customer cost savings, or other mechanisms.

3. The warming climate will reduce winter heating needs gradually decreasing residential gas sales.

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[21] Sierra Club https://www.sierraclub.org/articles/2021/07/californias-cities-lead-way-pollution-free-homes-and-buildings.

[22] Some jurisdictions adopt both an energy Reach Code and an ordinance.

Total annual residential demand is projected to continue declining, driven by efficiency gains, building and appliance electrification, and warming temperatures. By 2035, annual residential gas throughput is projected to be 33 percent lower than forecasted 2022 throughput, with most of this decrease occurring in the later years of the forecast.

COMMERCIAL

Northern California commercial demand, not including natural gas vehicles, is forecasted to decrease from 208 MMcf/d in 2022 to 163 MMcf/d in 2035. The number of commercial customers in the PG&E service area is projected to grow on average by 0.23 percent per year from 2022-2035. Similar to the residential customer class, PG&E expects new construction and retrofit building electrification, coupled with continuing existing trends of energy efficiency and climate change, to lead to a long-term decline in commercial throughput. As a result, total commercial gas demand is projected to decline at 1.9 percent per year over the next 13 years, with the decline increasing in later years because total commercial accounts flatten out in those years. Core natural gas vehicles (NGV) remain a minor component but continue to grow at about 3 percent per year.

INDUSTRIAL

Northern California industrial demand is forecasted to increase nominally from 462 MMcf/d in 2022 to 496 MMcf/d in 2035. 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 can fluctuate due to a combination of gas prices, noncore to core migration, capacity at local refineries, and manufacturing demand tied to market dynamics. While the industrial sector has the potential for high year-to-year variability, over the long-term, industrial gas consumption is expected to increase slowly, with energy efficiency and higher gas prices offsetting some growth.[23] As with the commercial category of NGV, industrial category NGV sees moderate growth from a small base, with some as yet unquantified possibilities for additional growth as described in "Future Opportunities" below.

[23] PG&E's industrial forecast includes impacts from California's Cap-and-Trade policies. Future GHG policies may impact industrial demand, adding uncertainty to the forecast.

NORTHERN CALIFORNIA

Given the state's GHG reduction targets, PG&E has been working with many of our industrial customers to begin converting them to natural gas from more polluting fuels, with an eye towards RNG and potentially renewable hydrogen in the future. With these conversions in the planning stage, natural gas demand from the industrial sector is expected to grow by 0.5 annually over the next 13 years.

ELECTRIC GENERATION

Gas demand from EG includes gas-fired cogeneration and power plants connected to PG&E's gas system. PG&E forecasts a relatively steady gas demand for electric generation through the 2020s, ranging between 441 and 493 MMcf/d. This reflects a continuing need in the mid-term for thermal plants to provide electric system reliability. In 2035, EG gas demand is forecasted at 549 MMcf/d.

Through the 2020s to 2035, the CPUC Integrated Resource Plan (IRP) Preferred System Plan (PSP) plans for additional renewables and storage[24] [25]. The IRP PSP forecasts most new renewable resource installation in Southern California, particularly solar. Additionally, transmission capacity constraints sometimes limit the ability to transport Southern California solar generation from south-to-north during daytime hours when solar is generating[26]. Additionally, increases in electric load, driven by electric vehicles and building electrification, need additional generation to meet load. The combination of the increasing level of planned Southern California renewable resources and south-to-north electric transmission congestion drives the EG gas demand higher.

As discussed above, the forecast has significant uncertainty due to factors, including:

- Future burner-tip gas prices;[27]
- Impact of electrification of vehicles and building appliances on electric load;

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[24] Total CAISO renewable and storage capacity planned from 2021 to 2026 is about 26,000 megawatts.

[25] By 2035, capacity increases 50,000 MW compared to 2021.

[26] Estimated at about 80 percent.

[27] Burnertip gas prices are the combination of the commodity price and transportation rate.

- Timing, location, and type of new generation, particularly renewable energy facilities;
- Variable precipitation affecting hydroelectric generation; and
- Impacts of GHG policies and regulations on generation.

The burner-tip gas price forecast and the relative difference between Northern and Southern California prices impacts the EG demand forecast. The price forecast used in this Report has the price of gas ranging from $4 to $6 per MMBtu, with a small price advantage for Southern California for most of the forecast period. This places the Northern California gas-fired EG plants at a competitive disadvantage compared to plants farther south.

Gas prices have recently shown significant volatility. For example, the forecasted PG&E Citygate price for June 2022 is about $5.30/MMBtu. Actual June 2022 daily gas prices show a range of about $7.50/MMBtu to $10.30/MMBtu. This type of volatility and the relative price volatility between prices in Northern and Southern California can drive significant uncertainty in the forecast.

As stated above, the IRP PSP indicates renewable generation and storage capacity buildout mostly built-in Southern California. Additionally, electric transmission capacity from south-to-north is assumed at about 3,000 MW. Differences in the amount or location of the actual California renewable buildout or transmission constraints will impact EG gas throughput.

Finally, variability in hydroelectric generation can significantly impact EG gas demand. In 2017 the average gas demand was 698 MMcf/d in 2017 and in 2021 it was 964 MMcf/d. One of the major drivers of this difference is hydroelectric generation. 2017 was a wet year with ample hydroelectric generation and 2021 was a dry year with lower hydroelectric generation. The wide year-to-year hydroelectric generation fluctuations further illustrate the inherent uncertainty in EG gas demand.

NORTHERN CALIFORNIA

SACRAMENTO MUNICIPAL UTILITY DISTRICT ELECTRIC GENERATION

Sacramental Municipal Utility District (SMUD) is the sixth largest community owned municipal utility in the U.S. 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 MW. The peak gas load of these units is approximately 171 MMcf/d, and the average load is about 96 MMcf/d. This forecast assumes the average load of 96 MMcf/d, which is embedded in this forecast.

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 3.8 percent in PG&E's Line 300 and approximately 4.2 percent in Line 401 for about 86 MMcf/d of capacity.

FORECAST SCENARIOS

The Average Year gas demand forecast presented above is a reasonable projection for an uncertain future. However, a point forecast presented in the Average Year forecast cannot capture the uncertainty in the major determinants of gas demand (e.g., weather, economic activity, decarbonization policies, appliance saturation, and efficiencies). Therefore, to capture some of the uncertainties in gas demand, PG&E developed a high gas demand situation for cold temperature conditions and dry hydroelectric (hydro) conditions.

HIGH DEMAND SCENARIO: COLD/DRY HYDRO

For the High Demand scenario, PG&E forecasts gas demand under cold temperature and dry hydro conditions. This forecast assumes that winter temperatures over the time horizon will have a 1-in-10 likelihood of occurrence. The cold weather assumption increases electric load for space heating needs and EG gas demand. To represent dry hydroelectric conditions throughout the WECC, this forecast assumes the same dry hydroelectric generation conditions as those that prevailed during 2014 and 2015. The dry hydroelectric conditions increase EG gas demand.

Total gas demand for this forecast averages 6 percent higher than the Average Year demand forecast. The cold weather impact drives gas throughput higher due to higher space heating.

Winter monthly core throughput is projected to increase on average by 8 percent, ranging from 7 to 10 percent. The noncore industrial segment demonstrates little correlation to temperature leading to an insignificant demand increase over the Average Year demand forecast.

This forecast projects that EG gas demand increases by 10 percent on average over the Average Year demand outlook. In this forecast, the generation from Northern California hydroelectric resources is about half of the 15-year average assumed in the Average Year demand outlook. This lower generation increases EG gas demand. Hydroelectric conditions can vary widely throughout the WECC and illustrates another degree of uncertainty in EG gas demand forecasting.

POLICIES IMPACTING GAS DEMAND

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 (EO) 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. EO B-55-18 set a goal to achieve carbon neutrality by 2045. The Global Warming Solutions Act of 2006 (Assembly Bill (AB) 32) established the 2020 GHG emission reduction goal into law. Senate Bill (SB) 32 went further, calling for a 40 percent reduction in GHG emissions below 1990 levels by 2030. Additionally, the California Air Resources Board (CARB) Cap-and-Trade Program complements these policies.

GHG POLICIES

The gas demand forecast includes a Cap-and-Trade GHG allowance price projection.[28] The forecast also incorporates complementary policies that aim to achieve California GHG emissions reductions goals. See below for further discussion of these policies. Finally, any trends embedded in historical demand patterns due to GHG goals and/or the compliance entities' participation in the Cap-and-Trade market translates to the forecast.

Given that the utilization of fossil natural gas emits GHGs, PG&E believes that renewable gases (renewable natural gas or hydrogen) must be part of the solution to reach California's

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

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

RENEWABLE ELECTRIC GENERATION

PG&E expects renewable EG to grow due to procurement orders by the CPUC in the IRP Proceeding[29]. While this increase in renewable generation will put downward pressure on the demand for generation from natural gas-fueled resources, the intermittent nature of the largest renewable generation supplies (i.e., wind and solar) should cause the electric system to continue to utilize natural gas-fired EG for reliability through the forecast horizon. Offsetting the impact on the EG demand forecast will be both short-term and long-term electric storage.

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.

PG&E's forecast of cumulative natural gas savings is dominated by the residential sector. Additionally, most of the forecasted savings are due to codes and standards, such as federal and state appliance standards and state building codes. State building codes (Title 24) make up most of these savings.

[29] https://www.cpuc.ca.gov/irp/.

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.[30] The CEC issued its final report doubling targets in October 2017,[31] and the CPUC incorporated higher levels of EE savings in their EE goals for 2018 and beyond,[32] which was partially due to the adoption of an interim GHG adder in the Integrated Distributed Energy Resources proceeding.[33] The CEC's final report suggests the State is on a path to meet or exceed the natural gas SB 350 doubling goal after accounting for IOU programs, POU programs, and codes and standards.[34]

IMPACT OF REACH CODES, APPLIANCE ORDINANCES, AND ELECTRIFICATION

In California, cities and counties have enacted ordinances or "reach" building codes that require or give preference to electric new construction. As of June 16, 2022, 57 local jurisdictions have adopted reach codes[35]. Electrification policies continue to evolve at both the local and state level. The California Air Resources Board (CARB) and Bay Area Air Quality Management District (BAAQMD) have introduced proposals aimed at the electrification of

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[30] 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."

[31] Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. 2017. SB 350: Doubling Energy Efficiency Savings by 2030. CEC. Publication Number: CEC-400-2017-010-CMF.

[32] D.17-09-025: Decision Adopting Energy Efficiency Goals for 2018-2030, CPUC, September 28, 2017.

[33] D.17-08-022: Decision Adopting Interim GHG Adder, CPUC, August 24, 2017.

[34] See Figure 2 from the CEC report cited above.

[35] Sierra Club, https://www.sierraclub.org/articles/2021/07/californias-cities-lead-way-pollution-free-homes-and-buildings.

existing buildings—namely space and water heating. BAAQMD's proposal to amend Rules 9-4 and 9-6 would put in place a point-of-sale ban on gas water heaters beginning in 2027 and gas furnaces in 2029.[36] Similarly, CARB's 2022 State Implementation Plan (SIP) calls for all furnaces and water heaters sold within California to comply with a 0 ng/joule NOx limit beginning in 2030. If implemented, this would effectively eliminate the sale of gas water heaters and furnaces in California. Electrification, consequently, appears to be adding electric load in the long-term while removing sources of growth in gas demand. How these policies become implemented, at an unknown scale and timeframe all introduce uncertainty to the gas demand forecasts.

As the Average Year forecast projects an increase in industrial and EG sectors, the effort to achieve the GHG emissions goal could come by differing gas supply options. The natural gas supply sources could be a cleaner version in the form of renewable natural gas (RNG) or renewable hydrogen (RH_2). The next chapter on natural gas supply will elaborate on these potential gas supplies.

FUTURE GAS DEMAND TRENDS AND POLICY

PG&E's gas demand forecast projects lower throughput over the long-term (due to GHG policies, such as electrification and procurement of renewable generation resources) which would show a decline in revenues at current rates. At the same time, policies on safe utility operations have put upward pressure on costs. Investments into long lived assets, such as gas pipelines, are typically recovered over the assets' useful lives, which extend beyond this forecast. The combination of lower throughput and remaining investment in need of being recovered will put upward pressure on gas transportation rates.

In addition, the transition from fossil fuel (traditional fuels) to other forms of energy usage needs to be carefully planned and managed. PG&E is committed to working with regulators and other stakeholders to support the statewide GHG reduction policies and develop options to minimize rate increase for the remaining gas customers.

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[36] Building Appliances (baaqmd.gov.)

To minimize the rate impacts on gas customers, PG&E is following a three-pronged approach while keeping safety as its top priority: (1) reduce cost, (2) identify alternative revenue sources and (3) leverage innovative financial mechanisms. To reduce cost, PG&E is pursuing opportunities to systematically retire infrastructure and reduce capital and operating expenses through PG&E's Integrated Investment Planning. Since 2018 this program has reached agreements with 84 customers which avoided 80 high pressure regulator rebuilds, retired 4.2 miles of distribution main, and retired 22 miles of transmission line. To increase utilization of existing infrastructure where electrification is not feasible or cost effective, PG&E is actively planning for and implementing programs to decarbonize existing gas throughput, exploring new opportunities to support RNG adoption across new industries, increase load on the natural gas system in areas that would replace less favorable hydrocarbon (e.g., marine, rail and transportation sectors) and seek opportunities to utilize the gas system as a long-term and large scale storage mechanism. Innovative financial mechanisms - such as accelerated depreciation, rate reform, and the capital treatment for cost-effective zonal electrification projects will help - but non-traditional funding sources may also be critical as we evolve to an affordable, decarbonized gas system.

FUTURE OPPORTUNITIES

One recent development that could increase throughput comes from the June 2020 California Air Resources Board (CARB) approval of the Advance Clean Truck (ACT) Regulation. This regulation requires increasing percentages of all new medium- and heavy-duty trucks sales in California to be zero-emission vehicles (ZEV)[37]. The regulation begins in 2024 with sales percentages ranging between 5 percent and 9 percent depending on truck or chassis type. By 2035, the percentages increase to a range of 40 percent to 75 percent.

Truck manufactures may choose hydrogen fuel cells as they decide how to meet this requirement. The fuel required for this could be transported via utility gas pipelines (under appropriate safety protocols) which could mitigate the potential for increasing customer costs.

In addition, companies such as Amazon have internal goals for decarbonizing fleets. Chevron has announced that they are building natural gas fueling stations, including about 15 in Northern California, and truck engine producer Cummins has announced a new 15-liter NGV truck engine. While adoption of such NGV technology is determined by market response, and the carbon status of this fuel choice depends on uncertain RNG implementation and markets, this is a potential path to higher NGV adoption than is reflected in the forecast numbers.

RAIL

Another high horsepower sector to consider for increasing gas throughput is rail transportation. Based on a study by the California Air Resource Board (CARB) from 2016, annual statewide locomotive diesel fuel consumption totals about 260 million gallons. Union Pacific Railroad (UP) and BNSF Railway Company (BNSF) combined interstate and intrastate locomotives account for 93 percent of this fuel usage, California's passenger locomotives are 6%, and the remaining 1percent is from military industrial locomotives[38].

[37] ZEVs are defined as either battery electric or hydrogen fuel cell vehicles.

[38] CARB. (2016). *Technology Assessment: Freight Locomotives.* Sacramento: California Air Resource Board.

CNG and LNG as a fuel source has been considered by the rail industry, but thus far has been mostly limited to pilot studies. Based on conversations with representatives from UP, BNSF, and CARB, some of the key obstacles to CNG and LNG locomotive adoption include: few, if any, new locomotives are planned to be purchased in the near future; the high cost of converting the fueling infrastructure from diesel to CNG or LNG; and current emission standards don't adequately promote fuels cleaner than low sulfur diesel. Additionally, because LNG has an energy density of approximately 60 percent that of diesel, its use for long interstate routes would require increased fuel storage volume. This comes in the form of an LNG tender, which is an additional railcar that includes an insulated cryogenic tank and other equipment to convert LNG back to CNG. The added tender increases cost and complexity to the fuel transition[39].

One possible path to greater CNG or LNG locomotive adoption is more stringent emissions standards. Locomotive emissions are governed by the U.S. EPA. Currently, their strictest emission level is Tier 4 and applies to locomotives manufactured in 2015 or later. In g/bhp-hr it limits nitrogen oxide (NO_x), particulate matter (PM), and hydrocarbon (HC) emissions to 1.3, 0.03, and 0.14 respectively[40]. In 2017, CARB petitioned to the U.S. EPA to consider adopting a new, stricter, Tier 5 standard with a proposed effective date of 2025. The Tier 5 standard would limit NO_{x-}, PM, and HC emissions to 0.2, <0.01, and 0.02.[41]

Marine

Another potential growth area for gas throughput is the marine transportation sector which is increasingly looking at reducing its SOx and GHG emissions. This is orchestrated by the International Maritime Organization (IMO) which regulates global shipping emissions under Annex VI.[42] The IMO updated Annex VI on January 1, 2020 to target reductions in nitrogen

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[39] *Ibid.*

[40] CFR 1033.101 (https://www.ecfr.gov/cgi-bin/text-idx?SID=159ba6f126272ea1995c71a43b7af309&mc=true&node=pt40.36.1033&rgn=div5#se40.36.1033_1101).

[41] https://www2.arb.ca.gov/sites/default/files/2020-07/final_locomotive_petition_and_cover_letter_4_3_17.pdf.

[42] http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx.

oxides (NOx) and sulfur oxides (SOx). To reduce SOx, the sulphur limit for all marine fuels were reduced from 3.50 percent m/m (mass by mass) to 0.50 percent m/m.

The consensus in the marine fuel industry is that the 0.50 percent sulphur limit is only a stop on the way to a global 0.10 percent sulphur limit, which currently exists in several Emissions Control Areas (ECA)[43] around the globe. Moving to 0.10% would necessitate using road grade diesel fuel as bunker fuel, therefore increasing fuel cost. Refining companies would need to further invest in hydrodesulfurization, which is costly to build and operate.

The push towards lowering SOx is driven by environmental groups, government regulations, and the shipping industry itself. Large European container companies are driving it as part of their corporate carbon strategies.[44]

LNG is widely recognized as the best path forward to reduce SOx and GHG for marine purposes but has not seen much growth in the previous decade. The updated IMO Annex VI are changing that, spurring investments in bunkering equipment[45] and vessels[46]. LNG also allows for decarbonizing of the shipping industry as the fuel can be made from RNG and, eventually, renewable hydrogen.

California marine fuel markets can be divided into ocean and coastal. The ocean market is the largest due to the fuel volumes vessels consume. California, with its large container ports in Oakland, Los Angeles, and Long Beach, may see demand for LNG in the future and would require large investments. Some of the investments needed to meet this demand include storage terminals, bunker loading vessels, or liquefaction terminals.

This demand may come sooner rather than later as modern ship engines are flex-fuel capable in that they can run on either fuel oil or natural gas, thus optimizing fuel costs and environmental

43 http://www.imo.org/en/OurWork/Environment/SpecialAreasUnderMARPOL/Pages/Default.aspx.

44 https://www.maersk.com/news/articles/2019/06/26/towards-a-zero-carbon-future .

45 https://sea-lng.org/why-lng/bunkering/; https://www.ship-technology.com/news/west-coasts-lng-bunker-abs/.

46 https://www.cma-cgm.com/news/2749/world-premiere-launching-of-the-world-s-largest-lng-powered-containership-and-future-cma-cgm-group-flagship .

compliance.[47] To give an idea of the potential size of this market, in 2020 vessel bunkering residual fuel oil use in California totaled about 12 million barrels or 62 Bcf.[48]

Coastal market consists mostly of smaller vessels such as passenger ferries, tugs, fishing vessels, etc. These smaller vessels already use an Ultra Low Sulphur Diesel under CARB regulations and these vessels, could see a cost reduction by switching to LNG powered fleets.[49] Small on-demand liquefaction terminals can bunker vessels at berth and have already been installed in Europe[50] successfully. They can be connected directly to the natural gas grid producing fuel on-demand.

NORTH AMERICAN GAS DEMAND

Liquefied Natural Gas Imports/Exports

In years past, the U.S. imported LNG to supplement North American supplies to meet demand. Since the mid-2010s, LNG imports have primarily been used to serve peak winter load[51]. The development of low-cost domestic shale gas supplies since the mid-2000s has largely eliminated the need for LNG imports and positioned the U.S. as a net exporter of LNG.

Recent global events have increased the expectations for more LNG exports from North America. As Europe embarks on measures to increase its energy security and diversify its energy sources, LNG export developers in North America are seeking development opportunities. The gas industry anticipates further growth in LNG exports from North America.

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47 https://www.wartsila.com/twentyfour7/energy/taking-dual-fuel-marine-engines-to-the-next-level.

48 U.S. Energy Information AdministrationSales of Residual Fuel Oil by End Use https://www.eia.gov/dnav/pet/pet_cons_821rsd_a_EPPR_VVB_Mgal_a.htm

49 https://www.mckinsey.com/industries/oil-and-gas/our-insights/imo-2020-and-the-outlook-for-marine-fuels# .

50 https://ec.europa.eu/energy/intelligent/projects/sites/iee-projects/files/projects/documents/magalog_lng_supply_chain.pdf .

51 U.S. Energy Information Administration (US EIA) U.S. Liquefied Natural Gas Imports https://www.eia.gov/dnav/ng/hist/n9103us2m.htm .

NORTHERN CALIFORNIA

The U.S. began exporting LNG in 2016. For projects proposing to export LNG, the U.S. Department of Energy (DOE) evaluates the impact of exports to countries without a Free Trade Agreement (FTA) with the U.S. The DOE grants approval if the project is deemed in the public interest. The U.S. Federal Energy Regulatory Commission (FERC) evaluates the environmental impacts of proposed LNG projects and authorizes the siting and construction of LNG facilities.

Currently, there are more than a dozen proposed projects to export LNG to world markets.[52] Many of the projects are "brownfield," using existing U.S. import terminals to export LNG. Some are "greenfield" projects where LNG infrastructure has not been developed in the past. Two greenfield projects on North America's West Coast are in British Columbia. The larger project is LNG Canada located in Kitimat.[53]

A brownfield project on North America's West Coast is the Energia Costal Azul (ECA) LNG export facility in Baja California, Mexico. ECA has received authorization from the DOE to liquify and re-export up to 1.7 billion cubic feet per day (Bcf/d) of U.S. produced natural gas.[54] This facility will have a nameplate capacity of 3.25 million metric tons (mmt) per annum of liquification capacity. Construction of the project is underway with an online date of 2024.[55]

The ECA LNG export project, which would be the second on the North America's West Coast, is positioned to source gas off the El Paso Mainline System. Thus, it could divert gas supplies currently available to Northern California. ECA diversion of gas supplies from California is currently under consideration at the CPUC in the R.20-01-007 Proceeding.[56] This proceeding will investigate whether the demand from ECA could impact supply reliability to California, especially the southern portion, and put upward pressure on gas prices.

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[52] U.S. EIA https://www.eia.gov/naturalgas/U.S.liquefactioncapacity.xlsx .

[53] LNG Canada https://www.lngcanada.ca/media-kit/ .

[54] https://ecalng.com/ .

[55] Mexico ECA LNG Development Advancing to 2024 Start Date, Natural Gas Intelligence, https://www.naturalgasintel.com/mexico-eca-lng-development-advancing-to-2024-start-date/#:~:text=The%20facility%20is%20adjacent%20to,the%20facility%20online%20in%202024.

[56] OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.

U.S. Natural Gas Pipeline Exports to Mexico

With low domestic natural gas prices compared to world markets, the U.S. remained a net exporter of natural gas in 2021.[57] The U.S. natural gas exports to Mexico have grown in recent years from 0.9 Bcf/d in 2010 to 5.9 Bcf/d in 2021,[58] and pipeline exports are projected to reach 7.4 Bcf/d by 2035.[59]

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

[57] Energy Information Administration (EIA), The U.S. exported more natural gas than it imported in 2017: https://www.eia.gove/todayinenergy/detail.php?id=35392.

[58] EIA, U.S. Natural Gas Pipeline Exports to Mexico: https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_NUS-NMX_a.htm.

[59] EIA, Annual Energy Outlook 2022 – Table 60. Natural Gas Imports and Exports Case: AEO2022 Reference case: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2022&cases=ref2022&sourcekey=0 .

GAS SUPPLY, CAPACITY, AND STORAGE

OVERVIEW

The Gas Supply, Capacity, and Storage section provides information about PG&E's current gas supply, natural gas pipelines, gas storage, and policies affecting these topics. The Gas Supply section includes information about current and anticipated developments regarding Renewable Natural Gas (RNG), as well as gas supply from sources throughout North America. The Pipeline section includes information about "upstream" interstate pipelines, as well as intrastate pipelines. The Storage section gives an overview of PG&E's gas storage capacity and its gas storage facilities. The Policies section looks at a range of current policy developments and their impacts on PG&E's gas supply, including integration challenges for alternative fuel types, such as hydrogen (H_2).

Competition for gas supply, market share, and transportation access has increased significantly since the late 1990s. Implementation of PG&E's Gas Accord in March 1998 and the addition of interstate pipeline capacity and storage capacity have provided all customers with direct access to gas supplies, intra- and inter-state transportation, and related services.

Since gas demand in California is greater than the limited amount of native California production available, most of the gas supplies that serve PG&E customers are sourced from out of state.

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. Supply can be delivered through a variety of sources, including any new and expanded interstate pipeline facilities and of PG&E's existing transmission facilities, or other storage facilities.

GAS SUPPLY

RENEWABLE NATURAL GAS

PG&E has several RNG projects in various phases. Four projects are already connected and flowing clean, renewable gas onto our system. Two projects are in development and should be online by the end of 2022. These six projects are expected to inject roughly 11,500 Mcf/d (thousand cubic feet per day) into PG&E's pipeline system by year end. In addition, there are over a dozen other projects that are in early-stage development that PG&E anticipates will be online over the next two to three years.

Two of the projects are a result of the SB 1383 Dairy Pilot Program, highlighted below, and the other five are identified in the Biomethane Project Incentive Reservation Queue located on the CPUC website.[60]

SB 1383 DAIRY PILOT PROJECTS

On December 3, 2018, the CPUC, CARB, and the California Department of Food and Agriculture (CDFA) issued a joint press release announcing the selection of six dairy pilot projects in compliance with CPUC D.17-02-004 and SB 1383. Two of the pilot projects were awarded in PG&E's service territory (see the Figure below): (1) the Merced Pipeline project sited at the Vander Woude Dairy in Merced (6 miles south of Merced); and (2) the J.G. Weststeyn Dairy project in Willows (5 miles west of Logandale).

On January 7, 2022, the Vander Woude Dairy project became operational, and the maximum RNG volumetric flow rate was met in February 2022, qualifying the project's entire authorized costs under the SB 1383 Dairy Pilot Program to be reimbursed.

As of May 2022, the J.G. Weststeyn Dairy project is completing its project design with an anticipated construction start date beginning in 2023.

[60] https://www.cpuc.ca.gov/renewable_natural_gas/.

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FIGURE 10 – PG&E SERVICE AREA: RNG PILOT PROJECTS LOCATION

FUTURE CALIFORNIA RNG SUPPLY

A 2016 CARB-sponsored study by University of California (UC), Davis, "The Feasibility of Renewable Natural Gas as a Large Scale, Low Carbon Substitute" (the "STEPS study"), anticipated that as much as 82 Bcf per year of RNG supply could become available in California with appropriate policy development and investment.[61] The STEPS study identified that the largest opportunity for increasing the supply of RNG would come from landfill sites, followed by dairy, municipal solid waste, and waste-water facilities.

A more recent assessment of in-state RNG supply for transportation, conducted by GNA[62], projects that there will be roughly 16 Bcf annually of RNG interconnected into gas pipelines in California by January 2024. Additionally, the CPUC has required the utilities to file an application in the Summer of 2023 to advance pilot projects that would convert woody biomass into RNG, further expanding the potential long-term supply of RNG in the state.

Given the STEPS study results, the gas flowing from RNG sources by January 2024 is just the first wave of RNG expected to be eventually injected into the gas system. Therefore, going forward, PG&E expects to see more RNG projects as developers realize the near- and mid-term potential of this supply source.

Gas Absorption Capacity

To encourage effective development of RNG, PG&E created the Gas Supply Absorption Capacity Map.[63] This map is a high-level snapshot of PG&E's gas system that is designed to help contractors and developers find potential project sites by showing the relative ability (high to low) to accept new gas supply on PG&E transmission pipelines. Suppliers are encouraged to contact PG&E to discuss opportunities to bring on RNG supplies. Currently this map is being revised to provide better information to potential developers.

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[61] STEPS Program Study, The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute, prepared by Amy Myers Jaffe, available at: https://steps.ucdavis.edu/the-feasibility-of-renewable-natural-gas-as-a-large-scale-low-carbon-substitute/.

[62] https://www.gladstein.org/gna_whitepapers/an-assessment-californias-in-state-rng-supply-for-transportation-2020-2024/ .

[63] Available at: https://www.pge.com/en_US/for-our-business-partners/interconnection-renewables/interconnections-renewables/biomethane-map-overview.page .

NORTH AMERICAN SUPPLY DEVELOPMENT

North America has an abundance of natural gas resources. In the United States, the Potential Gas Committee estimates resources of 3,368 trillion cubic feet (Tcf).[64] Natural gas resource development has improved over the past two decades as horizontal drilling and hydraulic fracturing has matured. Furthermore, advancements in drilling know-how and improved efficiencies have improved resource development, typically at lower costs. The U.S. produced almost 94 Bcf/d on average in 2021.[65] Three producing regions contributed about 60 percent of this production: the Haynesville region mainly in Louisiana and Texas, the Permian region in Texas and New Mexico, and the Appalachia region mostly located in Pennsylvania, Ohio, and West Virginia.[66] The resources that contribute to these production regions include both shale gas resources and associated gas from oil production.[67] Most industry forecasts continue to predict that gas production will meet most demand outlooks in the future.

The growth of associated gas production in the Permian Basin and eastern shale plays - the Haynesville and Appalachia) continue to push gas volumes from Canada, the Rocky Mountain area, and the Southwest towards California. These production regions interconnect with California via pipelines as highlighted below.

CALIFORNIA SOURCED GAS

Northern California sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2021, PG&E's customers obtained on average 23 MMcf/d of California sourced gas. PG&E anticipates that California sourced gas may increase from this level. The primary driver to this growth is RNG production.

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[64] http://potentialgas.org/press-release. This estimate represents the total mean technically recoverable resource base as of year-end 2020. Technically recoverable resources means gas can be produced using currently available technology and industry practices.

[65] U.S. Energy Information Administration Natural Gas Dry Production (eia.gov) .

[66] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis .

[67] Production - Amid uncertainty, the United States continues to be an important global supplier of crude oil and natural gas - U.S. Energy Information Administration (EIA) .

U.S. Southwest Gas

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

PG&E's customers can purchase 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 intrastate 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 (GTN) pipeline. Likewise, they can also purchase these supplies at the California-Oregon border or at the PG&E Citygate from marketers who hold interstate or intrastate pipeline capacity.

Rocky Mountain Gas

PG&E's customers have access to gas supplies from the Rocky Mountain area via the Kern River Gas Transmission Pipeline, the Ruby Pipeline and via the GTN Pipeline interconnect at Stanfield, Oregon.

GAS PIPELINE CAPACITY

Interstate Pipeline Capacity

California utilities and end-use customers benefit from access to multiple supply basins, enhanced by produced gas-on-gas and pipeline-on-pipeline competition. Interstate pipelines serving northern and central California include El Paso Natural Gas, Mojave, Transwestern, GTN, Paiute Pipeline Company, Ruby, and Kern River Gas Transmission pipelines. These pipelines provide northern and central California with access to gas producing regions in the U.S. Southwest, Rocky Mountains, and in Western Canada.

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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, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 935 MMcf/d.

CANADA AND ROCKY MOUNTAINS

PG&E's Redwood Path (Lines 400/401) is connected to GTN and Ruby at Malin, Oregon. The Redwood Path has a firm capacity of 2,060 MMcf/d.

IN-STATE PIPELINES

PG&E continues to accelerate the analysis of the existing pipeline system for opportunities to minimize rate increases for our customers by reducing our expenses, look for new opportunities for load growth and to decarbonize by increasing throughput of RNG. PG&E is actively pursuing a variety of initiatives including electrification opportunities on radial feeds where several miles of pipe are in place to serve a small handful of customers, pruning the system of pipe that is underutilized or no longer serving customers, downrating lines, and elimination or streamlining projects. Electrifying these customers and decommissioning the pipeline will achieve greater cost savings in the long term. These opportunities will also help inform PG&E's longer-term efforts, in partnership with cities, to strategize where to reduce our spending and predict long-term gas needs more accurately.

GAS STORAGE

Northern California is served by several gas storage facilities in addition to the longstanding PG&E fields at McDonald Island, Los Medanos, and a 25 percent ownership in Gill Ranch Storage.[68] These facilities combine for a total inventory of 167 Bcf, with 35 Bcf under PG&E management.

[68] PG&E also has operated the Pleasant Creek storage field. The Decision (D.) 19-09-025 for the 2019 Gas Transmission and Storage rate case, Ordering Paragraph 42, adopted PG&E's proposal to sell or decommission the Pleasant Creek storage field.

Other Northern California storage providers consist of Gill Ranch Storage, LLC (a 20 Bcf facility that was co-developed with PG&E), Wild Goose Storage, LLC, Lodi Gas Storage, LLC, and Central Valley Storage, LLC. The abundant storage capacity in Northern California has the effect of creating ample liquidity in the market both in Northern California and in other parts of the West.

Within the past ten years, Northern California natural gas storage facilities have experienced regulatory changes. In response to the Southern California Gas Company's Aliso Canyon Storage natural gas leak in October 2015, the California Department of Conservation, Geologic Energy Management Division (CalGEM), previously known as the Division of Oil Gas and Geothermal Resources (DOGGR), adopted new natural gas storage well safety regulations across California. Key elements of these new rules included requiring all operators to submit risk and integrity management plans, well casing inspection and pressure testing plans, and a schedule to convert or retrofit wells to tubing and packer.[69] Packers seal off the annulus space in the casing and limit the gas flow to the smaller diameter inner tubing only, which is forecasted to reduce traditional storage well performance on average by 40 percent.[70] Partly in response to the new regulations, PG&E proposed a Natural Gas Storage Strategy (NGSS) in its 2019 Gas Transmission and Storage (GT&S) Rate Case. Specifically, PG&E proposed to exit the commercial storage market and focus on reliability services. As a part of the NGSS, PG&E proposed to sell or decommission its Los Medanos and Pleasant Creek storage facilities. The CPUC approved the NGSS in Decision (D.) 19-09-025.

On December 1, 2020, PG&E announced the sale of the Pleasant Creek natural gas storage field, located in Yolo County, California. The Pleasant Creek field is the smallest of four underground natural gas storage fields owned wholly or partly by PG&E.

In PG&E's 2023 General Rate Case application, filed at the CPUC on June 30, 2021, PG&E proposed updates to the NGSS in response to evolving CalGEM regulations. These updates include a proposal to retain the Los Medanos storage facility while still decommissioning or

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[69] Geologic Energy Management Division Statutes & Regulations January 2022 (ca.gov) https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

[70] Workpaper Table 7-37. Pacific Gas and Electric Company 2023 General Rate Case Workpapers.

selling the Pleasant Creek storage facility. The proposal to retain Los Medanos is in lieu of drilling additional new wells at the McDonald Island facility to meet the utility's firm withdrawal obligations. PG&E's proposed NGSS updates are pending before the CPUC as of mid-2022.

Last, in March 2019, PG&E submitted an underground storage risk and integrity management plan and accompanying field specific well risk evaluation and construction standard implementation plan (2019 Implementation Plan) to CalGEM consistent with CalGEM's regulations. After input and feedback from CalGEM, PG&E submitted a revised implementation plan in January 2021 (2021 Revised Implementation Plan), which details our well testing, conversion, and risk management plans. In June 2021, CalGEM approved the 2021 Revised Implementation Plan with some additional requirements. Consistent with the 2021 Revised Implementation Plan, PG&E expects all new wells to be drilled and existing wells converted to tubing and packers by 2026.

OTHER CALIFORNIA STORAGE FACILITIES

In addition to storage services offered by PG&E, there are four other storage providers in Northern California: Wild Goose Storage, LLC; Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. These facilities have an estimated total working gas capacity of roughly 132 Bcf[71].

POLICIES IMPACTING FUTURE GAS SUPPLY AND ASSETS OVERVIEW

California's policies to reduce GHGs are expected to impact gas supply and assets. PG&E is responding to these policies and actively planning for and implementing programs to decarbonize existing gas throughput, supporting RNG adoption, supplying hard to electrify industries, and planning to utilize the gas system as a long-term energy storage mechanism.

[71] Capacities derived from information provided by Independent Storage Providers.

RENEWABLE NATURAL GAS

As a result of various policy and regulatory changes to decarbonize gas throughput, PG&E is seeing an influx of requests to interconnect RNG to utility pipelines in Northern California. RNG producers are leveraging available grants and incentives to encourage the production of RNG to reduce GHG emissions from these biogas-sources and for use as an alternative fuel source for transportation and other end use customers. PG&E is engaged in the following efforts regarding RNG:

- Procuring RNG for all PG&E-owned Compressed Natural Gas (CNG) fueling stations;
- Actively working with RNG developers to interconnect their projects through the biomethane program;
- Working to file an application to advance woody biomass pilot projects under CPUC D. 22-02-025;
- Planning for implementation of biomethane (RNG) procurement for core customers under CPUC Decision 22-02-025; and
- Participation in various Research and Development (R&D) efforts to further understand and develop new methods and technologies to produce RNG that reduce the carbon intensity of the gas in the pipeline.

NORTHERN CALIFORNIA

MONETARY INCENTIVE PROGRAM

D.15-06-029 established a biomethane monetary incentive program that included $40 million to encourage biomethane producers to design, construct, and safely operate projects that interconnect and inject biomethane into California's natural gas utilities' pipeline systems.

D.19-12-009 implements an Incentive Reservation System for the biomethane monetary incentive program established in D.15-06-029. The Incentive Reservation System opened to applications on February 3, 2020, and the queue is published on the CPUC's RNG website.[72]

D.20-12-031 authorized an additional $40 million of RNG project incentive funding sourced from Cap-and-Trade allowance auction proceeds subject to projects meeting applicable CARB program regulations.

Based on information provided on the CPUC's RNG website, seven projects have received a total of approximately $29.5 million of funding under the incentive program, leaving $50.5 million remaining in the program.

RESEARCH AND DEVELOPMENT

PG&E's R&D RNG roadmap[73] further outlines PG&E's goals for incorporating RNG into the supply portfolio.

HYDROGEN

Hydrogen, H_2, is seen as a game changer in decarbonizing the gas supply and sectors that will be difficult to electrify. To achieve the goals set forth in SB 100, discussed below, California will likely need to incorporate H_2 into the portfolio of green fuels for various sectors. Many other countries have already embraced H_2 and fuel cell technology to reduce their carbon footprint.

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[72] https://www.cpuc.ca.gov/renewable_natural_gas/ .

[73] https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/RNG_Roadmap_2020.pdf.

Given the momentum, California, through the Governor's Office of Business and Economic Development, is in the process of unifying Northern and Southern California efforts into a single application for the upcoming DOE (U.S. Department of Energy) RFP (Request For Proposals) for hydrogen infrastructure investment. This will be an important step in taking advantage of the geographic diversity in the northern and southern portions of the state.

Additionally, the California IOUs are working together on an action plan for incorporating H_2 into the pipelines through pilot and demonstration projects to help inform an eventual hydrogen injection standard.

HYDROGEN STORAGE (CONVENTIONAL AND NEW TECHNOLOGY)

H_2 has many potential applications. One such application is to produce H_2 through electrolysis from excess renewable energy and store it in the pipeline system (or dedicated underground storage facilities) for later use. Such uses may include H_2 as fuel for electric generation to backup intermittent renewable generation. H_2 storage has great potential for longer-term storage that current electric battery storage technology is unable to serve. Moreover, H_2 storage can provide clean fuel for electric generation at larger volumes as renewable generation experiences seasonal intermittency. Battery storage technology currently cannot provide the scale needed to backup seasonal intermittency.

NORTHERN CALIFORNIA

CNG AS RAIL AND LNG AS MARINE FUEL

As mentioned above in the Gas Demand section, there is tremendous opportunity for growth in the rail and marine markets. The gas supply needed for this demand will need to come from cleaner sources of fuel such as RNG and H_2. Additionally, LNG infrastructure would need to be developed at the appropriate scale to meet marine demand for LNG.

REGULATORY ENVIRONMENT

OVERVIEW

This section provides an overview of the existing and near-term regulatory policies and their effect on the Northern California gas system and its users.

Given the anticipated state and federal regulatory policies surrounding storage, transportation, inspection, and capacity requirements, the cost to safely and reliably operate PG&E's gas system will continue to rise. At the same time, a decline in throughput—which PG&E anticipates is a result of California's GHG reduction goals and cities taking action to establish new electric codes and ordinances—will mean those costs will be spread over fewer therms and possibly fewer customers. Unless the evolution of the gas system is well managed, rising costs combined with reduced throughput would impact the affordability of gas for customers.

Furthermore, despite readily available domestic gas supply and operational innovation, the complex regulatory environment and evolving policies are likely to create price uncertainty in the medium to long term.

FEDERAL AND CANADIAN REGULATORY MATTERS

PG&E actively participates in FERC ratemaking proceedings for interstate pipelines connected to PG&E's system since these proceedings can impact the cost of gas delivered, the reliability of gas supply, and the services provided to the PG&E's gas customers. 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.

GTN AND RUBY PIPELINES

Gas Transmission Northwest (GTN) and their shippers settled during pre-rate case negotiations with no rate increase for two years beginning on January 1, 2022. GTN has also filed a certification application in October 2021 for its Xpress Project that PG&E has intervened in and are monitoring for impacts on PG&E's customers. The proposed project will create 150

MDth/d of incremental mainline capacity on GTN's system. The in-service date is November 1, 2023.

On March 31, 2022, Ruby Pipeline, LLC (Ruby) filed to reorganize under Chapter 11 of the United States Bankruptcy Code in response to an upcoming debt repayment obligation.[74] PG&E will follow this event to limit the impacts to PG&E's operations and policies or natural gas market policies.

El Paso Natural Gas Company

On April 21, 2022, FERC issued an order initiating an investigation to determine whether the rates currently charged by El Paso Natural Gas Company, L.L.C. ("El Paso") are just and reasonable and setting the matter for hearing. PG&E is monitoring the proceeding.

Other Pipelines

There are currently no significant regulatory issues regarding Kern River Gas Transmission (Kern River); or Transwestern Pipeline Company, LLC (Transwestern) pipelines.

CANADIAN REGULATORY MATTERS

PG&E continually monitors Canadian regulatory matters that can impact PG&E's customers. Currently, no regulatory issues are currently present.

FERC AND CAISO GAS--ELECTRIC COORDINATION ACTIONS

While there are no general inquiries or proceedings at FERC addressing gas-electric coordination, the California Independent System Operator (CAISO), which is FERC-jurisdictional, has ongoing policy initiatives that may impact gas demand, supply, and prices. These initiatives include:

- Day-Ahead Market Enhancements; and
- Extended Day-Ahead Market

[74] https://cases.ra.kroll.com/rubypipeline/Administration.

These policy initiatives will need FERC approval before the proposed changes can be implemented.

STATE REGULATORY MATTERS

CALIFORNIA STATE SB 100 AND CARBON NEUTRALITY EXECUTIVE ORDER

On September 10, 2018, Governor Brown signed into law SB 100, which further increases the Renewable Portfolio Standard (RPS) targets and includes the following key requirements:

- Accelerates the RPS to 50 percent by 2026 and increases the RPS to 60 percent by 2030;
- Creates a separate state policy that requires 100 percent of all retail sales of electricity to serve end-use customers and 100 percent of electricity procured to serve state agencies to come from RPS-eligible or zero -carbon resources by 2045; and
- Requires the CPUC, in consultation with the CAISO and other balancing authorities, to issue a joint report to the Legislature by January 1, 2021, and every four years thereafter, that evaluates the anticipated costs and benefits of the 100 percent clean policy to electric, gas, and water utilities, including customer rate impacts and benefits.

Additionally, Governor Brown signed an EO on September 10, 2018, establishing a new statewide goal to achieve carbon neutrality by 2045 across all sectors of the California economy and to achieve and maintain net negative GHG emissions thereafter. Implementation of the order will require California to undertake additional decarbonization and carbon removal efforts. CARB is developing California's plan for achieving carbon neutrality in its Climate Change Scoping Plan Update, due to be completed by the end of 2022.[75]

[75] CARB Scoping Plan, available at: https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan.

NORTHERN CALIFORNIA

PIPELINE SAFETY

Since 2011, the CPUC and the California 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, Senate Bill (SB) 705 mandated that gas operators develop and implement safety plans that are consistent with the best practices in the gas industry.

On March 15, 2022, PG&E filed its 2022 Gas Safety Plan with the CPUC, which explains how PG&E puts the safety of the public, customers, employees, and contractors first, and details gas safety work performed in 2021. The Gas Safety Plan is reviewed and updated annually in accordance with General Order 112-F Section 123.2(k), and Public Utilities Code Sections 961 and 963.1.

Additionally, PG&E submits the following reports to the CPUC: (1) semi-annual Gas Transmission & Storage Compliance Report; (2) annual Gas Distribution Pipeline Safety Report; (3) annual Risk Spending Accountability Report; and (4) annual Safety Performance Metrics Report. These reports are designed to provide the CPUC and other interested stakeholders with insight into the amount of safety, reliability, and maintenance -related work PG&E has completed over the course of the reporting period and/or performance in key safety areas.

Below are selected highlights from PG&E's 2021 reports and the Gas Safety Plan which further demonstrate PG&E's commitment to pipeline safety:

- **Asset Management System:** PG&E maintains an asset management system to help drive the business toward achieving its commitment to the safe, reliable, and affordable management and operation of PG&E's gas assets. Using the Publicly Available Specification (PAS) 55: 2008 and International Organization for Standardization (ISO) 55001: PG&E's asset management system focuses on: (1) knowing the condition of the assets; (2) understanding the risks to those assets; (3) implementing asset risk reduction strategies; (4) maintaining asset condition and performance; and (5) balancing asset cost, risk, and performance in pursuit of the asset management strategic objectives.

- **Process Safety:** Guided by the elements set by the Center for Chemical Process Safety, PG&E's commitment to implement process safety aligns with American Petroleum

Institute (API) Recommended Practice (RP) 754 Process Safety Performance Indicators for the Refining and Petrochemical Industries. A risk-sorting criterion to track and trend process safety leading and lagging indicators is used to identify emerging issues before incidents occur. The Process Safety team continued to review changes to existing procedures and standards and new procedures and standards in order to help Gas Operations operate and maintain safe facilities and consistently implement process safety practices.

- **In-Line Inspection (ILI):** PG&E's current goal is to upgrade the gas transmission pipeline system to be capable of ILI for over 4,500 transmission pipeline miles by the end of 2036, which is approximately 69 percent of PG&E's GT pipeline miles. As of December 31, 2021, PG&E has successfully upgraded 46 percent of the GT pipeline system, resulting in approximately 2,956 miles of piggable transmission lines.

- **Third-Party Dig-Ins:** In 2021, PG&E experienced 0.91 third-party dig-ins per 1,000 Underground Service Alert (USA) tickets, outperforming its 2021 target of 1.07 third-party dig-ins per 1,000 tickets.

- **Community Pipeline Safety Initiative (CPSI)**: A multi-year program designed to enhance safety by improving access to pipeline rights-of-way. To date, the program has cleared more than 99 percent of the work scope, including approximately 1,544 vegetation miles and 359.9 structure miles. Pending outstanding municipality and customer agreements, and receipt of long-lead time permits, the remaining 8.38 miles of vegetation and 0.02 miles of structure clearing has been extended to at least December 2022. For areas with completed CPSI work, PG&E remains committed to keeping the area above and around the pipeline clear through our ongoing Gas Transmission Vegetation Management Program.

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STORAGE SAFETY

In response to the Southern California Aliso Canyon Storage natural gas leak in October 2015, the California Department of Conservation, Geologic Energy Management Division (CalGEM) adopted new safety regulations concerning natural gas storage wells across California. Key elements of these new rules included requiring all operators to submit risk and integrity management plans, well casing inspection and pressure testing plans, and a schedule to convert or retrofit wells to tubing and packer. The elimination of the annulus flow could reduce traditional well performance on average by 40 percent.

Partly in response to the new regulations, PG&E proposed a Natural Gas Storage Strategy (NGSS) in its 2019 Gas Transmission and Storage (GT&S) Rate Case. Specifically, PG&E proposed to exit the commercial storage market and focus on reliability services. As a part of the NGSS, PG&E proposed to sell or decommission its Los Medanos and Pleasant Creek storage facilities. The CPUC approved the NGSS in Decision (D.) 19-09-025.

In its 2023 General Rate Case application, filed at the CPUC on June 30, 2021, PG&E proposed updates to the NGSS in response to evolving CalGEM regulations. These updates include a proposal to retain the Los Medanos storage facility while still decommissioning or selling the Pleasant Creek storage facility. The proposal to retain Los Medanos is in lieu of drilling additional new wells at the McDonald Island facility to meet our firm withdrawal obligations. PG&E's proposed NGSS updates are still pending before the CPUC.

In March 2019, PG&E submitted an underground storage risk and integrity management plan (R&IMP) and accompanying field specific well risk evaluation and construction standard implementation plan (2019 Implementation Plan) to CalGEM consistent with CalGEM's regulations. After input and feedback from CalGEM, PG&E submitted a revised implementation plan in January 2021 (2021 Revised Implementation Plan), which details our well testing, conversion, and risk management plans. In June 2021, CalGEM approved the 2021 Revised Implementation Plan with some additional requirements. Consistent with the 2021 Revised Implementation Plan, PG&E expects all new wells to be drilled and existing wells converted to tubing and packers by of 2026.

CITIES, REGULATORS, AND AIR DISTRICTS PURSUE ELECTRIFICATION

Local governments continue to take steps towards electrification at the city and county level with new electric "reach" building codes that require or give preference to electric new construction.[76] The California Public Utilities Commission has also proposed a removal of gas line extension allowances, discounts, and refunds within the Building Decarbonization OIR (R.19-01-011). PG&E's position was to not oppose a removal of residential gas line extension allowances, but to request that allowances remain for non-residential customers that provide a financial or environmental benefit to ratepayers.

The spread of all-electric new construction and the consideration of point-of-sale bans on gas furnaces and water heaters suggests a future flattening of demand for gas in buildings.

KNOWN REGULATORY HURDLES

Federal regulation along with state and local climate action goals are set to create an evolving and time challenging environment for gas utilities and customers. To succeed in achieving operational safety and climate action goals, the following hurdles need to be addressed:

- As regulations continue to be revised and updated, the cost of providing a safe and reliable gas system will continue to rise. This increase in cost, paired with state and local GHG goals, are expected to drive down gas throughput. Lower gas throughput will likely result in a higher cost per-therm for customers if the evolution is not well-managed.

- While there is significant potential for renewable gas (RG) to replace some portion of natural gas supply, the current investments and incentives for RG end-use principally favor the transportation sector. With the clear financial advantage towards transportation, there is comparatively little RG available to establish a consistent RG supply to meet PG&E's customer or third-party needs now that an RG standard has been established. If this is to change, California will have to balance the funding mechanisms between the

[76] "California's Cities Lead the Way on Pollution-Free Homes and Buildings." Sierra Club, June 16, 2022: https://www.sierraclub.org/articles/2021/07/californias-cities-lead-way-pollution-free-homes-and-buildings.

transportation sector and other sectors so that RG project developers have opportunities to supply RG towards an RG standard or the transportation sector.

California's gas system is going through unprecedented changes. As it evolves, it is important that regulatory bodies and the utilities work together to ensure that Californians continue to have access to clean, reliable, and affordable energy.

OTHER REGULATORY MATTERS

OVERVIEW

This section includes PG&E's GHG and Cap-and-Trade reporting and discusses other regulatory matters that may impact Northern California's gas system.

PG&E is participating in several OIRs, which address crucial topics that will impact the California gas system. For example, the:

- Biomethane OIR (R.13-02-008) helped the utilities make RNG interconnections more efficient and affordable across California as well as established an RNG procurement program for core customers.

Gas System Planning OIR (R.20-01-007) which will allow the utilities to: (1) develop updated reliability standards that are in line with current and future operational challenges of gas system operators, (2) improve coordination between gas utilities and gas -fired generators, and (3) develop and implement a long -term strategy to work towards California's decarbonization goals.

GHG REPORTING AND CAP-AND-TRADE OBLIGATIONS

In March 2022, 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 2021 resulting from combustion at 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 2022, PG&E reported to CARB GHG emissions approximately 42.5 million mtCO2e (metric tons carbon dioxide equivalent) in these primary categories for reporting year 2021: 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 and one underground gas storage facility.

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 2021, CARB estimated that PG&E's responsibility for compliance obligations of GHG emissions as a natural gas supplier was approximately 17.9 million mtCO2e for reporting year 2020. CARB will issue the final 2020 PG&E's compliance obligations of GHG emissions as a natural gas supplier in October 2022.

In June 2021, PG&E filed the 2020 Annual Natural Gas Leakage Abatement Report and reported 3 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 two-year Leak Abatement Compliance Plan in March 2022. 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 transitioning from the three-year gas distribution leak survey cycle to optimized leak surveys, potential reduction of the Super Emitter threshold, extending blowdown reduction strategies to compressor station and storage facilities, lowering the pipeline pressure to near zero for scheduled transmission projects and applying degassing technologies for In-Line Inspection (ILI) and lower volume transmission projects.

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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. Each year, on a mandatory basis, PG&E reports its methane emissions to the California Public Utilities Commission and, on a voluntary basis, also reports—and obtains third-party verification for—a more comprehensive corporate greenhouse gas emissions inventory, including PG&E's methane emissions. Each year, PG&E also completes and publishes the Edison Electric Institute (EEI) and American Gas Association (AGA) voluntary Environmental, Social, Governance (ESG) and Sustainability reporting templates for investors, which includes methane emissions. PG&E believes it's essential that investors, customers, policymakers, and other stakeholders have access to information on PG&E's emissions profile. In addition, PG&E is committed through its 1-million-ton challenge to reduce GHG emissions from company operations through 2022. PG&E's strategy to meet this goal includes increased leak survey and repair, removing high-bleed pneumatic devices, replacing vintage distribution main, and reducing transmission pipeline blowdowns.

BIOMETHANE OIR R.13-02-008 PHASE 3

On July 5, 2018, the CPUC reopened R.13-02-008 Phase 3 and ordered the joint California utilities to propose a joint RNG interconnection tariff and interconnection agreements.

On October 28, 2020, the CPUC approved the joint utilities' Standard Renewable Gas Interconnection Tariff pursuant to D. 20-08-035 which established standards and requirements to permit the safe injection of RNG into a jurisdictional common carrier pipeline.

The CPUC also instituted a Reservation System in D.19-12-009 that became effective as of February 3, 2020, for the biomethane incentive program implemented by D.15-06-029.

BIOMETHANE OIR R.13-02-008 PHASE 4

On November 21, 2019, the CPUC issued a Ruling to establish Phase 4 of the proceeding that will address injection of renewable H2 into gas pipelines and implementation of SB 1440 (RNG procurement).

On February 24, 2022, the CPUC approved D.22-02-025 implementing Senate Bill 1440 establishing a framework of a mandatory Biomethane Procurement Program. This Biomethane Procurement Program will assist the state in meeting short-lived climate pollutant emissions reduction goals by requiring the Joint Utilities to procure biomethane (RNG) produced from organic waste for their core customers.

On April 5, and 6, 2022, the Joint Utilities hosted public workshops to discuss the Standard Biomethane Procurement Methodology (SBPM) that included panelists from each stakeholder group. The Joint Utilities are directed to file a joint Tier 2 Advice Letter with a report of the workshop and feedback received. On April 22, 2022, the Joint Utilities hosted a separate public workshop to discuss the Renewable Gas Procurement Plan (RGPP) that also included panelists from each stakeholder group. The Joint Utilities are directed to file a Tier 1 Advice Letter to establish a template RGPP. The joint utilities plan to file a new application outlining three distinct H_2 projects to further understand capabilities of H_2 and inform a statewide injection standard.

GAS SYSTEM PLANNING OIR R.20-01-007

The CPUC has an in-progress Rulemaking - Order Instituting Rulemaking to “Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.” This proceeding will be conducted in two tracks and will: (1) develop and adopt as necessary updated reliability standards that reflect current and future operational challenges to gas system operators, (2) determine the regulatory changes to improve coordination between gas utilities and gas-fired generators, and (3) implement a long-term planning strategy to manage the transition away from natural gas-fueled technologies to meet California’s decarbonization goals. This proceeding is currently in track two.

ABNORMAL PEAK DAY DEMAND AND SUPPLY

APD DEMAND FORECAST

The Abnormal Peak Day (APD) forecast is a projection of demand under extreme weather conditions. PG&E defines an APD as a 1-in-90 year cold temperature event. The 1-in-90 temperature corresponds to a 28.3 degree Fahrenheit system weighted mean temperature across the PG&E system. The PG&E core demand forecast corresponding to a 28.3 degree Fahrenheit temperature is estimated to be approximately 3.0 Bcf/d. The PG&E load forecast shown here excludes all noncore demand and excludes all electric generation (EG) demand. Under an APD design scenario PG&E is only required to ensure that it can supply enough gas to core customers on the system.

The APD core forecast in the table below 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 remaining balance of PG&E's core customers and have the same obligation as PG&E Core Gas Supply to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

In previous extreme cold weather events, PG&E has observed a drop in flowing pipeline supplies. Supply from Canada is affected as cold weather 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 PG&E's system, cold weather can affect producing wells in the basins, which in turn can affect the total supply to the PG&E system and others.

If core supplies are insufficient to meet core demand, PG&E can divert gas from noncore customers, including EG customers, to meet demand. PG&E's tariffs contain diversion and Emergency Flow Order non-compliance charges that are designed to cause the noncore market to either reduce or cease its use of gas, if required. Since little, if any, alternate fuel-burn capability exists today, supply diversions from the noncore would necessitate those noncore customers to curtail operations. Under supply-shortfall conditions—such as an APD—a significant portion of EG customers could be shut down potentially impacting electric system reliability.

TABLE 19 – FORECAST OF CORE GAS DEMAND AND SUPPLY ON AN ABNORMAL PEAK DAY (APD)
(MMcf/d)

Line No.		2022-23	2023-24	2024-25
1	APD Core Demand (1)	3,057	3,062	3,070
2	Independent Storage Provider Withdrawal (2)	2,162	2,162	2,162
3	Firm Flowing Supply (3)	3,051	3,051	3,051
4	Projected Resources to Meet Demands (4)	4,232	4,193	4,108

Notes:
(1) Includes PG&E's Gas Procurement Department's and other Core Aggregator's core customer demands. APD core demand forecast is calculated for 28.3 degrees F 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 Independent Storage Provider Withdrawal is based on information provided by the Independent Storage Providers to PG&E and internal analysis by PG&E.
(3) The Firm Flowing Supply includes firm Redwood and Baja capacities and nominal amounts of California gas production. These values are those currently approved for use within PG&E.
(4) Projected Resources to Meet Demands (Line No. 4) are less than the sum of Independent Storage Provider Withdrawal (Line No. 2) and Firm Flowing Supply (Line No. 3) because PG&E's system cannot simultaneously accommodate all flowing supplies and all storage withdrawals. This number is designed for a 1-in-10 design scenario while an APD is a 1-in-90 design scenario, meaning this number may not be representative of what the actual supply on a 1-in-90 day will be, but is sufficient to meet all APD Core demand.

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 Peak Day Demand Cases.

TABLE 20– WINTER PEAK DAY DEMAND (MMcf/d)

Year	Core Unadjusted for Building Electrification	Building Electrification Modifier	Core With Building Electrification	Noncore Non-EG	EG, Including SMUD	Total Demand
2022-2023	2,574	-2	2,572	458	897	3,927
2023-2024	2,579	-4	2,575	460	908	3,942
2024-2025	2,585	-6	2,579	475	929	3,984
2025-2026	2,591	-8	2,582	488	983	4,054
2026-2027	2,600	-11	2,589	489	1,006	4,085
2027-2028	2,609	-17	2,592	490	1,021	4,104

The core demand in the Winter Peak Day Demand table is developed using the observed relationship between historical daily weather and core gas usage. This relationship is then used to forecast the core load under a 1-in-10 temperature scenario. The building electrification modifier represents the California Energy Commission's 2021 Integrated Energy Policy Report Additional Achievable Fuel Substitution (Low Case, AAFS 2)[77]. The projection in the AAFS 2 represents the building electrification, moving from natural gas use to electric use. The noncore Non-EG forecast is the average daily December demand under 1-in-10 Cold and Dry conditions. Last, the EG, including SMUD projection is the 90th percentile for the months of December through February under 1-in-10 Cold, Dry Hydro Demand conditions.

[77] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report .

TABLE 21 – SUMMER PEAK DAY DEMAND
(MMcf/d)

Year	Core Unadjusted for Building Electrification	Building Electrification Modifier	Core With Building Electrification	Noncore Non-EG	EG, Including SMUD	Total Demand
2022	353	-3	351	585	979	1,914
2023	340	-5	335	598	929	1,892
2024	330	-7	323	610	927	1,860
2025	319	-10	309	615	853	1,777
2026	309	-13	296	616	978	1,890
2027	304	-17	287	616	1,025	1,929

The core and noncore Non-EG demands in the Summer Peak Day Demand table represent the average August daily summer demand under 1-in-10 cold and dry conditions. The building electrification modifier represents the California Energy Commission's 2021 Integrated Energy Policy Report Additional Achievable Fuel Substitution (Low Case, AAFS 2). Last, the EG including SMUD demand forecast is the 90th percentile for the months of July through September under 1-in-10 cold and dry conditions.

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TABLE 22

ANNUAL GAS SUPPLY AND REQUIREMENTS
RECORDED YEARS 2017-2021
MMCF/DAY

LINE		2017	2018	2019	2020	2021
GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS					
1	Core Purchases	0	0	0	0	0
2	Customer Gas Transport & Exchange	42	49	62	63	60
3	Total California Source Gas	42	49	62	63	60
	OUT-OF-STATE GAS					
	Core Net Purchases					
6	Rocky Mountain Gas	178	161	170	158	158
7	U.S. Southwest Gas	84	58	58	41	29
8	Canadian Gas	319	303	286	379	410
	Customer Gas Transport					
10	Rocky Mountain Gas	461	367	486	416	329
11	U.S. Southwest Gas	304	430	599	505	539
12	Canadian Gas	832	957	888	927	933
13	Total Out-of-State Gas	2,178	2,276	2,487	2,425	2,397
14	STORAGE WITHDRAWAL(2)	328	397	350	252	344
15	Total Gas Supply Taken	2,548	2,722	2,898	2,740	2,801
GAS SENDOUT						
	CORE					
19	Residential	483	489	503	495	488
20	Commercial	220	225	226	196	209
21	NGV	7	7	7	7	7
22	Total Throughput-Core	710	721	736	698	704
	NONCORE					
24	Industrial	543	562	534	467	453
25	Electric Generation (1)	698	855	865	895	964
26	NGV	2	3	4	3	4
27	Total Throughput-Noncore	1,244	1,421	1,403	1,365	1,421
28	WHOLESALE	9	9	9	8	8
29	Total Throughput	1,963	2,151	2,148	2,072	2,133
30	OFF-SYSTEM DELIVERIES	233	264	224	241	284
31	CALIFORNIA EXCHANGE GAS	14	22	38	37	38
32	STORAGE INJECTION (2)	294	244	441	343	292
33	SHRINKAGE Company Use / Unaccounted for	44	41	47	47	55
34	Total Gas Send Out	2,548	2,722	2,898	2,740	2,801
	TRANSPORTATION & EXCHANGE					
38	CORE ALL END USES	139	139	138	115	111
39	NONCORE INDUSTRIAL	543	562	534	467	453
40	ELECTRIC GENERATION	698	855	865	895	964
41	SUBTOTAL/RETAIL	1,380	1,557	1,538	1,477	1,529
43	WHOLESALE/INTERNATIONAL	9	9	9	8	8
45	TOTAL TRANSPORTATION AND EXCHANGE	1,389	1,566	1,547	1,485	1,537
	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.

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TABLE 23

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
AVERAGE DEMAND YEAR

LINE			2022	2023	2024	2025	2026	LINE
FIRM CAPACITY AVAILABLE								
1	**California Source Gas**		56	56	56	56	56	1
	Out of State Gas							
2	Baja Path [1]		960	960	960	960	960	2
3	Redwood Path [2]		2,060	2,060	2,060	1,915	1,915	3
3.a	SW Gas Corp. from Great Basin Gas Transmission Company		39	39	39	39	39	3.a
4	**Supplemental** [3]		0	0	0	0	0	4
5	**Total Supplies Available**		3,115	3,115	3,115	2,970	2,970	5
GAS SUPPLY TAKEN								
6	**California Source Gas**		56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**		2,049	2,054	2,043	2,038	2,063	7
8	**Supplemental**		0	0	0	0	0	8
9	**Total Supply Taken**		2,105	2,110	2,099	2,094	2,119	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	0	10
11	**Total Throughput**		2,105	2,110	2,099	2,094	2,119	11
REQUIREMENTS FORECAST BY END USE								
	Core							
12	Residential [4]		491	473	460	445	432	12
13	Commercial		208	214	213	210	208	13
14	NGV		7	7	8	8	8	14
15	**Total Core**		706	694	680	664	648	15
	Noncore							
16	Industrial		462	477	492	497	498	16
17	SMUD Electric Generation [5]		96	96	96	96	96	17
18	PG&E Electric Generation [6]		484	448	441	442	481	18
19	NGV		4	4	4	4	4	19
20	Wholesale		9	9	9	9	9	20
21	California Exchange Gas		38	38	38	38	38	21
22	**Total Noncore**		1,093	1,072	1,080	1,087	1,127	22
23	**Off-System Deliveries** [7]		272	310	305	310	310	23
	Shrinkage							
24	Company use and Unaccounted for		34	34	34	34	34	24
25	**TOTAL END USE**		2,105	2,110	2,099	2,094	2,119	25
	TRANSPORTATION & EXCHANGE							
26	CORE	ALL END USES	117	117	116	113	111	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	504	519	534	539	540	27
28		ELECTRIC GENERATION	580	544	537	538	577	28
29		SUBTOTAL/RETAIL	1,201	1,180	1,186	1,191	1,229	29
30		WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,210	1,189	1,195	1,200	1,238	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, and El Paso 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

TABLE 24

LINE			2027	2028	2029	2030	2035	LINE
FIRM CAPACITY AVAILABLE								
1	**California Source Gas**		56	56	56	56	56	1
	Out of State Gas							
2	Baja Path [(1)]		960	960	960	960	960	2
3	Redwood Path [(2)]		1,915	1,915	1,915	1,915	1,915	3
3.a	SW Gas Corp. from Great Basin Gas Transmission Company		39	39	39	39	39	3.a
4	**Supplemental** [(3)]		0	0	0	0	0	4
5	**Total Supplies Available**		2,970	2,970	2,970	2,970	2,970	5
GAS SUPPLY TAKEN								
6	**California Source Gas**		56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**		1,749	1,738	1,722	1,698	1,681	7
8	**Supplemental**		0	0	0	0	0	8
9	**Total Supply Taken**		1,805	1,794	1,778	1,754	1,737	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	0	10
11	**Total Throughput**		1,805	1,794	1,778	1,754	1,737	11
REQUIREMENTS FORECAST BY END USE								
	Core							
12	Residential [(4)]		423	412	402	391	338	12
13	Commercial		205	200	195	189	163	13
14	NGV		8	8	9	9	10	14
15	**Total Core**		636	620	605	589	511	15
	Noncore							
16	Industrial		499	499	499	498	496	16
17	SMUD Electric Generation [(5)]		96	96	96	96	96	17
18	PG&E Electric Generation [(6)]		489	493	493	486	549	18
19	NGV		4	5	5	5	5	19
20	Wholesale		9	9	9	9	9	20
21	California Exchange Gas		38	38	38	38	38	21
22	**Total Noncore**		1,135	1,140	1,139	1,132	1,193	22
23	**Off-System Deliveries** [(7)]		0	0	0	0	0	23
	Shrinkage							
24	Company use and Unaccounted for		33	33	33	33	33	24
25	**TOTAL END USE**		1,805	1,794	1,778	1,754	1,737	25
	TRANSPORTATION & EXCHANGE							
26	CORE	ALL END USES	109	106	104	101	86	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	541	542	541	541	539	27
28		ELECTRIC GENERATION	585	589	589	582	645	28
29		SUBTOTAL/RETAIL	1,236	1,238	1,234	1,223	1,270	29
30		WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,245	1,246	1,243	1,232	1,279	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, and El Paso 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.

NORTHERN CALIFORNIA

TABLE 25

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY
HIGH DEMAND YEAR

LINE		2022	2023	2024	2025	2026	LINE
	FIRM CAPACITY AVAILABLE						
1	**California Source Gas**	56	56	56	56	56	1
	Out of State Gas						
2	Baja Path [1]	960	960	960	960	960	2
3	Redwood Path [2]	2,060	2,060	2,060	1,915	1,915	3
3.a	SW Gas Corp. from Great Basin Gas Transmission Company	39	39	39	39	39	3.a
4	**Supplemental** [3]	0	0	0	0	0	4
5	**Total Supplies Available**	3,115	3,115	3,115	2,970	2,970	5
	GAS SUPPLY TAKEN						
6	**California Source Gas**	56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**	2,109	2,149	2,144	2,141	2,177	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	2,165	2,205	2,200	2,197	2,233	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	2,165	2,205	2,200	2,197	2,233	11
	REQUIREMENTS FORECAST BY END USE						
	Core						
12	Residential [4]	527	512	500	485	472	12
13	Commercial	224	224	222	220	217	13
14	NGV	7	7	8	8	8	14
15	**Total Core**	758	744	729	713	698	15
	Noncore						
16	Industrial	467	480	493	499	499	16
17	SMUD Electric Generation [5]	96	96	96	96	96	17
18	PG&E Electric Generation [6]	485	490	490	493	543	18
19	NGV	3	4	4	4	4	19
20	Wholesale	10	10	10	10	10	20
21	California Exchange Gas	38	38	38	38	38	21
22	**Total Noncore**	1,099	1,116	1,131	1,139	1,190	22
23	**Off-System Deliveries** [7]	272	310	305	310	310	23
	Shrinkage						
24	Company use and Unaccounted for	36	35	35	35	35	24
25	**TOTAL END USE**	2,165	2,205	2,200	2,197	2,233	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	126	124	122	120	118	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	508	521	535	540	541	27
28	ELECTRIC GENERATION	581	586	586	589	639	28
29	SUBTOTAL/RETAIL	1,215	1,231	1,244	1,249	1,299	29
30	WHOLESALE/INTERNATIONAL	10	10	10	10	10	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,225	1,241	1,253	1,259	1,308	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, and El Paso 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

TABLE 26

LINE		2027	2028	2029	2030	2035	LINE
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**	56	56	56	56	56	1
	Out of State Gas						
2	Baja Path (1)	960	960	960	960	960	2
3	Redwood Path (2)	1,915	1,915	1,915	1,915	1,915	3
3.a	SW Gas Corp. from Paiute Pipeline Comp.	39	39	39	39	39	3.a
4	**Supplemental (3)**	0	0	0	0	0	4
5	**Total Supplies Available**	2,970	2,970	2,970	2,970	2,970	5
GAS SUPPLY TAKEN							
6	**California Source Gas**	56	56	56	56	56	6
7	**Out of State Gas (via existing facilities)**	1,876	1,863	1,844	1,821	1,800	7
8	**Supplemental**	0	0	0	0	0	8
9	**Total Supply Taken**	1,932	1,919	1,900	1,877	1,856	9
10	**Net Underground Storage Withdrawal**	0	0	0	0	0	10
11	**Total Throughput**	1,932	1,919	1,900	1,877	1,856	11
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential (4)	463	452	441	431	378	12
13	Commercial	214	209	204	199	172	13
14	NGV	8	8	9	9	10	14
15	**Total Core**	685	670	654	638	560	15
	Noncore						
16	Industrial	500	500	500	500	497	16
17	SMUD Electric Generation (5)	96	96	96	96	96	17
18	PG&E Electric Generation (6)	565	567	564	557	616	18
19	NGV	4	4	4	4	5	19
20	Wholesale	10	9	9	9	9	20
21	California Exchange Gas	38	38	38	38	38	21
22	**Total Noncore**	1,213	1,215	1,212	1,205	1,261	22
23	**Off-System Deliveries (7)**	0	0	0	0	0	23
	Shrinkage						
24	Company use and Unaccounted for	35	35	34	34	35	24
25	**TOTAL END USE**	1,932	1,919	1,900	1,877	1,856	25
	TRANSPORTATION & EXCHANGE						
26	CORE — ALL END USES	116	113	110	108	93	26
27	NONCORE — COMMERCIAL/INDUSTRIAL	542	543	542	542	540	27
28	ELECTRIC GENERATION	661	663	660	653	712	28
29	SUBTOTAL/RETAIL	1,319	1,319	1,313	1,303	1,345	29
30	WHOLESALE/INTERNATIONAL	10	9	9	9	9	30
31	TOTAL TRANSPORTATION AND EXCHANGE	1,329	1,328	1,322	1,312	1,355	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, and El Paso 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.

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2022 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

SoCalGas is the principal distributor of natural gas in Southern California and provides retail and wholesale customers with transportation, exchange, storage services and also procurement services to most retail core customers. SoCalGas' distribution network is composed of approximately 51,070 miles of gas mains across an approximate 20,000 square mile service territory. Together with its intricate distribution network and transmission pipelines and four interconnected storage fields, SoCalGas delivered natural gas to over 5.874 million customers in 2021.

SoCalGas' vast system extends from the Colorado River on the eastern end to the Pacific Ocean on the western end and extending as far north as Tulare County and reaches the U.S./Mexico Border in the south (excluding San Diego County).

Figure 11: SoCalGas' Service Territory Map

Southern California

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. SDG&E, SWG, the City of Long Beach Energy Resources Department, and the City of Vernon are SoCalGas' four wholesale utility customers. SoCalGas provides gas transportation services across its service territory to a border crossing point at the California-Mexico border at Mexicali to ECOGAS Mexico S. de R.L. de C.V which is a wholesale international customer located in Mexico.

This report covers a 14-year demand and forecast period, from 2022 through 2035; only the consecutive years 2022 through 2030 and the point year 2035 are shown in the tabular data in the next sections. All forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

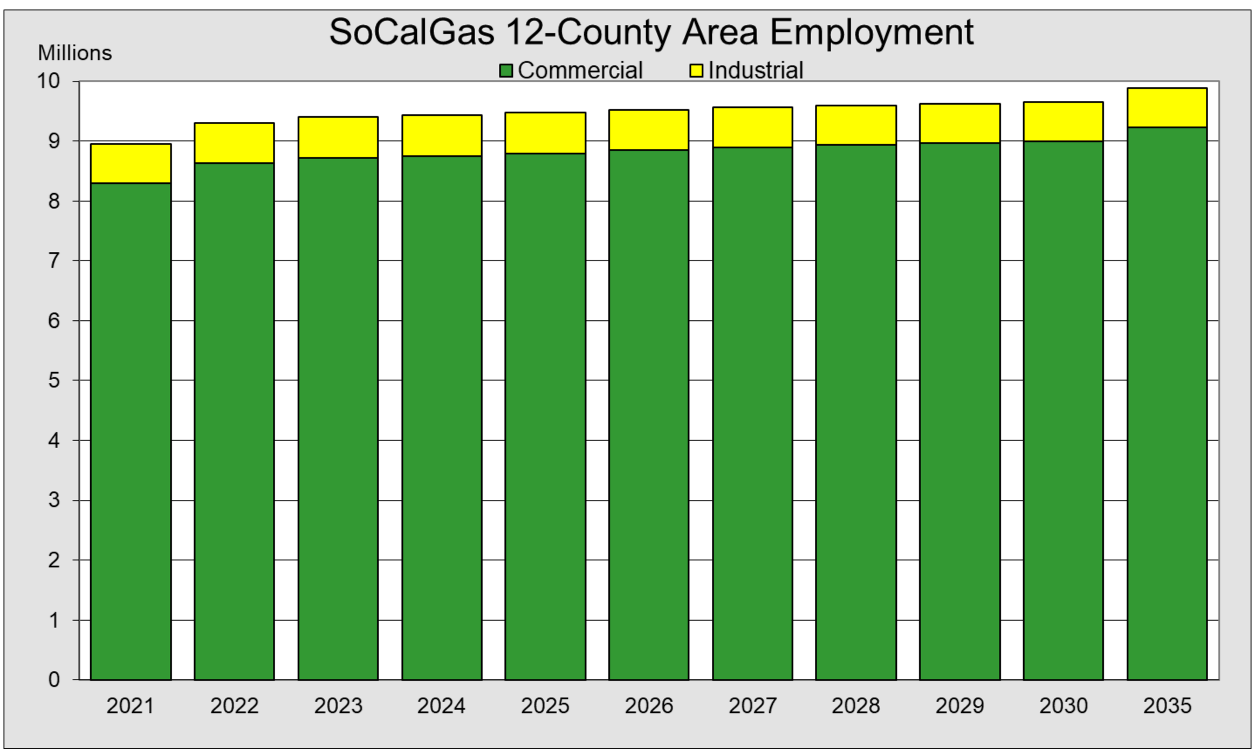
The Southern California section of the 2022 CGR begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The regulatory environment and GHG issues are also 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. After 2020's severe slowdown from the Covid-19 pandemic and related government restrictions, southern California's economy has nearly fully recovered. Total SoCalGas area jobs are expected to grow an average of 1.4% per year from 2021 through 2025. Local manufacturing and mining industrial employment is projected to average just 0.5% annual growth in the same period, with commercial jobs increasing about 1.5% annually. Jobs in accommodation, personal, and professional and business services should grow faster in the near term, as they recover from their pandemic plunge.

FIGURE 12 – SoCalGas 12-COUNTY AREA EMPLOYMENT



Southern California

Longer term, SoCalGas service-area employment is expected to increase slowly as population growth slows due to population aging and to more residents leaving for lower-cost locations primarily within the United States. From 2021 through 2035, total area job growth should average 0.7 percent per year. Area industrial jobs are forecasted to shrink an average of 0.1 percent per year through 2035; we expect the industrial share of total employment to fall from 7.4 percent in 2021 to 6.6 percent by 2035. Commercial jobs are expected to grow an average of 0.8 percent annually from 2021 through 2035.

Home building and meter hookups are expected to increase significantly in the next few years after the recent pandemic slowdown. Longer term growth should be sustained by pent-up demand and efforts to lessen southern California's longtime housing shortage. Net active meter growth --driven mainly by new home construction-- is projected to recover from a low pandemic-pressured 27,400 (+0.47 percent) in 2021, to 42,700 (+0.73 percent) in 2022 and 42,300 (+0.72 percent) in 2023--about the same percentage growth as last seen in 2017. Longer term, SoCalGas expects active meters to average about 0.6 percent annual growth from 2021 through 2035.

GAS DEMAND (REQUIREMENTS)

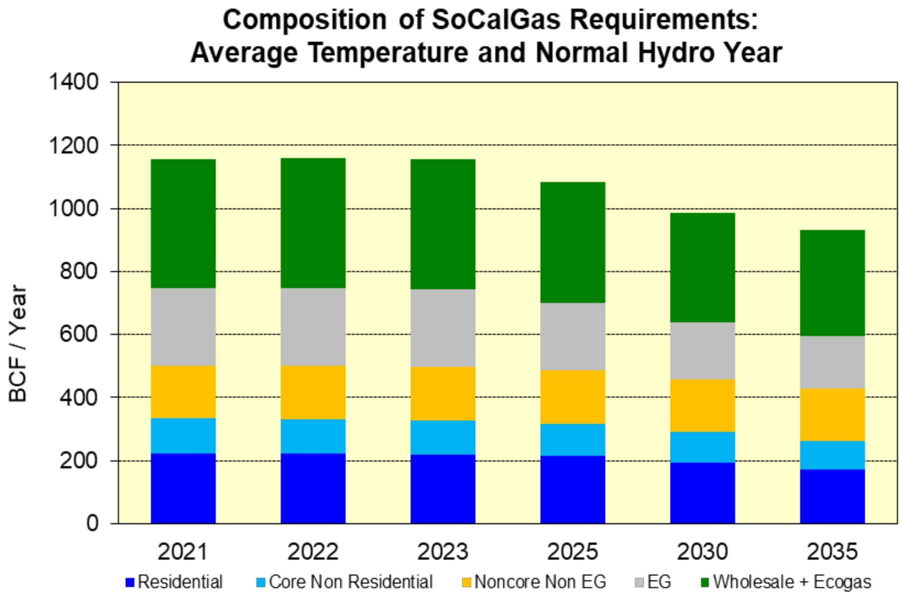
OVERVIEW

SoCalGas projects total gas demand to decline at an annual rate of 1.5 percent from 2022 to 2035. By comparison, the total gas demand had been projected to decline at an annual rate of 1.1 percent in the 2020 CGR. The forecasted, accelerated decline in throughput demand is being driven by modest economic growth and the forecasted energy efficiency and fuel substitution. Other factors that contribute to the downward trend are tighter standards created by revised Title 24 Codes and Standards, and renewable energy goals that impact gas-fired electricity.

The core, non-residential markets (comprised of core commercial, core industrial and natural gas vehicles (NGV)) are expected to decline at an average annual rate of 1.4 percent or from 224 Bcf in 2021 to 170 Bcf by 2035. However, the NGV market is expected to grow 2.1 percent over the forecast horizon. The NGV market is expected to grow due to government (federal, state and local) incentives and regulations encouraging the purchase and operation of alternate fuel vehicles as well as the increased use of RNG that provides significant GHG emission reduction benefits. The noncore, non EG- markets are expected to decline 0.1 percent from 167 Bcf in 2021 to 165 Bcf by 2035. That decline is being driven by very aggressive energy efficiency goals and associated programs. Total EG load, including large cogeneration and non-cogeneration- EG for a normal hydro year, is expected to decline from 243 Bcf in 2021 to 168 Bcf in 2035, a decrease of 2.6 percent per year.

The chart shows the composition of SoCalGas' throughput for the recorded year 2021 (with weather-sensitive market segments adjusted to average year HDD assumptions) and forecasts for the 2022 to 2035 forecast period.

FIGURE 13 – COMPOSITION OF SOCALGAS REQUIREMENTS AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR (2021-2035)



Notes:

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

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

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

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

MARKET SENSITIVITY

Temperature

Core demand forecasts are prepared for two design temperature conditions—average year and cold year—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 as when the average temperature for the day drops 1 degree below 65 degrees F. The cold design temperature conditions are based on a statistical likelihood of occurrence of 1-in-35 on an annual basis.

In our 2022 CGR, SoCalGas and SDG&E have included a climate-change warming trend that gradually reduces HDD's over the forecast period. First, average temperature year values were computed as the simple average of annual HDD's for the calendar years 2002 through 2021: 1,248 HDD's for SoCalGas and 1,158 HDD's for SDG&E. Corresponding 1-in-35 cold year HDD's were 1,476 for SoCalGas and 1,368 for SDG&E. For the forecast period, projected annual HDD's were reduced each year by 6 HDD's for both SoCalGas and SDG&E. For SoCalGas, projected average year and cold year HDD's both drop by 6 HDD annually: from 1,242 and 1,470 in year 2022, to 1,164 and 1,392 in year 2035. For SDG&E, projected average year and cold year HDD's drop by 6 HDD annually: from 1,152 and 1,362 in year 2022, to 1,074 and 1,284 in year 2035. The annual reductions are based on the latest 20-year trend in 20-year-averaged HDDs. That is, they are based on the observed trend in changes starting with average HDD's for years 1983-2002, then 1984-2003, 1985-2004...and ending with the average HDD's for years 2002-2021.

Southern California

Hydro Conditions

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

MARKET SECTORS

Residential

SoCalGas served approximately 5.67 million residential customers consisting of 3.79 million single-family households, 1.84 million multi-family households and 38,610 master meters in 2021. Residential usage varies for each of the market segments. Conditional demand estimates based on the 2019 Residential Appliance Saturation Survey (R.A.S.S.) indicate customer needs. This updated information formed part of the basis for the 2022 CGR residential market forecast.

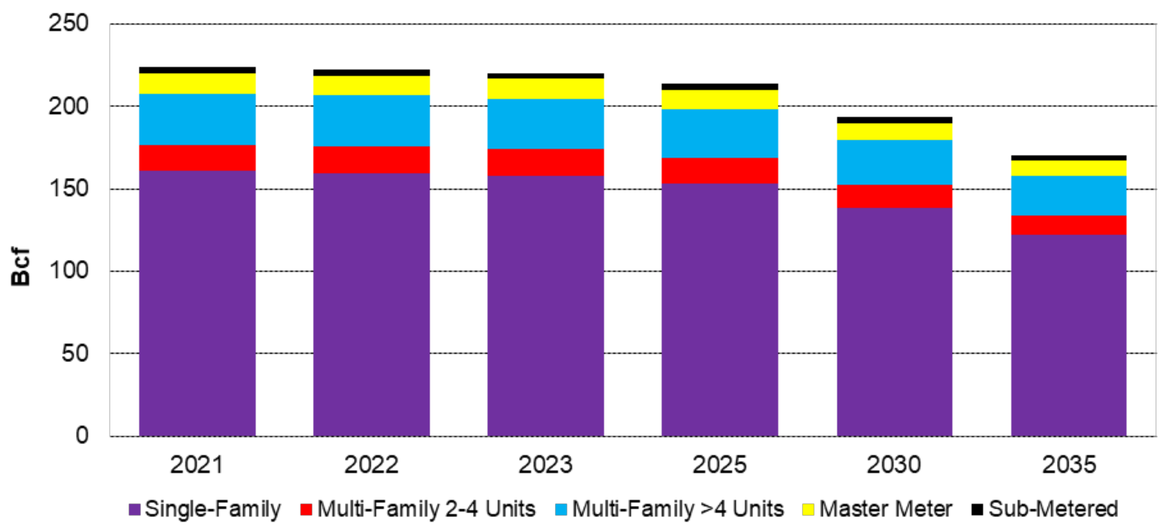
The table below shows the weather-normalized home usage by customer type and the saturations by end use for SoCalGas based upon the conditional demand study update.

Table 27: SoCalGas Residential Appliance Saturation Survey Results, 2019 Update

		2019 Residential Appliance Saturation Survey								
		Conditional Demand Study								
SoCalGas		Single Family Unit Energy Consumption (UEC)	Single Family Saturation (%)	Single Family Intensity	Single Family Use Proportion		Multi Family Unit Energy Consumption	Multi Family Saturation	Multi Family Intensity	Multi Family Use Proportion
	Space Heat	227	98.62%	224	51.75%		107	89.98%	96	46.67%
	Water Heat	141	95.98%	135	31.28%		94	81.33%	76	37.05%
	Cooking	30	82.37%	25	5.71%		28	77.80%	22	10.56%
	Clothes Drying	33	69.36%	23	5.29%		29	35.19%	10	4.95%
	Pool Heat	151	8.37%	13	2.92%		N/A			
	Spa Heat	102	9.68%	10	2.28%		47	1.19%	1	0.27%
	Gas Fireplace	11	7.33%	1	0.19%		7	4.58%	0	0.16%
	Gas Barbecue	16	15.56%	2	0.58%		14	5.17%	1	0.35%
	Total Household SF			433 Therms/Year	100%				206 Therms/Year	100%

The conditional demand estimates based on the 2019 R.A.S.S. show that the average use per meter is 433 therms for single-family households and 206 therms for multi-family households. The use-per-customer data is constructive in forming the forecast. For the residential market, the change in the baseline forecast from one year to the next is based on the confluence of two immediate economic drivers. In any given year, the residential load will grow due to the new customer hookups that occur. New customers generate a growth in demand. Second, the residential load will change due to existing customers' (vintage customers') changing needs. When gas appliances reach the end of their useful life, customers make a choice about equipment replacement. The choice consists of either replacing the older appliance with a more energy efficient gas appliance or substituting their gas appliance with one using another fuel, namely electricity. Customer choices can be influenced by economic factors, such as capital and operating costs, among other things, and are a key component of the baseline forecast. The usage calculator that generates the forecast is called the end use model.

Figure 14: Composition of SoCalGas' Residential Demand Forecast, 2021-2035



Residential gas demand is forecasted to decline from 224 Bcf in 2021 to 170 Bcf by 2035, or at an average annual rate of 1.9 percent. The decline is due to declining use per meter—primarily driven by very aggressive energy efficiency goals, anticipated fuel substitution, tightening Title 24 Codes and Standards, all of which affect the forecast by offsetting the new meter growth forecasted over the planning period.

As described above, SoCalGas' residential base forecast is developed from an end use model. The model results are modified by anticipated impacts of climate change as well as forecasts of policy adoptions that impact gas use. After the base forecast is developed, the forecast is modified by three out-of-model adjustments. The energy savings adjustments made to the forecast include (1) allowing for less heating degree days in the average weather design each year of the forecast period to account for climate change; (2) gas demand destruction due to greater energy efficiency savings forecast over the planning period; and (3) incremental energy savings created from assumed fuel substitution. All of the energy savings incorporated into the forecast reflect market potential and became load modifiers to create a final forecast of demand.

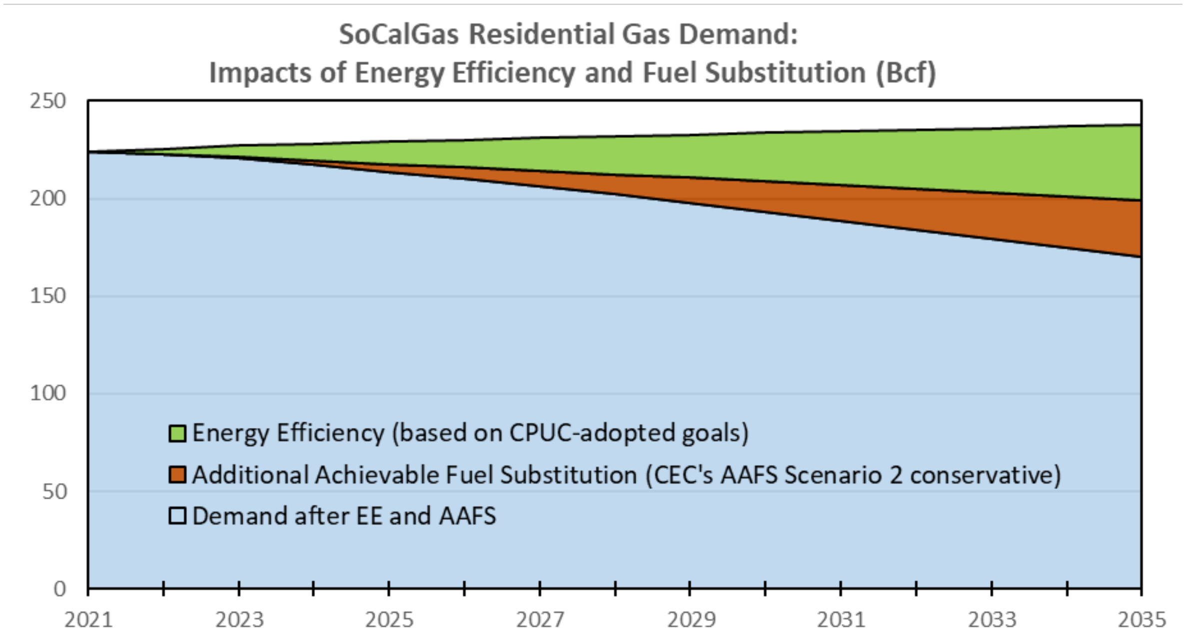
The major modifiers to the forecast are energy efficiency and building electrification. The energy efficiency forecast includes the confluence of two types of gas energy savings. Codes and Standards savings, which include current and expected modifications to Title 24, and the energy savings stemming from customer programs authorized by the CPUC's D.21-09-037. The baseline forecast was adjusted downward to account for these incremental energy saving influences that are expected to occur over the forecast period.

The final forecast also includes a load modifier for fuel substitution. For purposes of constructing a long-term reasonable forecast for the 2022 CGR, SoCalGas participated in an electrification working group committee together with PG&E, SDG&E and Southern California Edison (SCE) to evaluate different approaches and assumptions to modeling the effects of fuel substitution. After several meetings and discussions, SoCalGas aligned around the relatively conservative fuel substitution scenario forecast developed by the California Energy Commission. Fuel substitution was estimated and introduced separately from energy efficiency savings by the CEC in its 2021 IEPR as additional achievable fuel substitution (AAFS). Of the five possible fuel substitution scenarios developed by the CEC, the AAFS-2 Scenario, which is the CEC's mid-low scenario for electrification, was chosen by SoCalGas to prepare the final residential forecast. Scenario 2 quantifies the assumed fuel substitution that would take place with potential future updates in the Title 24 building standards and the presumed additional building electrification encouraged by future ratcheting driven by tighter goals, rate enhancements and higher uptake rates at future points in time. All of the above-mentioned gas reductions were included in the residential forecast as a modifier to the base forecast.

As can be seen from the following graph, the effects of both energy efficiency and fuel substitution have an impact on the residential market. By year 2035, the *assumed* additional energy efficiency removes 16 percent of residential gas demand. Evaluated separately, *assumed* additional fuel substitution removes another 12 percent of residential gas demand by 2035.

Southern California

Figure 15: SoCalGas: Residential Impacts of EE and AAFS



The final published forecast in this report is a product of the economic drivers in addition to policy drivers articulated and accounted for at the particular time the forecast was developed. As discussed elsewhere in this Report, much uncertainty remains in the timing, pace, extent, and overall evolution of residential natural gas demand in California.

Commercial

The core commercial market demand is expected to decline over the forecast period. On a temperature-adjusted basis, the 2021 core commercial market demand totaled 77 Bcf. By the year 2035, the load is anticipated to drop to approximately 56.5 Bcf. The average annual rate of decline from 2021-2035 is forecasted at 2.2 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 as well as some forecasted fuel substitution in this market.

In 2021, the noncore commercial temperature-adjusted usage was 17.4 Bcf. From 2021 through 2035, demand in this market is expected to be largely stable, reaching to about 17.7 Bcf in 2035. The noncore commercial market will be expected to grow at an average annual rate of 0.1 percent per year. Key factors of the trend are increasing commercial employment, commercial customers that move from core to noncore, and the CPUC-authorized energy efficiency programs.

FIGURE 16 – ANNUAL COMMERCIAL DEMAND FORECAST 2021-2035
BILLION CUBIC FEET PER YEAR (Bcf/y), AVERAGE YEAR WEATHER DESIGN

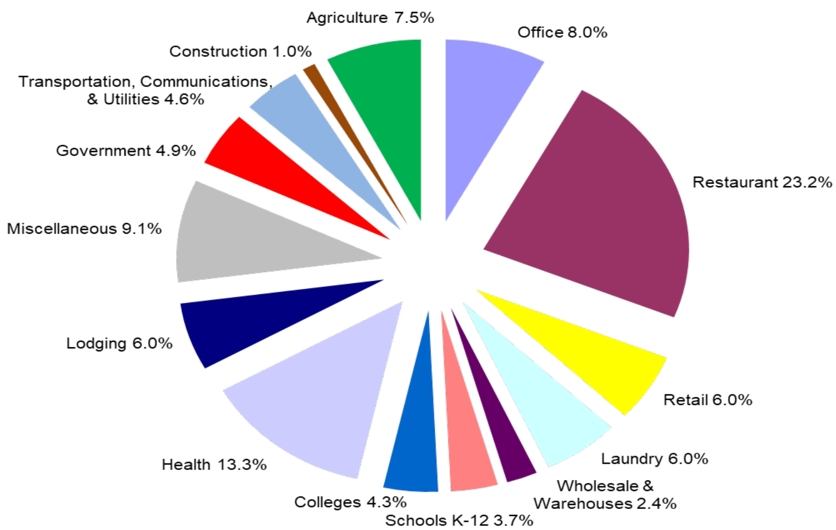
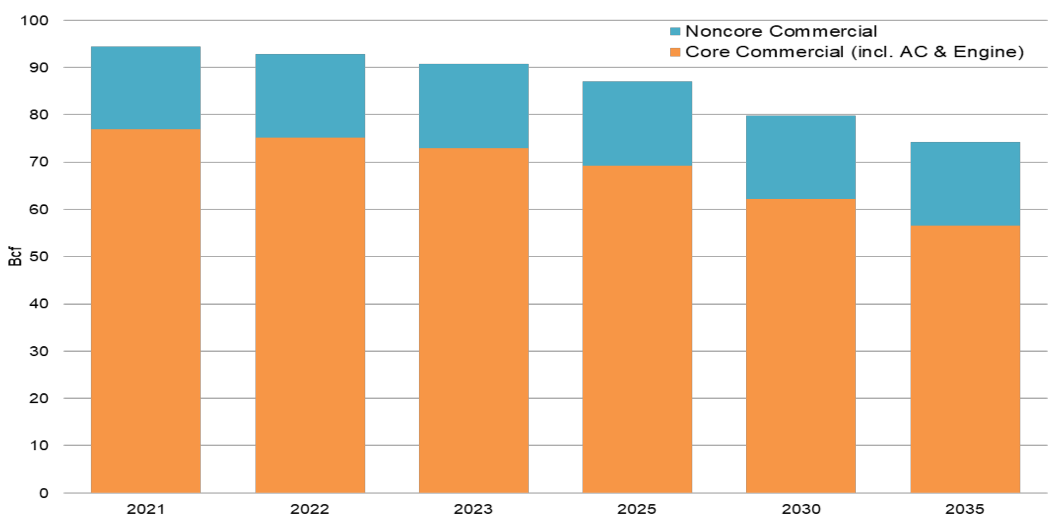


FIGURE 17 – COMMERCIAL GAS DEMAND BY BUSINESS TYPE
COMPOSITION OF INDUSTRY
(2021)



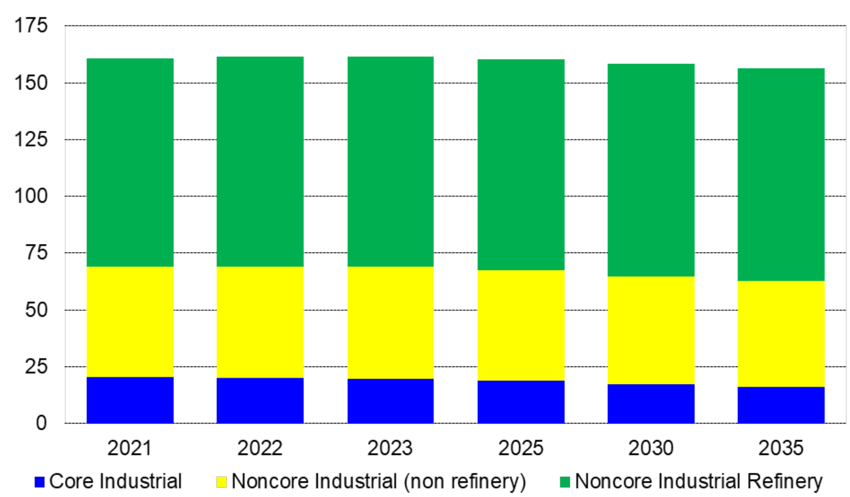
The commercial market consists of 14 business types identified by the customers' North American Industry Classification System codes. It represents includes both core and noncore usage. The restaurant business dominates this market with 23 percent of commercial usage in 2021, followed by the health services industry with a 13 percent share.

Industrial

Non-Refinery Industrial Demand

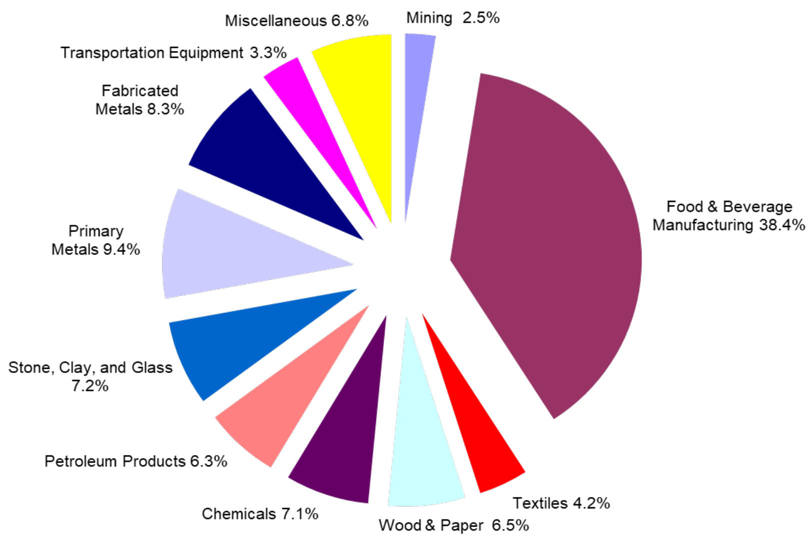
In 2021, temperature-adjusted core industrial demand was 20.4 Bcf. Core industrial market demand is projected to drop by 1.7 percent per year from 20.4 Bcf in 2021 to 16.1 Bcf in 2035. This decrease results from a combination of factors: a minor decrease in employment growth, an increase in marginal gas rates and CPUC-authorized energy efficiency programs.

FIGURE 18– ANNUAL INDUSTRIAL DEMAND FORECAST (Bcf) (2021-2035)



The 2021 non-refinery industrial gas demand served by SoCalGas is shown below. Food and beverage manufacturing, with 38.4 percent of the total share, dominates this market. The graph below summarizes the composition of the core and noncore industrial market by business type.

FIGURE 19 INDUSTRIAL GAS DEMAND BY BUSINESS TYPE COMPOSITION OF INDUSTRY (2021)–



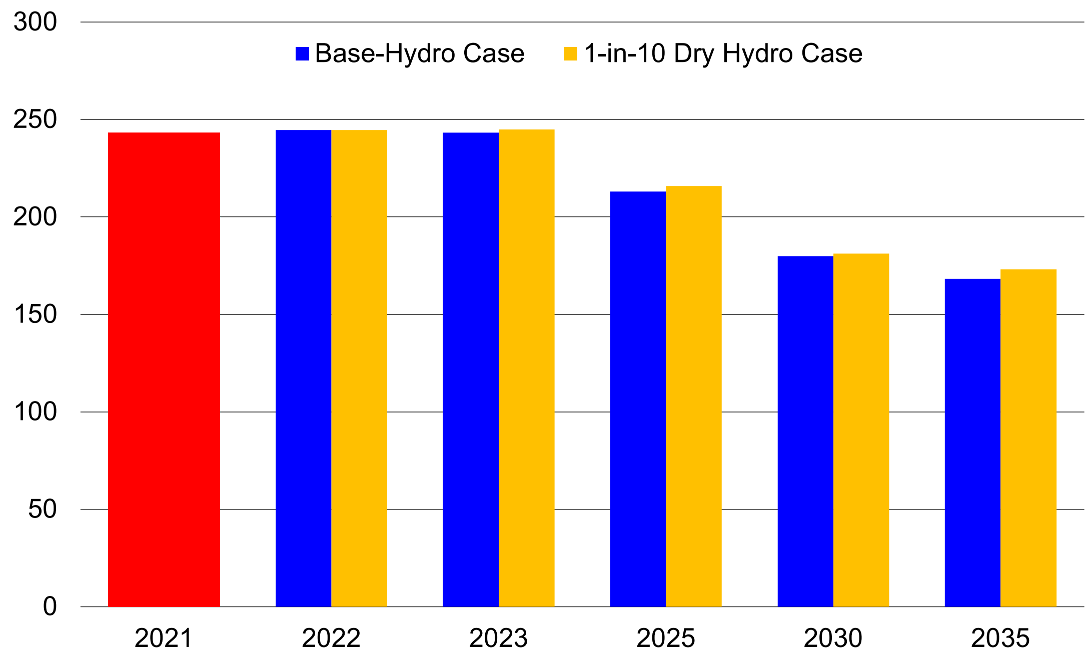
Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at an annual rate of 0.3 percent from 48.6 Bcf in 2021 to 46.8 Bcf by 2035. The reduced demand is primarily due to the CPUC-authorized energy efficiency programs, decreasing industrial employment, and the departure of customers within the City of Vernon to wholesale service by the City of Vernon.

Refinery Industrial Demand

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, H2 producers and refined petroleum product transporters. Gas demand in the refinery industrial market sector is forecasted to be largely stable over the 2022 - 2035 forecast period, from 91.7 Bcf in 2021 to 93.3 Bcf in 2035.

Electric Generation

FIGURE 20 – SoCalGas SERVICE AREA TOTAL EG
(Bcf)



The EG sector includes all commercial/industrial cogeneration, EOR-related cogeneration, and non-cogeneration electric generation. The EG load forecast is subject to a high degree of uncertainty. The forecast uncertainty is, in large part, due to load sensitivity to weather conditions, regional fuel price differences, the construction and retirement of power generating facilities (including thermal, renewable, and energy storage resources), the amount of California's import/export energy, and the state's overall long-term electricity demand growth. The EG gas throughput forecast can be higher or lower than the base case forecast, depending on the factors mentioned above. California's forecasted electricity demand is a major influence of southern California gas-demand EG. If the electricity demand forecast is higher, the EG gas throughput forecast would also tend to be higher. Please refer to the California Energy Commission's (CEC) 2021 Integrated Energy Policy Report for high, mid, and low electricity demand scenarios. On the supply side, lower SoCalGas Citygate gas prices relative to other regions, less energy imported into California, and dry hydro conditions are also factors that would increase the EG gas throughput forecast.

Additionally, many once through cooling (OTC) plants in California are scheduled to either retire or repower during the forecasted period. These are thermal plants, located near the coast, that use ocean water for cooling. A total of 5,370 MW of local gas-fired power plants and a 2,240 MW nuclear plant in northern California will retire by the end of 2029.

The gas-driven EG forecast uses a power market simulation for the period of 2022-2035. 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 the CPUC adopted 2021 Preferred System Plan, which also assumes compliance with the Mid-Term Reliability (MTR).[78] Also assumed in the forecast is compliance with the GHG planning target of 38 million by year 2030. This plan includes an aggressive amount of energy storage resources along with significant renewables resources throughout the study period. While California load-serving entities (LSEs) are working to meet their GHG goals, there are uncertainties as to how much renewable power and energy storage resources will be added specifically during the study period.

The EG demand forecast for the State of California, used in the simulation, is sourced from the CEC's California Energy Demand Forecast, 2021 – 2035, adopted January 2022. This energy demand forecast was developed as part of the CEC's Integrated Energy Policy Report process. The mid energy demand forecast with Additional Achievable Energy Efficiency (AAEE) Scenario 3 and Additional Achievable Fuel Substitution (AAFS) Scenario 2 was selected as the energy demand forecast.

Industrial/Commercial/Cogeneration <20 MW

A segment of EG demand is the commercial/industrial cogeneration (including self-generation) market. This segment is comprised by customers with generating capacity of less

[78] Decision D.21-06-035.

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). The gas demand in the small cogeneration market was 25.4 Bcf in 2021 and is expected to modestly increase to 27.6 Bcf by the year 2035, or at an average growth rate of 0.6 percent per year. The increase in demand is primarily due to the increasing electric price compared with natural gas.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. This market is forecasted to be stable over the 2022 - 2035 forecast period, changing from 23 Bcf in 2021 to 23.6 Bcf in 2035.

Enhanced Oil Recovery--Related Cogeneration

In 2021, recorded gas deliveries to the EOR -related cogeneration were 4.1 Bcf. EOR demand is forecasted to increase slightly and stabilize in the immediate future before gradually decreasing to 3.9 Bcf by 2035. Crude oil futures prices appear to be elevated and volatile for the immediate future which is expected to result in California EOR operations increasing slightly in the earlier part of the forecast before the gradual decrease, as volatility subsides.

Southern California

Electric Generation, Including Large Cogen

EG customers are comprised of utility electric generation (UEG) customers, various Exempt Wholesale Generator (EWG) customers and large cogeneration customers where usage exceeds 20 MW. For the base case (average hydro condition), gas demand is forecasted to decrease from 191 Bcf in 2021 to 113 Bcf in 2035. The main factors for the decline are aggressive energy storage resource additions, paired with significant renewable resource additions and the retirement of older gas-fired plants.

Wholesale

SoCalGas provides wholesale transportation service to SDG&E, the City of Long Beach Energy Resources Department (Long Beach), 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 38.6 Bcf in 2021 to 43.0 Bcf in 2035. The change reflects a 0.77 percent average annual increase.

SDG&E

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 1.9 percent per year from 94 Bcf in 2021 to 72 Bcf in 2035. Additional information regarding the composition of 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 Energy Resources Department. Long Beach's gas use is expected to increase slightly, from 8.8 Bcf in 2021 to 9.3 Bcf by 2035. Additional information regarding the City of Long Beach Energy Resources Department's gas demand is provided in the City of Long Beach Energy Resources Department section of this report.

Southwest Gas Corporation

SoCalGas used the forecast prepared by Southwest Gas for this report. In 2021, SoCalGas delivered 9.2 Bcf to Southwest Gas and the total load is expected to rise slightly to 10.3 Bcf by 2035. Refer to Southwest Gas for additional information regarding their gas demand.

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 8.5 Bcf in 2021 and increases to 9.3 Bcf by 2035. The forecasted throughput includes core and noncore 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 increase, from 12 Bcf in 2021 to 14 Bcf by 2035. Refer to Ecogas or IENova, Ecogas' parent company, for more information.

Enhanced Oil Recovery Steam

In 2021, recorded gas deliveries to the EOR market were 8.5 Bcf. EOR demand is forecasted to increase slightly and stabilize in the immediate future before gradually decreasing to 7.4 Bcf by 2035. Crude oil futures prices appear to be elevated and volatile for the immediate future which is expected to result in California EOR operations slightly increasing in the earlier part of the forecast before the gradual decrease, as volatility subsides.

Southern California

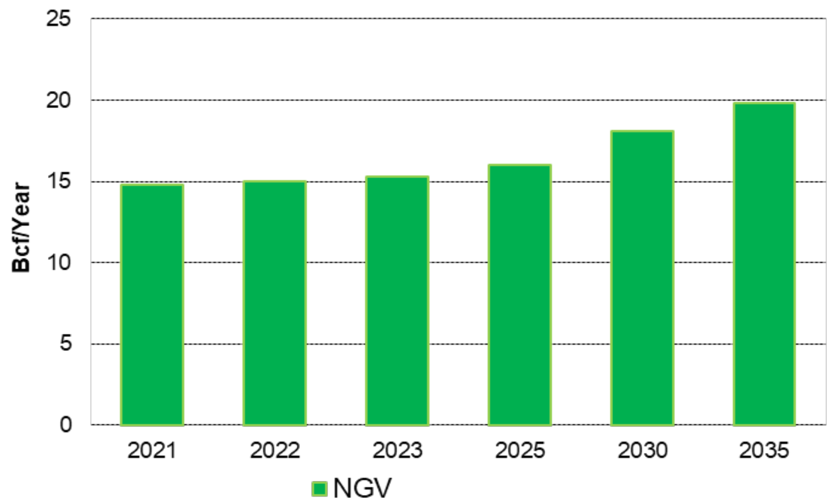
Natural Gas Vehicles

The NGV market is expected to continue to grow, albeit at a slower rate than in the past. State regulations encourage the adoption of zero emission alternative fuels. Growth will continue for the next several years until zero emission alternative fuels become cost competitive with gasoline and diesel. NGV growth is also supported by the increased use and availability of RNG that provides significant GHG emission reduction and cost reduction benefits.

At the end of 2021, there were 352 CNG fueling stations delivering approximately15.4 Bcf of natural gas during the year. The NGV market is expected to grow 1.8 percent per year, on average. At the end of 2035, it is expected there will be 414 CNG fueling stations delivering approximately 20.8 Bcf of natural gas during the year.

FIGURE 21 – NGV DEMAND FORECAST

(2021-2035)



ENERGY EFFICIENCY PROGRAMS

SoCalGas engages in several energy efficiency (EE) 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.

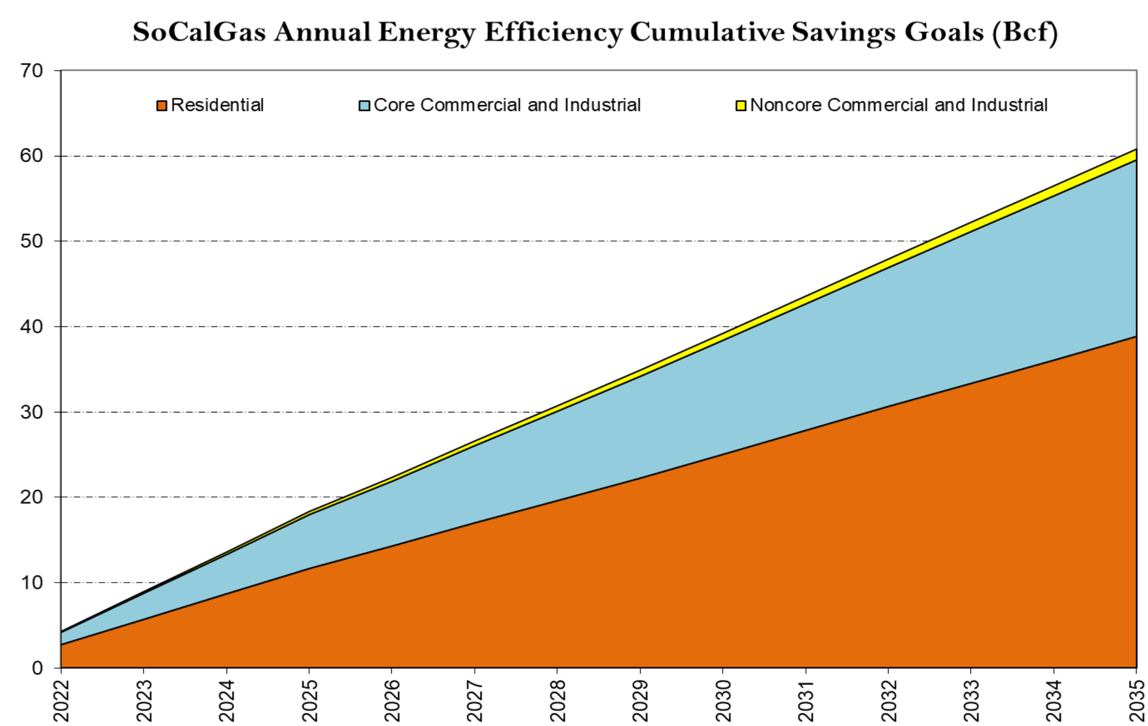
The forecast of cumulative natural gas savings due to SoCalGas' energy efficiency programs is provided in the figure below. The forecasts capture savings from programs developed in support of several goals and standards. Efforts were made to exclude the forecasted fuel substitution from the EE forecast. The forecast for fuel substitution is accounted in the separately in the AAFS Scenario 2, published in the CEC's 2021 Integrated Energy Policy Report. The savings shown below represent the net load impact for the energy efficiency portfolio that includes program savings and the codes and standards savings that SoCalGas anticipates will occur through year 2035.

SoCalGas' EE forecast is based upon inputs from the 2022-23 energy efficiency bi-annual budget advice letter (AL5898-A), utilizing program level energy savings values forecasted for the 2022 program year. Savings estimates from SoCalGas' 2022 EE programs are grouped by the classifications identified in the 2022 CGR (Residential, Commercial, Industrial, Industrial Refinery). These savings estimates are further split between the core and noncore classifications based on the estimated historical core and non-core savings achievements in 2017-2021. The EE program savings for 2017-2021 have been updated for this report.

Forecasted savings for the 2023-2035 period are based on the 2020 EE forecast scaled to the goals approved in the recent EE proceeding goals decision, D.21-09-037, which set EE goals through 2032. Forecasted savings beyond 2032 are held constant based on 2032 forecasted values. Cumulative savings reflect the lifecycle EE program achievements from forecasted program savings starting in 2022 and does not include lifecycle savings from prior program years. SoCalGas currently uses a 15-year lifecycle for cumulative savings calculations.

Combined EE Portfolio of EE Programs and Codes and Standards

FIGURE 22



GAS SUPPLY, CAPACITY, AND STORAGE

GAS SUPPLY SOURCES

SoCalGas and SDG&E receive gas supplies from several sedimentary basins in the Western U.S. 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 2017 through 2021 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 69 MMcf/d in 2021.

SOUTH-WESTERN 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 pipeline with some volumes also on Transwestern pipeline. The San Juan Basin's gas supplies peaked in 1999 and have been declining at an annual rate of roughly 2 percent. The Permian Basin has experienced a major increase in gas production as a byproduct of the tremendous amount of oil development in the area. Permian gas production increased by over 130 percent during the period 2017-2021. This increase positioned the Permian Basin as a preferred gas supply source of economical gas.

Mexican demand for southwestern U.S. gas along with east of California demand continue to steadily increase and compete for southwestern supplies. This increasing demand will likely continue to compete with southern California for southwest supplies.

Southern California

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 supply other markets connect to Rocky Mountain region, which allows Rockies gas 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 relatively high cost of transport.

LIQUEFIED NATURAL GAS

US liquified natural gas (LNG) exports grew in 2021 as additional capacity came online in 2020, however, global LNG demand increased sharply in 2021. Russia supplies to Europe decreased during 2021 which increased the demand for replacement gas in the form of LNG and caused international prices to spike while domestic prices saw less volatility. The global demand increase in 2021 created a supply/demand imbalance in Europe causing prices to spike to record highs. Current LNG supply is insufficient to replace Russian gas previously delivered into Europe which indicates international prices may remain high for several years.

RENEWABLE NATURAL GAS (RNG)

In February 2022, the CPUC adopted Decision (D.) 22-02-025 that implemented SB 1440 (Hueso) and established RNG procurement targets for years 2025 and 2030 to be met by the California natural gas utilities, "Joint Utilities", specifically Pacific Gas & Electric, San Diego Gas & Electric, Southern California Gas Company and Southwest Gas. This CPUC Decision established the nation's first Renewable Gas Standard (RGS) and provided additional support to meet the bill's short-lived pollution reduction goals. In particular, SB 1383 requires California to reduce emissions of methane by 40 percent below 2013 levels by 2030 and also develop landfill-diverted organic waste-to-RNG projects.

The RGS includes short and medium term biomethane procurement targets. The 2025 short-term target for biomethane procurement is 17.6 billion cubic feet (Bcf) annually, produced from eight million tons of organic waste, including wood waste, diverted annually from landfills. Joint Utilities, each, are responsible for procuring a percentage of the 17.6 Bcf according to each of their respective Cap-and-Trade allowance shares: Southern California Gas Company 49.26 percent, Pacific Gas and Electric Company 42.34 percent, San Diego Gas & Electric Company 6.77 percent, and Southwest Gas Corporation 1.63 percent.[79] The medium-term target is by year 2030, where the Joint Utilities, shall procure, on an annual basis, an amount of biomethane equivalent to 12.2 percent of its own share of 2020 annual bundled core customer natural gas demand, excluding Compressed Natural Gas Vehicle demand as noted in the California Gas Report (or approximately 72.8 Bcf).[80]

There is a growing recognition that clean fuels like hydrogen and renewable natural gas (RNG) will play an essential role in diversifying energy supplies while also helping California decarbonize and transform into a carbon neutral economy over the next twenty years.[81] RNG is methane produced from anaerobic digestion (AD) or by a non-combustion gasification process of organic feedstock material that can replace traditional natural gas. RNG produced from AD is typically derived from organic waste streams such as dairy manure, landfilled gas, and municipal organic waste (i.e., food scraps, lawn clippings, and animal or plant-based material). Non-combustion gasification pathways typically process agricultural waste, forest debris, and wastewater treatment by-products, among other feedstocks. Under baseline conditions, these organic waste streams typically release methane into the atmosphere as they decompose. Directing these feedstocks toward RNG production can help to capture and prevent the release of methane into the atmosphere.[82]

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[79] D. 22-02-025, op. 14-16.
[80] D. 22-02-025, op. 18.
[81] Final 2021 Integrated Energy Policy Report, Volume III.
[82] U.S. EPA's Landfill Methane Outreach Program (LMOP) at https://www.epa.gov/Imop/renewable-natural-gas .

RNG interconnected to a gas utility's pipeline[83] replaces traditional natural gas and can similarly be nominated to a variety of end users, providing decarbonized energy for hard-to-electrify sectors of the economy like heavy-duty transportation, industrial activities and dispatchable electric generation. RNG is a drop-in fuel replacing traditional natural gas and does not typically require equipment adjustments, upgrades, replacements or other modifications.

Unlike traditional natural gas, RNG feedstocks are composed of material containing biogenic carbon that has been absorbed from the atmosphere. Carbon emissions from fossil fuels such as traditional natural gas are drawn from geological sources such as deep wells or rocks and contain carbon that has accumulated over a geological timescale. In contrast, biogenic carbon, such as that in RNG, was sourced from the atmosphere on a much shorter biological timescale. This biogenic carbon is cycled from the atmosphere to plants over the course of only a few years or decades.[84] This means that carbon emissions released from the use of RNG are already part of a sustainable natural cycle, which is why GHG reporting protocols treat CO_2 emissions from RNG as carbon neutral.[85] RNG can even be a carbon negative fuel, reducing additional GHG emissions beyond the carbon emissions associated with its combustion, depending on the feedstock and production system used.

[83] SoCalGas Tariff Rule 30 (https://www2.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf) must be met in order to qualify for pipeline injection into SoCalGas' gas pipeline system.

[84] https://clear.ucdavis.edu/explainers/biogenic-carbon-cycle-and-cattle.

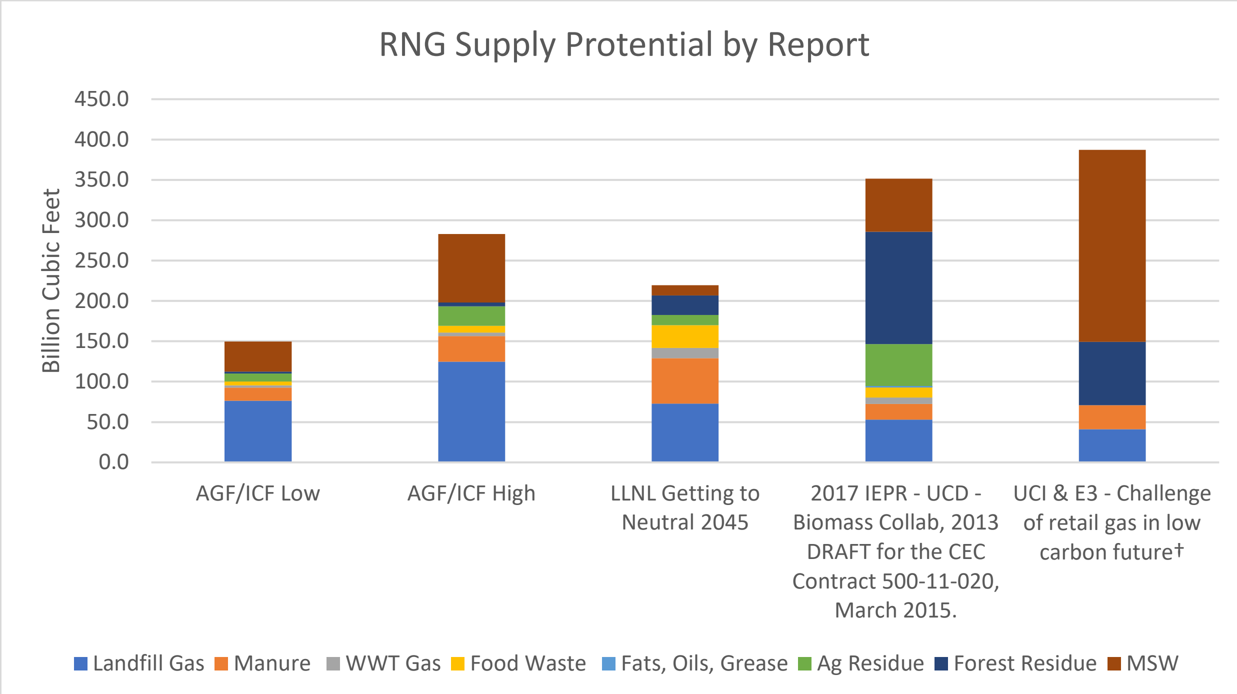
[85] https://www.ipccnggip.iges.or.jp/public/2019rf/pdf/2_volume2/19R_V2_2_Ch02_Stationary_Compbustion.pdf; 2.3-2.4 Treatment of Biomass .

Recent reports estimating RNG supply potential published by Livermore Laboratory Foundation, [86] the CEC, [87] E3 and the University of California Irvine,[88] and ICF,[89] illustrate there is a significant amount of feedstock available within California for the production of biogas and RNG to help replace traditional natural gas and help decarbonize the gas grid. These studies estimate between 70 and 170 Bcf of annual RNG production potential available solely from AD with potential for an additional 50 to 257 Bcf of annual RNG available from non-combustion gasification. Studies that sum both AD and gasification estimates provide an estimate between 148 and 387 Bcf of annual RNG potential within California.[90] RNG potential at the higher end of these summed estimates would be sufficient to meet either approximately 75 percent of the 2020 residential natural gas demand in California or approximately 150 percent of the commercial demand, or approximately 45 percent of industrial demand.[91]

[86] "Getting to Neutral: Options for Negative Carbon Emissions in California," Livermore Laboratory Foundation & Climateworks Foundation, August 2020. Available at https://wwwhttps://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdfgs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.
[87] "Final 2017 Integrated Energy Policy Report," CEC, February 2018. Available at https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2017-integrated-energy-policyhttps://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2017-integrated-energy-policy-reportreport.
[88] "The Challenge of Retail Gas in California's Low Carbon Future, Appendix A," E3 and University of California, Irvine, 2020. Available at https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-APhttps://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-AP-G.pdfG.pdf.
[89] "ICF 2019 Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," American Gas Foundation, 2019. Available at https://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNGhttps://www.gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdfStudy-Full-Report-FINAL-12-18-19.pdf.
[90] Using the top or 'high' estimate when a range is documented, but not the 'technical resource potential,' which does not consider accessibility or economic constraints.
[91] https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SCA_A.htm

Southern California

Figure 23 – RNG In-State Supply Potential



INTERSTATE PIPELINE CAPACITY

California utilities and end users benefit from access to supply basins and enhanced gas and pipeline competition. Interstate, international, and intrastate pipelines serving Southern and central California include the El Paso Natural Gas, Mojave, Transwestern, Kern River, TGN, North Baja, and PG&E pipelines. These pipelines provide southern and central California with access to gas producing regions in the southwest U.S. and Rocky Mountain areas, western Canada, California production and Mexico LNG. Indicated firm capacities for each SoCalGas receipt zone for receiving these supplies are specified in the SoCalGas GBTS Rate Schedule.

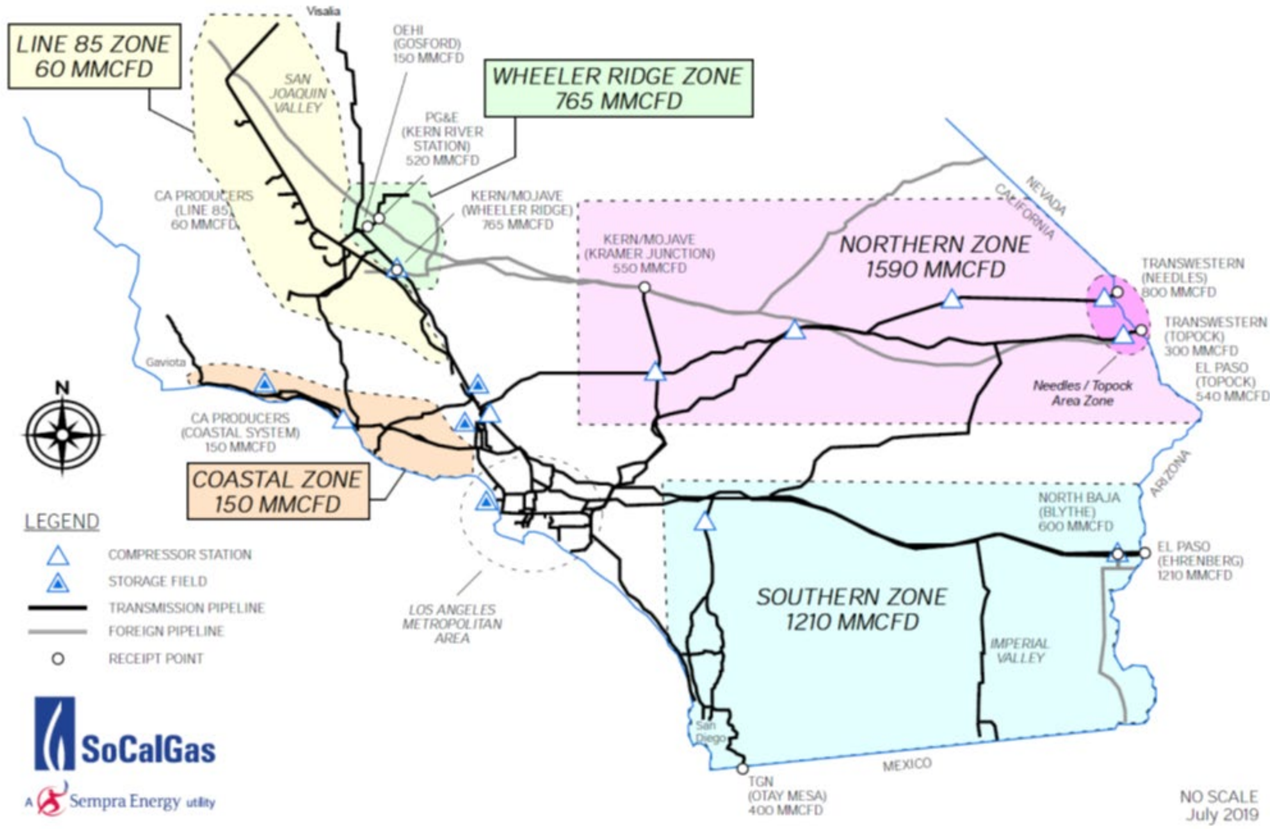
SoCalGas' Southern Zone is connected to U.S. Southwest and Mexico pipeline systems at Ehrenberg, Blythe, and Otay Mesa (to El Paso, North Baja, and TGN) respectively. The Southern Zone has a firm receipt capability of 1,210 MMcf/d.

SoCalGas' Northern Zone is connected to southwestern U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Kern River, and Mojave) at Needles, west of

Topock AZ, and Kramer Junction. The Northern Zone has a nominal firm receipt capacity of 1,590 MMcf/d. Effective October 1, 2021, Line 4000 returned to service at a higher operating pressure. As a result, the amount of firm BTS capacity available in the Northern Zone and the Needles/Topock Area Zone increased to 1,250 MMcf/d and 800 MMcf/d respectively.

SoCalGas' Wheeler Ridge Zone is connected to Kern River/Mojave, OEHI Gosford, and PG&E and receives supplies from the U.S. Southwest, Rocky Mountain, and Western Canada production areas and California production from Elk Hills. The Wheeler Ridge Zone's firm receipt capacity is 765 MMcf/d.

FIGURE 24– RECEIPT POINT AND TRANSMISSION ZONE FIRM CAPACITIES



STORAGE

Underground storage of natural gas plays a vital role in balancing the region's energy supply and demand, and for systemwide reliability.[92] 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.[93] SoCalGas owns and operates four natural gas

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[92] 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 pp 504 at: Full-Technical-Report-v2_max.pdf (ccst.us) .
[93] *Id.,* Conclusion 2.5 at pp 506.

storage facilities within southern California: Aliso Canyon, Honor Rancho, La Goleta, and Playa Del Rey.

Southern California

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 systems 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 more than 130 Bcf.[94] However, the combined working inventory for SoCalGas is reduced due to current working inventory regulatory restrictions imposed at Aliso Canyon.

Prior to 2016 the Aliso Canyon working inventory was 86 Bcf.[95] Since October 2015,[96] the CPUC and CalGEM[97] have maintained restrictions on SoCalGas' use of Aliso Canyon. In November 2020, the CPUC set the Aliso Canyon storage inventory level at 34 BCF based on the prior Energy Division reports assessing whether monthly 1-in-10 peak day demand could be met with forecasted storage inventory levels.[98] In November 2021, the CPUC issued an order increasing the inventory limit for the Aliso Canyon Storage Field from 34 to 41.16 Bcf.[99] The CPUC and CalGEM may authorize a different maximum inventory in the future.

In July 2019, to improve short-term reliability and price stability in the southern California region, the CPUC deemed that Aliso Canyon be made available for withdrawals if certain conditions are met.[100] Aliso Canyon may be used for withdrawals only if any of the following four conditions are met: 1) Preliminary low Operational Flow Order (OFO) calculations for any

[94] SoCalGas 2019 General Rate Case (GRC) Filing, Exhibit SCG-10-R, p. NPN-3 and NPN-4.
[95] As of July 19, 2017, CalGEM authorized Aliso Canyon to operate with a working inventory of equivalently 68.6 Bcf.
[96] 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.
[97] Formerly DOGGR.
[98] CPUC Decision (D.)20-11-044.
[99] CPUC Decision (D.)21-11-008 issued on November 4, 2021.
[100] https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2020/WithdrawalProtocol-revised-April112020clean.pdf

cycle result in a Stage 2 low OFO or higher for the applicable gas day. 2) Aliso Canyon is above 70% of its maximum allowable inventory between February 1 and March 31. 3) Honor Rancho and/or Goleta fields decline to 110% of their month-end minimum inventory requirements during the winter season and 4) There is an imminent and identifiable risk of gas curtailments created by an emergency condition that would impact public health and safety or result in curtailments of electric load that could be mitigated by withdrawals from Aliso Canyon.

STORAGE REGULATIONS

Since 2015, the CPUC, CalGEM, and Pipeline and Hazardous Materials Safety Administration (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.

Most recently, PHMSA issued their Final Rule for Underground Storage regulations, CFR Part 192.12, amending its minimum safety standards for underground natural gas storage facilities, effective March 13, 2020. The PHMSA Final Rule adopts API RP 1171, Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs, as published, modifies compliance timelines, formalizes integrity management practices, and clarifies the state's regulatory role.

CalGEM established fourteen California Code of Regulations §1726 California Underground Gas Storage regulations effective October 1, 2018, which includes mechanical testing mandates that require each well to be taken out of service for inspection every 24 months, unless an alternative frequency is approved by CalGEM, and semiannual field shut in tests for inventory certification.

REGULATORY ENVIRONMENT

STATE REGULATORY MATTERS

GENERAL RATE CASE

On September 26, 2019, the CPUC unanimously approved a final 2019 GRC decision that adopted a TY 2019 revenue requirement of $2.770 billion for SoCalGas which is $166 million lower than the $2.937 billion that SoCalGas had requested in its updated testimony. The adopted revenue requirement represents an increase of $314 million or a 12.8 percent increase over 2018. The final decision adopted post-test year (PTY) revenue requirement adjustments for SoCalGas are $220 million for 2020 (7.9 percent increase) and $150 million for 2021 (5.0 percent increase).

In January 2020, the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SoCalGas was directed to file a Petition for Modification (PFM) to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional 5-year GRC period (2019-2023).

In April 2020, SoCalGas filed a PFM of its 2019 GRC decision requesting attrition year increases of $155 million (+4.95 percent) for 2022 and $137 million (+4.15 percent) for 2023. In May 2021, the CPUC issued a decision authorizing SoCalGas to apply its PTY mechanism adopted in the 2019 GRC decision to 2022 and 2023 but updated the calculations based on the 2020 4th Quarter Global Insight forecast to more fully capture the impact of Covid-19 to the economy. This decision resulted in revenue requirements of $3.3 and $3.4 billion for SoCalGas for 2022 and 2023 respectively, which were slightly less than the original requests made in SoCalGas' PFM.

In May 2022, SoCalGas filed its 2024 General Rate Case seeking to revise its authorized revenue requirements, effective on January 1, 2024, to recover the reasonable costs of gas operations, facilities, infrastructure, and other functions necessary to provide utility services to customers. SoCalGas requests a $4.426 billion revenue requirement for 2024, which, if approved, would be an increase of $767 million over the expected 2023 revenue requirement, or a 20.9% increase. SoCalGas' 2024-2027 rate request includes investments in four key areas: maintaining and enhancing reliability and safety, supporting sustainability, and promoting innovation and technology to meet operational and customer needs and workforce development. SoCalGas also includes a post-test year revenue requirement and a regulatory account-related proposal. The general rate request process is scheduled to take between 18 months and two years and is expected to conclude in late 2023.

GAS RELIABILITY AND PLANNING OIR

The CPUC initiated a rulemaking (R.20-01-007) to update gas reliability standards, determine the regulatory changes necessary to improve coordination between gas utilities and gas-fired electric generators, and implement a long-term planning strategy to manage the state's transition away from natural gas-fueled technologies to meet California's decarbonization goals.

The rulemaking has two tracks. Track 1 is intended to establish baseline standards and address issues of more immediate concern. These Track 1 issues include: determining whether changes to the reliability standards are needed and, if so, how any additional costs will be recovered and allocated; considering a change to the Operational Flow Order (OFO) penalty structure, which provides a financial incentive for gas customers, including electric generators, to deliver sufficient gas supply; and evaluating whether gas and electric interdependency requires the establishment of new reliability and cost containment protocols. A Proposed Decision (PD) on the OFO penalty structure was issued on March 18, 2022, and voted out at the April 21, 2022, CPUC Business Meeting. A final decision on the remaining Track 1 issues was adopted in July 2022, and includes no changes to design standards, a citation program for failure to meet minimum design standards and new reporting requirements for the California Gas Report starting in 2024.

Track 2 of the Gas Reliability OIR focuses on long-term system planning. Track 2A focuses on gas infrastructure. Its goal is to create new criteria for the CPUC to use when evaluating utility requests for spending on infrastructure as well as for proactively identifying distribution pipelines that can be decommissioned. In this track, the CPUC seeks to find a balance in which California has sufficient transmission and storage infrastructure to avoid creating reliability issues and scarcity that drive up gas commodity prices while at the same time avoiding unneeded investments that could lead to stranded assets and reducing distribution pipeline miles to decrease revenue requirement over time. The CPUC held two workshops in January and issued a workshop report in March 2022. A PD is expected in November 2022.

Track 2B focuses on equity, rates, safety, and workforce issues. The equity portion focuses on barriers that low-income customers would face in advancing state electrification goals and what the CPUC can do to mitigate those barriers. The rates portion will look at ratemaking strategies and develop ways to mitigate the impact of the gas transition on customer rates both now and in the future. The safety portion will look at ways to streamline safety spending where possible, given that most safety spending is required by state or federal agencies.

Track 2C will focus on data and process, considering a long-term strategy for managing gas planning going forward. It is expected to begin in 2023.

Southern California

ALISO CANYON ORDER INSTITUTING INVESTIGATION

On February 9, 2017, the CPUC opened the Aliso Canyon proceeding, Investigation I.17-02-002, as directed by SB 380 (Pavley, 2016). SB 380 required the CPUC to "determine the feasibility of minimizing or eliminating the use of the SoCalGas Aliso Canyon Natural Gas Storage Facility (Aliso Canyon) while still maintaining energy and electric reliability for the region." This facility is the largest of four gas storage facilities serving southern California. The CPUC has modeled the current gas system, finding that the Aliso Canyon facility is currently necessary for winter reliability and cost containment.

A third-party consultant modeled the costs and benefits of adding new infrastructure that would allow Aliso Canyon to be closed by 2027 or 2035. The consultant modeled several different infrastructure portfolios, including gas infrastructure upgrades, new electricity transmission, increased energy efficiency and building electrification, and additional electric generation and storage. This analysis concluded that any of these portfolios could successfully replace the services provided by Aliso Canyon. The consultant found that any of the portfolios modeled, except for new gas infrastructure, would result in a net decrease in energy system costs, when factoring in the costs of compliance with the Cap-and-Trade Program and Renewable Portfolio Standard, because the benefits of using the new resources would outweigh the investment costs. However, on balance the savings would accrue to gas ratepayers, while electricity ratepayer costs would increase. This analysis did not address costs or usage of the Aliso Canyon site itself. The proceeding remains open, with the CPUC yet to determine whether to order that Aliso Canyon be closed and, if so, what infrastructure will be procured to allow that closure and what the timeline and other parameters will be. The CPUC anticipates a ruling in this proceeding before 2023.

The CPUC is also using this proceeding to determine the Aliso Canyon facility's maximum allowable gas storage inventory. The allowed inventory level impacts customers rates because higher storage inventory allows for lower gas costs to ratepayers by enabling the utility to buy and store gas when prices are low and use its stored gas when prices are high. The CPUC increased the maximum inventory level for the facility in November 2021 which will remain in place until the Commission issues a new decision in the proceeding.

BUILDING DECARBONIZATION POLICY

In September 2018, former Governor Brown signed two bills into law related to reducing GHG emissions from buildings, SB 1477 and AB 3232. SB 1477 calls on the CPUC to develop, in consultation with the CEC, two programs (BUILD and TECH) aimed at reducing GHG emissions associated with buildings. AB 3232 calls on the CEC, by 2021, to develop plans and projections to reduce GHG emissions of California's residential and commercial buildings to 40 percent below 1990 levels by 2030, working in consultation with the CPUC and other state agencies.

In January 2019, the CPUC issued an OIR on building decarbonization (R.19-01-011). The proposed scope of the rulemaking includes: (1) implementing SB 1477; (2) potential pilot programs to address new construction in areas damaged by wildfires; (3) coordinating CPUC policies with Title 24 Building Energy Efficiency Standards and Title 20 Appliance Efficiency Standards developed at the CEC; and (4) establishing a building decarbonization policy framework. A final decision D.20-03-027 was issued on April 6, 2020, which establishes a framework for CPUC oversight of two building decarbonization pilot programs—the Building Initiative for Low-Emissions Development (BUILD Program) program and the Technology and Equipment for Clean Heating (TECH Initiative) initiative. These two pilot programs are designed to develop valuable market experience for the purpose of decarbonizing California's residential buildings in order to achieve California's zero-emissions goals. SB 1477 makes available $50 million annually for four years, for a total of $200 million, derived from the revenue generated from GHG emission allowances directly allocated to gas corporations and consigned to auction as part of the Air Resources Board's (ARB) Cap-and-Trade Program. Incentive eligibility for the BUILD Program shall be limited strictly to newly constructed all-electric building projects, without any hookup to the gas distribution grid.

Phase II issued a Final Decision on November 4, 2021, which adopted the Wildfire and Natural Disaster Resilience Rebuild (WNDRR) Program to support all-electric rebuilding of residential properties that were destroyed or red-tagged due to a natural or man-made disaster on or after January 1, 2017. WNDRR will be offered for a ten-year period (2022-2032) across the service territories of the electric IOUs. Further, the decision directs the electric IOUs to study the total electric and gas bill impacts resulting from a customer switching from a natural gas water heater to an electric heat pump water heater (HPWH). Based on this analysis, each electric IOU must propose a HPWH rate adjustment in its next General Rate Case (Phase II) or Rate Design Window applications. In an effort to allow the CPUC and stakeholders to better understand propane use, the decision directs the electric IOUs to ask all new customers whether or not they use: (i) electric space heating equipment; (ii) electric water heating equipment; and (iii) propane to power any appliance other than an outdoor grill. The electric IOUs must report these responses to ED annually beginning on February 1, 2023, along with the number of total customers receiving the all-electric baseline allowance, as well as total customers receiving the new HPWH baseline allowance. Lastly, the decision adopts detailed non-binding guiding principles for how to determine program costs and benefits when programs overlap. These principles apply to the programs adopted under this proceeding (BUILD, TECH, and WNDRR), as well as programs authorized to incentivize clean heating technologies, specifically under Energy Efficiency (EE) (incl. the new statewide Heating, Ventilation, and Air Conditioning and Plug Load Appliance Programs administered by SDG&E), and the Self-Generation Incentive Program (SGIP) (HPWH sub-program).

In Phase III of R.19-01-011, the CPUC is considering changing the rules regarding allowances, refunds, and discounts paid to builders to help facilitate the connection of buildings to the gas distribution system. In November 2021, CPUC's Energy Division staff released a report recommending the complete elimination of these payments for all customer classes effective July 1, 2023. According to the staff report, gas ratepayers subsidize gas line extensions at a cost exceeding $100 million annually. According to the staff report, "By eliminating all gas line extension allowances, builders would be forced to shoulder greater expense if they choose to construct a building that uses gas...the added up-front gas burden would send a signal to builders that building new gas infrastructure is more expensive, and thus make dual-fuel construction less desirable and financially riskier. As such, the builder community would be more likely to gravitate towards all-electric new construction." The CPUC is expected to issue a Proposed Decision in the third quarter of 2022.

AFFORDABILITY OIR

On July 12, 2018, the Commission instituted the OIR (R.18-07-006) to develop a common understanding, methods and processes to assess, the impacts on affordability of individual Commission proceedings and utility rate requests. This OIR includes gas, electric, water and communications utilities. On July 16, 2020, the Commission issued its Phase 1 decision (D.20-07-032), which defines affordability as the degree to which a representative household is able to pay for an essential utility service, given its socioeconomic status. This decision also adopts three metrics and supporting methodologies to be used by the Commission for assessing the affordability of essential utility services, including: hours at minimum wage required to pay for essential utility services; Socioeconomic vulnerability index (SEVI) of various communities; and ratio of essential utility service charges to non-disposable household income—known as the affordability ratio. The decision does not adopt an absolute definition of what constitutes affordable essential utility services; rather, the decision adopts metrics and methodologies for assessing affordability across utilities over time.

In Phase II of the Affordability Proceeding, a Proposed Decision was issued on June 10, 2021, providing further direction on implementation of the three metrics adopted in Phase I the CPUC will use to assess the affordability of utility service. The PD establishes how the affordability framework will be applied in CPUC proceedings and further develops the tools and methodologies used to calculate the three metrics. Gas and electric utilities must include certain Affordability Ratio and Hours-at-Minimum Wage data in any filing that would result in a revenue increase estimated to exceed one percent of currently authorized systemwide revenues. They must also include various estimated bill impacts by climate zone. The affordability metrics must also be updated at the time of a PD in General Rate Case (GRC) proceedings. SDG&E is directed to introduce the required affordability analysis in its next GRC Phase 2 application. Electric, gas and water utilities will also now all be required to submit quarterly rate trackers to the CPUC, aggregating the rate impacts of their various revenue requirements, pending rate requests, and authorizations.

The CPUC held an Affordability Proceeding 2022 En Banc on February 28 and March 1 of 2022 as part of Phase 3 of Affordability Rulemaking A.18-07-006, which examined proposals to contain costs and mitigate rate increases. Stakeholder proposals focusing on gas ratepayers included the following:

- Authorize utilities to deploy capital and recover cost for building decarbonization upgrades via tariffed on-bill structures that enable participation regardless of income, credit score, or renter status.

- Implement rate or infrastructure planning mechanisms to avoid excessive gas infrastructure costs falling disproportionately on residential customers who cannot electrify.

- Determine if electrification warrants securitization and/or accelerated depreciation of natural gas assets.

- Implement a Renewable Balancing Services tariff that would charge different rates to different customer classes, especially during peak hours, based on amount of natural gas use.

- Evaluate natural gas rates and affordability in coordination with the Long-Term Gas Planning Rulemaking.

- Determine how to efficiently prune the natural gas system while providing safety.

- Legislative action to ensure long-term budget availability and use state revenue to recover costs for programs, such as CARE.

The next step in Phase 3 of the proceeding is to build on the En Banc discussions. There will be Statewide listening sessions and a workshop held by the CPUC to solicit recommendations and strategies from parties to mitigate rate increases. A proposed decision is scheduled for Q2-Q3 2023.

PIPELINE SAFETY

In 2011, the CPUC issued an OIR, R.11-02-019, 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, pursuant to D.11-06-017. 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 and Phase 2 covers less populated areas of SoCalGas' and SDG&E's service territories.

In June 2014, the CPUC issued D.14-06-007 approving the utilities' plan for implementing PSEP, subject to after-the-fact reasonableness review, established criteria to determine the costs that may be recovered from ratepayers, and authorized the establishment of balancing accounts to facilitate the recovery of costs for implementing Phase 1.

Subsequently, in D.16-12-063 the Commission approved SoCalGas' and SDG&E's joint application, (Application (A.) 14-12-016, requesting review and recovery of $33.2 million, which is a portion of the tracked PSEP costs incurred prior to June 12, 2014. Additionally, D.16-08-003, approved SoCalGas' and SDG&E's application (A.15-06-013) to establish Phase 2 memorandum accounts. The decision also authorized 50 percent interim cost recovery for Phase 1 actual revenue requirements booked to the regulatory accounts subject to refund, and a long-term procedural schedule for PSEP going forward. D.16-08-003 ordered SoCalGas and SDG&E to transition PSEP to the GRC starting with Test Year 2019 and that future GRC applications could include PSEP costs until implementation of the Plan is complete.

From 2011 through March 2022, SoCalGas and SDG&E have invested approximately $2.4 billion and $790 million, respectively, in PSEP, with additional expenditures planned, involving the remediation of more than 450 pipeline miles for SoCalGas and 60 miles for SDG&E.

In D,19-02-004, the Commission approved SoCalGas' and SDG&E's second PSEP Reasonableness Review application (A.16-09-005), which presented costs totaling $195 million (including certain costs for which the utilities are not seeking recovery) of pipeline safety projects completed by June 30, 2015. The Commission approved cost recovery of approximately $187 million ($172 million for SoCalGas and $15 million for SDG&E).

In D.19-03-025, the Commission also approved SoCalGas' and SDG&E's PSEP forecast application (A.17-03-021), finding $254.5 million associated with twelve SoCalGas Phase 1B and 2A pipeline projects reasonable and eligible for cost recovery. The decision directs SoCalGas and SDG&E to record costs to a one-way balancing account on an aggregate basis and balance to the authorized revenue requirements.

In December 2018, SoCalGas and SDG&E filed a third joint PSEP reasonableness review application (A.18-11-010) requesting cost review and rate recovery for 83 completed Phase 1 projects. The total costs submitted for review are approximately $941 million ($811 million for SoCalGas and $130 million for SDG&E). In D.20-08-034, the Commission approved a settlement agreement which addressed the reasonableness review of approximately $940 million in costs incurred executing 44 pipeline projects and 39 valve pipeline safety enhancement plan projects by granting cost recovery in total of $934,607,000.

SoCalGas most recently requested additional PSEP funding in its 2024 GRC application (A.22-05-015) that will enable SoCalGas to continue the implementation and prudent execution of PSEP as mandated in Decision (D.) 14-06-007 and in furtherance of the CPUC's order to complete the Plan "as soon as practicable," while balancing other pipeline safety compliance regulations and the obligation to provide customers with safe and reliable service. Since its inception, the four objectives of PSEP have been and continue to be: (1) enhance public safety; (2) comply with Commission directives; (3) minimize customer impacts; and (4) maximize the cost effectiveness of safety investments.

ANGELES LINK APPLICATION

On February 17, 2022, SoCalGas filed A.22-02-007 requesting authorization to establish the Angeles Link Memorandum Account, which would track the incremental costs associated with stakeholder engagement, engineering, design, and environmental work for a proposed pipeline delivering "renewable green hydrogen" into the Los Angeles Basin. The application does not specify a cost recovery mechanism for expenses recorded in the memorandum account, but the company could request cost recovery from ratepayers in a future proceeding if the memorandum account is approved. It states that the project must be approved prior to SoCalGas's next GRC due to the urgent climate benefits that the project would bring. The anticipated costs for the proposed memorandum account do not include construction or capital costs. The application references the use of underground hydrogen transportation infrastructure and "new in-state dedicated hydrogen pipelines," suggesting much of the pipeline will be new infrastructure built underground.

The application says that the project is designed to facilitate the closure of the Aliso Canyon methane storage facility and preserve energy reliability, as well as address overall climate change concerns. The application does not name specific end users of the renewable hydrogen, but it describes an intent to serve future hydrogen end users, including "hard-to-electrify" industries, electric generators, and the heavy-duty transportation sector. The application says that the foundation of the system would be one or more transmission pipelines that would run from generation sources in areas such as the Central Valley, Mojave Desert/Needles, or the Blythe area. The application does not specify how the hydrogen would be produced other than that it would come from electrolysis powered by renewable electricity.

The application describes three phases for the project. Phase 1 would last from 12 to 18 months and cost an estimated $26 million. It would support a pre-Front End Engineering and Design analysis assessing hydrogen demand, identifying end users, and conducting energy studies, in addition to engaging stakeholders. Phase 2 would last from 18 to 24 months and cost $92 million. It would identify a preferred option through design, engineering, and environmental studies and complete refined engineering and implementation plans. Phase 3 would last from 18 to 30 months and cost "several hundreds of millions of dollars." This phase would prepare permit applications, including an application to the CPUC for a Certificate of Public Convenience and Necessity and other long-lead permit applications.

FEDERAL REGULATORY MATTERS

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

EL PASO

On August 15, 2021, El Paso Natural Gas's (EPNG) Line 2000 ruptured near Coolidge, Arizona. The National Transportation Safety Board (NTSB) opened Investigation PLD21FR003 into the incident. On April 19, 2022, EPNG reported that "the pipeline failure remains under a PHMSA order, and the entire Line 2000 system is under a reduced operating pressure. The reduced operating pressure in effect removes the Line 2000 system from service from Black River compressor station to the California border."

On April 21, 2022, FERC issued against EPNG an Order on Cost and Revenue Study, Instituting Investigation and Setting Matter for Hearing Procedures Pursuant to Section 5 of the Natural Gas Act. In that section 5 proceeding, FERC alleged that EPNG may be substantially over-recovering its cost of service, causing El Paso's existing rates to be unjust and unreasonable. The section 5 proceeding is anticipated to be resolved by mid-2023.

GTN AND CANADIAN PIPELINES

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

On November 18, 2021, FERC issued a letter order approving GTN's settlement agreement in lieu of GTN filing a NGA section 4 general rate case filing. That settlement agreement, among other things, maintained existing tariff recourse rates, established a moratorium on rate changes through December 31, 2023, and obligated GTN to file a NGA section 4 rate case in early 2024.

NORTH BAJA XPRESS PROJECT

On April 21, 2022, FERC issued a certificate of public convenience and necessity (CPCN) to North Baja Pipeline Company to construct and operate the North Baja Xpress project. The project will enable North Baja to provide 495,000 Dth/day of firm transportation service to Sempra LNG from the EPNG system at Ehrenberg for export to Mexico. The CPCN is conditioned on (1) making the facilities available within 3 years of the order date; (2) compliance with environmental conditions stated in the order; and (3) the execution of a firm service agreement before commencing construction.

GREENHOUSE GAS ISSUES

NATIONAL POLICY

Fundamental elements of the nation's greenhouse gas(es) (GHG) program were established by the Clean Power Plan, which was adopted by the U.S. EPA in August 2015 pursuant to their authority under the federal Clean Air Act. The intent of the Clean Power Plan was to reduce carbon emissions from power plants while maintaining energy reliability and affordability. The Clean Power Plan established customized goals for each state. It was projected to reduce carbon emissions from the power sector 32 percent from 2005 levels by 2030. Individual state targets were based on national uniform "emission performance rate" standards (pounds of carbon dioxide (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 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 directing the EPA Administrator to review the Clean Power Plan and if appropriate, suspend, revise, or rescind the rule. On October 10, 2017, the EPA released a proposed rule to repeal the Clean Power Plan. On June 30, 2022, the U.S. Supreme Court determined that the EPA lacks authority under the Clean Air Act to set GHG standards that require power producers to significantly change the generation mix. The Court held that such consequential rules must be based on explicit congressional authorization.

Former President Trump announced the United States' withdrawal from the Paris Agreement[101] (the international treaty on climate change) in 2017, but a number of U.S. states including California formed the United States Climate Alliance to maintain the objectives of the Clean Power Plan within their state borders separately from the federal government. President

[101] The Paris Agreement | UNFCCC

Biden signed an executive order on January 20, 2021, to re-admit the United States into the Paris Agreement. Readmission became effective 30 days later.

MOTOR VEHICLE EMISSIONS REDUCTIONS

National GHG policymakers 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 the EPA's Mandatory Reporting of GHGs rule, all vehicle and engine manufacturers outside of the light-duty sector must report emission rates of CO_2, nitrous oxide, and methane from their products.

ASSEMBLY BILL 32

The Global Warming Solutions Act of 2006 (AB 32) requires California to reduce GHG emissions to the adopted statewide 1990 level by 2020. AB 32 directs the Air Resources Board (ARB) to adopt rules and regulations in an open public process to achieve the "maximum technologically feasible and cost-effective GHG emission reductions".[102] AB 32 also required the ARB to prepare and approve a scoping plan that provides a roadmap to reach the 2020 emissions reduction target. The first scoping plan was approved by the ARB in 2008 and the ARB is required to update the plan at least once every 5 years. The most recent update, as of this writing, was adopted in December 2017. For each scoping plan, the ARB is required to use a collaborative consultation process through engagement with State agencies including the CPUC and CEC, 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 recommended GHG reduction strategies and regulations, including a market-based compliance mechanism that are cost effective and minimizes administrative burden and GHG emission leakage.

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

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SENATE BILL 32

SB 32 (Pavley) was enacted on September 8, 2016 and went into effect on January 1, 2017. The law extended the goals of AB 32 by requiring the ARB to ensure statewide GHG emissions are 40 percent below the 1990 levels by 2030. 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 target 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, provides increased legislative oversight of the ARB through a Joint Legislative Committee on Climate Change Policies and directed it to take certain actions to improve local air quality. These actions include internet posting of emissions of GHG, criteria pollutants, and toxic air contaminants from stationary and mobile sources, prioritization of specified emission reduction rules and regulations to protect disadvantaged communities, and consideration of the social cost of carbon when preparing plans to meet GHG reduction targets and goals.

On May 10, 2022, the ARB released the Draft 2022 Scoping Plan Update. The draft of the 2022 Update reflects direction from major climate legislation and four Governor's Executive Orders issued since the adoption of the 2017 Scoping Plan Update. One of the executive orders, B-55-18 (signed September 2018) establishes a statewide goal to achieve carbon neutrality (i.e., the point at which removal of carbon pollution from the atmosphere meets or exceeds emissions) as soon as possible, and no later than 2045, and to achieve and maintain net negative GHG emissions thereafter. It also calls for the ARB to ensure future scoping plans identify and recommend measures to achieve this carbon neutrality goal and to develop a framework for implementation and accounting that tracks progress toward the goal. Further, in July 2021, Governor Newsom wrote to the ARB Chair requesting that the ARB evaluate how to achieve carbon neutrality no later than 2035 including analysis of how to reduce or eliminate demand for fossil fuel and end oil extraction in California. Additionally, the Governor asked for the pathway to carbon neutrality to prioritize strategies that reduce emissions of GHG as well as provide public health co-benefits, include an evaluation of cost effectiveness, and protect against leakage of GHG emissions to other states as mandated by law (AB 32). The Draft 2022 Scoping Plan Update recommends an alternative that achieves carbon neutrality in 2045 and found that the two 2035 alternatives evaluated have much higher direct costs, job losses, rate of slowing economic growth and degree of uncertainty.

SENATE BILL 350

The Clean Energy and Pollution Reduction Act, or SB 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 increased and extended the RPS target to 50 percent by 2030, which later was amended by SB 100. 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 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, ARB, and CAISO—to implement the bill. SoCalGas has been engaged with these agencies throughout the process and has provided input.

SENATE BILL 1383

SB 1383 was signed into law on September 19, 2016, establishing methane emissions reduction targets in a statewide effort to reduce emissions of Short-Lived Climate Pollutants (SLCP) in various sectors of California's economy.[103] SB 1383 requires a 40 percent reduction in methane, a 40 percent reduction on hydrofluorocarbon gases and a 50 percent reduction in anthropogenic black carbon by 2030, relative to 2013 baseline levels and requires the ARB, the CPUC, and the CEC to undertake various actions related to reducing SLCPs in the state.
SB 1383 also establishes targets to achieve a 50 percent reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and a 75 percent reduction by 2025. The law grants CalRecycle the regulatory authority required to achieve the organic waste disposal reduction targets and establishes an additional target that not less than 20 percent of currently disposed edible food is recovered for human consumption by 2025. The bill mandates the ARB,

[103] http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.

in consultation with the Department of Food and Agriculture, to adopt regulations to reduce methane emissions from livestock and dairy manure operations. SB 1383 also requires state agencies to consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of RNG.

Pursuant to SB 1383, the ARB formed a Dairy and Livestock GHG Reduction working group in 2017 to help understand ways to reduce dairy and livestock methane emissions by 40 percent from 2013 levels by 2030. The working group's assignment was to identify and address technical, market, regulatory, and other barriers to development of methane reduction projects. SoCalGas actively participated in the working group and its three sub-groups including SoCalGas staff serving as co-chair of the Fostering Markets for Digester Projects sub-group whose task was to establish a roadmap, attentive to the SB 1383 statute dates of July 1, 2020 and January 1, 2024, to significantly expand the number of livestock digester projects in California that support the state's climate and air quality goals.

SoCalGas has participated in the CDFA Dairy Digester Research and Development Program (DDRDP), which provides financial assistance for the installation of dairy digesters in California, which will result in reduced GHG emissions. SoCalGas staff attended and presented at CDFA DDRDP workshops, webinars and listening sessions held in environmental justice (also known as disadvantaged communities) areas near dairies. SoCalGas also provided education and assisted customers who showed interest in the CDFA Program, as well as on other topics related to RNG, such as alternative fuel vehicles. A specific example is our promotion of RNG in our marketing materials especially those developed and displayed at the International Ag Expo held every year in Tulare, California. CDFA also includes a link on their DDRDP website to SoCalGas' RNG website.

SENATE BILL 100 AND EXECUTIVE ORDER B-55-18

The 100 Percent Clean Energy Act of 2019, or SB 100, was signed into law on September 10, 2018. SB 100 sets a state policy that eligible renewable energy and zero-carbon resources supply 100 percent of all retail sales of electricity in California by 2045. The bill also accelerates California's RPS, which, pursuant to a 2016 bill by the same author (SB 350), already mandates that load-serving entities procure at least 50 percent of retail sales from eligible renewable energy resources by 2030; under SB 100, the 2030 target will be increased to 60 percent, and the 50 percent target will be advanced to 2026, in recognition that California retail sellers are well on their way to achieving the target in advance of the existing deadlines. EO B-55-18 establishes a new statewide goal to achieve economy-wide carbon neutrality no later than 2045. In March 2021, the Joint Agencies (California Energy Commission, California Public Utilities Commission, and California Air Resources Board), published the 2021 *SB 100 Joint Agency Report: Achieving 100 Percent Clean Electricity in California: An Initial Assessment*. The report includes a review of the policy to provide 100 percent of electricity retail sales and state loads from renewable and zero-carbon resources in California by 2045. The report assesses various pathways to achieve the target and an initial assessment of costs and benefits. It also includes results from capacity expansion modeling and makes recommendations for further analysis and actions by the joint agencies. The Joint Agencies followed up with a workshop in October 2021 to analyze the non-energy benefits, social costs and reliability. Then the CEC conducted a workshop in collaboration with the CPUC and CAISO in February 2022, to discuss approaches for examining the environmental and land use implications of potential resource portfolios to meet SB 100 targets.

ASSEMBLY BILL 3232

The zero emissions buildings and sources of heat energy bill requires the CEC to assess the potential for the state to reduce the emissions of GHGs from the state's residential and commercial building stock by at least 40 percent below 1990 levels by January 1, 2030. AB 3232 also requires consideration of the impact of emission reduction strategies on grid reliability and as directed by AB 3232, the CEC will conduct additional analyses on strategies and update progress on reducing GHG emissions from residential and commercial buildings in the 2021 and future IEPRs. On August 11, 2021, the California Energy Commission (CEC) voted to adopt the AB 3232 California Building Decarbonization Assessment Final Staff Report (AB 3232 Final Report) during their regular Business Meeting. The Final Commissioner Report was published on August 13, 2021. In addition, a workbook containing updated assumptions being used in the Fuel Substitution Scenario Analysis Tool (FSSAT) was published to the 19-DECARB-01 Docket on February 28, 2022.

Southern California

AB 3232 suggests two baseline approaches from which California can track building decarbonization: systemwide and direct emissions. According to the Final Commissioner Report, the bulk of building GHG emissions in 2030 are from today's existing buildings and California has approximately 14 million existing single-family homes and multifamily units. The report defined and analyzed seven GHG emission strategies within seven high-level categories and the analysis concluded that as of 2018, systemwide GHG emissions in residential and commercial buildings are 26 percent below 1990 levels and current policies and activities are on a trajectory to reach 36 percent below 1990 levels by 2030. SoCalGas engaged with the CEC Commissioners and Staff on the Draft Version of the Building Decarbonization Assessment mandated by AB 3232 through attending six public workshops from December 2019 to May 2021 to discuss and share feedback on the findings presented in the AB 3232 Final Report; the CEC received many comments submitted to the public docket 19-DECARB-01.

GHG RULEMAKING

Beginning on January 1, 2015, the ARB'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 mtCO_2e equivalent per year have a direct obligation to the ARB 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.[104] The rulemaking had also addressed how revenues generated from the sale of directly allocated allowances will be returned to ratepayers. The rulemaking had initially determined that all Cap-and-Trade compliance costs will be included on a forecasted basis in customers' transportation rates beginning April 1, 2016. Customers with a direct obligation to the ARB 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

[104] CPUC D.15-10-032.

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 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 (3) 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

The ARB publishes total, covered and non-covered emissions because total emissions are used to calculate California's GHG emissions inventory and covered emissions are used to determine a facility's Cap-and-Trade obligation. At the time of the writing of the 2020 CGR, the 2019 GHG numbers have not been verified by the independent third party. The 2018 numbers were the most recent verified numbers for the reporting category. As of 2018, SoCalGas reported to the ARB *verified* GHG emissions of approximately 41.4 mmtCO_2E in three primary categories: (1) combustion emissions at five compressor stations and two storage fields, where annual emissions exceed 10,000 mtCO_2E; (2) vented and fugitive emissions from three compressor stations, two storage fields and the natural gas distribution system; and (3) the GHG emissions resulting from combustion of natural gas delivered to all customers.

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In 2018, GHG emissions for gas delivered to all customers was 39.9 $mmtCO_2e$, but 20.7 $mmtCO_2e$ for gas delivered to non-covered customers. Non-covered customers consist of smaller customers with emissions of less than 25,000 $mtCO_2E$. For Cap-and-Trade obligation, 20.7 $mmtCO_2e$ is the appropriate Cap-and-Trade value. Large, covered customers pay their own Cap-and-Trade bill.

Four of the five facilities subject to the EPA's mandatory reporting regulation are also subject to ARB's 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 ARB's Cap-and-Trade Program). More recently, SoCalGas estimated that its GHG emissions compliance obligation as a natural gas supplier to be approximately 22.0 $mtCO_2E$ for 2019. ARB will issue final 2019 GHG emissions compliance obligations for natural gas suppliers in November 2020.

The adoption of rules and procedures to minimize natural gas leakage from Commission-regulated natural gas pipelines consistent with Pub. Util. Code Section 961 (d), § 192.703 (c) of Subpart M of Title 49 of the CFR, and the Commission's General Order 112-F are covered under R.15-01-008. 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 2020, SoCalGas reported 2.2 Bcf of methane emissions from intentional and unintentional releases for the year 2019. These emissions were reported in the SB 1371 report. Only some intentional emissions are subject to the ARB Cap-and-Trade Program.

PROGRAMMATIC EMISSIONS REDUCTION: CALIFORNIA GHG REDUCTION STRATEGIES

The ARB has the responsibility to develop the broad strategies to achieve California's GHG emissions reduction targets. The 2017 Scoping Plan Update identified several strategies to achieve the 2030 target to reduce emissions by 40 percent from 1990 levels: double building efficiency; 50 percent renewable power; cleaner transportation; and reduce SLCPs and Cap emissions from various sectors. The SLCP includes targets to reduce methane emissions from organic sources of methane and methane leakage from the oil and gas industry.

The CPUC has 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 26 Best Practices for emission mitigation. This proceeding is led by the CPUC in consultation with the ARB. The first phase will develop the overall policies and guidelines for a natural gas leak abatement program consistent with SB 1371. The second phase will develop ratemaking and performance-based financial incentives associated with the natural gas leak abatement program determined through Phase 1 of the proceeding. Energy efficiency and renewables are considered fundamental to GHG emission reduction in the electric sector. As a result, integration of additional renewables will require quick-start peaking capacity for firming and shaping of intermittent power, which in the foreseeable future will be gas-fired combustion turbines.

RENEWABLE NATURAL GAS

STATE AND FEDERAL POLICIES FOR RNG

STATE POLICIES ON RNG

AB 1900 (2012, Gatto) required that the Commission open a rulemaking to ensure that each gas corporation provide non-discriminatory open access to its gas pipeline system to any party for the purposes of physically interconnecting with the gas pipeline system and effectuating the safe delivery of gas. On February 13, 2013, the Commission opened the order instituting rulemaking (OIR) R.13-02-008, (or 'Biomethane OIR') to adopt a biomethane standard and requirement, pipeline open access rules, and related enforcement provisions. In collaboration with and the Office of Environmental Health Hazard Assessment, the Commission determined that biomethane could be safely injected into the natural gas pipeline system and Decision D.14-01-034 (January 16, 2014) adopted pipeline injection standards for 17 constituents of concern potentially found in biomethane. The establishment of these biomethane injection standards was Phase 1 of the Biomethane OIR.

Phase 2 of the Biomethane OIR resulted in Decision D.15-06-029, which adopted a biomethane interconnector monetary incentive program to encourage the development of biomethane projects interconnecting to the utilities gas pipeline systems. The incentive program authorized a total of $40 million for incentives, providing up to $1.5 million per project that successfully interconnect and operate by June 11, 2020. Pub. Util. Code § 399.19 later increased the incentive amounts to $3 million for non-dairy clusters and $5 million for dairy clusters and extended the incentive program to December 31, 2021.

On October 2, 2019, Governor Newsom signed into law SB 457, which extended the biomethane incentive program again until December 31, 2026, or until all available program funds were expended. Decision D.19-12-009 implemented the SB 457 extension which also implemented a reservation system for the biomethane monetary incentive program that allowed project developers to reserve incentive funds during the development of a project and receive the incentive funds once the project is operating. The Incentive Reservation System is publicly available online to promote the transparency of the use of funds and all $40 million earmarked for incentives was reserved by 11 biomethane projects, with an additional 8 projects placed on a waiting list for possible incentive funding later.

Phase 3 of the Biomethane OIR addressed the need for a statewide standard renewable gas interconnection tariff (SRGIT) and interconnection agreement (SRGIA) between the California natural gas utilities and RNG developers. On August 27, 2020, the Commission issued decision D.20-08-035, which adopted the SRGIT filed by SoCalGas, SDG&E, Southwest Gas, and PG&E (IUOs). Decision D.20-08-035 also allocated an additional $40 million for biomethane interconnection incentives to assist those RNG interconnection projects on the incentive waiting list.

Phase 4 of the Biomethane OIR was opened November 21, 2019, to address two issues: (1) standards for injection of renewable H2 into gas pipelines; and (2) implementation of SB 1440 that was signed into law on September 23, 2018 and required the Commission to consider adopting biomethane procurement targets (or goals) for each natural gas corporation in the state.

SB 1440 AND RNG

On February 24, 2022, the Commission issued Decision D.22-02-025 to implement SB 1440 and defined two biomethane procurement targets for the IOUs. A short-term 2025 biomethane procurement target was set at 17.6 billion cubic feet (BCF) of biomethane, which corresponds to 8 million tons of organic waste diverted statewide annually from landfills. This target was set to support the organic waste diversion targets established previously in SB 1383. With this target, each utility will be responsible for procuring only RNG produced from organic waste, including wood waste, at a level in accordance with its proportionate share of statewide Cap-and-Trade allowances.

The medium-term 2030 target for annual biomethane procurement was established at 72.8 BCF to assist the state achieve its goal to reduce methane emissions 40 percent by 2030[105] and is referred to as a "Renewable Gas Standard" (RGS) for California.[106] With this target, each utility will be responsible for procuring a percentage of the total in accordance with its proportionate share of 2020 annual bundled core customer natural gas demand, excluding NGV demand, as noted in the 2020 California Gas Report. Each utility may procure RNG produced from other feedstocks besides organic waste, including landfill, WWTP, Syngas or dairy.[107]

SB 1383 AND RNG

Another significant driver for RNG development in California is SB 1383. Signed into law on September 19, 2016, SB 1383 required the state board to implement a comprehensive strategy to reduce emissions of SLCPs so as to achieve a reduction in methane by 40%, hydrofluorocarbon gases by 40%, and anthropogenic black carbon by 50% below 2013 levels by 2030. The bill established specified targets for reducing organic waste in landfill and required state agencies to consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of renewable gas.

[105] SB-32 California Global Warming Solutions Act of 2006.
[106] D.22-02-025, p. 32.
[107] Dairy purchases are limited to 4% of the total utility proportionate share of the target volume.

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SB 1383 requires that beginning in 2022, all cities and counties provide organic waste collection services to all residents and businesses and also recycle these organic materials at recycling facilities such as anaerobic digestion facilities that create biofuel and electricity or composting facilities that make soil amendments. City and county governments are also required to procure prescribed amounts of products from in-state recycled organic material depending on their population. Allowed recycled products are, compost, mulch that meets SB 1383 regulations, renewable gas used as fuel for transportation, electricity, or heating applications and electricity generated from biomass conversion of municipal-solid-waste.

SB 1383 also required that the CPUC implement at least 5 dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system. For these pilot projects the gas corporations were allowed to fund and recover in rates the cost of pipeline infrastructure, including biogas collection lines and costs to interconnect with existing pipelines, removing many upfront costs developers would otherwise have to incur. On December 3, 2018, a selection committee consisting of staff members and attorneys from the CPUC, the ARB, and the CDFA, selected six dairy biomethane pilot projects. Four pilot projects are in SoCalGas service territory: CalBioGas Buttonwillow LLC; CalBioGas North Visalia LLC; CalBioGas South Tulare LLC; and Lakeside Pipeline LLC. (The other two projects are in PG&E service territory: Maas Energy Works in Merced; and Weststeyn Dairy in Willows.)

A.19-02-005[108] AND RNG

On February 28, 2019, SoCalGas and SDG&E filed a joint application A.19-02-005 for a voluntary RNG Tariff offering that would give the option to residential and small industrial and commercial customers to identify an amount of their monthly natural gas bill for the purchase of RNG in lieu of traditional natural gas. On December 17, 2020, Decision D.20-12-022, approved the voluntary renewable natural gas tariff authorizing a three-year voluntary Renewable Natural Gas (RNG) Tariff pilot program with two additional years for program wind-down. On March 14, 2022 SoCalGas filed an Advice Letter affirming their intention to implement the program

[108] On June 21, 2021, the Commission granted the Utilities' request for an extension of time to comply with D.20-12-022 as the Commission had provided guidance in OP 1(a) of D.20-12-022 that the Utilities should wait to consider sourcing long-term contracts for the voluntary RNG pilot program in conjunction with any RNG procurement authorized in the implementation of SB 1440.

within one year and review contract opportunities now that D.22-02-025 has implemented SB 1440.

FUEL STANDARDS AND RNG

Fuel standards are evolving and becoming more stringent in California. Established by Executive Order and signed into law by then Governor Schwarzenegger in 2007, the fuel standard required a 10 percent carbon intensity reduction in the transportation sector by 2020. Those regulations were amended in 2018 to require a 20 percent reduction by 2030. The fuel standard(s) require fuel providers to ensure that the mix of fuel they sell into the California market meets, on average, provides a declining standard for GHG emissions measured in CO_2 equivalent grams per unit of fuel energy sold.

There is a significant amount of RNG used in California NGVs. The most recent data from the Low Carbon Fuel Standard (LCFS) Program[109] shows that approximately 98 percent of fuel delivered to NGVs in 2021 was RNG. The chart below shows how RNG usage in this important program has grown over time. Since 2013, RNG use by NGV's has displaced more than 886 million gallons of diesel fuel and has been responsible for reducing more than 8.4 MMT of carbon emissions.[110]

[109] https://ww2.arb.ca.gov/sites/default/files/2022-05/quarterlysummary_043022.xlsx.
[110] *Id.*

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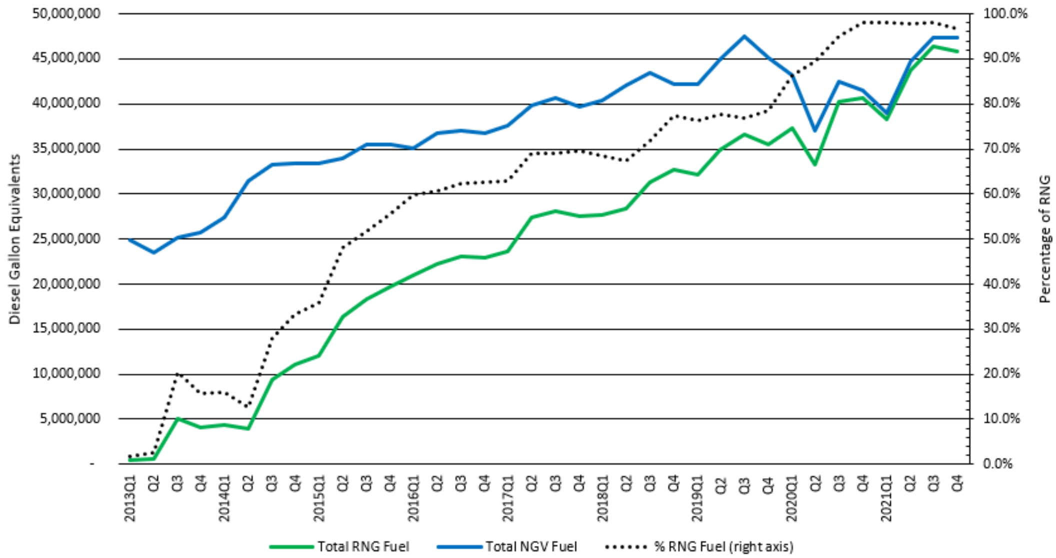
Figure 25 - LCFS Program NGV Statistics for Years 2013 - 2021



The California NGV market continues to represent 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 traditional fuels such as natural gas or diesel.

SoCalGas opted into the LCFS program in 2013 and began generating credits from fossil natural gas dispensed at utility owned CNG refueling stations that serve both company vehicles and the general public. In 2018, the CPUC approved a SoCalGas Advice Letter to initiate a Voluntary RNG Procurement Pilot program to procure and dispense RNG at its utility owned CNG stations. As RNG is an eligible alternative fuel under LCFS program and EPA's Renewable Fuel Standard (RFS), it generates Renewable Identification Number credits from the RFS Program in addition to the LCFS credits. The value from the credits generated is returned to CNG customers by reducing the price at the pump. Also, RNG has as lower carbon intensity than traditional CNG and will generate more credits per unit of energy under the LCFS program. On April 1, 2019, SoCalGas began procuring 100 percent RNG at all utility owned CNG stations. SoCalGas anticipates the Pilot will result in more value returned to its CNG customers while supporting the development of the RNG market.

CAP-AND-TRADE

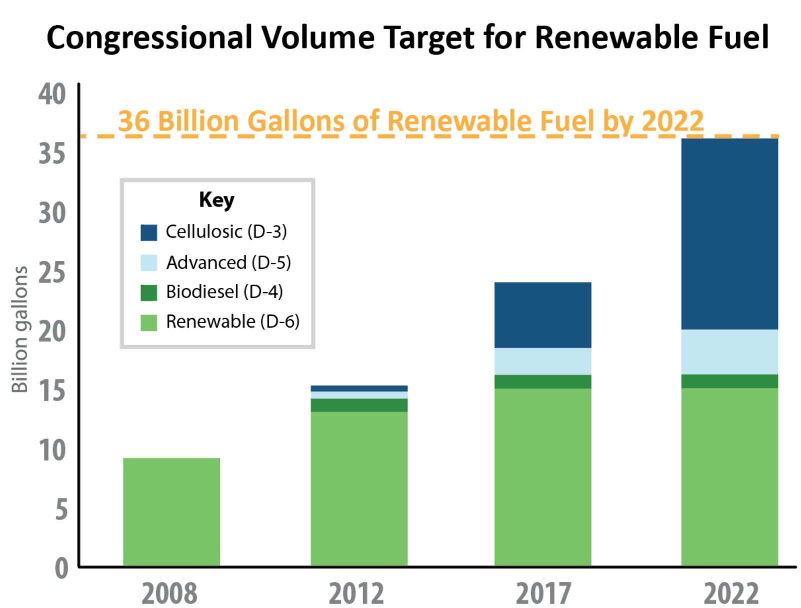
The Cap-and-Trade Regulation establishes a declining limit on major sources of GHG emissions throughout California. The Program applies to certain GHG emission sources and certain fuel suppliers, including natural gas utilities. CARB creates allowances equal to the total amount of permissible emissions and each year reduces the number of allowances created as the annual cap declines. An increasing auction reserve price for allowances and the reduction in annual allowances provides a carbon price signal intended to promote GHG emissions reductions. Many entities covered under the regulation must purchase allowances at quarterly auctions, however, qualifying RNG is exempt from compliance obligations under the program.

FEDERAL POLICIES ON RNG

RENEWABLE FUEL STANDARD (RFS)

The Renewable Fuel Standard (RFS) is a federal program that requires transportation fuel sold in the United States to contain a minimum volume of renewable fuels to expand the use of renewable fuels and reduce reliance on imported oil. RFS originated with the Energy Policy Act of 2005 and was expanded and extended by Congress in the Energy Independence and Security Act of 2007 (EISA). The RFS program provides a market-based monetary value for renewable fuels, including RNG that can be combined with LCFS incentives to increase the incentive amounts available to RNG developers, suppliers, or marketers. The RFS requires renewable fuel to be blended into transportation fuel in increasing amounts each year, escalating to 36 billion gallons by 2022.[111] For a fuel to qualify as a renewable fuel under the RFS program, EPA must determine that the fuel qualifies under the statute and regulations and the fuel must achieve a reduction in greenhouse gas (GHG) emissions as compared to a 2005 petroleum baseline.[112]

Figure 26 – Federal Renewable Fuel Targets



[111] https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard
[112] *Id.*

HYDROGEN

Hydrogen is the simplest and most abundant element, making up approximately 75 percent of the observable universe. Hydrogen can be utilized as a fuel to generate energy. With its abundance and simple chemical structure, hydrogen can be manufactured from feedstock such as methane, or water and electricity, using scalable, sustainable, and renewable methods. Hydrogen has favorable emissions characteristics because it does not contain carbon or produce GHG when it is consumed. For this reason, hydrogen can play an important role in the transition to a clean, low-carbon energy system in California.[113]

As part of the State of California's climate strategy, hydrogen can provide important GHG emissions reductions, and can also play a key role in enabling the use of zero-emissions fuel cell electric vehicles, which can reduce criteria emissions from on-road diesel, the largest and hardest to electrify contributors to the State's black carbon and nitrogen oxides (NOx) inventories.[114] California has also been at the forefront of developing hydrogen fueling stations to demonstrate the feasibility of hydrogen-fueled transportation and the potential that such a network creates for deployment of light duty fuel-cell electric vehicles (FCEVs).

Hydrogen fuel for transportation was adopted in California through the policy framework by Assembly Bill (AB) 8, which provided certainty for hydrogen fueling station deployment.[115] In addition, new programs and policies have been developed and initiated to ensure that some of the most ambitious public-private goals are met as projected. The Low Carbon Fuel Standard's (LCFS) Hydrogen Refueling Infrastructure (HRI) credit provisions took effect, predicated on the goal of reaching 200 hydrogen stations by 2025 as described by Governor Brown's Executive Order B-48-18 (EO B-48-18).[116]

Globally, hydrogen is widely seen as a pivotal component of the future clean energy economy. The two primary technological processes used today to produce hydrogen are electrolysis and

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113 http://hydrogencouncil.com .

114 https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm .

115 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB8 .

116 https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html.

reformation, including steam methane reformation (SMR) and autothermal reformation (ATR). Hydrogen is also produced when organic mass is gasified, but this "syngas," consisting of mainly carbon monoxide (CO) and hydrogen, is typically an intermediate product often used to generate methane or electricity. Reforming is a mature technology and is the most economical way to produce hydrogen, supplying 95% or more of the hydrogen used in the United States today.[117] The electrolysis process uses renewable electricity to split water (H_2O) into hydrogen (H_2) and oxygen (O_2).

As a gaseous fuel, hydrogen can help decarbonize the gas grid and be used in a variety of end use applications, beyond transportation. The hydrogen can either be stored directly, or methanated and injected into the natural gas grid to be stored and delivered to a variety of end uses, supplementing or displacing traditional natural gas. Storing hydrogen from electrolysis is a scalable and versatile energy storage pathway.

In 2022, SoCalGas proposed the development of what would be the nation's largest green hydrogen energy infrastructure system, the Angeles Link, to deliver clean, reliable energy to the Los Angeles region. As proposed, the Angeles Link would support the integration of more renewable electricity resources like solar and wind and would significantly reduce greenhouse gas emissions from electric generation, industrial processes, heavy-duty trucks, and other hard-to-electrify sectors of the Southern California economy. The proposed Angeles Link would also significantly decrease demand for natural gas, diesel and other fossil fuels in the LA Basin, helping accelerate California's and the region's climate and clean air goals.

Electrolytic green hydrogen is produced entirely from renewable electricity, and it expands our renewable energy storage capabilities, allowing us to utilize more renewable electricity and avoid curtailment while reducing emissions in hard-to-electrify sectors. As contemplated, the Angeles Link would deliver green hydrogen in an amount equivalent to almost 25 percent of the natural gas SoCalGas delivers today. Building the system to provide a clean alternative fuel could, over time and combined with other future clean energy projects, reduce

[117] The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology, Institute of Transportation Studies, UC Davis (March 2017), available at https://steps.ucdavis.edu/wp-content/uploads/2017/05/2017-UCD-ITS- RR-17-04-1.pdf

natural gas demand served by the Aliso Canyon natural gas storage facility, facilitating its ultimate retirement while continuing to provide reliable and affordable energy to the region.

PEAK DAY DEMAND

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's bundled 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 foreach utility's service area. This criteria correlates to a system average temperature of 40.5 degrees Fahrenheit for SoCalGas' service area and 43.3 degrees Fahrenheit for SDG&E's service area.

TABLE 28 – CORE 1-IN-35 YEAR EXTREME PEAK DAY DEMAND (MMcf/d)

Year	SoCalGas Core Demand 1/	SDG&E Core Demand 2/	Other Core Demand 3/	Total Demand	*Estimated AAFS Impact on Core Peak Day Demand* 5/
2022	2,869	404	170	**3,443**	-2
2023	2,827	403	170	**3,401**	-9
2024	2,782	402	171	**3,355**	-25
2025	2,735	400	173	**3,308**	-44
2026	2,691	398	174	**3,263**	-65
2027	2,647	397	175	**3,218**	-88
2028	2,601	395	176	**3,173**	-113

Notes:

(1) 1-in-35 peak temperature cold day SoCalGas core sales and transportation. Forecast embodies the baseline forecast with load modifiers that include changing weather design to account for climate change, assumed EE savings and assumed fuel substitution under AAFS 2.
(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, City of Vernon, and Ecogas.
(4) The criteria for extreme peak day design are defined as a 1-in-35 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 40.5 degrees Fahrenheit for SoCalGas' service area and 43.3 degrees Fahrenheit for SDG&E's service area.
(5) Estimated impact shown represents SoCalGas and SDG&E's combined AAFS impacts. SoCalGas and SDG&E's AAFS Impacts are included in the forecast of Peak day demand of "SoCalGas Core Demand", "SDG&E Core Demand", and "Total Demand".

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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.

SoCalGas aligned around the fuel substitution scenario developed by the California Energy Commission (CEC). SoCalGas emphasizes that we are still in the early stages of this energy transition and forecasts around the timing and degree of these changes are highly uncertain. These forecasts will improve over time as trends are observed in the real world and policy and market drivers mature. SoCalGas will be actively monitoring these trends and expects that each update of the CGR will incorporate greater definition of these factors and their impact(s) on the resultant gas demand segment forecasts.

It is also important to note that the CGR is relied upon for system planning purposes to inform important infrastructure investment and operating decisions that impact the natural gas system capacity and reliability. For these reasons, it is important to recognize that while we need to evolve with the energy transition, we also consider a measured view around prospective load reductions to avoid premature design standard reductions that may not serve California well if less load reductions materialize than are anticipated. We have an obligation to our customers to make sure they have safe, clean, reliable and affordable sources of energy and compromising these outcomes based on prospective and uncertain projections will not serve the public interest so ambition must be appropriately balanced with reality.

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.

TABLE 29 – WINTER 1-IN-10 YEAR COLD DAY DEMAND CONDITION (MMcf/d)

Year	SoCalGas Core (1)	SDG&E Core (2)	Other Core (3)	Noncore NonEG (4)	Electric Generation (5)	Total Demand	*Estimated AAFS Impact on Core Peak Day Demand* (7)
2022	2,709	380	150	621	812	4,672	-2
2023	2,670	380	150	621	792	4,612	-9
2024	2,628	378	151	622	749	4,528	-23
2025	2,584	376	152	622	725	4,459	-41
2026	2,542	375	153	621	710	4,402	-61
2027	2,500	373	154	621	735	4,383	-83
2028	2,458	372	155	620	669	4,274	-107

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, City of Vernon, and Ecogas.
(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 Ecogas. Average daily December Noncore-Non-EG demand for all market segments except Refinery and SoCalGas noncore Commercial; SoCalGas noncore Commercial is at 1-in-10 peak temperature cold day demand and Refinery is at connected load.
(5) Electric Generation includes UEG/EWG Base Hydro, large cogeneration, industrial and commercial cogeneration (<20MW), refinery-related cogeneration, and EOR-related cogeneration.
(6) The criteria for 1-in-10 peak day design are defined as a 1-in-10 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 42.2 degrees Fahrenheit for SoCalGas' service area and 44.8 degrees Fahrenheit for SDG&E's service area.
(7) Estimated impact shown represents SoCalGas and SDG&E's combined AAFS impacts. SoCalGas and SDG&E's AAFS Impacts are included in the forecast of Peak day demand of "SoCalGas Core Demand", "SDG&E Core Demand", and "Total Demand".

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.

TABLE 30 – SUMMER HIGH SENDOUT DAY DEMAND (MMcf/d)

Year	High Demand Month (1)	SoCalGas Core (2)	SDG&E Core (3)	Other Core (4)	Noncore NonEG (5)	Electric Generation (6)	Total Demand
2022	Sep	607	87	57	587	1,241	2,579
2023	Sep	599	87	57	589	1,180	2,513
2024	Sep	591	87	57	590	981	2,306
2025	Sep	582	86	58	590	1,031	2,347
2026	Sep	575	86	58	589	1,080	2,387
2027	Sep	567	85	58	589	1,104	2,403
2028	Sep	558	84	59	588	1,022	2,312

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, City of Vernon, and Ecogas.
(5) 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 Ecogas. Average daily September Noncore-Non-EG demand for all noncore market segments except Refinery; Refinery is at connected load.
(6) Highest demand during the high demand month under 1-in-10 dry hydro conditions except year 2022, when the Electric Generation highest demand is based on 2022 hydro condition.

2022 CALIFORNIA GAS REPORT

SOUTHERN CALIFORNIA GAS COMPANY – TABULAR DATA

Table 31

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
RECORDED YEARS 2017 TO 2021

Line	CAPACITY AVAILABLE		2017	2018	2019	2020	2021
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		84	104	97	87	86
	Out-of-State Gas						
11	Other Out-of-State		2,434	2,246	2,305	2,366	2,377
12	Total Out-of-State Gas		2,434	2,246	2,305	2,366	2,377
13	TOTAL SUPPLY TAKEN		2,518	2,350	2,402	2,453	2,463
14	Net Underground Storage Withdrawal		(14)	(8)	7	(19)	(20)
15	TOTAL THROUGHPUT (1)(2)		2,504	2,342	2,409	2,435	2,443
	DELIVERIES BY END-USE						
16	Core	Residential	565	569	645	635	621
17		Commercial	214	217	226	196	211
18		Industrial	55	57	61	53	55
19		NGV	38	40	41	37	40
20		Subtotal	872	883	973	920	927
21	Noncore	Commercial	56	59	58	57	57
22		Industrial	389	389	**357**	369	376
23		EOR Steaming	39	38	51	51	34
24		Electric Generation	713	615	589	641	654
25		Subtotal	1,198	1,101	1,055	1,118	1,121
26	Wholesale/International		401	333	342	374	372
27	Co. Use & LUAF		33	25	39	23	23
28	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,504	2,342	2,409	2,435	2,443
	TRANSPORTATION AND EXCHANGE						
29	Core	All End Uses	62	71	74	63	64
30	Noncore	Commercial/Industrial	446	448	415	426	433
31		EOR Steaming	39	38	51	51	34
32		Electric Generation	713	623	589	641	654
33		Subtotal-Retail	1,260	1,181	1,129	1,181	1,185
34	Wholesale/International		401	333	342	374	372
35	TOTAL TRANSPORTATION & EXCHANGE		1,660	1,514	1,471	1,554	1,557
36	CURTAILMENT (3)						
37	REFUSAL						
38		Total BTU Factor (Dth/Mcf)	1.0343	1.0319	1.0336	1.0293	1.0322

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. This table does not explicitly show any curtailment data for the recorded years, the noncore customer usage data implicitly captures the effects of any curtailment events.

TABLE 1-SCG

Table 32

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2022 THRU 2026

AVERAGE TEMPERATURE YEAR

LINE			2022	2023	2024	2025	2026	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/]		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE [4/]		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas [5/]		61	61	61	61	61	8
9	Out-of-State		2,379	2,354	2,266	2,219	2,190	9
10	TOTAL SUPPLY TAKEN		2,440	2,415	2,327	2,280	2,251	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [6/]		2,440	2,415	2,327	2,280	2,251	12
	REQUIREMENTS FORECAST BY END-USE [7/]							
13	CORE [8/]	Residential	610	604	594	585	575	13
14		Commercial	206	200	194	190	185	14
15		Industrial	54	54	53	52	51	15
16		NGV	41	42	43	44	45	16
17		Subtotal-CORE	912	900	883	870	856	17
18	NONCORE	Commercial	48	49	49	49	49	18
19		Industrial	389	390	389	389	388	19
20		EOR Steaming	27	27	27	27	27	20
21		Electric Generation (EG)	670	667	612	584	571	21
22		Subtotal-NONCORE	1,135	1,132	1,076	1,049	1,035	22
23	WHOLESALE &	Core	208	208	207	207	206	23
24	INTERNATIONAL	Noncore Excl. EG	28	27	27	28	28	24
25		Electric Generation (EG)	127	117	104	97	97	25
26		Subtotal-WHOLESALE & INTL.	363	352	339	332	331	26
27		Co. Use & LUAF	31	30	29	29	28	27
28	SYSTEM TOTAL THROUGHPUT [6/]		2,440	2,415	2,327	2,280	2,251	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	64	64	63	63	62	29
30	NONCORE	Commercial/Industrial	437	438	437	438	437	30
31		EOR Steaming	27	27	27	27	27	31
32		Electric Generation (EG)	670	667	612	584	571	32
33		Subtotal-RETAIL	1,199	1,196	1,139	1,112	1,097	33
34	WHOLESALE & INTERNATIONAL	All End Uses	363	352	339	332	331	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,562	1,548	1,478	1,443	1,428	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); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

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 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2022	2023	2024	2025	2026
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.3	1.3	1.3	1.2	1.2

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

	2022	2023	2024	2025	2026
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	875	863	847	834	820

Table 33

TABLE 2-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2027 THRU 2035

AVERAGE TEMPERATURE YEAR

LINE			2027	2028	2029	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/]		1,250	1,250	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,225	3,225	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE [4/]		3,435	3,435	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas [5/]		61	61	61	61	61	8
9	Out-of-State		2,160	2,106	2,080	2,034	1,912	9
10	TOTAL SUPPLY TAKEN		2,221	2,167	2,141	2,095	1,973	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [6/]		2,221	2,167	2,141	2,095	1,973	12
	REQUIREMENTS FORECAST BY END-USE [7/]							
13	CORE [8/]	Residential	565	552	542	530	466	13
14		Commercial	181	177	174	170	155	14
15		Industrial	50	49	48	47	44	15
16		NGV	46	47	48	50	54	16
17		Subtotal-CORE	842	825	813	797	719	17
18	NONCORE	Commercial	49	49	49	49	48	18
19		Industrial	388	388	388	387	385	19
20		EOR Steaming	26	25	24	24	20	20
21		Electric Generation (EG)	558	529	516	493	461	21
22		Subtotal-NONCORE	1,021	991	977	952	914	22
23	WHOLESALE &	Core	206	205	204	203	199	23
24	INTERNATIONAL	Noncore Excl. EG	28	28	28	28	29	24
25		Electric Generation (EG)	96	92	92	88	87	25
26		Subtotal-WHOLESALE & INTL.	330	324	325	319	315	26
27		Co. Use & LUAF	28	27	27	26	25	27
28	SYSTEM TOTAL THROUGHPUT [6/]		2,221	2,167	2,141	2,095	1,973	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	62	62	62	61	61	29
30	NONCORE	Commercial/Industrial	437	437	436	436	433	30
31		EOR Steaming	26	25	24	24	20	31
32		Electric Generation (EG)	558	529	516	493	461	32
33		Subtotal-RETAIL	1,083	1,052	1,039	1,013	975	33
34	WHOLESALE & INTERNATIONAL	All End Uses	330	324	325	319	315	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,413	1,376	1,363	1,333	1,290	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	

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); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

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 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2027	2028	2029	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.2	1.2	1.2	1.2	1.1

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

	2027	2028	2029	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	805	788	775	759	680

TABLE 3-SCG

Table 34

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2022 THRU 2026

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

LINE			2022	2023	2024	2025	2026	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/		1,250	1,250	1,250	1,250	1,250	5
6	Total Out-of-State Gas		3,225	3,225	3,225	3,225	3,225	6
7	TOTAL CAPACITY AVAILABLE 4/		3,435	3,435	3,435	3,435	3,435	7
	GAS SUPPLY TAKEN							
8	California Source Gas 5/		61	61	61	61	61	8
9	Out-of-State		2,452	2,432	2,343	2,298	2,267	9
10	TOTAL SUPPLY TAKEN		2,513	2,493	2,404	2,359	2,328	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,513	2,493	2,404	2,359	2,328	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	660	653	642	632	622	13
14		Commercial	214	208	202	197	193	14
15		Industrial	55	55	53	52	51	15
16		NGV	41	42	43	44	45	16
17		Subtotal-CORE	970	957	940	926	911	17
18	NONCORE	Commercial	49	49	49	50	50	18
19		Industrial	389	390	389	389	388	19
20		EOR Steaming	27	27	27	27	27	20
21		Electric Generation (EG)	670	671	616	591	578	21
22		Subtotal-NONCORE	1,136	1,138	1,081	1,057	1,042	22
23	WHOLESALE &	Core	221	221	220	220	219	23
24	INTERNATIONAL	Noncore Excl. EG	28	28	28	28	28	24
25		Electric Generation (EG)	127	118	105	98	98	25
26		Subtotal-WHOLESALE & INTL.	376	366	353	346	345	26
27		Co. Use & LUAF	32	31	30	30	29	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,513	2,493	2,404	2,359	2,328	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	66	65	64	64	64	29
30	NONCORE	Commercial/Industrial	438	439	438	439	438	30
31		EOR Steaming	27	27	27	27	27	31
32		Electric Generation (EG)	670	671	616	591	578	32
33		Subtotal-RETAIL	1,201	1,203	1,146	1,121	1,106	33
34	WHOLESALE & INTERNATIONAL	All End Uses	376	366	353	346	345	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,577	1,569	1,498	1,467	1,451	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	

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); ability to receive 1,210 MMcfd dependent on local area demand
3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision
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 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

Note	2022	2023	2024	2025	2026
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.3	1.3	1.3	1.3	1.3

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

Note	2022	2023	2024	2025	2026
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	934	921	903	889	874

Table 35

TABLE 4-SCG

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2027 THRU 2035

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

LINE			2027	2028	2029	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/]		1,250	1,250	1,590	1,590	1,590	5
6	Total Out-of-State Gas		3,225	3,225	3,565	3,565	3,565	6
7	TOTAL CAPACITY AVAILABLE [4/]		3,435	3,435	3,775	3,775	3,775	7
	GAS SUPPLY TAKEN							
8	California Source Gas [5/]		61	61	61	61	61	8
9	Out-of-State		2,239	2,180	2,156	2,104	1,992	9
10	TOTAL SUPPLY TAKEN		2,300	2,241	2,217	2,165	2,053	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [6/]		2,300	2,241	2,217	2,165	2,053	12
	REQUIREMENTS FORECAST BY END-USE [7/]							
13	CORE [8/]	Residential	610	597	586	573	506	13
14		Commercial	189	184	181	177	161	14
15		Industrial	51	50	49	48	45	15
16		NGV	46	47	48	50	54	16
17		Subtotal-CORE	896	878	864	848	766	17
18	NONCORE	Commercial	50	49	49	49	49	18
19		Industrial	388	388	388	387	385	19
20		EOR Steaming	26	25	24	24	20	20
21		Electric Generation (EG)	567	534	524	496	474	21
22		Subtotal-NONCORE	1,031	996	985	956	928	22
23	WHOLESALE &	Core	219	217	217	216	212	23
24	INTERNATIONAL	Noncore Excl. EG	28	28	28	28	29	24
25		Electric Generation (EG)	98	93	94	89	92	25
26		Subtotal-WHOLESALE & INTL.	344	339	339	334	333	26
27		Co. Use & LUAF	29	28	28	27	26	27
28	SYSTEM TOTAL THROUGHPUT [6/]		2,300	2,241	2,217	2,165	2,053	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	64	63	63	63	62	29
30	NONCORE	Commercial/Industrial	438	437	437	436	434	30
31		EOR Steaming	26	25	24	24	20	31
32		Electric Generation (EG)	567	534	524	496	474	32
33		Subtotal-RETAIL	1,095	1,059	1,048	1,019	990	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	344	339	339	334	333	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,439	1,398	1,387	1,353	1,324	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	

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); ability to receive 1,210 MMcfd dependent on local area demand

3/ Northern Zone (TW at No. Needles, EPN at Topok, QST at No. Needles, KR at Kramer Jct.); projected capacity may vary from that shown over the span of the CGR timeframe pending 2024 General Rate Case decision

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 2021 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2027	2028	2029	2030	2035
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.3	1.3	1.3	1.3	1.3

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

	2027	2028	2029	2030	2035
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	859	841	827	811	727

TABLE 36

SOUTHERN CALIFORNIA GAS COMPANY

ANNUAL GAS REQUIREMENTS - MMCF/DAY

1-IN-10 COLD TEMPERATURE YEAR & DRY HYDRO YEAR (1)

Year	CORE	NONCORE	WHOLESALE & INTERNATIONAL	Company Use & LUAF	SYSTEM TOTAL THROUGHPUT
2022	950	1,135	373	31	2,490
2023	938	1,137	363	31	2,469
2024	920	1,081	350	30	2,381
2025	907	1,057	343	29	2,336
2026	892	1,042	342	29	2,305
2027	878	1,031	341	29	2,278
2028	860	996	336	28	2,219
2029	847	985	336	28	2,195
2030	831	956	331	27	2,144
2035	750	928	330	26	2,034

NOTES:

(1) SoCalGas' Demand forecast of 1-in-10 cold temperature year and dry hydro year is used to evaluate the backbone transmission capacity and slack capacity in compliance with CPUC Decision (D.) 06-09-039 and the daily receipt capacity in compliance with D.22-07-002.

2022 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT

The annual gas supply and forecast requirements prepared by the Long Beach Energy Resources Department (Long Beach) are shown on the following tables for the years 2022 through 2035.

Long Beach operates the fifth largest municipally owned natural gas utility in the country and is one of only three in the State. The gas utility provides safe and reliable natural gas services to about 500,000 residents and businesses via approximately 150,000 connected gas meters, delivered through more than 1,800 miles of gas pipelines. 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 gas use is split at 53 percent residential and 47 percent commercial/industrial.

Long Beach serves core and noncore customers from three incremental supply sources: (1) interstate supplies delivered into the SoCalGas' intrastate pipeline system; (2) gas storage withdrawals; and (3) local gas delivered directly to Long Beach Energy Resources Department's pipeline system from gas fields within the city. Currently, local production supplies about 5 percent of Long Beach's gas use. Long Beach purchases most of its gas supplies from producers in the South-Western U.S. As a Wholesale customer, Long Beach contracts with SoCalGas for intrastate transmission service to deliver that gas from the California border to its service area.

The City of Long Beach is the only municipal government in the State of California that manages oil operations. Through its Energy Resources Department, the City operates the Wilmington Oil Field and has various financial interests in smaller oil fields throughout the City, such as the Signal Hill East and West Units, Recreation Park, and City Wasem.

As a municipal utility, Long Beach's gas 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.

2022 CALIFORNIA GAS REPORT

CITY OF LONG BEACH ENERGY RESOURCES DEPARTMENT – TABULAR DATA

TABLE 37 – CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2017-2021

LINE	GAS SUPPLY AVAILABLE	2017	2018	2019	2020	2021	LINE
	California Source Gas						
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	4
	Out-of-State Gas						
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN						
	California Source Gas						
13	Regular Purchases	0.6	0.6	1.1	0.7	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	0.6	0.6	1.1	0.7	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	16
	Out-of-State Gas						
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	24.6	23.9	25.2	24.8	24.2	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	24.6	23.9	25.2	24.8	24.2	21
22	Subtotal	25.2	24.5	26.3	25.5	25.5	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	25.2	24.5	26.3	25.5	25.5	24

TABLE 38 – CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d
RECORDED YEARS 2017-2021 (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2017	2018	2019	2020	2021	LINE
1	CORE	Residential	11.8	12.1	12.9	12.9	12.6	1
2	CORE/NONCORE	Commercial	6.0	5.9	6.1	5.3	5.7	2
3	CORE/NONCORE	Industrial	4.7	4.3	4.7	4.1	4.3	3
4		Subtotal	22.5	22.3	23.8	22.2	22.6	4
5	NON CORE	Non-EOR Cogeneration	2.2	1.9	1.7	2.5	2.3	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.2	1.9	1.7	2.5	2.3	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.5	0.2	0.8	0.7	0.6	13
14		Subtotal-END USE	25.1	24.5	26.3	25.5	25.4	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		25.1	24.5	26.3	25.5	25.4	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	2.9	3.0	3.1	2.8	3.1	18
19		Non-EOR Cogeneration	2.0	1.9	1.5	2.5	2.3	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.0	4.9	4.7	5.3	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.0	4.9	4.7	5.3	5.4	24
	ACTUAL CURTAILMENT							
25		Residential	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	32

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

TABLE 39– CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 1A-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d AVERAGE YEAR FORECAST FOR THE 2022 CGR REPORT

LINE	ACTUAL DELIVERIES BY END-USE		2022	2023	2024	2025	2030	2035	LINE
1	CORE	Residential	12.3	12.3	12.3	12.4	12.5	12.5	1
2	CORE/NONCORE	Commercial	5.5	5.5	5.5	5.6	5.6	5.7	2
3	CORE/NONCORE	Industrial	3.9	3.9	3.9	3.9	4.0	4.1	3
4		Subtotal	21.7	21.7	21.7	21.9	22.1	22.3	4
5	NON CORE	Non-EOR Cogeneration	2.3	2.3	2.4	2.4	2.6	2.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.3	2.3	2.4	2.4	2.6	2.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	24.9	24.9	25.0	25.2	25.6	25.9	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		24.9	24.9	25.0	25.2	25.6	25.9	16
	ACTUAL TRANSPORTATION AND EXCHANGE								
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.3	3.4	3.4	3.4	3.5	3.7	18
19		Non-EOR Cogeneration	1.7	1.8	1.8	1.8	1.8	1.9	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.0	5.1	5.1	5.1	5.3	5.6	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.0	5.1	5.1	5.1	5.3	5.6	24
	ACTUAL CURTAILMENT								
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0	32

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

TABLE 40 – CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 2A-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d AVERAGE YEAR FORECAST (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2022	2023	2024	2025	2030	2035	LINE
1	CORE	Residential	12.3	12.3	12.3	12.4	12.5	12.5	1
2	CORE/NONCORE	Commercial	5.5	5.5	5.5	5.6	5.6	5.7	2
3	CORE/NONCORE	Industrial	3.9	3.9	3.9	3.9	4.0	4.1	3
4		Subtotal	21.7	21.7	21.7	21.9	22.1	22.3	4
5	NON CORE	Non-EOR Cogeneration	2.3	2.3	2.4	2.4	2.6	2.7	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.3	2.3	2.4	2.4	2.6	2.7	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	24.9	24.9	25.0	25.2	25.6	25.9	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		24.9	24.9	25.0	25.2	25.6	25.9	16
	ACTUAL TRANSPORTATION AND EXCHANGE								
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.3	3.4	3.4	3.4	3.5	3.7	18
19		Non-EOR Cogeneration	1.7	1.8	1.8	1.8	1.8	1.9	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.0	5.1	5.1	5.1	5.3	5.6	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.0	5.1	5.1	5.1	5.3	5.6	24
	ACTUAL CURTAILMENT								
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0	32

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

TABLE 41– CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 3C-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2022 CGR REPORT (CONTINUED)

LINE	GAS SUPPLY AVAILABLE	2022	2023	2024	2025	2030	2035	LINE
	California Source Gas							
1	Regular Purchases	0.0	0.0	0.0	0.0	0.0	0.0	1
2	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0	2
3	Total California Source Gas	0.0	0.0	0.0	0.0	0.0	0.0	3
4	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0	4
	Out-of-State Gas							
5	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0	5
6	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	0.0	6
7	Incremental Supplies	0.0	0.0	0.0	0.0	0.0	0.0	7
8	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0	8
		0.0	0.0	0.0	0.0	0.0	0.0	
9	Total Out-of-State Gas	0.0	0.0	0.0	0.0	0.0	0.0	9
10	Subtotal	0.0	0.0	0.0	0.0	0.0	0.0	10
11	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0	11
12	GAS SUPPLY AVAILABLE	0.0	0.0	0.0	0.0	0.0	0.0	12
	GAS SUPPLY TAKEN							
	California Source Gas							
13	Regular Purchases	1.3	1.3	1.3	1.3	1.3	1.3	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.3	1.3	1.3	1.3	1.3	1.3	15
16	Purchases from Other Utilities	0.0	0.0	0.0	0.0	0.0	0.0	16
	Out-of-State Gas							
17	Pacific Interstate Companies	0.0	0.0	0.0	0.0	0.0	0.0	17
18	Additional Core Supplies	0.0	0.0	0.0	0.0	0.0	0.0	18
19	Incremental Supplies	29.4	29.4	29.4	29.4	29.4	29.4	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	29.4	29.4	29.4	29.4	29.4	29.4	21
22	Subtotal	30.7	30.7	30.7	30.7	30.7	30.7	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	30.7	30.7	30.7	30.7	30.7	30.7	24

TABLE 42– CITY OF LONG BEACH-GAS AND OIL DEPARTMENT: TABLE 4C-LB ANNUAL GAS SUPPLY AND SENDOUT – MMcf/d COLD YEAR FORECAST FOR THE 2022 CGR REPORT (CONTINUED)

LINE	ACTUAL DELIVERIES BY END-USE		2022	2023	2024	2025	2030	2035	LINE
1	CORE	Residential	15.1	15.1	15.1	15.1	15.1	15.1	1
2	CORE/NONCORE	Commercial	7.2	7.2	7.2	7.2	7.2	7.2	2
3	CORE/NONCORE	Industrial	5.6	5.6	5.6	5.6	5.6	5.6	3
4		Subtotal	27.8	27.8	27.8	27.8	27.8	27.8	4
5	NON CORE	Non-EOR Cogeneration	2.0	2.0	2.0	2.0	2.0	2.0	5
6		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	6
7		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	7
8		Subtotal	2.0	2.0	2.0	2.0	2.0	2.0	8
9	WHOLESALE	Residential	0.0	0.0	0.0	0.0	0.0	0.0	9
10		Com. & Ind., others	0.0	0.0	0.0	0.0	0.0	0.0	10
11		Electric Utilities	0.0	0.0	0.0	0.0	0.0	0.0	11
12		Subtotal-WHOLESALE	0.0	0.0	0.0	0.0	0.0	0.0	12
13		Co. Use & LUAF	0.9	0.9	0.9	0.9	0.9	0.9	13
14		Subtotal-END USE	30.7	30.7	30.7	30.7	30.7	30.7	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		30.7	30.7	30.7	30.7	30.7	30.7	16
	ACTUAL TRANSPORTATION AND EXCHANGE								
17		Residential	N/A	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.6	3.6	3.6	3.6	3.6	3.6	18
19		Non-EOR Cogeneration	1.8	1.8	1.8	1.8	1.8	1.8	19
20		EOR Cogen. & Steaming	N/A	N/A	N/A	N/A	N/A	N/A	20
21		Electric Utilites	N/A	N/A	N/A	N/A	N/A	N/A	21
22		Subtotal-RETAIL	5.4	5.4	5.4	5.4	5.4	5.4	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		5.4	5.4	5.4	5.4	5.4	5.4	24
	ACTUAL CURTAILMENT								
25		Residential	0.0	0.0	0.0	0.0	0.0	0.0	25
26		Commercial/Industrial	0.0	0.0	0.0	0.0	0.0	0.0	26
27		Non-EOR Cogeneration	0.0	0.0	0.0	0.0	0.0	0.0	27
28		EOR Cogen. & Steaming	0.0	0.0	0.0	0.0	0.0	0.0	28
29		Electric Utilites	0.0	0.0	0.0	0.0	0.0	0.0	29
30		Wholesale	0.0	0.0	0.0	0.0	0.0	0.0	30
31		TOTAL- Curtailment	0.0	0.0	0.0	0.0	0.0	0.0	31
32	REFUSAL		0.0	0.0	0.0	0.0	0.0	0.0	32

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

2022 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 903,649 customers in San Diego County in 2021, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2021 were approximately 94 billion cubic feet (Bcf), which is an average of 258.5 MMcf/d.

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 EG demand and noncore demand, begins with a usage calculator derived from end use models that integrates demographic assumptions, economic growth, energy prices, energy efficiency programs, detailed customer information, building and appliance standards, weather and other factors. After the forecast is developed, the forecast is treated for three out-of-model adjustments. The adjustments made to the forecasts include (1) allowing for less heating degree days in the average weather design each year of the forecast period to account for climate change; (2) gas demand destruction due to greater energy efficiency savings forecast over the planning period; and (3) incremental energy savings created from assumed fuel substitution. All of the energy savings incorporated into the forecast reflect market potential and were used as load modifiers to create a final forecast of demand. The baseline forecast was adjusted downward to account for the incremental energy savings influences that are expected to occur.

The introduction of potential fuel substitution into the long-term demand forecast is new for SDG&E in the CGR long term forecast development. SDG&E's own internal estimates of fuel substitution are preliminary. SDG&E is working on finding methods, using historical usage data, to identify customers who may be converting gas space and water heating to electric substitutes.

Fuel substitution was introduced into the 2021 IEPR as additional achievable fuel substitution (AAFS).[118] The AAFS2 was utilized. It includes the effects of potential updates in

[118] SEE IEPR, Chapter 2, pp. 33-49. See also Appendix A.

the Title 24 building standards and the presumed building electrification encouraged by future ratcheting driven by tighter goals, rate enhancements and higher uptake rates at future points in time.

Altogether, SDG&E's gas demand, not inclusive of gas driven EG, is projected to drop slightly from 52 Bcf in 2021 to 46 Bcf in 2035, which is an average annual rate of decline of 0.8 percent. Including EG, overall demand adjusted for average temperature conditions totaled 94 Bcf in 2021 and is expected to drop about 1.9 percent per year to 72 Bcf by 2035.

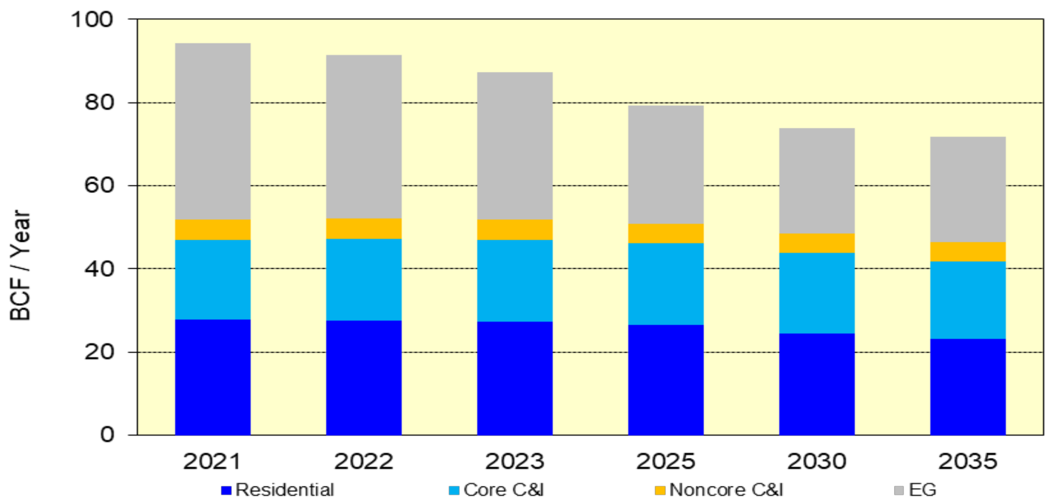
Assumptions for SDG&E's gas transportation requirements for EG are included as part of the wholesale market sector description for SoCalGas.

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. San Diego County's total employment is forecasted to grow on average just over 1% annually from 2021 to 2035; the subset of industrial (mining and manufacturing) jobs is projected to grow an average of 0.1% per year during the same period. The number of SDG&E gas meters is expected to increase an average of about 0.8% annually from 2021 through 2035.

FIGURE 27 – SDG&E'S COMPOSITION OF NATURAL GAS THROUGHPUT AVERAGE TEMPERATURE, NORMAL YEAR (2021-2035)

(Bcf/year)



From 2021 through 2035, SDG&E's forecasted gas demand is expected to decline at an average annual rate of 1.9 percent. The decline is being driven by future projected reductions in the EG load. Additional factors reducing the load forecast are energy efficiency programs and new requirements on Title 24 building codes and standards and assumed fuel substitution over the forecast period.

MARKET SECTORS

Residential

SDG&E served approximately 873,304 residential customers in 2021. The residential usage varies for each of the various residential market segments that SDG&E serves. Conditional demand estimates based on the 2019 Residential Appliance Saturation Survey (R.A.S.S.) have allowed SDG&E to better understand customer usage and needs. The updated survey information included below was part of the estimation and resulting baseline residential market forecast.

The table below shows the weather-normalized home usage by customer type and the saturations by end use for SDG&E based upon the conditional demand study.

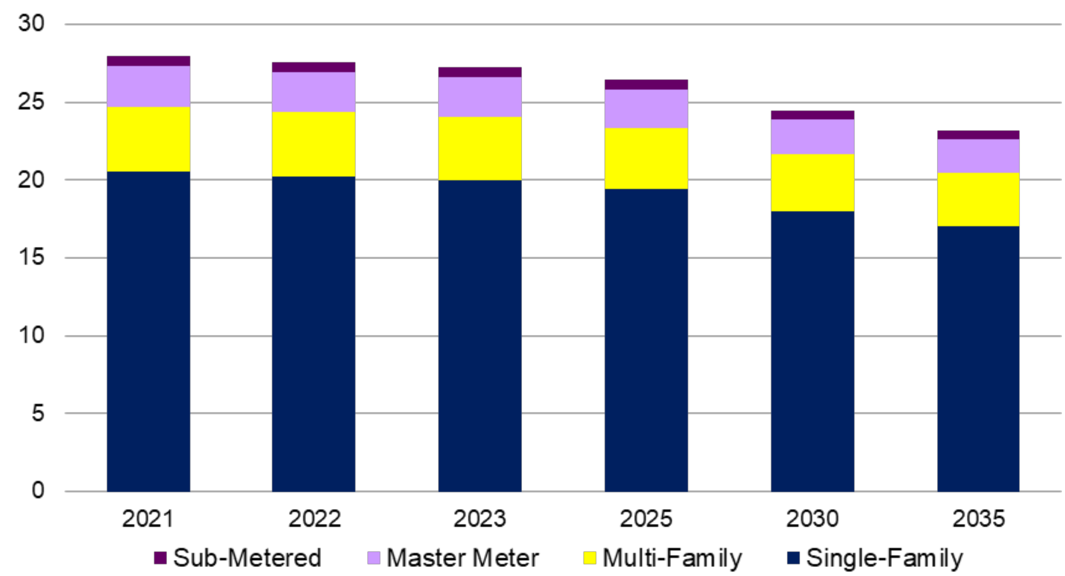
Table 43: SDG&E Residential Appliance Saturation Survey, 2019 Update

		2019 Residential Appliance Saturation Survey								
		Conditional Demand Study								
SDG&E		Single Family Unit Energy Consumption (UEC)	Single Family Saturation (%)	Single Family Intensity	Single Family Use Proportion		Multi Family Unit Energy Consumption	Multi Family Saturation	Multi Family Intensity	Multi Family Use Proportion
	Space Heat	211	98.00%	207	52.91%		107	92.62%	99	46.45%
	Water Heat	128	99.80%	128	32.69%		92	91.54%	84	39.48%
	Cooking	30	75.20%	23	5.78%		27	64.99%	18	8.23%
	Clothes Drying	31	63.71%	20	5.05%		27	40.91%	11	5.18%
	Pool Heat	144	3.40%	5	1.25%		N/A		N/A	
	Spa Heat	101	5.95%	6	1.54%		41	0.97%	0	0.19%
	Gas Fireplace	11	8.33%	1	0.23%		6	7.50%	0	0.21%
	Gas Barbecue	15	14.09%	2	0.54%		10	5.73%	1	0.27%
	Total Household SF			391 Therms/Year	100%				213 Therms/Year	100%

The conditional demand estimates based on the 2019 R.A.S.S. show that the average use per meter is 391 therms for single-family households and 213 therms for multi-family households. The use-per-customer data is constructive in forming the forecast. For the residential market, the change in the forecast from one year to the next is based on the confluence of two immediate economic drivers. In any given year, the residential load will grow due to the new customer hookups that occur. New customers generate a growth in demand. Second, the residential load will change due to existing customers' (vintage customers') changing needs. When gas appliances reach the end of their useful life, customers make a choice. The choice consists of either replacing the older appliance with a more energy efficient gas-using appliance, or changing out the replacement appliance from gas to its electric substitute, a behavior characterized as fuel substitution. The usage calculator that compiles the forecast is referred to as an end use model.

The total residential customer count for SDG&E consists of four residential segment types and each of the segment types exhibits variation in usage behavior that can be identified. The customer types are single-family and multi-family customers, as well as master-meter and sub-metered customers. Residential demand, adjusted for average temperature conditions, totaled 27.9 Bcf in 2021. By the year 2035, the residential demand is expected to drop to 23.2 Bcf. The change reflects a 1.3 percent average annual rate of decline. There are several reasons that justify the decline.

Figure 28 – Composition of SDG&E's Residential Demand Forecast Average Year Weather Design, 2021-2035 (Bcf/year)



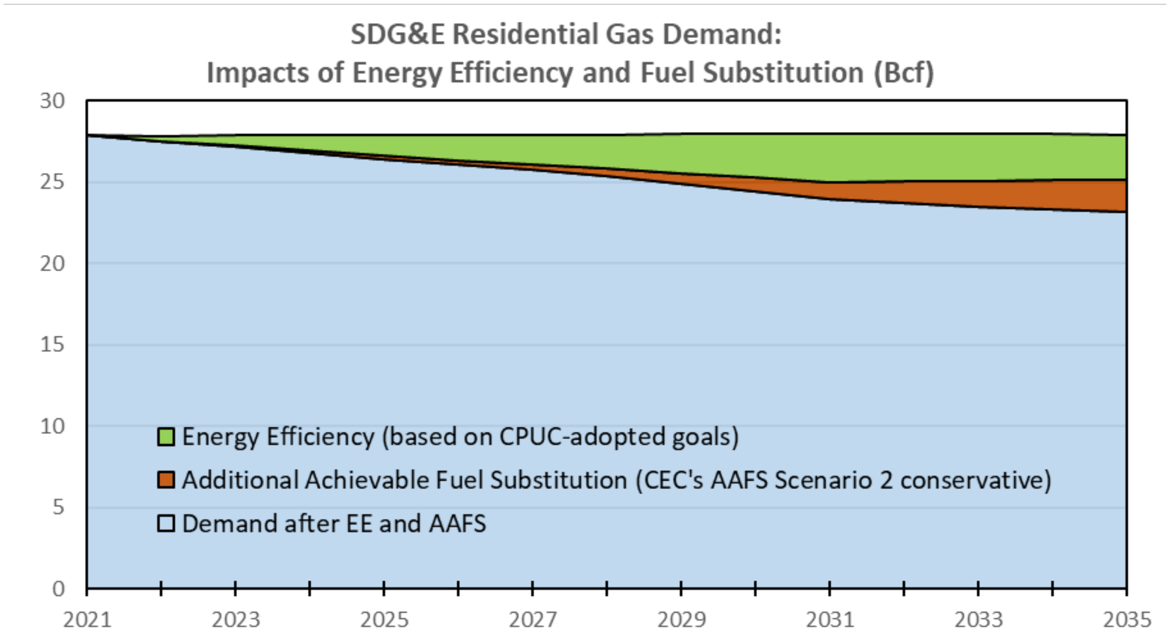
As described above, SDG&E's residential base forecast is developed from an end use model. The model results are modified by anticipated impacts of climate change as well as forecasts of policy adoptions that impact gas use. After the base forecast is developed, the forecast is modified with three out-of-model adjustments. The energy savings adjustments made to the forecast include: (1) allowing for fewer heating degree days in the average weather design for each consecutive year of the forecast to account for climate change; (2) gas demand destruction due to greater energy efficiency savings forecasted over the planning period; and (3) incremental energy savings created from assumed fuel substitution. All of these energy savings incorporated into the forecast reflect market potential and became load modifiers to create a final forecast of demand.

The major modifiers to the forecast are energy efficiency and building electrification. The energy efficiency forecast includes the confluence of two types of gas energy savings: Codes and Standards savings, which include current and expected modifications to Title 24 and the energy savings stemming from the customer programs authorized by the CPUC under D.19-08-034 and D.21-09-037. The baseline forecast was adjusted downward to account for the incremental energy saving influences that are expected to occur over the forecast period.

The final forecast also includes a load modifier for fuel substitution. For purposes of constructing a long-term reasonable forecast for the 2022 CGR, SDG&E participated in an electrification working group committee along with PG&E, SoCalGas and Southern California Edison (SCE) to evaluate different approaches and assumptions to modeling the effects of fuel substitution. After several meetings and discussions, SDG&E aligned around the relatively conservative fuel substitution forecast scenario developed by the California Energy Commission. Fuel substitution was estimated and introduced separately from energy efficiency savings by the CEC in its 2021 IEPR as additional achievable fuel substitution (AAFS). Of the five possible fuel substitution scenarios developed by the CEC, the AAFS-2 Scenario, which is the CEC's mid-low scenario for electrification, was chosen by SDG&E to prepare the final residential forecast. Scenario 2 quantifies the assumed fuel substitution that would take place with potential future updates in the Title 24 building standards and the presumed additional building electrification encouraged by future ratcheting driven by tighter goals, rate enhancements and higher uptake rates at future points in time. All of the above-mentioned gas reductions were included in the residential forecast as modifiers to the base forecast.

As can be seen from the following graph, the effects of both energy efficiency and fuel substitution have an impact on the residential market, with increasing impact out to the end of the forecast period in 2035.

Figure 29: SDG&E Residential EE and Fuel Substitution



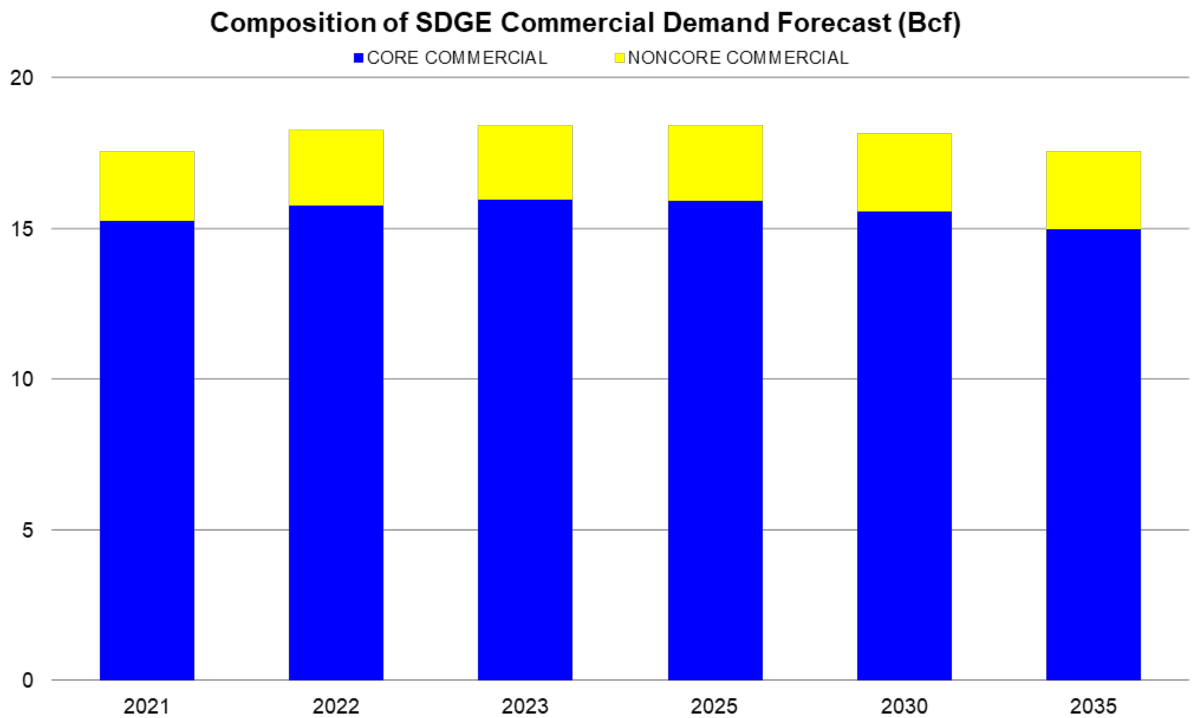
By year 2035, the *assumed* additional energy efficiency removes 10 percent of residential gas demand. Evaluated separately, the *assumed* additional fuel substitution removes another 7 percent of residential gas demand by 2035.

Commercial

On a temperature-adjusted basis, SDG&E's core commercial demand in 2021 totaled 15.23 Bcf. By the year 2035, the core commercial load is expected to decline slightly to 14.98 Bcf. The forecasted annual average rate of decline is 0.1 percent.

SDG&E's non-core commercial load in 2021 was 2.35 Bcf. Over the forecast period, gas demand in this market is projected to grow an average of 0.7 percent per year to 2.58 BCF by 2035, driven by increased economic activity.

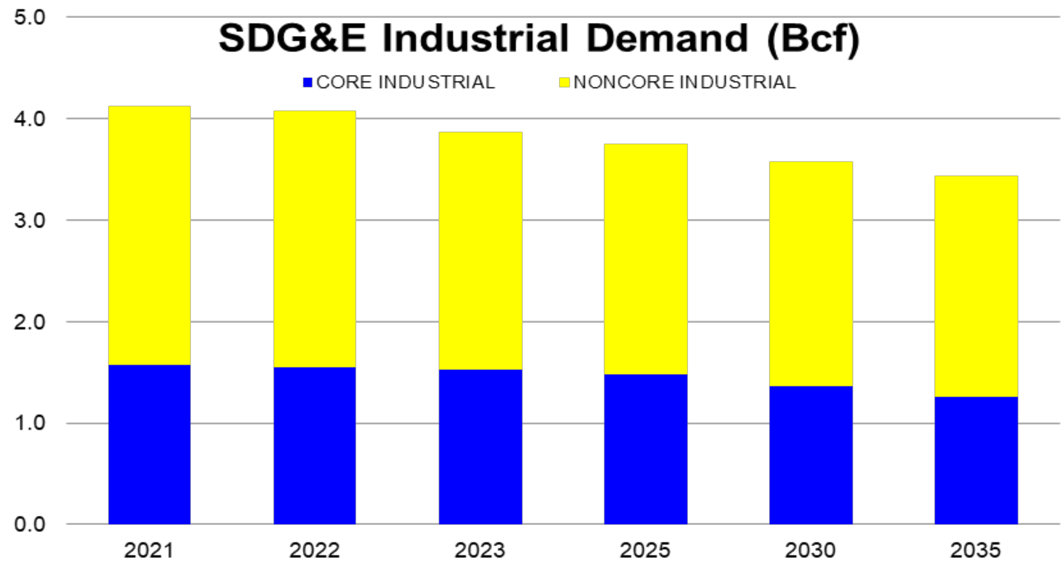
FIGURE 30 –SDG&E COMMERCIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN
(2021-2035)



Industrial

Temperature-adjusted core industrial demand was 1.57 Bcf in 2021 and is expected to decline to 1.26 Bcf by 2035, an average decrease of 1.6 percent per year. This result is due to a yearly average increase in marginal gas rates and the impact of savings from CPUC-authorized energy efficiency programs in the core industrial sector.

FIGURE 31 –SDG&E INDUSTRIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN
(2021-2035)



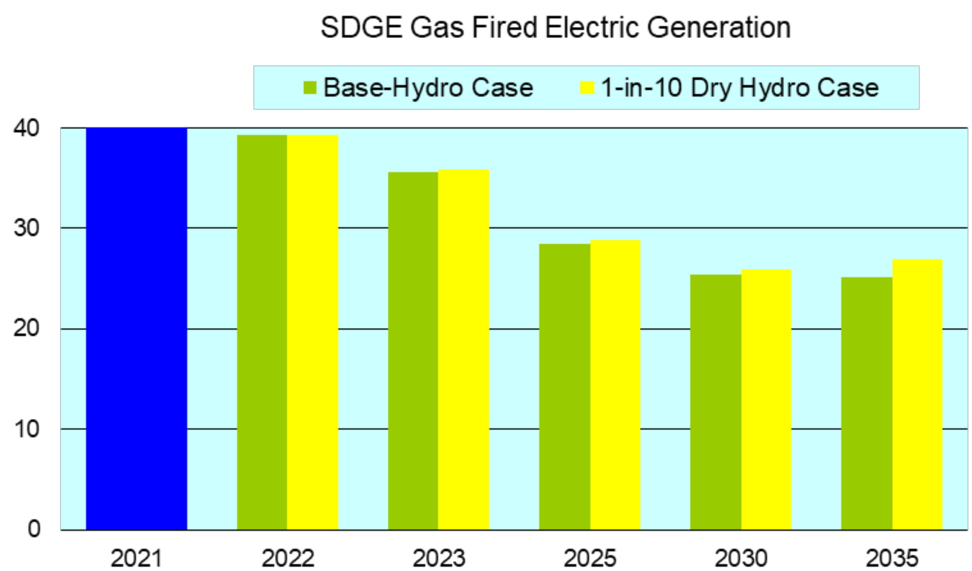
Non-core industrial load in 2019 was 2.4 Bcf and is expected to shrink about 0.6 percent per year to 2.2 Bcf by 2035. Demand-dampening effects of higher energy efficiency and higher carbon-allowance fees will more than offset slight increases from economic growth.

Electric Generation

Total EG, including cogeneration and non-cogeneration EG, was 29 Bcf in 2019. From 2019, EG load is expected to decline an average of 1.35 percent per year to 23 Bcf by 2035. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.

FIGURE 32 – SDG&E'S TOTAL EG GAS DEMAND: BASE HYDRO AND 1-IN-10 DRY HYDRO DESIGN, 2021-2035

(Bcf/year)



Small Cogeneration (<20 MW)

Small Electric Generation load from self-generation totaled 7.1 Bcf in 2021 and is projected to increase an average of 0.3 percent per year to 7.3 Bcf by 2035. Economic growth is expected to slightly outpace demand-dampening effects of higher carbon-allowance fees.

Electric Generation Including Large Cogeneration (>20 MW)

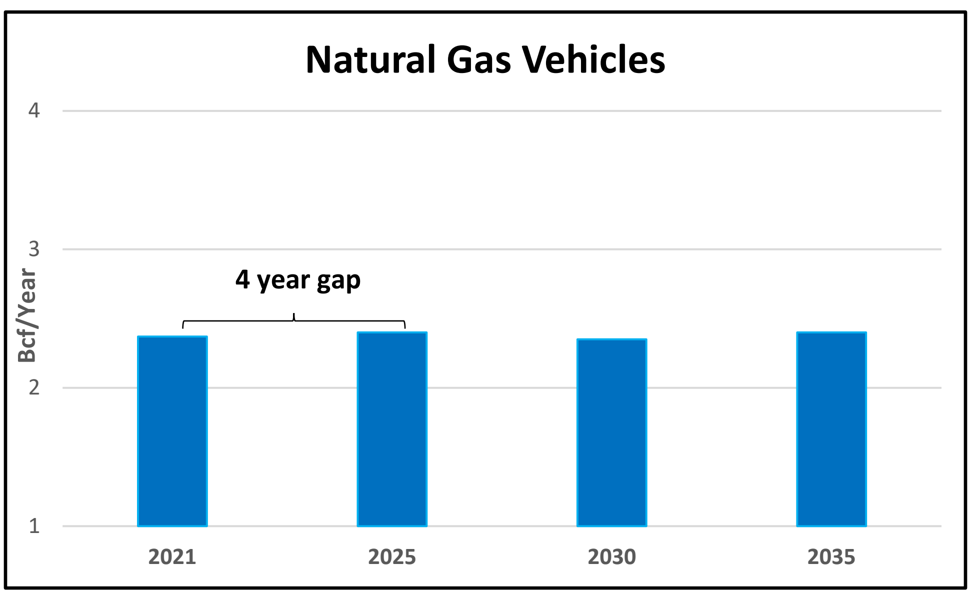
The forecast of large EG loads in SDG&E's service area is based on the power market simulation noted in SoCalGas' EG chapter for "Electric Generation Including All Cogeneration EG demand is forecasted to decrease from 32 Bcf in 2022 to 18 Bcf in 2035. This forecast includes no additional thermal generating resources in its service area, and it assumes no retirement during the same time period. It assumes the same 2021 Preferred System Plan as discussed in the Southern California Gas Company's EG section.

Natural Gas Vehicles

The clean vehicle market is expected to grow due to strong economic fundamentals, increased vehicle options, the continuation of government (federal, state, and local) incentives, additional regulations encouraging alternative fuel vehicle adoption, and regional collaboration for the deployment of necessary infrastructure. Additionally, since April 2019 SDG&E has been procuring 100 percent renewable natural gas (RNG) at all utility owned CNG stations, which provides significant GHG emission reduction benefits.

However, NGV growth may be offset by competing technologies such as vehicle electrification and hydrogen fuel-cell technologies. In addition, the COVID-19 pandemic which began in 2020, disrupted usage and consumption levels compared to a regular year. In 2021, SDG&E served 38 compressed natural gas (CNG) fueling stations located throughout the service territory and delivered approximately 2 Bcf of natural gas. The SDG&E NGV market is expected to remain stable with an average annual rate of 0.11 percent over the forecast horizon.

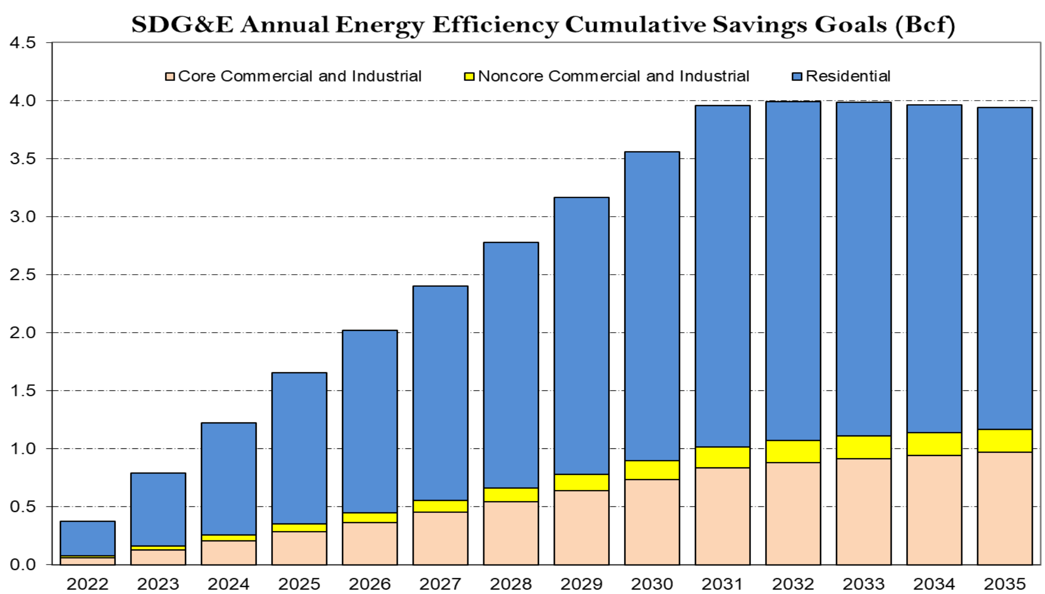
FIGURE 33 – ANNUAL NGV DEMAND FORECAST



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.

FIGURE 34 – SDG&E ANNUAL ENERGY EFFICIENCY CUMULATIVE SAVING GOALS (Bcf)



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 above. The net load impact includes all energy efficiency programs, both gas and electric, that SDG&E has forecasted to be implemented beginning in year 2022 and occurring through the year 2035 in addition to the Title 24 Codes and Standards expected over the 2022-2035 horizon. Savings and goals for these programs are based on the program goals authorized by the Commission in D.19-08-034 and D.21-09-037.

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.[119] 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.

Gas Supply

Beginning in 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 of December 6, 2007. For more information, refer above to the "Gas Supply, Capacity, and Storage" section in the Southern California part of this report.

[119] 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.110 This EE forecast does not include the impacts of fuel substitution measures (natural gas to electric measures). Fuel substitution is addressed in the overview section of the writeup.

REGULATORY ENVIRONMENT

GENERAL RATE CASE

On September 26, 2019, CPUC unanimously approved a final 2019 GRC decision that adopted a TY 2019 revenue requirement of $1.990 billion for SDG&E's combined operations ($1.590 billion for electric, $0.400 billion for gas) which is $213 million lower than the $2.203 billion that SDG&E had requested in its Update testimony. The adopted revenue requirement represents an increase of $107 million or a 5.7 percent increase over 2018. The final decision adopted PTY revenue requirement adjustments for SDG&E of $134 million for 2020 (6.7 percent increase) and $102 million for 2021 (4.8 percent increase).

In January 2020, the CPUC revised the rate case plans and implemented a 4-year GRC cycle for California IOUs. SDG&E was directed to file a PFM to revise its 2019 GRC decision to add two additional attrition years including adjustment amounts, resulting in a transitional five-year GRC period (2019-2023).

In April 2020 (then slightly revised in May), SDG&E filed a PFM of its 2019 GRC decision requesting attrition year increases of $94 million (+4.24 percent) for 2022 and $96 million (+4.13 percent) for 2023. In May 2021, the CPUC issued a decision authorizing SDG&E to apply its PTY mechanism adopted in the 2019 GRC decision to 2022 and 2023 but updated the calculations based on the 2020 4th Quarter Global Insight forecast to more fully capture the impact of Covid-19 to the economy. This decision resulted in revenue requirements of $2.3 and $2.4 billion for SDG&E for 2022 and 2023 respectively, which were slightly less than the original requests made in SDG&E's PFM.

In May 2022 SDG&E filed its 2024 General Rate Case seeking to revise its authorized revenue requirements, effective on January 1, 2024, to recover the reasonable costs of electric and gas operations, facilities, infrastructure, and other functions necessary to provide utility services to customers. SDG&E requests a combined $3.022 billion revenue requirement ($674 million gas and $2.348 billion electric), which, if approved, would be an increase of $475 million over the expected 2023 revenue requirement. SDG&E also includes post-test year revenue requirement and regulatory account-related proposals. The general rate request process is scheduled to take between 18 months and two years and is expected to conclude in late 2023.

Other Regulatory Matters

For more information on non-GRC regulatory matters, refer above to the "Regulatory Environment" section in the Southern California part of this report, which generally applies to SDG&E's gas business as well.

PEAK DAY DEMAND

Gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio that contains 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 and SDG&E) retail core peak day demand.

The table below shows SDG&E's Core 1-in-35 Year Extreme Peak Day Demand and Winter 1-in-10 Year Cold Day System Demand.

TABLE 44– SDG&E WINTER PEAK DAY DEMAND (MMcf/d)

Year	Core 1-in-35 Extreme Peak Day Demand 1/		1-in-10 Cold Day Demand			
			Core 2/	Noncore C&I 3/	EG 4/	Total
2022	**404**		380	13	116	**510**
2023	**403**		380	13	104	**496**
2024	**402**		378	13	94	**484**
2025	**400**		376	13	98	**487**
2026	**398**		375	13	102	**490**
2027	**397**		373	13	102	**488**
2028	**395**		372	13	78	**462**

Notes:
(1) The criterion for core 1-in-35 extreme peak day design is defined as a 1-in-35 likelihood for SDG&E's service area. This criteria correlates to 43.3 degrees Fahrenheit for SDG&E's service area. 1-in-35 and 1-in-10 Core peak day demand forecasts embody the baseline forecast with load modifiers that include changing weather design to account for climate change, assumed EE savings and assumed fuel substitution under AAFS 2.
(2) The criterion for 1-in-10 peak day design is defined as a 1-in-10 likelihood for SDG&E's service area. This criterion correlates to 44.8 degrees Fahrenheit for SDG&E's service area.
(3) Average daily December demand for noncore commercial and noncore industrial.
(4) Electric Generation includes UEG/EWG Base Hydro, large cogeneration, industrial and commercial cogeneration (<20MW).

2022 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY – TABULAR DATA

TABLE 45 – SDG&E
ANNUAL GAS SUPPLY TAKEN– MMcf/d
RECORDED YEARS 2017-2021

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY TAKEN (MMCF/DAY)
RECORDED YEARS 2017 -2021

LINE		2017	2018	2019	2020	2021
	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	2017	2018	2019	2020	2021
	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	111	112	128	126	126
18	Out-of-State Transport-Others	188	127	103	151	139
19	**Total Out-of-State Gas**	299	239	230	277	265
20	**TOTAL Gas Supply Taken & Transported**	299	239	230	277	265

(MMCFD)

Table 46

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND SENDOUT (MMCF/DAY)
RECORDED YEARS 2017-2021

Actual Deliveries by End-Use		2017	2018	2019	2020	2021
CORE	Residential	72	70	81	81	78
	Commercial	52	54	57	50	52
	Industrial	-	-	-	-	-
Subtotal -	*CORE*	124	124	138	131	130
NONCORE	Commercial	-	-	-	-	-
	Industrial	11	12	13	13	15
	Non-EOR Cogen/EG	71	51	43	84	77
	Electric Utilities	92	49	33	41	36
Subtotal -	*NONCORE*	174	112	89	138	128
WHOLESALE	All End Uses	-	-	-	-	-
Subtotal -	*Co Use & LUAF*	1	3	4	8	7
SYSTEM TOTAL THROUGHPUT		299	239	230	277	265
Actual Transport & Exchange						
CORE	Residential	1	1	1	1	-
	Commercial	13	14	14	12	11
NONCORE	Industrial	11	12	13	13	15
	Non-EOR Cogen/EG	71	51	43	84	77
	Electric Utilities	92	49	33	41	36
Subtotal -	*RETAIL*	188	127	103	151	139
WHOLESALE	All End Uses	-	-	-	-	-
TOTAL TRANSPORT & EXCHANGE		188	127	103	151	139
Storage						
	Storage Injection	-	-	-	-	-
	Storage Withdrawal	-	-	-	-	-
Actual Curtailment						
	Residential	-	-	-	-	-
	Com/Indl & Cogen	-	-	-	-	-
	Electric Generation	-	-	-	-	-
TOTAL CURTAILMENT		-	-	-	-	-
REFUSAL		-	-	-	-	-

ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes

	2017	2018	2019	2020	2021
MMbtu/Mcf:	1.040	1.038	1.032	1.025	1.030

le and MMCFD Supplies are used in the odd year reports (see P 17-18 of CGR)

TABLE 47 – SDG&E: SDG&E
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2022-2026
AVERAGE TEMPERATURE YEARS

AVERAGE TEMPERATURE YEAR

LINE			2022	2023	2024	2025	2026	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		253	241	227	219	218	5
6	TOTAL SUPPLY TAKEN		253	241	227	219	218	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		253	241	227	219	218	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	75	75	73	72	71	9
10		Commercial	43	44	44	44	44	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	129	129	127	126	125	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	7	6	6	6	6	15
16		Electric Generation (EG)	108	97	85	78	77	16
17		Subtotal-NONCORE	121	111	98	91	91	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		253	241	227	219	218	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	12	12	12	12	12	20
21	NONCORE	Commercial/Industrial	14	13	13	13	13	21
22		Electric Generation (EG)	108	97	85	78	77	22
23	TOTAL TRANSPORTATION & EXCHANGE		134	123	110	103	103	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 v based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 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:

	2022	2023	2024	2025	2026
transportation (CAT) in MDth/d:	120	120	118	117	116

TABLE 48 – SDG&E: -SDG&E
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2027-2035
AVERAGE TEMPERATURE YEARS

AVERAGE TEMPERATURE YEAR

LINE			2027	2028	2029	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	Southern Zone of SoCalGas		215	210	209	204	198	5
6	TOTAL SUPPLY TAKEN		215	210	209	204	198	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		215	210	209	204	198	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	71	69	68	67	63	9
10		Commercial	43	43	43	43	41	10
11		Industrial	4	4	4	4	3	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	124	122	121	120	114	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	76	73	73	70	69	16
17		Subtotal-NONCORE	90	86	86	83	82	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		215	210	209	204	198	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	12	12	12	12	12	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	76	73	73	70	69	22
23	TOTAL TRANSPORTATION & EXCHANGE		102	98	99	95	94	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 v
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2020 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:

	2027	2028	2029	2030	2035
transportation (CAT) in MDth/d:	115	113	112	111	105

TABLE 49 – SDG&E:
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2022-2026
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

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

LINE			2022	2023	2024	2025	2026	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		262	251	237	229	228	5
6	TOTAL SUPPLY TAKEN		262	251	237	229	228	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		262	251	237	229	228	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	83	82	81	80	79	9
10		Commercial	45	45	45	45	45	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	138	138	136	135	134	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	7	6	6	6	6	15
16		Electric Generation (EG)	108	98	86	79	79	16
17		Subtotal-NONCORE	121	111	99	92	92	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		262	251	237	229	228	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	13	13	13	13	20
21	NONCORE	Commercial/Industrial	14	13	13	13	13	21
22		Electric Generation (EG)	108	98	86	79	79	22
23	TOTAL TRANSPORTATION & EXCHANGE		134	124	112	105	104	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 v
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).
2/ For 2020 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:

	2022	2023	2024	2025	2026
transportation (CAT) in MDth/d:	129	129	127	126	125

TABLE 50 – SDG&E:
ANNUAL GAS SUPPLY AND REQUIREMENTS – MMcf/d
ESTIMATED YEARS 2027-2035
COLD TEMPERATURE YEAR (1-IN-35 COLD YEAR EVENT) AND DRY HYDRO YEAR

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

LINE			2027	2028	2029	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	Southern Zone of SoCalGas		226	220	220	215	212	5
6	TOTAL SUPPLY TAKEN		226	220	220	215	212	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		226	220	220	215	212	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	78	77	76	74	71	9
10		Commercial	45	45	45	44	42	10
11		Industrial	4	4	4	4	4	11
12		NGV	6	6	6	6	6	12
13		Subtotal-CORE	133	131	130	129	123	13
14	NONCORE	Commercial	7	7	7	7	7	14
15		Industrial	6	6	6	6	6	15
16		Electric Generation (EG)	78	74	74	71	74	16
17		Subtotal-NONCORE	91	87	87	84	87	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		226	220	220	215	212	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	13	13	13	13	12	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	78	74	74	71	74	22
23	TOTAL TRANSPORTATION & EXCHANGE		104	100	100	97	99	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 valu
based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).
2/ For 2020 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: 124 122 121 120 114

2022 CALIFORNIA GAS REPORT

GLOSSARY

GLOSSARY

A.
Application.

AAEE
Additional Achievable Energy Efficiency.

AAFS
Additional Achievable Fuel Substitution. The scenarios forecast reductions for gas consumption which are "substituted out" through electrification.

AB
Assembly Bill.

AMI
Advanced Metering Infrastructure.

APD
Abnormal Peak Day.

API
American Petroleum Institute.

A/S
ancillary services.

Average Day (Operational Definition)
Annual gas sales or requirements assuming average temperature year conditions divided by 365 days.

Average Temperature Year
Long-term average recorded temperature.

Bcf
billion cubic feet.

Bcf/d
billion cubic feet per day.

Bcf/y
billion cubic feet per year.

BTU (British Thermal Unit)
Unit of measurement equal to the amount of heat energy required to raise the temperature of one pound of water 1 degree F. This unit is commonly used to measure the quantity of heat available from complete combustion of natural gas.

CAISO
California Independent System Operator.

CalGEM
California Geologic Energy Management Division (formerly, DOGGR).

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

CARB
California Air Resources Board.

CCST
California Council on Science and Technology.

CDFA
California Department of Food and Agriculture.

CEC
California Energy Commission.

CFR
Code of Federal Regulations.

CGR
California Gas Report.

CNG (Compressed Natural Gas)
Fuel for NGVs, typically natural gas compressed to 3000 pounds per square inch.

CO_2
carbon dioxide.

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 EG resource.

Commercial (SoCalGas and 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 EG, EOR, or gas resale activities with usage less than 20,800 therms per month.

Commission
California Public Utilities Commission (see also CPUC).

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

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

Conversion Factor (Natural Gas)

• 1 cf (Cubic Feet)	= Approximately 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 (MMBtu 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

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.

Core Customer (PG&E)
All customers with average usage less than 20,800 therms per month.

Core Customers (SoCalGas and 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 Subscription
Noncore customers who elect to use the LDC as a procurement agent to meet their commodity gas requirements.

COVID-19
Coronavirus Disease 2019.

CPUC
California Public Utilities Commission (see also Commission).

Cubic Foot of Gas
Volume of natural gas, which, at a temperature of 60 degrees 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.

D.
Decision.

DDRDP
Dairy Digester Research and Development Program.

DOE
Department of Energy.

DOGGR
California Division of Oil, Gas, and Geothermal Resources (now CalGEM).

ECA
Energia Costal Azul.

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

Electrification (Building Electrification)
Fuel Substitution

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.

EO
Executive Order.

EOR (Enhanced Oil Recovery)
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.

EWG (Exempt Wholesale Generator)
A category of customers consuming gas for the purpose of generating electric power.

F
Fahrenheit.

FERC
Federal Energy Regulatory Commission.

FTA
Free Trade Agreement.

Futures (Gas)
Unit of natural gas futures contract trades in units of 10,000 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 (Green House Gas)
GHGs 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 GHGs are, in order of relative abundance are water vapor, CO_2, methane, nitrous oxide, ozone and CFCs.

GRC
General Rate Case.

GT&S
Gas Transmission and Storage.

GTN
Gas Transmission Northwest LLC.

H2
Hydrogen.

HDD (Heating Degree Day)
A HDD is accumulated for every degree F the daily average temperature is below a standard reference temperature (SoCalGas and SDG&E: 65 degrees F; PG&E 60 degrees F). A basis for computing how much electricity and gas are needed for space heating purposes. For example, for a 50 degrees 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 60 degrees F and a pressure base of 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 7 pounds or less per one million cubic feet, the natural gas shall be considered dry.

IEPR
Integrated Energy Policy Report.

ILI
In-Line Inspection.

Industrial (PG&E)
Non-residential customers not engaged in EG, EOR, or gas resale activities using more than 20,800 therms per month.

Industrial (SoCalGas and SDG&E)
Category of gas customers who are engaged in mining and in manufacturing.

IOU
investor-owned utility.

IRP
Integrated Resource Plan.

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 degrees F (-162 degrees C) and condensed into a liquid that takes up 600 times less space than in its gaseous state.

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

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

MHP
Mobile Home Park.

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

MMcf/d
Million cubic feet per day.

mmt
million metric tons.

mmtCO_2e
million metric tons of carbon dioxide equivalent.

$mtCO_2e$
metric tons of carbon dioxide equivalent.

MW
megawatt.

MWh
megawatt-hour.

NGSS
Natural Gas Storage Strategy.

NGTL
NOVA Gas Transmission Ltd.

NGV (Natural Gas Vehicle)
Vehicle that uses CNG or LNG as its source of fuel for its internal combustion engine.

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

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

Off-System Sales
Gas sales to customers outside the utility's service area.

OIR
Order Instituting Rulemaking.

OTC
once-through-cooling.

Out-of-State Gas
Gas from sources outside the state of California.

PFM
Petition for Modification.

PG&E
Pacific Gas and Electric Company.

PHMSA
Pipeline and Hazardous Materials Safety Administration.

Piggable
Refers to the process of using devices known as "pigs" to perform various maintenance operations such as pipeline cleaning and inspection.

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); and
5. Market Center Services.

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 EG load;
- Up to 100 percent of nonEG noncore except for refineries;
- Up to 100 percent of refineries and up to 100 percent of the remaining dispatched EG load;
- Non-Residential Core customers; and
- Residential Core customers.

PSEP
Pipeline Safety Enhancement Plan.

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

Pub. Util. Code
Public Utilities Code.

Purchase from Other Utilities
Gas purchased from other utilities in California.

R.
Rulemaking.

R.
Rulemaking.

R&D
Research and Development.

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

Res.
Resolution.

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.

RNG
Renewable Natural Gas.

RNGS
Renewable Gas Standard.

RP
Recommended Practice.

RPS
Renewables Portfolio Standard.

RSP
Reference System Plan.

SB
Senate Bill.

SDG&E
San Diego Gas & Electric Company.

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

SLCP
Short-Lived Climate Pollutants.

SMUD
Sacramento Municipal Utility District.

SoCalGas
Southern California Gas Company.

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.

SWG
Southwest Gas Corporation.

SWRCB
State Water Resources Control Board.

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.

Traditional Gas
A term designated to refer to fossil fuels, including but not limited to, natural gas.

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

UC
University of California.

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.

U.S.
United States.

USA
Underground Service Alert.

WACOG
Weighted average cost of gas.

WECC
Western Electricity Coordinating Council.

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.

2022 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 Energy Resources 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- SoCalGas/SDG&E- *Statewide Chair, 2022 CGR*
- Todd Peterson-PG&E

- Scott Wilder- SoCalGas/SDG&E
- Sharim Chaudhury- SoCalGas/SDG&E
- William Guo – SoCalGas/SDG&E
- Jeff Huang– SoCalGas/SDG&E
- Michelle Clay-Ijomah-SDG&E
- Nasim Ahmed- SoCalGas
- Julia Cortez- SoCalGas
- Brandon Duran-SoCalGas
- Dave Bisi- SoCalGas
- Stan Sinclair- SoCalGas
- Heng Yang- SoCalGas/SDG&E
- Athena Besa-SDG&E
- Lonnie Mansi-SDG&E
- Perla Anaya-SDG&E
- Michelle Clay-Ijomah-SDG&E
- William Flemetakis- Kern River
- Tony Chun-SoCalGas
- Anupama Pandey - PG&E
- Kurtis Kolnowski-PG&E
- Andrew Klingler-PG&E

Observers

- Jean Spencer – CPUC Energy Division
- Eileen Hlavka-CPUC Energy Division
- Melissa Jones-CEC
- Ingrid Neumann-CEC
- Robert Gulliksen-CEC

2023 CALIFORNIA GAS REPORT

RESERVATIONS

RESERVE YOUR SUBSCRIPTION

2023 CALIFORNIA GAS REPORT SUPPLEMENT

Southern California Gas Company
2023 CGR Reservation Form
C/O Rosemarie Payan
Box 3249, Mail Location GT14D6
Los Angeles, CA 90051-1249
or
Fax: (213) 244-4957
Email: Rose-Marie Payan
RPayan@semprautilities.com

- ❑ ▪Send me a 2023 CGR Supplement
- ❑ ▪New subscriber
- ❑ ▪Change of address

Company Name: ____
C/O: ____
Address: ____
City: ________________ State: ____________ Zip: _________
Phone: (____) _______________ Fax: (_____) _____________

Please visit our website for digital copies of this Report and the accompanying workpapers. They are located in the regulatory section of the following websites:

www.socalgas.com
www.SDG&E.com

RESERVE YOUR SUBSCRIPTION

2023 CALIFORNIA GAS REPORT – SUPPLEMENT

Pacific Gas and Electric Company
2023 CGR Reservation Form
C/O Todd Peterson
Mail Code B10B
P. O. Box 770000
San Francisco, CA 94177
or
Email: Todd.Peterson@pge.com

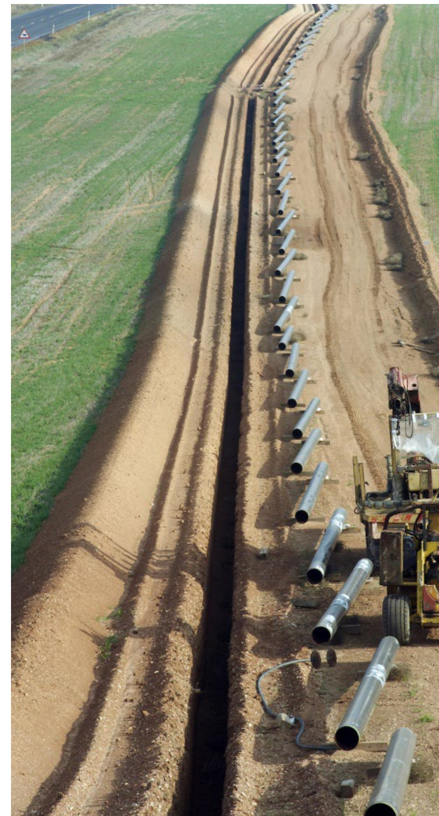
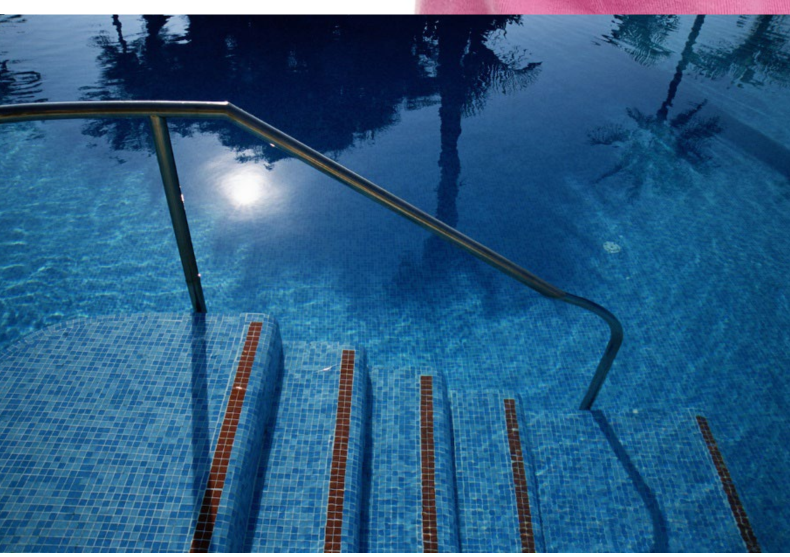
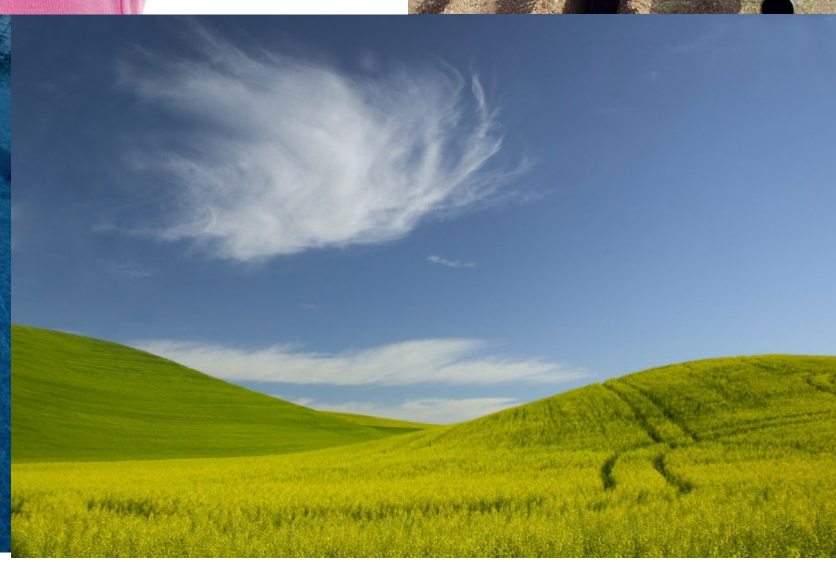
❑ ▪Send me a 2023 CGR
❑ ▪New subscriber
❑ ▪Change of address

Company Name: ____
C/O: ____
Address: ____
City: ________________ State: ____________ Zip: ________
Phone: (_____) _______________ Fax: (_____) _____________

Please visit our website for digital copies of this and past reports: http://www.pge.com/pipeline/library/regulatory/cgr_index.shtml



2022 CGR


Guidelines for Energy Project Applications Requiring CEQA Compliance:

Pre-filing and Proponent's Environmental Assessments

November 2019

Version 1.0

Energy Division

Infrastructure Permitting and CEQA Unit

California Public Utilities Commission

Guidelines for Energy Project Applications Requiring CEQA Compliance:

Pre-filing and Proponent's Environmental Assessments

Contents

Foreword

November 12, 2019

To: Applicants Filing Proponent's Environmental Assessments for Energy Infrastructure Projects at the California Public Utilities Commission (CPUC or Commission)

From: Merideth Sterkel (Program Manager, Infrastructure Planning and Permitting) and Mary Jo Borak and Lonn Maier, Supervisors, Infrastructure Permitting and California Environmental Quality Act, Energy Division, CPUC

Subject: Introducing revisions to the Pre-filing Guidelines for Energy Infrastructure Projects and a Unified and Updated Electric and Gas PEA Checklist

We are pleased to release a 2019 revision to the California Environmental Quality Act (CEQA) Proponent's Environmental Assessments (PEA) Checklist. This substantially revised document is now entitled "Guidelines for Energy Project Applications Requiring CEQA Compliance: Pre-filing and Proponent's Environmental Assessments" (Guidelines). Future updates to this document will be made as determined necessary. The CPUC's Rules of Practice and Procedure Sections 2.4 provide that all applications to the CPUC for authority to undertake projects that are not statutorily or categorically exempt from CEQA requirements shall include an Applicant-prepared PEA.

Updates Overview

Prior versions of the Working Draft PEA Checklist were published in 2008 and 2012. For this 2019 update, extensive revisions were made to all sections based on our experience with the prior checklist versions. All electric and natural gas projects are now addressed in a single PEA Checklist, and the following updates were made:

- **CEQA Statute and Guidelines 2019 Updates:** The PEA Checklist is updated pursuant to the 2019 CEQA Statues and Guidelines, including new energy and wildfire resource areas.
- **Pre-filing Consultation Guidelines:** Pre-filing guidelines are now provided since the pre-filing and PEA development processes are intertwined.
- **Unified PEA Checklist for Energy Projects:** All electric and natural gas projects are now addressed in a single PEA Checklist.
- **Additional CEQA Impact Questions:** Questions are included for the following PEA Checklist sections: 5.4, Biological Resources; 5.6, Energy; 5.9, Hazards, Hazardous Materials, and Public Safety; 5.16, Recreation; 5.17, Transportation; and 5.19, Utilities and Service Systems.
- **CPUC Draft Environmental Measures:** Draft measures are provided in PEA Checklist Attachment 4 for Aesthetics, Air Quality, Cultural Resources, Greenhouse Gas Emissions, Utilities and Service Systems and Wildfire.

Purpose of the Guidelines Document

The purpose and objective of the PEA Checklist included within this Guidelines document has not changed, which is to provide project Proponents (Applicants) with detailed guidance about information our CEQA Unit Staff expect in sufficient PEAs. The document details the information Applicants must provide the CPUC to complete environmental reviews that satisfy CEQA requirements. Specifically, the Pre-filing Consultation Guidelines and PEA Checklist, together, are intended to achieve the following objectives:

1. Provide useful guidance to Applicants, CPUC staff, and outside consultants regarding the type and detail of information needed to quickly and efficiently deem an application complete;

2. Ensure PEAs provide reviewers with a detailed project description and associated information sufficient to deem an application complete, avoid lengthy review periods and numerous data requests for the purpose of augmenting a PEA, and avoid unnecessary PEA production costs;
3. Increase the level of consistency between PEAs submitted and provide for more consistent review by CPUC CEQA Unit Staff and outside consultants; and
4. Promote transparency and reduce the potential for conflicts between utility and CPUC Staff about the types, scope, and thoroughness of data expected for data adequacy purposes.

The Guidelines document provides detailed instructions to Applicants for use during the Pre-filing process and PEA development. The document is intended to fully inform Applicants and focus the role of outside consultants, thus, enabling Applicants to submit more complete, useful, and immediately data-adequate PEAs.

Benefits of High Quality and Complete PEAs

CPUC CEQA Unit Staff seek to complete the environmental review process required under CEQA as quickly and efficiently as possible. Table 1 shows the average duration in months of CPUC applications that require CEQA documents. While there are tensions between speed and quality in all project management, the achievement of expeditious environmental reviews can result in lower project costs to ratepayers. Our staff have reviewed the timelines for 108 past CPUC applications that required review pursuant to CEQA and determined that the average length of time from application filing to PEA deemed complete is four months, regardless of the type of CEQA document. The goal for our agency is to deem PEAs complete within 30 days. The faster PEAs are deemed complete, the sooner staff can prepare the CEQA document. With each delay to PEA completeness, the fundamental project purpose and need and baseline circumstances may shift, requiring refreshing of the data. The Guidelines document will improve the initial accuracy of PEAs and reduce the time required to deem PEAs complete. Once an application is formally filed, the Applicant will receive a notification letter from CPUC CEQA Unit Staff when the PEA is deemed complete.

Table 1. Average Duration in Months of CPUC Applications that Require CEQA Documents (1996–2019)

	I: Application Filed to PEA Deemed Complete	II: PEA Deemed Complete to Draft Environmental Document Circulated	III: Draft Environmental Document to Final Released	IV: Final Released to Proposed Decision	V: Proposed Decision to Final Decision (with Certification of CEQA Document)	I-V: Overall Duration (1)
Environmental Impact Report (EIR; n=49)	5	13	7	5	2	**29**
Initial Study/ Mitigated Negative Declaration (IS/MND; n=56)	4	8	3	4	1	**19**
All Document Types (n=108)	4	8	4	5	2	**23**
Range: All Document Types	*1-9*	*5-18*	*2-10*	*1-7*	*1-2*	***12-38***

Note:
(1) The overall duration is not a sum of the average durations for each step. The overall duration was calculated using “n,” the number of applications with data available for the date of application filing and final decision date. Not all projects had data available for each step. The data include several instances where the CEQA document was developed in conjunction with a NEPA document, e.g., an EIR/Environmental Impact Statement or IS/MND/Environmental Assessment/Finding of No Significant Impact was prepared instead of an EIR or MND, respectively. The above data is not inclusive of projects that had averages and ranges that are statistically abnormal.

Lessons Learned about the PEA Process

In the past, Applicants have filed PEAs using the checklist to ensure the correct information was provided but have not followed the format and organization of the PEA checklist and sometimes chose not to engage in Pre-filing activities with our staff. To achieve the objectives and benefits listed above, Applicants will file all future PEAs in the same organizational format as the updated checklist and adhere to the Pre-filing Consultation Guidelines in coordination with CPUC CEQA Unit Staff.

The Guidelines document describes the level effort required for the assessments necessary to not only finalize a CEQA document but ensure its legal defensibility. While final design and survey information is preferred, the PEA may incorporate preliminary design and survey data as appropriate and in consultation with CEQA Unit Staff during Pre-filing. We recognize that projects are fact specific, and deviations from the Pre-filing Consultation Guidelines and PEA Checklist are inevitable but providing concise and accurate information as soon as possible is paramount. Any deviations from these Guidelines must include clear justification and should be discussed and submitted during the Pre-filing Consultation process to avoid subsequent delays.

The PEA Checklist is written with the assumption that an Environmental Impact Report will be prepared, however, a Mitigated Negative Declaration or other form of CEQA document (e.g., exemption) may be appropriate. This determination, however, must be made in consultation with CPUC CEQA Unit Staff during Pre-filing and prior to submittal of the Draft PEA.

Future Modifications and Improvements

Like the predecessor PEA checklists, this is a working document that will be modified over time based on experience and changes to the CEQA Statute and Guidelines. To meet the above stated objectives and maintain consistency with CEQA. We expect Applicants, their consultants, CPUC consultants, and the CPUC to engage in a regular and ongoing dialogue about specific improvements to the CEQA process overall, and these Guidelines in particular.

We look forward to working with Applicants during the Pre-filing Consultation process to ensure that the level of effort that goes into preparing PEAs can be effectively and efficiently transferred into the CEQA document prepared by CPUC Staff and consultants. Applicants are invited to debrief with our staff about the efficacy of these Guidelines.

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California Public Utilities Commission

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/s/
Supervisor, Infrastructure Permitting and CEQA Unit
California Public Utilities Commission

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California Public Utilities Commission

Pre-Filing Consultation Guidelines

The following Pre-filing Consultation Guidelines apply to all PEAs filed with applications to the CPUC and outline a process for Applicants to engage with CPUC CEQA Unit Staff about upcoming projects that will require environmental review pursuant to CEQA. The CPUC is typically the Lead Agency for large projects by investor-owned gas and electric utilities. The CPUC's CEQA Unit Staff are experienced with developing robust CEQA documents for long, linear energy projects. The PEA Checklist, starting in the next section, is based upon that experience.

Pre-filing Consultation Process

During Pre-filing Consultation, Applicants and CPUC Staff meet to discuss the upcoming application. Successful projects will commence Pre-filing Consultation no less than six months prior to application filing at the CPUC. When the application is formally filed at the CPUC, the Application and the PEA are submitted to the CPUC Docket Office.

1. Meetings with CPUC Staff

To initiate Pre-filing Consultation, Applicants will request and attend a meeting with CPUC CEQA Unit Staff at least six months prior to application filing.

   a. Applicants can request a Pre-Filing Consultation meeting via email or letter. Initial contact via telephone may occur, but staff request written documentation of Pre-filing Consultation commencement.
   b. For the initial meeting, Applicants will provide staff with a summary of the proposed project including maps and basic GIS data at least one week prior to the meeting.
   c. Applicants will receive initial feedback on the scope of the proposed project and PEA. Staff will work with Applicants to establish a schedule for subsequent Pre-filing meetings and milestones.

2. Consultant Resources

CPUC CEQA Unit Staff will initiate the consultant contract immediately following the initial Pre-filing Consultation meeting. CPUC's consultant contract resources will be executed prior to Applicant filing of the Draft PEA. The consultant contract is critical to the Pre-filing Consultation process. Applicants are encouraged to request updates about the status of the contract. The CPUC may use its on-call consulting resources contract for these purposes. If CEQA Unit Staff determine that their on-call consulting resources are not appropriate due to the anticipated project scope, staff may initiate a request for proposals process to engage consulting resources, and the resulting contracting process will be completed and consultant contract in place prior to Draft PEA filing.

3. Draft PEA Provided Prior to PEA Filing

A complete Draft PEA will be filed at least three months prior to application filing. CPUC CEQA Unit Staff and the CPUC consultant team will review and provide comments on the Draft PEA to the Applicant early in the three-month period to allow time for Applicant revisions to the PEA.

4. Project Site Visits

One or more site visits will be scheduled with CPUC CEQA Unit Staff and their consultant at the time of Draft PEA filing (or prior). Appropriate federal, state, and local agencies will also be engaged at this time.

5. Consultation with Public Agencies

The Applicant and CPUC CEQA Unit Staff will jointly reach out and conduct consultation meetings with public agencies and other interested parties in the project area. CPUC CEQA Unit Staff may also choose to conduct separate consultation meetings if needed.

If a federal agency will be a co-lead pursuant to the National Environmental Policy Act and coordinating with the CPUC during the environmental review process, the Applicant and CPUC CEQA Unit Staff will ensure that the agency has the opportunity to comment on the Draft PEA and participate jointly with the CPUC throughout the application review process. Applicant and Commission CEQA Unit Staff coordination with the federal agency (if applicable) will likely need to occur more than six months in advance of application filing.

6. Alternatives Development

PEAs will be drafted with the assumption that an Environmental Impact Report (EIR) will be prepared. Applicants will include a reasonable range of alternatives in the PEA (even though a Mitigated Negative Declaration [MND] may ultimately be prepared), including sufficient information about each alternative. In some situations, CPUC CEQA Unit Staff and project Applicants may agree during Pre-filing Consultation that an MND is likely and a reasonable range of alternatives is not required for the PEA. This determination, however, must be made in consultation with CEQA Unit Staff during Pre-filing and is not final. The type of document to be prepared may change based on public scoping results and other findings during the environmental review process.

CEQA Unit Staff will provide feedback on the range of alternatives prior to Draft PEA filing (if possible) based on their review of the Draft PEA. It is critical that Applicants receive feedback from CEQA Unit Staff about the range of alternatives prior to filing the PEA. Applicants will ensure that each alternative is described and evaluated in the PEA with an equal level of detail as the proposed project unless otherwise instructed in writing by CEQA Unit Staff.

7. Format of PEA Submittal

Each PEA submittal will include the completed PEA Checklist tables. Each PEA submittal will be formatted and organized as shown in the Example PEA Table of Contents provided in the PEA Checklist unless otherwise directed by CPUC CEQA Unit Staff in writing prior to application filing. The example PEA Table of Contents is modeled after typical CPUC EIRs.

8. Transmission and Distribution System Information

A key component of CEQA projects analyzed during CPUC environmental reviews is the context of the project within the larger transmission and distribution system. Detailed descriptions of the regional transmission system, including GIS data, to which the proposed project would interconnect are required. The required level of detail about interconnecting systems is project specific and will be specified by CEQA Unit Staff in writing during Pre-filing Consultation. Detailed distribution system information may also be required.

9. Data and Technical Adequacy

Applicants will focus PEA development efforts on providing thorough, up-to-date data and technical reports required for CPUC CEQA Unit Staff to complete the environmental document and alternatives analysis.

The Applicant-drafted PEA Executive Summary, Introduction, Project Description, Description of Alternatives, and other chapters typically found in past CPUC EIRs and Initial Study/MNDs will be *thorough*—emulate the level of detail provided in typical CPUC EIRs. The setting sections provided for

PEA Chapter 5, Environmental Analysis, will also be thorough. Applicants will ensure that the PEA text, graphics, and file formats can be efficiently converted into CPUC's CEQA document with minimal revision, reformatting, and redevelopment by CPUC Staff and consultants.

The impact analyses and determinations provided for Chapter 5, Environmental Analysis, and Chapter 6, Comparison of Alternatives, need not be as thorough as those to be prepared by the CPUC for its CEQA document. These two sections are expected to be revised and redeveloped by CPUC Staff and consultants. Other sections of the CEQA document will only be revised and redeveloped by CPUC Staff and consultants if determined to be necessary after PEA filing.

10. Applicant Proposed Measures

The Pre-filing Consultation process can support the development Applicant Proposed Measures (APMs); measures that Applicants incorporate into the PEA project description to avoid or reduce what otherwise may be considered significant impacts. APMs that use phrases, such as, "as practicable," "as needed," or other conditional language will be superseded by Mitigation Measures if required to avoid or reduce a potentially significant impact. CPUC CEQA Unit Staff and their consultant team may review and provide comments on the Draft PEA APMs during Pre-filing Consultation.

Applicants will carefully consider each CPUC Draft Environmental Measure identified in Chapter 5 of this PEA Checklist. The measures may be applied to the proposed project if appropriate and may be subject to modification by the CPUC during its environmental review.[1]

11. PEA Checklist Deviations

CPUC CEQA Unit Staff understand that the PEA Checklist requires Applicants to develop a significant quantity of information. There are times when it is appropriate to deviate from the PEA Checklist. Deviations to the Pre-Filing Consultation Guidelines or the PEA Checklist contents may be approved by the CPUC's CEQA Unit Staff. Staff approval will be in writing and will occur prior to Applicant filing of the Draft PEA. Note that any deviations approved in writing by staff during the Pre-filing period may be reversed or modified after application and PEA filing and at any time throughout the environmental review period at the discretion of CPUC CEQA Unit Staff.

12. Submittal of Confidential Information

CPUC Staff are available during Pre-filing Consultation to discuss concerns that Applicants may have about confidentiality. However, the CEQA process requires public disclosure about projects, and such disclosure can often appear to conflict with Applicant requests for confidentiality. CPUC CEQA Unit Staff will rely on CPUC adopted confidentiality procedures to resolve confidentiality concerns. Applicants that expect aspects of a PEA filing to be confidential must follow CPUC confidentiality procedures. Applicants may mark information as confidential if allowed pursuant to General Order 66 or latest applicable Commission rule (e.g., see Public Records Act Proceeding Rulemaking (R.14-11-001).

13. Additional CEQA Impact Questions

Additional CEQA Impact Questions that are specific to the types of projects evaluated by the Commission's CEQA Unit are identified in the PEA Checklist to be considered in addition to the checklist items in CEQA Guidelines Appendix G.

The next section of this Guidelines document provides the PEA Checklist for all energy project applications that require CEQA compliance.

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[1] At this time, the CPUC environmental measures are in draft format, see PEA Checklist Attachment 4. They may be formally incorporated into Chapter 5 of future versions of the PEA Checklist.

Proponent's Environmental Assessment (PEA) Checklist

The PEA Checklist provides project Applicants (e.g., projects involving electric transmission lines, electric substations or switching stations, natural gas transmission pipelines, and underground natural gas storage facilities) with detailed guidance regarding the level of detail CPUC CEQA Unit Staff expect to deem PEAs complete. Applicants will prepare their PEAs using the same section headers and numbering as provided in the PEA Checklist. Applicants will also provide supporting data that is specific to each item within the PEA Checklist. As noted in the Pre-Filing Consultation Guidelines, the PEA Checklist is written with the assumption that an EIR will be prepared. PEA contents may not need to support the development of an EIR, but this determination can only be made in consultation with CPUC CEQA Unit Staff as described in the Pre-Filing Consultation Guidelines.

Formatting and Basic PEA Data Needs, Including GIS Data

1. Provide **editable and fully functional source files** in electronic format for all PDF files, hardcopies, maps, images, and diagrams. Files will be provided in their original file format as well as the output file format. All Excel and other spreadsheet files or modeling files will include all underlying formulas/modeling details. All modeling files must be fully functional.

2. Details about the types of **GIS data and maps** to be submitted are provided in Attachment 1. GIS data not specified in this checklist may also be requested depending on the Proposed Project and alternatives.

3. The Applicant is responsible for ensuring that all project features, including project components and temporary and permanent work areas, are included within all **survey boundaries** (e.g., biological and cultural resources).

4. Excel spreadsheets with **emissions calculations** will be provided that are complete with all project assumptions, values, and formulas used to prepare emissions calculations in the PEA. Accompanying PDF files with the same information will be provided as Appendix B to the PEA (see List of Appendices below).

5. Applicants will provide in an Excel spreadsheet a comprehensive **mailing list** that includes the names and addresses of all affected landowners and residents, including unit numbers for multi-unit properties for both the proposed project <u>and alternatives</u>.

    a. An affected resident or landowner is defined as one whose place of residence or property is:

        i. Crossed by or abuts any component of the proposed project or an alternative including any permanent or temporary disturbance area (either above or below ground) and any extra work area (e.g., staging or parking area); or

        ii. Located within approximately 1,000 feet[2] of the edge of any construction work area.

    b. Include in the following information for each resident in a spreadsheet, at minimum: parcel APN number, owner name and mailing address, and parcel physical address. If individual occupant names, facility names, or business names are available, also provide these names and addresses in the spreadsheet. A sample mailing list format is provided in Table 2.

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[2] Notice to all property owners within 300 feet of a Proposed Project is required at the time of application filing under GO 131-D. Commission notices of CEQA document preparation may be mailed to residents and property owners greater than 300 feet from a Proposed Project to ensure adequate notification (e.g., 1,000 feet) and the extent of notification will be determined on a project specific basis. Appropriate notice expectations will be discussed during Pre-filing (e.g., with respect to visual impact areas and other types of impacts specific to the Proposed Project and its study area).

Table 2. Sample Project Mailing List

Category	Company/ Agency	Name	Mailing Address	Phone Number	Email	APN	Source
State Agency	California Resources Agency	John Doe	1234 California Street City, CA 98765	(333) 456-7899	johndoe@email.com	123-456-789	County Assessor
Individual	n/a	Jane Doe	222 Main Street City, CA 97531	(909) 876-5432	janedoe@email.com	101-202-303	Public meeting on Month, Day 2019

6. **PEA Organization:** This PEA Checklist is organized to include each of the chapters and sections found in typical CPUC EIRs. The following sections will serve as the outline for all Draft PEAs submitted during Pre-filing and all PEAs filed with the CPUC Docket Office. PEAs will include each chapter and section identified (in matching numerical order) unless otherwise directed by CPUC CEQA Unit Staff in writing prior to filing.

Cover

A single sheet with the following information:	Applicant Notes, Comments
Title "Proponent's Environmental Assessment" and filing date	
Proponent Name (the Applicant)	
Name of the proposed project[3]	
Technical subheading summarizing the type of project and its major components, in one sentence or about 40 words, for example: A new 1,120 MVA, 500/115kV substation, 10 miles of new singled-circuit 500kV transmission lines, 25 miles of new and replaced double-circuit 115kV power lines, and upgrades at three existing substations are proposed.	
Location of the proposed project (all counties and municipalities or map figure for the cover that shows the areas crossed)	
Proceeding for which the PEA was prepared and CPUC Docket number (if known) or simply leave a blank where the Docket number would go	
Primary Contact's name, address, telephone number, and email address for both the project Applicant(s) and entities that prepared the PEA	
See example PEA cover in Figure 1.	

[3] If approved by the California Independent System Operator (CAISO), the project name listed will match the name specified in the CAISO approval. If multiple names apply, list all versions.

Figure 1. Example PEA Cover

Proponent's Environmental Assessment for

California Utility Company's Evergreen Electric

Substation and Transmission Line Project

May 1, 2019 (PEA filing date)

A new 230 kV substation, 10 miles of new single-circuit 230kV transmission lines, and upgrades at two existing substations are proposed.

The Proposed Project would be located primarily in __ County but would also cross __ and __ counties and areas within the City of __.

Application A.19-05-01 to the California Public Utilities Commission

Prepared by California Environmental Consulting
1234 Avenue
City, CA Zip Code
Primary Contact's Name
Position
Phone Number
Email

Prepared for California Utility Company
1234 Avenue
City, CA Zip Code
Primary Contact's Name
Position
Phone Number
Email

Table of Contents

Sections

Order	The format of the PEA will be organized as follows:	Applicant Notes, Comments
--	Cover	
--	Table of Contents, List of Tables, List of Figures, List of Appendices	
1	Executive Summary	
2	Introduction	
3	Proposed Project Description	
4	Description of Alternatives	
5	Environmental Analysis	
5.1	Aesthetics	
5.2	Agriculture and Forestry	
5.3	Air Quality	
5.4	Biological Resources	
5.5	Cultural Resources	
5.6	Energy	
5.7	Geology, Soils, and Paleontological Resources	
5.8	Greenhouse Gas Emissions	
5.9	Hazards, Hazardous Materials, and Public Safety	
5.10	Hydrology and Water Quality	
5.11	Land Use and Planning	
5.12	Mineral Resources	
5.13	Noise	
5.14	Population and Housing	
5.15	Public Services	
5.16	Recreation	
5.17	Transportation	
5.18	Tribal Cultural Resources	
5.19	Utilities and Service Systems	
5.20	Wildfire	
5.21	Mandatory Findings of Significance	
6	Comparison of Alternatives	

7	Cumulative Impacts and Other CEQA Considerations	
8	List of Preparers	
9	References[4]	
--	Appendices	

Required PEA Appendices and Supporting Materials

Order	Title	Applicant Notes, Comments
Appendix A	Detailed Maps and Design Drawings	
Appendix B	Emissions Calculations	
Appendix C	Biological Resources Technical Reports (see Attachment 2)	
Appendix D	Cultural Resources Studies (see Attachment 3)	
Appendix E	Detailed Tribal Consultation Report[5]	
Appendix F	Environmental Data Resources Report, Phase I Environmental Site Assessment, or similar hazardous materials report	
Appendix G	Agency Consultation and Public Outreach Report and Records of Correspondence	
Appendix H	Construction Fire Prevention Plan[6]	

Potentially Required[7] Appendices and Supporting Materials

Order	Title	Applicant Notes, Comments
Appendix I	Noise Technical Studies	
Appendix J	Traffic Studies	
Appendix K	Geotechnical Investigations (may preliminary at time of PEA filing)	
Appendix L	Hazardous Substance Control and Emergency Response Plan / Hazardous Waste and Spill Prevention Plan	

4 References will be organized by section but contained in a single chapter called, "References."
5 Include summary and timing of all correspondence to and from any Tribes and the State Historic Preservation Office/Native American Heritage Commission, including Sacred Lands File search results, and full description of any issues identified by Tribes in their interactions with the Applicant.
6 The Construction Fire Prevention Plan will be provided to federal, state, and local fire agencies for review and comment as applicable to where components of the proposed project would be located. CPUC will approve the final Construction Fire Prevention Plan. Record of the request for review and comment and any comments received from these agencies will be provided to CPUC CEQA Unit Staff.
7 Anticipated Appendix and study requirements should be discussed with CPUC CEQA Unit Staff during Pre-filing.

Appendix M	Erosion and Sedimentation Control Best Management Practice Plan / Draft Storm Water Pollution Prevention Plan (may be preliminary at time of PEA filing)	
Appendix N	FAA Notice and Criteria Tool Results	
Appendix O	Revegetation or Site Restoration Plan	
Appendix P	Health and Safety Plan	
Appendix Q	Existing Easements[8]	
Appendix R	Blasting Plan (may be preliminary at time of PEA filing)	
Appendix S	Traffic Control/Management Plan (may be preliminary at time of PEA filing)	
Appendix T	Worker Environmental Awareness Program (may preliminary at time of PEA filing)	
Appendix U	Helicopter Use and Safety Plan (may be preliminary at time of PEA filing)	
Appendix V	Electric and Magnetic Fields Management Plan (may be part of the Application rather than the PEA)	

[8] Easements should be provided military lands, conservation easements, or other lands where the real estate agreement specifies the range of activities that can be conducted

1 Executive Summary

This section will include, but is not limited to, the following:	PEA Section and Page Number[9]	Applicant Notes, Comments
1.1: Proposed Project Summary. Provide a summary of the proposed project and its underlying purpose and basic objectives.		
1.2: Land Ownership and Right-of-Way Requirements. Provide a summary of the existing and proposed land ownership and rights-of-way for the proposed project.		
1.3: Areas of Controversy. Identify areas of anticipated controversy and public concern regarding the project.		
1.4: Summary of Impacts a) Identify all impacts expected by the Applicant to be potentially significant. Identify and discuss Applicant Proposed Measures here and provide a reference to the full listing of Applicant Proposed Measures provided in the table described in Section 3.11 of this PEA Checklist. b) Identify any significant and unavoidable impacts that may occur.		
1.5: Summary of Alternatives. Summarize alternatives that were considered by the Applicant and the process and criteria that were used to select the proposed project.		
1.6: Pre-filing Consultation and Public Outreach Summary. Briefly summarize Pre-filing consultation and public outreach efforts that occurred and identify any significant outcomes that were incorporated into the proposed project.		
1.7: Conclusions. Provide a summary of the major PEA conclusions.		
1.8: Remaining Issues. Describe any major issues that must still be resolved.		

[9] The *PEA Section and Page Number* column and *Applicant Notes, Comments* column are intended to be filled out and provided with PEA submittals. The PEA Checklist is provided in Word to all Applicants to allow column resizing as appropriate to reduce PEA checklist length when completed for submittal. Landscape formatting may also be appropriate for completed PEA Checklist tables.

2 Introduction

2.1 Project Background

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
2.1.1: Purpose and Need a) Explain why the proposed project is needed. b) Describe localities the proposed project would serve and how the project would fit into the local and regional utility system. c) If the proposed project was identified by the California Independent System Operator (CAISO), thoroughly describe the CAISO's consideration of the proposed project and provide the following information: i. Include references to all CAISO Transmission Planning Processes that considered the proposed project. ii. Explain if the proposed project is considered an economic, reliability, or policy-driven project or a combination thereof. iii. Identify whether and how the Participating Transmission Owner recommended the project in response to a CAISO identified need, if applicable. iv. Identify if the CAISO approved the original scope of the project or an alternative and the rationale for their approval either for the original scope or an alternative. v. Identify how and whether the proposed project would exceed, combine, or modify in any way the CAISO identified project need. vi. If the Applicant was selected as part of a competitive bid process, identify the factors that contributed to the selection and CAISO's requirements for in-service date. d) If the project was not considered by the CAISO, explain why.		
(Natural Gas Storage Only) e) Provide storage capacity or storage capacity increase in billion cubic feet. If the project does not increase capacity, make this statement. f) Describe how existing storage facilities will work in conjunction with the proposed project. Describe the purchasing process (injection, etc.) and transportation arrangements this facility will have with its customers.		
2.1.2: Project Objectives a) Identify and describe the basic project objectives.[10] The objectives will include reasons for constructing the project based on its		

[10] Tangential project goals should not be included as basic project objectives, such as, minimizing environmental impacts, using existing ROWs and disturbed land to the maximum extent feasible, ensuring safety during construction and operation, building on property already controlled by the Applicant/existing site control. Goals of this type do not describe the underlying purpose or basic objectives but, rather, are good general practices for all projects.

purpose and need (i.e., address a specific reliability issue). The description of the project objectives will be sufficiently detailed to permit CPUC to independently evaluate the project need and benefits to accurately consider them in light of the potential environmental impacts. The basic project objectives will be used to guide the alternatives screening process, when applicable. b) Explain how implementing the project will achieve the basic project objectives and underlying purpose and need. c) Discuss the reasons why attainment of each basic objective is necessary or desirable.		
2.1.3: Project Applicant(s). Identify the project Applicant(s) and ownership of each component of the proposed project. Describe each Applicant's utility services and their local and regional service territories.		

2.2 Pre-filing Consultation and Public Outreach[11]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
2.2.1: Pre-filing Consultation and Public Outreach a) Describe all Pre-filing consultation and public outreach that occurred, such as, but not limited to: i. CAISO ii. Public agencies with jurisdiction over project areas or resources that may occur in the project area iii. Native American tribes affiliated with the project area iv. Private landowners and homeowner associations v. Developers for large housing or commercial projects near the project area vi. Other utility owners and operators vii. Federal, state, and local fire management agencies b) Provide meeting dates, attendees, and discussion summaries, including any preliminary concerns and how they were addressed and any project alternatives that were suggested. c) Clearly identify any significant outcomes of consultation that were incorporated into the proposed project. d) Clearly identify any developments that could coincide or conflict with project activities (i.e., developments within or adjacent to a proposed ROW).		
2.2.2: Records of Consultation and Public Outreach. Provide contact information, notification materials, meeting dates and materials, meeting notes, and records of communication organized by entity as an Appendix to the PEA (Appendix G).		

[11] CPUC CEQA Unit Staff request that consultation and public outreach that occurs during the Pre-filing period and throughout environmental review include the assigned CPUC Staff person and CPUC consultant.

2.3 Environmental Review Process

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
2.3.1: Environmental Review Process. Provide a summary of the anticipated environmental review process and schedule.		
2.3.2: CEQA Review a) Explain why CPUC is the appropriate CEQA Lead agency. b) Identify other state agencies and any federal agencies that may have discretionary permitting authority over any aspect of the proposed project. c) Identify all potential involvement by federal, state, and local agencies not expected to have discretionary permitting authority (i.e., ministerial actions). d) Summarize the results of any preliminary outreach with these agencies as well as future plans for outreach.		
2.3.3: NEPA Review (if applicable). If review according to the National Environmental Policy Act (NEPA) is expected, explain the portions of the project that will require the NEPA review process. Discuss which agency is anticipated to be the NEPA Lead agency if discretionary approval by more than one federal agency is required.		
2.3.4: Pre-filing CEQA and NEPA Coordination. Describe the results of Pre-filing coordination with CEQA and NEPA review agencies (refer to CPUC's Pre-Filing Consultation Guidelines). Identify major outcomes of the Pre-filing coordination process and how the information was incorporated into the PEA, including suggestions on the type of environmental documents and joint or separate processes based on discussions with agency staff.		

2.4 Document Organization

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
2.4: PEA Organization. Summarize the contents of the PEA and provide an annotated list of its sections.		

3 Proposed Project Description[12]

3.1 Project Overview

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.1: Project Overview a) Provide a concise summary of the proposed project and components in a few paragraphs. b) Described the geographical location of the proposed project (i.e., county, city, etc.). c) Provide an overview map of the proposed project location.		

3.2 Existing and Proposed System

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.2.1: Existing System a) Identify and describe the existing utility system that would be modified by the proposed project, including connected facilities to provide context. Include detailed information about substations, transmission lines, distribution lines, compressor stations, metering stations, valve stations, nearby renewable generation and energy storage facilities, telecommunications facilities, control systems, SCADA systems, etc. b) Provide information on users and the area served by the existing system features. c) Explain how the proposed project would fit into the existing local and regional systems. d) Provide a schematic diagram of the existing system features. e) Provide detailed maps and associated GIS data for existing facilities that would be modified by the proposed project.		
3.2.2: Proposed Project System a) Describe the whole of the proposed project by component, including all new facilities and any modifications, upgrades, or expansions to existing facilities and any interrelated activities that are part of the whole of the action. b) Clearly identify system features that would be added, modified, removed, disconnected and left in place, etc. c) Identify the expected capacities of the proposed facilities, highlighting any changes from the existing system. If the project would not change existing capacities, make this statement. For electrical projects, provide the anticipated capacity increase in amps or megawatts or in the typical units for the types of facilities proposed. For gas projects, provide the total volume of gas to be		

12 Applicant review of the Administrative Draft Project Description or sections of the Administrative Draft Project Description prepared for the CEQA document may be requested by CPUC CEQA Unit Staff to ensure technical accuracy.

delivered by the proposed facilities, anticipated system capacity increase (typically in million cubic feet per day), expected customers, delivery points and corresponding volumes, and the anticipated maximum allowable operating pressure(s). d) Describe the initial buildout and eventual full buildout of the proposed project facilities. For example, if an electrical substation or gas compressor station would be installed to accommodate additional demand in the future, then include the designs for both the initial construction based on current demand and the design for all infrastructure that could ultimately be installed within the planned footprint of an electric substation or compressor station. e) Explain whether the electric line or gas pipeline will create a second system tie or loop for reliability. f) Provide information on users and the area served by the proposed system features, highlighting any differences from the existing system. g) Provide a schematic diagram of the proposed system features. h) Provide detailed maps and associated GIS data for proposed facilities that would be installed, modified, or relocated by the proposed project.		
3.2.3: System Reliability. Explain whether the electric line or gas pipeline will create a second system tie or loop for reliability. Clearly explain and show how the proposed project relates to and supports the existing utility systems.		
3.2.4: Planning Area. Describe the system planning area served or to be served by the project. Clearly define the Applicant's term for the planning area (e.g., Electrical Needs Area or Distribution Planning Area).		

3.3 Project Components

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
Required for all Project Types		
3.3.1: Preliminary Design and Engineering a) Provide preliminary design and engineering information for all above-ground and below-ground facilities for the proposed project. The approximately locations, maximum dimensions of facilities, and limits of areas that would be needed to construction and operate the facilities should be clearly defined.[13] b) Provide preliminary design drawings for project features and explain the level of completeness (i.e., percentage). c) Provide detailed project maps (approximately 1:3,000 scale) and associated GIS data of all facility locations and boundaries with attributes and spatial geometry that corresponds to information in the Project Description.		

[13] Refer to Attachment 1 for mapping and GIS data requirements for the project layout and design.

3.3.2: Segments, Components, and Phases a) Define all project segments, components, and phases for the proposed project. b) Provide the length/area of each segment or component, and the timing of each development phase. c) Provide an overview map showing each segment and provide associated GIS data (may be combined with other mapping efforts).		
3.3.3: Existing Facilities a) Identify the types of existing facilities that would be removed or modified by the proposed project (i.e., conductor/cable, poles/towers, substations, switching stations, gas storage facilities, gas pipelines, service buildings, communication systems, etc.). b) Describe the existing facilities by project segment and/or component, and provide information regarding existing dimensions, areas/footprints, quantities, locations, spans, etc. c) Distinguish between above-ground and below-ground facilities and provide both depth and height ranges for each type of facility. For poles/towers, provide the installation method (i.e., foundation type or direct bury), and maximum above-ground heights and below-ground depths. d) Explain what would happen to the existing facilities. Would they be replaced, completely removed, modified, or abandoned? Explain why. e) Identify the names, types, materials, and capacity/volumes ranges (i.e., minimum and maximum) of existing facilities that would be installed or modified by the proposed project. f) Provide diagrams with dimensions representing existing facilities to provide context on how the proposed facilities would be different. g) Briefly describe the surface colors, textures, light reflectivity, and any lighting of existing facilities.		
3.3.4: Proposed Facilities a) Identify the types of proposed facilities to be installed or modified by the proposed project (e.g., conductor/cable, poles/towers, substations, switching stations, gas storage facilities, gas pipelines, service buildings, communication systems). b) Describe the proposed facilities by project segment and/or component, and provide information regarding maximum dimensions, areas/footprints, quantities, locations, spans, etc. c) Distinguish between above-ground and below-ground facilities and provide both depth and height ranges for each type of facility. For poles/towers, provide the installation method (i.e., foundation type or direct bury), and maximum above-ground heights and below-ground depths.		

d) Identify where facilities would be different (e.g., where unique or larger poles would be located, large guy supports or snub poles). e) Provide details about civil engineering requirements (i.e., permanent roads, foundations, pads, drainage systems, detention basins, spill containment, etc.). f) Distinguish between permanent facilities and any temporary facilities (i.e., poles, shoo-fly lines, mobile substations, mobile compressors, transformers, capacitors, switch racks, compressors, valves, driveways, and lighting). g) Identify the names, types, materials, and capacity/volumes ranges (i.e., minimum and maximum) of proposed facilities that would be installed or modified by the proposed project. h) Provide diagrams with dimensions representing existing facilities. i) Briefly describe the surface colors, textures, light reflectivity, and any lighting of proposed facilities.		
3.3.5: Other Potentially Required Facilities a) Identify and describe in detail any other actions or facilities that may be required to complete the project. For example, consider the following questions: i. Could the project require the relocation (temporary or permanent), modification, or replacement of unconnected utilities or other types of infrastructure by the Applicant or any other entity? ii. Could the project require aviation lighting and/or marking? iii. Could the project require additional civil engineering requirements to address site conditions or slope stabilization issues, such as pads and retaining walls, etc.? b) Provide the location of each facility and a description of the facility.		
3.3.6: Future Expansions and Equipment Lifespans a) Provide detailed information about the current and reasonably foreseeable plans for expansion and future phases of development. b) Provide the expected usable life of all facilities. c) Describe all reasonably foreseeable consequences of the proposed project (e.g., future ability to upgrade gas compressor station to match added pipeline capacity).		
Required for Certain Project Types		
3.3.7: Below-ground Conductor/Cable Installations (as Applicable) a) Describe the type of line to be installed (e.g., single circuit cross-linked polyethylene-insulated solid-dielectric, copper-conductor cables). b) Describe the type of casing the cable would be installed in (e.g., concrete-encased duct bank system) and provide the dimensions of the casing.		

c) Describe the types of infrastructure would likely be installed within the duct bank (e.g., transmission, fiber optics, etc.).		
3.3.8: Electric Substations and Switching Stations (as Applicable) a) Provide the number of transformer banks that will be added at initial and full buildout of the substation. Identify the transformer voltage and number of each transformer type. b) Identify any gas insulated switchgear that will be installed within the substation. c) Describe any operation and maintenance facilities, telecommunications equipment, and SCADA equipment that would be installed within the substation.		
3.3.9: Gas Pipelines (as Applicable). For each segment: a) Identify pipe diameter, number and length of exposed sections, classes and types of pipe to be installed, pressure of pipe, and cathodic protection for each linear segment. b) Describe new and existing inspection facilities (e.g., pig launcher sites). c) Describe system cross ties and laterals/taps. d) Identify the spacing between each valve station. e) Describe the compressor station, if needed, for any new or existing pipeline. f) Describe all pipelines and interconnections with existing and proposed facilities: i. Number of interconnections and locations and sizes; ii. All below-ground and above-ground installations; and iii. All remote facility locations for metering, telemetry, control.		
3.3.10: Gas Storage Facilities – Background and Resource Information (as Applicable) a) Provide detailed background information on the natural gas formation contributing to the existing or proposed natural gas facility, including the following: i. Description of overlying stratigraphy, especially caps ii. Description of production, injection, and intervening strata iii. Types of rock iv. Description of types of rocks in formation, including permeability or fractures v. Thickness of strata b) Provide a graphic and/or table showing formation thicknesses. c) Identify and describe any potential gas migration pathways, such as faults, permeable contacts, abandoned wells, underground water or other pipelines. d) Provide a summary and detailed cross-section diagrams of the geologic formations and structures of the oil/gas field or area. e) Provide the first well drilling and production history, abandonment procedures, inspections, etc. f) Describe production zones, including depth, types of formations, and characteristics of field/area.		

g) Describe the existing and proposed storage capacity and limiting factors, such as injection or withdrawal capacities. h) Describe existing simulation studies that were used to predict the reservoir pressure response under gas injection and withdrawal operations, and simulation studies for how the system would change as proposed. Provide the studies as a PEA Appendix. i) Provide the history of the oil/gas field or area.		
3.3.11: Gas Storage Facilities – Well-Head Sites (as Applicable). Describe the location, depth, size and completion information for all existing, abandoned, proposed production and injection, monitoring, and test wells.		
3.3.12: Gas Storage Facilities – Production and Injection (as Applicable) a) Provide the proposed storage capacity of production and injection wells. b) Provide production and injection pressures, depths, and rates. c) Provide production and injection cycles by day, week, and year. d) Describe existing and proposed withdrawal/production wells (i.e., size, depth, formations, etc.). e) Describe existing and proposed cushion gas requirements. f) Describe any cushion gas injection—formation the well is completed in (cushion gas formation), and injection information.		
3.3.13: Gas Storage Facilities – Electrical Energy (as Applicable). Describe all existing and proposed electric lines, telecommunications facilities, and other utilities/facilities (e.g., administrative offices, service buildings, and non-hazardous storage), and chemical storage associated with the proposed project.		
3.3.14: Telecommunication Lines (as Applicable) a) Identify the type of cable that is proposed and length in linear miles by segment. b) Identify any antenna and node facilities that are part of the project. c) For below-ground telecommunication lines, provide the depth of cable and type of conduit. d) For above-ground telecommunication lines, provide: i. Types of poles that will be installed (if new poles are required) ii. Where existing poles will be used iii. Any additional infrastructure (e.g., guy wires) or pole changes required to support the additional cable on existing poles		

3.4 Land Ownership, Rights-of-Way, and Easements

This section will include, but is not limited to, the following:	**PEA Section and Page Number**	**Applicant Notes, Comments**
3.4.1: Land Ownership. Describe existing land ownership where each project component would be located. State whether the proposed		

project would be located on property(ies) owned by the Applicant or if additional property would be required.		
3.4.2: Existing Rights-of-Way or Easements a) Identify and describe existing rights-of-way (ROWs) or easements where project components would be located. Provide the approximately lengths and widths in each project area. b) Clearly state if project facilities would be replaced, modified, or relocated within existing ROWs or easements.		
3.4.3: New or Modified Rights-of-Way or Easements a) Describe new permanent or modified ROWs or easements that would be required. Provide the approximately lengths and widths in each project area. b) Describe how any new permanent or modified ROWs or easements would be acquired. c) Provide site plans identifying all properties/parcels and partial properties/parcels that may require acquisition and the anticipated ROWs or easements. Provide associated GIS data. d) Describe any development restrictions within new ROWs or easements, e.g., building clearances and height restrictions, etc. e) Describe any relocation or demolition of commercial or residential property/structures that may be necessary.		
3.4.4: Temporary Rights-of-Way or Easements f) Describe temporary ROWs or easements that would be required to access project areas, including ROWs or easements for temporary construction areas (i.e., staging areas or landing zones). g) Explain where temporary construction areas would be located with existing ROWs or easements for the project or otherwise available to the Applicant without a temporary ROW or easement. h) Describe how any temporary ROWs or easements would be acquired.		

3.5 Construction

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.5.1 Construction Access (All Projects)		
3.5.1.1: Existing Access Roads a) Provide the lengths, widths, ownership details (both public and private roads), and surface characteristics (i.e., paved, graveled, bare soil) of existing access roads that would be used during construction. Provide the area of existing roads that would be used (see example in Table 3 below). b) Describe any road modifications or stabilization that would be required prior to construction, including on the adjacent road		

shoulders or slopes. Identify any roads that would be expanded and provide the proposed width increases. c) Describe any procedures to address incidental road damage cause by project activities following construction. d) Provide detailed maps and associated GIS data for all existing access roads.		

Table 3. Access Roads

Type of Road	Description	Area Proposed Project
Existing Dirt Road	Typically double track. May have been graded previously. No other preparation required, although a few sections may need to be re-graded and crushed rock applied in very limited areas for traction.	_____ acres
New Permanent	Would be xx feet wide, bladed. No other preparation required although crushed rock may need to be applied in very limited areas for traction.	_____ acres
Overland Access	No preparation required. Typically grassy areas that are relatively flat. No restoration would be necessary.	_____ acres

3.5.1.2: New Access Roads a) Identify any new access roads that would be developed for project construction purposes, such as where any blading, grading, or gravel placement could occur to provide equipment access outside of a designated workspace.[14] b) Provide lengths, widths, and development methods for new access roads. c) Identify any temporary or permanent gates that would be installed. d) Clearly identify any roads that would be temporary and fully restored following construction. Otherwise it will be assumed the new access road is a permanent feature. e) Provide detailed maps and associated GIS data for all new access roads.		
3.5.1.3: Overland Access Routes a) Identify any overland access routes that would be used during construction, such as where vehicles and equipment would travel over existing vegetation and where blading, grading, or gravel placement would occur. b) Provide lengths and widths for new access roads. c) Provide detailed maps and associated GIS data for all overland access routes.		
3.5.1.4: Watercourse Crossings a) Identify all temporary watercourse crossings that would be required during construction. Provide specific methods and procedures for temporary watercourse crossings.		

[14] Temporary roads that would not require these activities should be considered an overland route.

b) Describe any bridges or culverts that replacement or installation of would be required for construction access. c) Provide details about the location, design and construction methods.		
3.5.1.5: Helicopter Access. If helicopters would be used during construction: a) Describe the types and quantities of helicopters that would be used during construction (e.g., light, medium, heavy, or sky crane), and a description of the activities that each helicopter would be used for. b) Identify areas for helicopter takeoff and landing. c) Describe helicopter refueling procedures and locations. d) Describe flight paths, payloads, and expected hours and durations of helicopter operation. e) Describe any safety procedures or requirements unique to helicopter operations, such as but not limited to obtaining a Congested Area Plan from the Federal Aviation Administration (FAA).		
3.5.2 Staging Areas (All Projects)		
3.5.2.1: Staging Area Locations a) Identify the locations of all staging area(s). Provide a map and GIS data for each.[15] b) Provide the size (in acres) for each staging area and the total staging area requirements for the project.		
3.5.2.2: Staging Area Preparation a) Describe any site preparation required, if known, or generally describe what might be required (i.e., vegetation removal, new access road, installation of rock base, etc.). b) Describe what the staging area would be used for (i.e., material and equipment storage, field office, reporting location for workers, parking area for vehicles and equipment, etc.). c) Describe how the staging area would be secured. Would a fence be installed? If so, describe the type and extent of the fencing. d) Describe how power to the site would be provided if required (i.e., tap into existing distribution, use of diesel generators, etc.). e) Describe any temporary lightning facilities for the site. f) Describe any grading activities and/or slope stabilization issues.		

[15] While not all potential local site staging areas will be known prior to selection of a contractor, it is expected that approximate area and likely locations of staging areas be disclosed. The identification of extra or optional staging areas should be considered to reduce the risk of changes after project approval that could necessitate further CEQA review.

3.5.3 Construction Work Areas (All Projects)		
3.5.3.1: Construction Work Areas a) Describe known work areas that may be required for specific construction activities (e.g., pole assembly, hillside construction)[16] b) Describe the types of activities that would be performed at each work area. Work areas may include but are not necessarily limited to: i. Helicopter landing zones and touchdown areas ii. Vehicle and equipment parking, passing, or turnaround areas iii. Railroad, bridge, or watercourse crossings iv. Temporary work pads for facility installation, modification, or removal v. Excavations and associated equipment work areas vi. Temporary guard structures vii. Pull-and-tension/stringing sites viii. Jack and bore pits, drilling areas and pull-back areas for horizontal directional drills ix. Retaining walls		
3.5.3.2 Work Area Disturbance a) Provide the dimensions of each work area including the maximum area that would be disturbed during construction (e.g., 100 feet by 200 feet) (see example in Table 4 below). b) Provide a table with temporary and permanent disturbance at each work area (in square feet or acres), and the total area of temporary and permanent disturbance for the entire project (in acres).		
3.5.3.3: Temporary Power. Identify how power would be provided at work area (i.e., tap into existing distribution, use of diesel generators, etc.). Provide the disturbance area for any temporary power lines.		
3.5.4 Site Preparation (All Projects)		
3.5.4.1: Surveying and Staking. Describe initial surveying and staking procedures for site preparation and access.		
3.5.4.2: Utilities a) Describe the process for identifying any underground utilities prior to construction (i.e., underground service alerts, etc.). b) Describe the process for relocating any existing overhead or underground utilities that aren't directly connected to the project system. c) Describe the process for installing any temporary power or other utility lines for construction.		

[16] Understanding that each specific work area may not be determined until the final work plan is submitted by the construction contractor, estimate total area likely to be disturbed.

Table 4. Work Areas

	Proposed Project (approximate metrics)
Pole Diameter: • Wood • Self-Supporting Steel	 _____ inches _____inches
Lattice Tower Base Dimension: • Self-Supporting Lattice Structure	_____feet
Auger Hole Depth: • Wood • Self-Supporting Steel	 _____ to _____ feet _____ to _____ feet
Permanent Footprint per Pole/Tower: • Wood • Self-Supporting Steel • Self-Supporting Steel Tower	 _____ sq. feet _____ sq. feet _____ sq. feet
Number of Poles/Towers: • Wood • Self-Supporting Steel • Self-Supporting Steel Tower	 _____ _____ _____
Average Work Area around Pole/Towers (e.g., for old pole removal and new pole installation): • Tangent structure work areas • Dead End / Angle structure work areas	 _____ sq. feet _____ sq. feet
Total Permanent Footprint for Poles/Towers	Approximately _____ acres

3.5.4.3: Vegetation Clearing a) Describe what types of vegetation clearing may be required (e.g., tree removal, brush removal, flammable fuels removal) and why (e.g., to provide access, etc.). b) Provide calculations of temporary and permanent disturbance of each vegetation community and include all areas of vegetation removal in the GIS database. Distinguish between disturbance that would occur in previously developed areas (i.e., paved, graveled, or otherwise urbanized), and naturally vegetated areas. c) Describe how each type of vegetation removal would be accomplished. d) Describe the types of equipment that would be used for vegetation removal.		
3.5.4.4: Tree Trimming Removal a) For electrical projects, distinguish between tree trimming as required under CPUC General Order 95-D and tree removal. b) Identify the types, locations, approximate numbers, and sizes of trees that may need to be removed or trimmed substantially. c) Identify potentially protected trees that may be removed or substantially trimmed, such as but not limited to riparian trees, oaks trees, Joshua trees, or palm trees.		

d) Describe the types of equipment that would typically be used for tree removal.		
3.5.4.5: Work Area Stabilization. Describe the processes to stabilize temporary work areas and access roads including the materials that would be used (e.g., gravel).		
3.5.4.6: Grading a) Describe any earth moving or substantial grading activities (i.e., grading below a 6-inch depth) that would be required and identify locations where it would occur. b) Provide estimated volumes of grading (in cubic yards) including total cut, total fill, cut that would be reused, cut that would be hauled away, and clean fill that would be hauled to the site.		
3.5.5 Transmission Line Construction (Above Ground)		
3.5.5.1: Poles/Towers a) Describe the process and equipment for removing poles, towers, and associated foundations for the proposed project (where applicable). Describe how they would be disconnected, demolished, and removed from the site. Describe backfilling procedures and where the material would be obtained. b) Describe the process and equipment for installing or otherwise modifying poles and towers for the proposed project. Describe how they would be put into place and connected to the system. Identify any special construction methods (e.g., helicopter installation) at specific locations or specific types of poles/towers. c) Describe how foundations, if any, would be installed. Provide a description of the construction method(s), approximate average depth and diameter of excavation, approximate volume of soil to be excavated, approximate volume of concrete or other backfill required, etc. for foundations. Describe what would be done with soil removed from a hole/foundation site. d) Describe how the poles/towers and associated hardware would be delivered to the site and assembled. e) Describe any pole topping procedures that would occur, identify specific locations and reasons, and describe how each facility would be modified. Describe any special methods that would be required to top poles that may be difficult to access.		
3.5.5.2: Aboveground and Underground Conductor/Cable a) Provide a process-based description of how new conductor/cable would be installed and how old conductor/cable would be removed, if applicable. b) Identify where conductor/cable stringing/installation activities would occur. c) Provide a diagram of the general sequencing and equipment that would be used. d) Describe the conductor/cable splicing process.		

e) Provide the general or average distance between pull-and-tension sites. Describe the approximate dimensions and where pull-and-tension sites would generally be required (as indicated by the designated work areas), such as the approximate distance to pole/tower height ratio, at set distances, or at significant direction changes. Describe the equipment that would be required at these sites. f) For underground conductor/cable installations, describe all specialized construction methods that would be used for installing underground conductor or cable. If vaults are required, provide their dimensions and location/spacing along the alignment. Provide a detailed description for how the vaults would be delivered to the site and installed. g) Describe any safety precautions or areas where special methodology would be required (e.g., crossing roadways, stream crossing).		
3.5.5.3: Telecommunications. Identify the procedures for installation of proposed telecommunication cables and associated infrastructure.		
3.5.5.4: Guard Structures. Identify the types of guard structures that would be used at crossings of utility lines, roads, railroads, highways, etc. Describe the different types of guard structures or methods that may be used (i.e., buried poles and netting, poles secured to a weighted object, bucket trucks, etc.). Describe any pole installation and removal procedures associated with guard structures. Describe guard structure installation and removal process and duration that guard structures would remain in place.		
3.5.5.5: Blasting a) Describe any blasting that may be required to construct the project. b) If blasting may be required, provide a Blasting Plan that identifies the blasting locations; types and amounts of blasting agent to be used at each location; estimated impact radii; and, noise estimates. The Blasting Plan should be provided as an Appendix to the PEA. c) Provide a map identifying the locations where blasting may be required with estimated impact radii. Provide associated GIS data.		
3.5.6 Transmission Line Construction (Below Ground)		
3.5.6.1: Trenching a) Describe the approximate dimensions of the trench (e.g., depth, width). b) Provide the total approximate volume of material to be removed from the trench, the amount to be used as backfill, and any amount to subsequently be removed/disposed of offsite in cubic yards. c) Describe the methods used for making the trench (e.g., saw cutter to cut the pavement, backhoe to remove, etc.). d) Provide off-site disposal location, if known, or describe possible option(s). e) Describe if dewatering would be anticipated and if so, how the trench would be dewatered, the anticipated flows of the water,		

whether there would be treatment, and how the water would be disposed of. f) Describe the process for testing excavated soil or groundwater for the presence of pre-existing environmental contaminants that could be exposed from trenching operations. g) If a pre-existing hazardous waste were encountered, describe the process of removal and disposal. h) Describe the state of the ground surface after backfilling the trench. i) Describe standard Best Management Practices to be implemented.		
3.5.6.2: Trenchless Techniques (Microtunnel, Jack and Bore, Horizontal Directional Drilling) a) Identify any locations/features for which the Applicant expects to use a trenchless (i.e., microtunneling, jack and bore, horizontal directional drilling) crossing method and which method is planned for each crossing. b) Describe the methodology of the trenchless technique. c) Provide the approximate location and dimensions of the sending and receiving pits. d) Describe the methodology of excavating and shoring the pits. e) Provide the total volume of material to be removed from the pits, the amount to be used as backfill, and the amount subsequently to be removed/disposed of offsite in cubic yards. f) Describe process for safe handling of drilling mud and bore lubricants. g) Describe the process for detecting and avoiding "fracturing-out" during horizontal directional drilling operations. h) Describe the process for avoiding contact between drilling mud/lubricants and stream beds. i) If engineered fill would be used as backfill, indicate the type of engineered backfill and the amount that would be typically used (e.g., the top 2 feet would be filled with thermal-select backfill). j) Describe if dewatering is anticipated and, if so, how the pits would be dewatered, the anticipated flows of the water, whether there would there be treatment, and how the water would be disposed of. k) Describe the process for testing excavated soil or groundwater for the presence of pre-existing environmental contaminants. Describe the process of disposing of any pre-existing hazardous waste that is encountered during excavation. l) Describe any standard BMPs that would be implemented for trenchless construction.		
3.5.7 Substation, Switching Stations, Gas Compressor Stations		
3.5.7.1: Installation or Facility Modification. Describe the process and equipment for removing, installing, or modifying any substations, switching stations, or compressor stations including: a) Transformers/ electric components b) Gas components c) Control and operation buildings d) Driveways		

e) Fences f) Gates g) Communication systems (SCADA) h) Grounding systems		
3.5.7.2: Civil Works. Describe the process and equipment required to construct any slope stabilization, drainage, retention basins, and spill containment required for the facility.		
3.5.8 Gas Pipelines		
3.5.8.1: Gas Pipeline Construction. Describe the process for proposed pipeline construction including site development, trenching and trenchless techniques, pipe installation, and backfilling.		
3.5.8.2: Water Crossings. Describe water feature crossings that will occur during trenching, the method of trenching through stream crossings, and the process for avoiding impacts to the water features required for pipeline construction. Identify all locations where the pipeline will cross water features. Cite to any associated geotechnical or hydrological investigations completed and provide a full copy of each report as an Appendix to the PEA.[17]		
3.5.8.3: Gas Pipeline Other Requirements a) Describe hydrostatic testing process including pressures, timing, source of flushing water, discharge of water. b) Describe energy dissipation basin, and the size and length of segments to be tested. c) Describe pig launching locations and any inline inspection techniques used during or immediately post construction.		
3.5.9 Gas Storage Facilities		
3.5.9.1: Gas Storage Construction a) Describe the process for constructing the gas storage facility including constructing well pads and drilling wells. b) Describe the specific construction equipment that would be used, such as the type of drill rig (i.e., size, diesel, electric, etc.), depth of drilling, well-drilling schedule and equipment.		
3.5.9.2: Drilling Muds and Fluids. Describe the use of any drilling muds, fluids, and other drilling materials. Provided estimated types and quantities.		
3.5.10 Public Safety and Traffic Control (All Projects)		
3.5.10.1: Public Safety a) Describe specific public safety considerations during construction and best management practices to appropriately manage public safety. Clearly state when and where they each safety measure would be applied.		

[17] If a geotechnical study is not available at the time of PEA filing, provide the best information available.

b) Identify procedures for managing work sites in urban areas, covering open excavations securely, installing barriers, installing guard structures, etc. c) Identify specific project areas where public access may be restricted for safety purposes and provide the approximate durations and timing of restricted access at each location.		
3.5.10.2: Traffic Control a) Describe traffic control procedures that would be implemented during construction. b) Identify the locations, process, and timing for closing any sidewalks, lanes, roads, trails, paths, or driveways to manage public access. c) Identify temporary detour routes and locations. d) Provide a preliminary Traffic Control Plan(s) for the project.		
3.5.10.3: Security. Describe any security measures, such as fencing, lighting, alarms, etc. that may be required. State if security personnel will be stationed at project areas and anticipated duration of security.		
3.5.10.4: Livestock. Describe any livestock fencing or guards that may be necessary to prevent livestock from entering project areas. State if the fencing would be electrified and if so, how it would be powered.		
3.5.11 Dust, Erosion, and Runoff Controls (All Projects)		
3.5.11.1: Dust. Describe specific best management practices that would be implemented to manage fugitive dust.		
3.5.11.2: Erosion. Describe specific best management practices that would be implemented to manage erosion.		
3.5.11.3: Runoff. Describe specific best management practices that would be implemented to manage stormwater runoff and sediment.		
3.5.12 Water Use and Dewatering (All Projects)		
3.5.12.1: Water Use. Describe the estimated volumes of water that would be used by construction activity (e.g., dust control, compaction, etc.). State if recycled or reclaimed water would be used and provide estimated volumes. Identify the anticipated sources where the water would be acquired or purchased. Identify if the source of water is groundwater and the quantity of groundwater that could be used.		
3.5.12.2: Dewatering a) Describe dewatering procedures during construction, including pumping, storing, testing, permitted discharging, and disposal requirements that would be followed. b) Describe the types of equipment and workspace considerations to be used to dewater, store, transport, or discharge extracted water.		
3.5.13 Hazardous Materials and Management (All Projects)		
3.5.13.1: Hazardous Materials a) Describe the types, uses, and volumes of all hazardous materials that would be used during construction. b) State if herbicides or pesticides may be used during construction.		

c) If a pre-existing hazardous waste were encountered, describe the process of removal and disposal.		
3.5.13.2: Hazardous Materials Management a) Identify specific best management practices that would be followed for transporting, storing, and handling hazardous materials. b) Identify specific best management practices that would be followed in the event of an incidental leak or spill of hazardous materials. c) Provide a Hazardous Substance Control and Emergency Response Plan / Hazardous Waste and Spill Prevention Plan as an Appendix to the PEA, if appropriate.		
3.5.14 Waste Generation and Management (All Projects)		
3.5.14.1: Solid Waste a) Describe solid waste streams from existing and proposed facilities during construction. b) Identify procedures to be implemented to manage solid waste, including collection, containment, storage, treatment, and disposal. c) Provide estimated total volumes of solid waste by construction activity or project component. d) Describe the recycling potential of solid waste materials and provide estimated volumes of recyclable materials by construction activity or project component. e) Identify the locations of appropriate disposal and recycling facilities where solid wastes would be transported.		
3.5.14.2: Liquid Waste a) Describe liquid waste streams during construction (i.e., sanitary waste, drilling fluids, contaminated water, etc.) b) Describe procedures to be implemented to manage liquid waste, including collection, containment, storage, treatment, and disposal. c) Provide estimated volumes of liquid waste generated by construction activity or project component. d) Identify the locations of appropriate disposal facilities where liquid wastes would be transported.		
3.5.14.3: Hazardous Waste a) Describe potentially hazardous waste streams during construction and procedures to be implemented to manage hazardous wastes, including collection, containment, storage, treatment, and disposal. b) If large volumes of hazardous waste are anticipated, such as from a pre-existing contaminant in the soil that must be collected and disposed of, provide estimated volumes of hazardous waste that would be generated by construction activity or project component. c) Identify the locations of appropriate disposal facilities where hazardous wastes would be transported.		
3.5.15 Fire Prevention and Response (All Projects)		
3.5.15.1: Fire Prevention and Response Procedures. Describe fire prevention and response procedures that would be implemented during		

construction. Provide a Construction Fire Prevention Plan or specific procedures as an Appendix to the PEA.		
3.5.15.2: Fire Breaks. Identify any fire breaks (i.e., vegetation clearance) requirements around specific project activities (i.e., hot work). Ensure that such clearance buffers are included in the limits of the defined work areas, and the vegetation removal in that area is attributed to Fire Prevention and Response (refer to 3.5.4.3: Vegetation Clearing).		

3.6 Construction Workforce, Equipment, Traffic, and Schedule

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.6.1: Construction Workforce a) Provide the estimated number of construction crew members. In the absence of project-specific data, provide estimates based on past projects of a similar size and type. b) Describe the crew deployment. Would crews work concurrently (i.e., multiple crews at different sites); would they be phased? How many crews could be working at the same time and where? c) Describe the different types of activities to be undertaken during construction, the number of crew members for each activity (i.e. trenching, grading, etc.), and number and types of equipment expected to be used for the activity. Include a written description of the activity. See example in Table 5.		
3.6.2: Construction Equipment. Provide a tabular list of the types of equipment expected to be used during construction of the proposed project including the horsepower. Define the equipment that would be used by each phase as shown in the example table below (Table 5).		

Table 5. Construction Equipment and Workforce

Work Activity				Activity Production				
Equipment Description	**Estimated Horse-power**	**Probable Fuel Type**	**Equipment Quantity**	**Estimated Workforce**	**Estimated Start Date**	**Estimated End Date**	**Duration of Use (Hrs./Day)**	**Estimated Production**
Survey				**4**	**January 2020**	**December 2020**		**358 Miles**
1-Ton Truck, 4x4	300	Diesel	2		January 2020	December 2020	10	1 Mile/Day
Staging Yards				**5**	**DOP**			
1-Ton Truck, 4x4	300	Diesel	1		Duration of Project		4	
R/T Forklift	350	Diesel	1				5	
Boom/Crane Truck	350	Diesel	1				5	
Water Truck	300	Diesel	2				10	
Jet A Fuel Truck	300	Diesel	1				4	
Truck, Semi-Tractor	500	Diesel	1				6	
Road Work				**6**	**January 2020**	**March 2020**		**426 Miles**
1-Ton Truck, 4x4	300	Diesel	2		January 2020	March 2020	5	
Backhoe/Front Loader	350	Diesel	1		January 2020	March 2020	7	
Track Type Dozer	350	Diesel	1		January 2020	March 2020	7	
Motor Grader	350	Diesel	1		January 2020	March 2020	5	
Water Truck	300	Diesel	2		January 2020	March 2020	10	
Drum Type Compactor	250	Diesel	1		January 2020	March 2020	5	
Excavator	300	Diesel	1		January 2020	February 2020	7	
Lowboy Truck/Trailer	500	Diesel	1		January 2020	February 2020	4	

3.6.3: Construction Traffic a) Describe how the construction crews and their equipment would be transported to and from the proposed project site. b) Provide vehicle type, number of vehicles, and estimated hours of operation per day, week, and month for each construction activity and phase. c) Provide estimated vehicle trips and vehicles miles traveled (VMT) for each construction activity and phase. Provide separate values for construction crews commuting, haul trips, and other types of construction traffic.		
3.6.4: Construction Schedule a) Provide the proposed construction schedule (e.g., month and year) for each segment or project component, and for each construction activity and phase. b) Provide and explain the sequencing of construction activities, and if they would or would not occur concurrently. c) Provide the total duration of each construction activity and phase in days or weeks. d) Identify seasonal considerations that may affect the construction schedule, such as weather or anticipated wildlife restrictions, etc. The proposed construction should account for such factors.		
3.6.5: Work Schedule a) Describe the anticipated work schedule, including the days of the week and hours of the day when work would occur. Clearly state if work would occur at night or on weekends and identify when and where this could occur. b) Provide the estimated number of days or weeks that construction activities would occur at each type of work area. For example, construction at a stationary facility or staging area may occur for the entire duration of construction, but construction at individual work areas along a linear project would be limited to a few hours, days or weeks, and only a fraction of the total construction period.		

3.7 Post-Construction

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.7.1: Configuring and Testing. Describe the process and duration for post-construction configuring and testing of facilities. Describe the number of personnel and types of equipment that would be involved.		
3.7.2: Landscaping. Describe any landscaping that would be installed. Provide a conceptual landscape plan that identifies the locations and types of plantings that will be used. Identify whether plantings will include container plants or seeds. Include any water required for landscaping in the description of water use above.		

3.7.3 Demobilization and Site Restoration		
3.7.3.1: Demobilization. Describe the process for demobilization after construction activities, but prior to leaving the work site. For example, describe final processes for removing stationary equipment and materials, etc.		
3.7.3.2: Site Restoration. Describe how cleanup and post-construction restoration would be performed (i.e., personnel, equipment, and methods) on all project ROWs, sites, and extra work areas. Things to consider include, but are not limited to, restoration of the following: a) Restoring natural drainage patterns b) Recontouring disturbed soil c) Removing construction debris d) Vegetation e) Permanent and semi-permanent erosion control measures f) Restoration of all disturbed areas and access roads, including restoration of any public trails that are used as access, as well as any damaged sidewalks, agricultural infrastructure, or landscaping, etc. g) Road repaving and striping, including proposed timing of road restoration for underground construction within public roadways		

3.8 Operation and Maintenance

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.8.1: Regulations and Standards a) Identify and describe all regulations and standards applicable to operation and maintenance of project facilities. b) Provide a copy of any applicable Wildfire Management Plan and describe any special procedures for wildfire management.		
3.8.2: System Controls and Operation Staff a) Describe the systems and methods that the Applicant would use for monitoring and control of project facilities (e.g., on-site control rooms, remote facilities, standard monitoring and protection equipment, pressure sensors, automatic shut-off valves, and site and equipment specific for monitoring and control such as at natural gas well pads). b) If new full-time staff would be required for operation and/or maintenance, provide the number of positions and purpose.		
3.8.3: Inspection Programs a) Describe the existing and proposed inspection programs for each project component, including the type, frequency, and timing of scheduled inspections (i.e., aerial inspection, ground inspection, pipeline inline inspections). b) Describe any enhanced inspections, such as within any High Fire Threat Districts consistent with applicable Wildfire Management Plan requirements.		

c) Describe the inspection processes, such as the methods, number of crew members, and how access would occur (i.e., walk, vehicle, all-terrain vehicle, helicopter, drone, etc.). If new access would be required, describe any restoration that would be provided for the access roads.		
3.8.4: Maintenance Programs a) Describe the existing and proposed maintenance programs for each project component. b) Describe scheduled maintenance or facility replacement after the designated lifespan of the equipment. c) Identify typical parts and materials that require regular maintenance and describe the repair procedures. d) Describe any access road maintenance that would occur. e) Describe maintenance for surface or color treatment. f) Describe cathodic protection maintenance that would occur. g) Describe ongoing landscaping maintenance that would occur.		
3.8.5: Vegetation Management Programs a) Describe vegetation management programs within and surrounding project facilities. Distinguish between any different types of vegetation management. b) Describe any enhanced vegetation management, such as within any High Fire Threat Districts consistent with any applicable Wildfire Management Plan requirements. Identify the areas where enhanced vegetation management would be conducted.		

3.9 Decommissioning

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.9.1: Decommissioning. Provide detailed information about the current and reasonably foreseeable plans for the disposal, recycling, or future abandonment of all project facilities.		

3.10 Anticipated Permits and Approvals

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.10.1: Anticipated Permits and Approvals. Identify all necessary federal, state, regional, and local permits that may be required for the project. For each permit, list the responsible agency and district/office representative with contact information, type of permit or approval, and status of each permit with date filed or planned to file. For example: a) Federal Permits and Approvals i. U.S. Fish and Wildlife Service ii. U.S. Army Corps of Engineers iii. Federal Aviation Administration iv. U.S. Forest Service		

v. U.S. Department of Transportation – Office of Pipeline Safety vi. U.S. Environmental Protection Agency (Resource Conservation and Recovery Act; Comprehensive Environmental Response, Compensation, and Liability Act) b) State and Regional Permits i. California Department of Fish and Wildlife ii. California Department of Transportation iii. California State Lands Commission iv. California Coastal Commission v. State Historic Preservation Office, Native American Heritage Commission vi. State Water Resources Control Board vii. California Division of Oil, Gas and Geothermal Resources viii. Regional Air Quality Management District ix. Regional Water Quality Control Board (National Pollutant Discharge Elimination System General Industrial Storm Water Discharge Permit) x. Habitat Conservation Plan Authority (if applicable) See also Table 6 of example permitting requirements and processes.		
3.10.2: Rights-of-Way or Easement Applications. Demonstrate that applications for ROWs or other proposed land use have been or soon will be filed with federal, state, or other land-managing agencies that have jurisdiction over land that would be affected by the project (if any). Discuss permitting plans and timeframes and provide the contact information at the federal agency(ies) approached.		

3.11 Applicant Proposed Measures

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.11 Applicant Proposed Measures a) Provide a table with the full text of any Applicant Proposed Measure. Where applicable, provide a copy of Applicant procedures, plans, and standards referenced in the Applicant Proposed Measures. b) Within Chapter 5, describe the basis for selecting a particular Applicant Proposed Measure and how the Applicant Proposed Measure would reduce the impacts of the project.[18] c) Carefully consider each CPUC Draft Environmental Measure identified in Chapter 5 of this PEA Checklist. The CPUC Draft Environmental Measures will be applied to the proposed project where applicable.		

[18] Applicant Proposed Measures that use phrases, such as, "as practicable" or other conditional language are not acceptable and will be superseded by Mitigation Measures if required to avoid or reduce a potentially significant impact.

Table 6. Example Permitting Requirements and Processes

Note: In addition to the CPCN or PTC, the applicant may also be required to secure resource agency permits for the project.

Disclaimer: Below is a general list of permits required for transmission projects. Permit requirements for individual projects may vary slightly depending on project conditions.

Agency	Permit	Regulation	Protected Resource	Trigger	Application Process	Timing
				Federal		
Army Corps of Engineers	404 Permit	Clean Water Act	Waters of the United States (including wetlands)	Placement of dredge or fill material into waters of the U.S., including wetlands. If project impacts less than 0.5 acres a **nationwide permit (NWP)** is typically issued	**NWP:** prepare a preconstruction notification (PCN) along with the draft Corps's application (Engineer Form 4345). Information in the PCN includes, but is not limited to: results of wetland delineation including areas of waters of the U.S.; temporary and permanent impacts to waters of the U.S. and discussion of avoidance; construction techniques, timeline, and equipment that would be used; special status species that potentially occur in the project area, and discussion of mitigation (if applicable) to replace wetlands	**NWP:** takes approximately nine months from the date of application submittal (depending on level of impacts and level of consultation required by other agencies). Initial review is 30 days after which application is deemed complete or additional information is requested.
				If project would impact more than 0.5 acres a **regional or individual permit** may be required.	**Regional or Individual Permit:** Same requirements as NWP as well as preparation and submittal of 404(b)(1) Alternatives analysis which identifies the Least Environmentally Damaging Practicable Alternative (LEDPA). Public notice also required	**Regional or Individual Permit:** An additional three to six months may be required on top of the nine months expected for an NWP. A 30 day public notice is also required to inform the public about the project before the Corps issues the permit.
USFWS	Section 7 Consultation	Federal Endangered Species Act	Federally Listed Species	Potential impact to a federally listed threatened or endangered species	Biological Assessment (BA) prepared and submitted to Corps. BA contains information on each species and describes potential for "take" of species and/or habitat.	The timeline for processing and receiving a formal **Biological Opinion (BO)** from USFWS can be six months to a year from when the Corps has initiated consultation and depending on the level of impact to listed species. The typical timeline for issuance of a BO is no less than 135 days after acceptance of the BA as complete.
US Department of Agriculture, Forest Service	Special Use Authorization	National Forest Management Act/NEPA	National Forest lands	Use of federal lands managed by the USDA Forest Service for a transmission line. Typically constitutes a Major Federal Action which in turn triggers NEPA analysis.	**Special Use Authorization Application:** prepare a special use application for consideration by the Forest Service. Prior to submitting a proposal, applicant is required to arrange a preapplicaiton meeting at the local Forest Service office. Application typically includes project plan, operating plans, liability insurance, licenses/registrations and other documents. If it is determined that NEPA is required either an EA or EIS would be prepared. The NEPA document may be prepared jointly with the CEQA document.	Revies of Special Use Authorization applications is often dependent upon what level of NEPA analysis is required. An EA is typically 9-12 months, and EIS is generally 18 months. NEPA process may occur concurrently with CEQA process.
US Department of the Interior, Bureau of Land Management	Right-of-Way Grant	Federal Land Policy and Management Act/NEPA	Federal Lands	Use of federal lands managed by the BLM for a transmission line. Typically constitutes a Major Federal Action which in turn triggers NEPA analysis.	**Right-of-Way Application**: Contact the BLM office with management responsibility. Obtain an application form "Application for Transportation and Utility Systems and Facilities on Federal Lands". Arrange a pre-application meeting with a BLM Realty Specialist or appropriate staff member. Submit completed application to the appropriate BLM office. If it is determined that NEPA is required either an EA or EIS would be prepared. The NEPA document may be prepared jointly with the CEQA document.	BLM attempts to review completed applications within 60 days of submittal. Full timing is often dependent upon what level of NEPA analysis is required. An EA is typically 9-12 months, and EIS is generally 18 months. NEPA process may occur concurrently with CEQA process.

Agency	Permit	Regulation	Protected Resource	Trigger	Application Process	Timing
				State (continued)		
State Historic Preservation Officer (SHPO)	Section 106 National Historic Preservation Act (NHPA)	National Historic Preservation Act	Cultural and/or historical resources	Required if there are potential impacts to cultural and/or historical resources that are listed or eligible for listing on the National Register of Historic Places.	Information on cultural and historical resources gathered during the draft CEQA document preparation is included in a 106 Technical Report and submitted to the Corps along with the Area of Potential Effect (APE) map. The information is then evaluated by the Corps' cultural resources evaluator for potential adverse effects within the APE. Depending upon the level of potential adverse effect, the Corps then forwards its finding to SHPO for concurrence or begins the process for a Memorandum of Agreement (MOA). Native American consultation is also mandatory for the 106 process but can begin during preparation of the environmental document. All letters and correspondence for the Native American consultation must be provided to the Corps.Consultation with federally-recongized tribes may require a more extensive consultation.	Once SHPO has received the Corps' determination, it has approximately 60 days to agree or request additional information. However, SHPO has recently become more involved in projects and this timeframe is only an estimate and if a potential adverse effect to cultural or historical resources could occur, the SHPO process can take up to a year or more. Depending on the level of impacts to cultural resources, the Corps may determine no effect and issue the permit before receiving concurrence from SHPO.
California State Lands Commission (CSLC)	Right of Way Lease Agreement	Division 6 of the California Public Resources Code	California Sovereign Lands	May be triggered if the transmission line crosses state lands under the jurisdiction of the CSLC, which includes the beds of 1) more than 120 rivers, streams and sloughs; 2) nearly 40 non-tidal navigable lakes, such as Lake Tahoe and Clear Lake; 3) the tidal navigable bays and lagoons; and 4) the tide and submerged lands adjacent to the entire coast and offshore islands of the State from the mean high tide line to three nautical miles offshore.	Leases or permits may be issued to qualified applicants and the Commission shall have broad discretion in all aspects of leasing including category of lease or permit and which use, method or amount of rental is most appropriate, whether competitive bidding should be used in awarding a lease, what term should apply, how rental should be adjusted during the term, whether bonding and insurance should be required and in what amounts, whether an applicant is qualified based on what it deems to be in the best interest of the State.	Most coordination should be done concurrently with the CEQA process to ensure that any CSLC-required issues are addressed under CEQA. Once a final route/alternative is selected, the lease process may take two to three months for final Commission approval.
				Local / Other		
Air Quality Management District or Air Pollution Control District	Permit to Construct	Federal Clean Air Act	Air Quality	Depends on the air disctrict involved; may not be required for most transmission projects. Some air districts have a trigger level based on disturbed acreage.	Application forms need to be prepared and submiited to the local AQMD or APCD	Typically 30 to 90 days after submittal of a complete application.

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[19] Permitting is project specific. This table is provided for discussion purposes.

3.12 Project Description Graphics, Mapbook, and GIS Requirements

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
3.12.1: Graphics. Provide diagrams of the following as applicable: a) All pole, tower, pipe, vault, conduit, and retaining wall types b) For poles, provide typical drawings with approximate diameter at the base and tip; for towers, estimate the width at base and top. c) A typical detail for any proposed underground duct banks and vaults d) All substation, switchyard, building, and facility layouts e) Trenching, drilling, pole installation, pipe installation, vault installation, roadway construction, facility removal, helicopter uses, conductor installation, traffic control, and other construction activities where a diagram would assist the reader in visualizing the work area and construction approach f) Typical profile views of proposed aboveground facilities and existing facilities to be modified within the existing and proposed ROW (e.g., typical cross-section of existing and proposed facilities by project segment). g) Photos of representative existing and proposed structures		
3.12.2: Mapbook. Provide a detailed mapbook on an aerial imagery basemap at a scale between 1:3000 and 1:6000 (or as appropriate and legible) that show mileposts, roadways, and all project components and work areas including: a) All proposed above-ground and underground structure/facility locations (e.g., poles, conductor, substations, compressor stations, telecommunication lines, vaults, duct bank, lighting, markers, etc.) b) All existing structures/facilities that would be modified or removed c) Identify by milepost where existing ROW will be used and where new ROW or land acquisition will be required. d) All permanent work areas including permanent facility access e) All access roads including, existing, temporary, and new permanent access f) All temporary work areas including staging, material storage, field offices, material laydown, temporary work areas for above ground (e.g., pole installation) and underground facility construction (e.g., trenching and duct banks), helicopter landing zones, pull and tension sites, guard structures, shoo flys etc. g) Areas where special construction methods (e.g., jack and bore, HDD, blasting, retaining walls etc.) may need to be employed		

h) Areas where vegetation removal may occur i) Areas to be heavily graded and where slope stabilization measures would be employed including any retaining walls		
3.12.3: GIS Data. Provide GIS data for all features and ROW shown on the detailed mapbook.		
3.12.4: GIS Requirements. Provide the following information for each pole/tower that would be installed and for each pole/tower that would be removed: a) Unique ID number and type of pole (e.g., wood, steel, etc.) or tower (e.g., self-supporting lattice) both in a table and in the attributes of the GIS data provided b) Identify pole/tower heights and conductor sizes in the attributes of the GIS data provided.		
3.12.5: Natural Gas Facilities GIS Data. For natural gas facilities, provide GIS data for system cross ties and all laterals/taps, valve stations, and new and existing inspection facilities (e.g., pig launcher sites).		

4 Description of Alternatives

All Applicants will assume that alternatives will be required for the environmental analysis and that an EIR will be prepared unless otherwise instructed by CPUC CEQA Unit Staff in writing prior to application filing. See PEA Requirements at the beginning of this checklist document. The consideration and discussion of alternatives will adhere to CEQA Guidelines Section 15126.6. The description of alternatives will be provided in this chapter of the PEA, and the comparison of each alternative to the proposed project is provided in PEA Chapter 6. The amount of detail required for the description of various alternatives to the proposed project and what may be considered a reasonable range of alternatives will be discussed with CPUC during Pre-filing.

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
4.1 Alternatives Considered. Identify alternatives to the proposed project.[20] Include the following: a) All alternatives to the proposed project that were suggested, considered, or studied by the CAISO or by CAISO stakeholders b) Alternatives suggested by the public or agencies during public outreach efforts conducted by the Applicant c) Reduced footprint alternatives, including, e.g., smaller diameter pipelines and space for fewer electric transformers d) Project phasing options (e.g., evaluate the full build out for environmental clearance but consider an initial, smaller buildout that would only be expanded [in phases] if needed) e) Alternative facility and construction activity sites (e.g., substation, compressor station, drilling sites, well-head sites, staging areas) f) Renewable, energy conservation, energy efficiency, demand response, distributed energy resources, and energy storage alternatives g) Alternatives that would avoid or limit the construction of new transmission-voltage facilities or new gas transmission pipelines h) Other technological alternatives (e.g., conductor type) i) Route alternatives and route variations j) Alternative engineering or technological approaches (e.g., alternative types of facilities, or materials, or configurations) k) Assign an identification label and brief, descriptive title to each alternative described in this PEA chapter (e.g., Alternative A: No Project; Alterative B: Reduced Footprint 500/115-kV Substation; Alternative C: Ringo Hills 16-inch Pipeline Alignment; Alternative D1: Lincoln Street Route Variation; etc.). Each alternative will be easily identifiable by reading the brief title. Provide a description of each alternative. The description of each alternative will discuss to what extent it would be potentially feasible,		

[20] Reduced footprint alternatives; siting alternatives; renewable, energy conservation, energy efficiency, demand response, distributed energy resources, and energy storage alternatives; and non-wires alternatives (electric projects only) are typically required. For linear projects, route alternatives and route variations are typically required as well.

meet the project's underlying purpose, meet most of the basic project objectives, and avoid or reduce one or more potentially significant impacts. If the Applicant believes that an alternative is infeasible or the implementation is remote and speculative (CEQA Guidelines Section 15126.6(f)(3), clearly explain why. If significant environmental effects are possible without mitigation, alternatives will be provided in the PEA that are capable of avoiding or reducing any potentially significant environmental effects, even if the alternative(s) substantially impede the attainment of some project objectives or are costlier.[21]		
4.2 No Project Alternative. Include a thorough description of the No Project Alternative. The No Project Alternative needs to describe the range of actions that are reasonably foreseeable if the proposed project is not approved. The No Project Alternative will be described to meet the requirements of CEQA Guidelines Section15126.6(e).		
4.3 Rejected Alternatives. Provide a detailed discussion of all alternatives considered by the Applicant that were not selected by the Applicant for a full description in the PEA and analysis in PEA Chapter 5. The detailed discussion will include the following: a) Description of the alternative and its components b) Map of any alternative sites or routes c) Discussion about the extent to which the alternative would meet the underlying purpose of the project and its basic objectives d) Discussion about the feasibility of implementing the alternative e) Discussion of whether the alternative would reduce or avoid any significant environmental impacts of the proposed project f) Discussion of any new significant impacts that could occur from implementation of the alternative g) Description of why the alternative was rejected h) Any comments from the public or agencies about the alternative during PEA preparation		
For Natural Gas Storage Projects:		
4.4 Natural Gas Storage Alternatives. In addition to the requirements included above, alternatives to be considered for proposed natural gas storage projects include the following, where applicable: a) Alternative reservoir locations considered for gas storage including other field locations and other potential storage areas b) Alternative pipelines, road, and utility siting c) Alternative suction gas requirements, and injection/withdrawal options		

[21] CPUC CEQA Unit Staff will determine whether an alternative could *substantially* reduce one or more potentially significant impacts of the proposed project (CEQA Guidelines Section 15125.5). Applicants are strongly advised to provide more rather than less alternatives for CPUC's consideration or as determined during Pre-filing.

5 Environmental Analysis

Include a description of the environmental setting, regulatory setting, and impact analysis for each resource area. The resource areas addressed will include each environmental factor (resource area) identified in the most recent adopted version of the CEQA Guidelines Appendix G checklist and any additional relevant resource areas and impact questions that are defined in this PEA checklist.

1. Environmental Setting
    a. For each resource area, the PEA will include a detailed description of the natural and built environment in the vicinity of the proposed project area (e.g., topography, land use patterns, biological environment, etc.) as applicable to the resource area. Both regional and local environmental setting information will be provided.
    b. All setting information provided will relate in some way to the impacts of the proposed project discussed in the PEA's impacts analysis, however CPUC's impacts analysis may be more thorough, which may necessitate additional setting information than the Applicant might otherwise provide.
2. Regulatory Setting
    a. Organized by federal, State, regional, and local sections
    b. Describe the policy or regulation and briefly explain why it is applicable to the proposed project.
        i. Identify in the setting all laws, regulations, and policies that would be applicable for CPUC's exclusive jurisdiction over the siting and design of electric and gas facilities. Public utilities under CPUC's jurisdiction are expected to consult with local agencies regarding land use matters. Local laws, regulations, and policies will be considered for the consideration of potential impacts during CPUC's CEQA review (e.g., encroachment, grading, erosion control, scenic corridors, overhead line undergrounding, tree removal, fire protection, permanent and temporary noise limits, zoning requirements, general plan polices, and all local and regional laws, regulations, and policies).
3. Impact Questions
    a. Includes all impact questions in the current version of CEQA Guidelines, Appendix G.
    b. Additional impact questions that are frequently relevant to utility projects are provided in Attachment 4, CPUC Draft Environmental Measures.
4. Impact Analyses
    a. Discussion organized by CEQA Guidelines, Appendix G impact items and any Additional CEQA Impact Questions in the PEA Checklist. Assess all potential environmental impacts and make determinations, such as, No Impact, Less than Significant, Less than Significant with Mitigation, Significant and Unavoidable, or Beneficial Impact with respect to construction, operations, and maintenance activities.
    b. The impact analyses provided in PEA Chapter 5, Environmental Analysis, need not be as thorough as those to be prepared by CPUC for the CEQA environmental document. A preliminary determination will be provided but with only brief justification unless otherwise directed by CPUC Staff in writing during Pre-filing.
5. CPUC Draft Environmental Measures
    a. CPUC Draft Environmental Measures are provided for some of the resource areas in Attachment 4, CPUC Draft Environmental Measures. The measures may be applied to the proposed project as written or modified by the CPUC during its environmental review if the measure would avoid or reduce a potentially significant impact.

b. The CPUC Draft Environmental Measures should be discussed with the CPUC's CEQA Unit Staff during Pre-filing, especially with respect to the development of Applicant Proposed Measures.
c. In general, impact avoidance is preferred to the reduction of potentially significant impacts.

Additional requirements specific to each resource area are identified in the following sections.

5.1 Aesthetics

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.1.1 Environmental Setting		
5.1.1.1: Landscape Setting. Briefly described the regional and local landscape setting.		
5.1.1.2: Scenic Resources. Identify and describe any vistas, scenic highways, national scenic areas, or other scenic resources within and surrounding the project area (approximately 5-mile buffer but may be greater if necessary). Scenic resources may also include but are not limited to historic structures, trees, or other resources that contribute to the scenic values where the project would be located.		
5.1.1.3: Viewshed Analysis a) Conduct a viewshed analysis for the project area (approximately 5-mile buffer but may be greater if necessary). b) Describe the project viewshed, including important visibility characteristics for the project site, such as viewing distance, viewing angle, and intervening topography, vegetation, or structures. c) Provide a supporting map (or maps) showing project area, landscape units, topography (i.e., hillshade), and the results of the viewshed analysis. Provide associated GIS data.		
5.1.1.4: Landscape Units. Identify and describe landscape units (geographic zones) within and surrounding the project area (approximately 5-mile buffer but may be greater if necessary) that categorizes different landscape types and visual characteristics, with consideration to topography, vegetation, and existing land uses. Landscape units should be developed based on the existing landscape characteristics rather than the project's features or segments.		
5.1.1.5: Viewers and Viewer Sensitivity. Identify and described the types of viewers expected within the viewshed and landscape units. Describe visual sensitivity to general visual change based on viewing conditions, use of the area, feedback from the public about the project, and landscape characteristics.		

5.1.1.6: Representative Viewpoints a) Identify representative viewpoints from publicly accessible locations (up to approximately 5-mile buffer but may be greater if appropriate). The number and location of the viewpoints must represent a range of views of the project site from major roads, highways, trails, parks, vistas, landmarks, and other scenic resources near the project site. Multiple viewpoints should be included where the project site would be visible from sensitive scenic resources to provide context on different viewing distances, perspectives, and directions. b) Provide the following information for each viewpoint: i. Number, title, and brief description of the location ii. Types of viewers iii. Viewing direction(s) and distance(s) to the nearest proposed project features iv. Description of the existing visual conditions and visibility of the project site as seen from the viewpoint and shown in the representative photographs c) Provide a supporting map (or maps) showing project features and representative viewpoints with arrows indicating the viewing direction(s). Provide associated GIS data (may be combined with GIS data request below for representative photographs).		
5.1.1.7: Representative Photographs a) Provide high resolution photographs taken from the representative viewpoints in the directions of all proposed project features.[22] Multiple photographs should be provided where project features may be visible in different viewing directions from the same location. b) Provide the following information for each photograph: i. Capture time and date ii. Camera body and lens model iii. Lens focal length and camera height when taken c) Provide GIS data associated with each photograph location that includes coordinates (<1 meter resolution), elevations, and viewing directions, as well as the associated viewpoint.		
5.1.1.8: Visual Resource Management Areas a) Identify any visual resource management areas within and surrounding the project area (approximately 5-mile buffer). b) Describe any project areas within visual resource management areas.		

[22] All representative photographs should be taken using a digital single-lens reflex camera with standard 50-millimeter lens equivalent, which represents an approximately 40-degree horizontal view angle. The precise photograph coordinates and elevations should be collected using a high accuracy GPS unit.

c) Provide a supporting map (or maps) showing project features and visual resource management areas. Provide associated GIS data.		
5.1.2 Regulatory Setting		
5.1.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding aesthetics and visual resource management.		
5.1.3 Impact Questions		
5.1.3.1: Impact Questions. The impact questions include all aesthetic impact questions in the current version of CEQA Guidelines, Appendix G. **5.1.3.2:** Additional CEQA Impact Questions: None.		
5.1.4 Impact Analysis		
5.1.4.1: Visual Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
The following information will be included in the PEA or a technical Appendix to support the aesthetic impact analysis:		
5.1.4.2: Analysis of Selected Viewpoints. Identify the methodology and assumptions that were applied in selecting key observation points for visual simulation. It is recommended that viewpoints are selected where viewers may be sensitive to visual change (public views) and in areas that are visually sensitive, or heavily trafficked or visited.[23]		
5.1.4.3: Visual Simulation a) Identify methodology and assumptions for completing the visual simulations. The simulations should include photorealistic 3-D models of project features and any land changes within the KOP view. The visual simulations should depict conditions: i. Immediately following construction, and ii. After vegetation establishment in all areas of temporary impact to illustrate the visual impact from vegetation removal. b) Provide high resolution images for the visual simulations.		
5.1.4.4: Analysis of Visual Change a) Identify the methodology and assumptions for completing the visual change analysis.[24] The methodology should be consistent with applicable visual resource management criteria. b) Provide a description of the visual change for each selected viewpoint. Describe any conditions that would change over time, such as vegetation growth.		

[23] The KOP selection process should be discussed with CPUC during Pre-filing
[24] The visual impact assessment methodology should be discussed with CPUC during Pre-filing

c) Describe the effects of visual change that would result in the entire project area, as indicated by the selected viewpoints that were simulated and analyzed.		
5.1.4.5: Lighting and Marking. Identify all new sources of permanent lighting. Identify any proposed structures or lines that could require FAA notification. Identify any structures or line segments that could require lighting and marking based on flight patterns and FAA or military requirements. Provide supporting documentation in an Appendix (e.g., FAA notice and criteria tool results).		
5.1.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.2 Agriculture and Forestry Resources

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.2.1 Environmental Setting		
5.2.1.1: Agricultural Resources and GIS a) Identify all agricultural resources that occur within the project area including: i. Areas designated as Prime Farmland, Unique Farmland, or Farmland of Statewide Importance ii. Areas under Williamson Act contracts and provide information on the status of the Williamson Act contract iii. Any areas zoned for agricultural use in local plans iv. Areas subject to active agricultural use b) Provide GIS data for agricultural resources within the proposed project area.		
5.2.1.2: Forestry Resources and GIS a) Identify all forestry resources within the project area including: i. Forest land as defined in Public Resources Code 12220(g)25 ii. Timberland as defined in Public Resource Code section 4526 iii. Timberland zoned Timberland Production as defined in Government Code section 51104(g) b) Provide GIS data for all forestry resources within the proposed project area.		
5.2.2 Regulatory Setting		
5.2.2: Agriculture and Forestry Regulations. Identify all federal, state, and local policies for protection of agricultural and forestry resources that apply to the proposed project.		

[25] Forest land is defined in Public Resources Code as, "land that can support 10 percent native tree cover of any species, including hardwoods, under natural conditions, and that allows for management of one or more forest resources, including timber, aesthetics, fish and wildlife, biodiversity, water quality, recreation, and other public benefits."

5.2.3 Impact Questions		
5.2.3.1: Agriculture and Forestry Impact Questions. The impact questions include all agriculture and forestry impact questions in the current version of CEQA Guidelines, Appendix G. **5.2.3.2:** Additional CEQA Impact Questions: None.		
5.2.4 Impact Analyses		
5.2.4.1: Agriculture and Forestry Impacts. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
Incorporate the following discussions into the analysis of impacts:		
5.2.4.2: Prime Farmland Soil Impacts. Calculate the acreage of Prime Farmland soils that would be affected by construction and operation and maintenance.		
5.2.4.3. Williamson Act Impacts. Describe the approach to resolve potential conflicts with Williamson Act contract (if applicable)		
5.2.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.3 Air Quality

This section will include, but is not limited to, the following:	**PEA Section and Page Number**	**Applicant Notes, Comments**
5.3.1 Environmental Setting		
5.3.1.1: Air Quality Plans Identify and describe all applicable air quality plans and attainment areas. Identify the air basin(s) for the project area. If the project is located in more than one attainment area and/or air basin, provide the extent in each attainment area and air basin.		
5.3.1.2: Air Quality. Describe existing air quality in the project area. a) Identify existing air quality exceedance of National Ambient Air Quality Standards and California Ambient Air Quality Standards in the air basin. b) Provide the number of days that air quality in the area exceeds state and federal air standards for each criteria pollutant that where air quality standards are exceeded. c) Provide air quality data from the nearest representative air monitoring station(s).		
5.3.1.3: Sensitive Receptor Locations. Identify the location and types of each sensitive receptor locations[26] within 1,000 feet of the project area. Provide GIS data for sensitive receptor locations.		

[26] Sensitive Receptor locations may include hospitals, schools, and day care centers, and such other locations as the air district board or California Air Resources Board may determine (California Health and Safety Code § 42705.5(a)(5)).

5.3.2 Regulatory Setting		
5.3.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding aesthetics and visual resource management.		
5.3.2.2: Air Permits. Identify and list all necessary air permits.		
5.3.3 Impact Questions		
5.3.3.1: Impact Questions. The impact questions include all air quality impact questions in the current version of CEQA Guidelines, Appendix G. **5.3.3.2:** Additional CEQA Impact Questions: None.		
5.3.4 Impact Analysis		
5.3.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
The following information will be presented in the PEA or a technical Appendix to support the air quality impact analysis:		
5.3.4.2: Air Quality Emissions Modeling. Model project emissions using the most recent version of CalEEMod and/or a current version of other applicable modeling program. Provide all model input and output data sheets in Microsoft Excel format to allow CPUC to evaluate whether project data was entered into the modeling program accurately. The assumptions used in the air quality modeling must be consistent with all PEA information about the project's schedule, workforce, and equipment. The following information will be addressed in the emissions modeling, Air Quality Appendix, and PEA: a) Quantify the expected emissions of criteria pollutants from all project-related sources. Quantify emissions for both construction and operation (e.g., compressor equipment). b) Identify manufacturer's specifications for all proposed new emission sources. For proposed new, additional, or modified compressor units, include the horsepower, type, and energy source. c) Describe any emission control systems that are included in the air quality analysis (e.g., installation of filters, use of EPA Tier II, III, or IV equipment, use of electric engines, etc.). d) When multiple air basins may be affected by the project, model air emissions within each air basin and provide a narrative (supported by calculations) that clearly describes the assumptions around the project activities considered for each air basin. Provide modeled emissions by attainment area or air basin (supported by calculations).		

5.3.4.3: Air Quality Emissions Summary. Provide a table summarizing the air quality emissions for the project and applicable thresholds for each applicable attainment area. Include a summary of uncontrolled emissions (prior to application of any APMs) and controlled emissions (after application of APMs). Clearly identify the assumptions that were applied in the controlled emissions estimates.		
5.3.4.4: Health Risk Assessment. Complete a Health Risk Assessment when air quality emissions have the potential to lead to human health impacts[27]. If health impacts are not anticipated from project emissions, the analysis should clearly describe why emissions would not lead to health impacts.		
5.3.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.4 Biological Resources

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.4.1 Environmental Setting		
5.4.1.1: Biological Resources Technical Report. Provide a Biological Resources Technical Report as an Appendix to the PEA that includes all information specified in Attachment 2.		
The following biological resources information will be presented in the PEA:		
5.4.1.2: Survey Area (Local Setting). Identify and describe the biological resources survey area as documented in the Biological Resources Technical Report. All temporary and permanent project areas must be within the survey area.		
5.4.1.3: Vegetation Communities and Land Cover a) Identify, describe, and quantify vegetation communities and land cover types within the biological resources survey area. b) Clearly identify any sensitive natural vegetation communities that meet the definition of a biological resource under CEQA (i.e., rare, designated, or otherwise protected), such as, but not limited to, riparian habitat. c) Provide a supporting map (or maps) showing project features and vegetation communities and land cover type.		

27 Refer to Office of Environmental Health Hazard Assessment (OEHHA) most recent guidance for preparation of Health Risk Assessments to determine whether a Health Risk Assessment is required for the project. The need for an HRA should also be discussed with CPUC during Pre-filing.

5.4.1.4: Aquatic Features a) Identify, describe, and quantify aquatic features within the biological resources survey area that may provide potentially suitable aquatic habitat for rare and special-status species. b) Identify and quantify potentially jurisdictional aquatic features and delineated wetlands, according to the Wetland Delineation Report and Biological Resources Technical Report. c) Provide a supporting map (or maps) showing project features and aquatic resources.		
5.4.1.5: Habitat Assessment. Identify rare and special-status species with potential to occur in the project region (approximately a 5-mile buffer but may be larger if necessary). For each species, provide the following information: a) Common and scientific name b) Status and/or rank c) Habitat characteristics (i.e., vegetation communities, elevations, seasonal changes, etc.) d) Blooming characteristics for plants e) Breeding and other dispersal (range) behavior for wildlife f) Potential to occur within the survey area (i.e., Present, High Potential, Moderate Potential, Low Potential, or Not Expected), with justification based on the results of the records search, survey findings, and presence of potentially suitable habitat g) Specific types and locations of potentially suitable habitat that correspond to the vegetation communities and land cover and aquatic features		
5.4.1.6: Critical Habitat a) Identify and describe any critical habitat for rare or special-status species within and surrounding the project area (approximately a 5-mile buffer). b) Provide a supporting map (or maps) showing project features and critical habitat.		
5.4.1.7: Native Wildlife Corridors and Nursery Sites a) Identify and describe regional and local wildlife corridors within and surrounding the project area (approximately a 5-mile buffer), including but not limited to, landscape and aquatic features that connect suitable habitat in regions otherwise fragmented by terrain, changes in vegetation, or human development. b) Identify and describe regional and local native wildlife nursery sites within and surrounding the project area (approximately a 5-mile buffer), as identified through the records search, surveys, and habitat assessment.		

c) Provide a supporting map (or maps) showing project features, native wildlife corridors, and native nursery sites.		
5.4.1.8: Biological Resource Management Areas a) Identify any biological resource management areas (i.e., conservation or mitigation areas, HCP or NCCP boundaries, etc.) within and surrounding the project area (approximately 5-mile buffer). b) Identify and quantify any project areas within biological resource management areas. c) Provide a supporting map (or maps) showing project features and biological resource management areas.		
5.4.2 Regulatory Setting		
5.4.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding biological resources.		
5.4.2.2: Habitat Conservation Plan. Provide a copy of any relevant Habitat Conservation Plan.		
5.4.3 Impact Questions		
5.4.3.1: Impact Questions. The impact questions include all biological resource impact questions in the current version of CEQA Guidelines, Appendix G. **5.4.3.2:** Additional CEQA Impact Question: Would the project create a substantial collision or electrocution risk for birds or bats?		
5.4.4 Impact Analysis		
5.4.4.1: Impact Analysis Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for Biological Resources and any additional impact questions listed above.		
The following information will be included in the impact analysis:		
5.4.4.2: Quantify Habitat Impacts. Provide the area of impact in acres by each habitat type. Quantify temporary and permanent impacts. For all temporary impacts provide the following: a) Description of the restoration and revegetation approach b) Vegetation species that would be planted within the area of temporary disturbance c) Procedures to reduce invasive weed encroachment within areas of temporary disturbance d) Expected timeframe for restoration of the site		
5.4.4.3: Special-Status Species Impacts. Identify anticipated impacts on special-status species. Identify any take permits that are anticipated for the project. If an existing habitat conservation plan (HCP) or natural communities conservation plan (NCCP) would be used for the project, provide current accounting of take coverage included in the HCP/NCCP		

to demonstrate that there is sufficient habitat coverage remaining under the existing permit.		
5.4.4.4: Wetland Impacts. Quantify the area (in acres) of temporary and permanent impacts on wetlands. Include the following details: a) Provide a table identifying all wetlands, by milepost and length, crossed by the project and the total acreage of each wetland type that would be affected by construction. b) Discuss construction and restoration methods proposed for crossing wetlands. c) If wetlands would be filled or permanently lost, describe proposed measures to compensate for permanent wetland losses. d) If forested wetlands would be affected, describe proposed measures to restore forested wetlands following construction.		
5.4.4.5: Avian Impacts. Describe avian obstructions and risk of electrocution from the project. Describe any standards that will be implemented as part of the project to reduce the risk of collision and electrocution.		
5.4.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.5 Cultural Resources[28]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.5.1 Environmental Setting		
5.5.1.1: Cultural Resource Reports. Provide a cultural resource inventory and evaluation report that addresses the technical requirement provided in Attachment 3.		
5.5.1.2: Cultural Resources Summary. Summarize cultural resource survey and inventory results and survey methods. Do not provide any confidential cultural resource information within the PEA chapter.		
5.5.1.3: Cultural Resource Survey Boundaries. Provide a map with mileposts showing the boundaries of all survey areas in the report. Provide the GIS data for the survey area. Provide confidential GIS data for the resource locations and boundaries separately under confidential cover.		
5.5.2 Regulatory Setting		
5.5.2.1: Regulatory Setting. Identify applicable federal and state regulations for protection of cultural resources.		

[28] For a description and evaluation of cultural resources specific to Tribes, see Section 5.18, Tribal Cultural Resources.

5.5.3 Impact Questions		
5.5.3.1: Impact Questions. The impact questions include all cultural resource impact questions in the current version of CEQA Guidelines, Appendix G. **5.5.3.2:** Additional CEQA Impact Questions: None.		
5.5.4 Impact Analysis		
5.5.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis		
5.5.4.2: Human Remains. Describe the potential for encountering human remains or grave goods during the trenching or any other phase of construction. Describe the procedures that would be used if human remains are encountered.		
5.5.4.3: Resource Avoidance. Describe avoidance procedures that would be implemented to avoid known resources.		
5.5.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.6 Energy

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.6.1 Environmental Setting		
5.6.1.1: Existing Energy Use. Identify energy use of existing infrastructure if the proposed project would replace or upgrade an existing facility.		
5.6.2 Regulatory Setting		
5.6.2.1: Regulatory Setting. Identify applicable federal, state, or local regulations or policies applicable to energy use for the proposed project.		
5.6.3 Impact Questions		
5.6.3.1: Impact Questions: The impact questions include all energy impact questions in the current version of CEQA Guidelines, Appendix G. **5.6.3.2:** Additional CEQA Impact Question: Would the project add capacity for the purpose of serving a non-renewable energy resource?		

5.6.4 Impact Analysis		
5.6.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.6.4.2: Nonrenewable Energy. Identify renewable and non-renewable energy projects that may interconnected to or be supplied by the proposed project.		
5.6.4.3: Fuels and Energy Use a) Provide an estimation of the amount of fuels (gasoline, diesel, helicopter fuel, etc.) that would be used during construction and operation and maintenance of the project. Fuel estimates should be consistent with Air Quality calculations supporting the PEA. b) Provide the following information on energy use: i. Total energy requirements of the project by fuel type and end use ii. Energy conservation equipment and design features iii. Identification of energy supplies that would serve the project		
5.6.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.7 Geology, Soils, and Paleontological Resources

This section will include, but is not limited to, the following:	**PEA Section and Page Number**	**Applicant Notes, Comments**
5.7.1 Environmental Setting		
5.7.1.1: Regional and Local Geologic Setting. Briefly describe the regional and local physiography, topography, and geologic setting in the project area.		
5.7.1.2: Seismic Hazards a) Provide the following information on potential seismic hazards in the project area: i. Identify and describe regional and local seismic risk including any active faults within and surrounding the project area (will be a 10-mile buffer unless otherwise instructed in writing by CEQA Unit Staff during Pre-filing) ii. Identify any areas that are prone to seismic-induced landslides iii. Provide the liquefaction potential for the project area b) Provide a supporting map (or maps) showing project features and major faults, areas of landslide risk, and areas at high risk of liquefaction. Provide GIS data for all faults, landslides, and areas of high liquefaction potential.		

5.7.1.3: Geologic Units. Identify and describe the types of geologic units in the project area. Include the following information for each geologic unit: a) Summarize the geologic units within the project area. b) Identify any previous landslides in the area and any areas that are at risk of landslide. c) Identify any unstable geologic units. d) Provide a supporting map (or maps) showing project features and geologic units. Clearly identify any areas with potentially hazardous geologic conditions. Provide associated GIS data.		
5.7.1.4: Soils. Identify and describe the types of soils in the project area. a) Summarize the soils within the project area. b) Clearly identify any soils types that could be unstable (e.g., at risk of lateral spreading, subsidence, liquefaction, or collapse). c) Provide information on erosion susceptibility for each soil type that occurs in the project area. d) Provide a supporting map (or maps) showing project features and soils. Provide associated GIS data.		
5.7.1.5: Paleontological Report. Provide a paleontological report that includes the following: a) Information on any documented fossil collection localities within the project area and a 500-foot buffer. b) A paleontological resource sensitivity analysis based on published geological mapping and the resource sensitivity of each rock type. c) Supporting maps and GIS data.		
5.7.2 Regulatory Setting		
5.7.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding geology, soils, and paleontological resources.		
5.7.3 Impact Questions		
5.7.3.1: Impact Questions. The impact questions include all geology, soils, and paleontological resource impact questions in the current version of CEQA Guidelines, Appendix G. **5.7.3.2:** Additional CEQA Impact Questions: None.		
5.7.4 Impact Analysis		
5.7.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		

5.7.4.2: Geotechnical Requirements. Identify any geotechnical requirements that would be implemented to address effects from unstable geologic units or soils. Describe how the recommendation would be applied (i.e., when and where).		
5.7.4.3: Paleontological Resources. Identify the potential to disturb paleontological resources based on the depth of proposed excavation and paleontological sensitivity of geologic units within the project area.		
5.7.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.8 Greenhouse Gas Emissions

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.8.1 Environmental Setting		
5.8.1.1: GHG Setting. Provide a description of the setting for greenhouse gases (GHGs). The setting should consider any GHG emissions from existing infrastructure that would be upgraded or replaced by the proposed project.		
5.8.2 Regulatory Setting		
5.8.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for greenhouse gases.		
5.8.3 Impact Questions		
5.8.3.1 Impact Questions. The impact questions include all greenhouse gas impact questions in the current version of CEQA Guidelines, Appendix G. **5.8.3.2:** Additional CEQA Impact Questions: None.		
5.8.4 Impact Analysis		
5.8.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.8.4.2: GHG Emissions. Provide a quantitative assessment of GHG emissions for construction and operation and maintenance of the proposed project. Provide model results and all model files. Modeling will be conducted using the latest version of the emissions model at the time of application filing (e.g., most recent version of CalEEMod). GHG emissions will be provided for the following conditions: a) Uncontrolled emissions (before APMs are applied) b) Controlled emissions considering application of APMs i. Based on the modeled GHG emissions, quantify the project's contribution to and analyze the project's effect on		

climate change. Identify and provide justification for the timeframe considered in the analysis. ii. Discuss any programs already in place to reduce GHG emissions on a system-wide level. This includes the Applicant's voluntary compliance with the EPA SF6 reduction program, reductions from energy efficiency, demand response, LTPP, etc. iii. For any significant impacts, identify potential strategies that could be employed by the project to reduce GHGs during construction or operation and maintenance consistent with OPR Advisory on CEQA and Climate Change.		
Natural Gas Storage		
5.8.4.3: Natural Gas Storage Accident Conditions. In addition to the requirements above, identify the potential GHG emissions that could result in the event of a gas leak.		
5.8.4.4: Monitoring and Contingency Plan. Provide a comprehensive monitoring plan that would be implemented during project operation to monitor for gas leaks. The plan should identify a monitoring schedule, description of monitoring activities, and actions to be implemented if gas leaks are observed.		
5.8.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.9 Hazards, Hazardous Materials, and Public Safety[29]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.9.1 Environmental Setting		
5.9.1.1: Hazardous Materials Report. Provide a Phase I Environmental Site Assessment or similar hazards report for the proposed project area. Describe any known hazardous materials locations within the project area and the status of the site.		
5.9.1.2: Airport Land Use Plan. Identify any airport land use plan(s) within the project area.		
5.9.1.3: Fire Hazard. Identify if the project occurs within federal, state, or local fire responsibility areas and identify the fire hazard severity rating for all project areas, including temporary work areas and access roads.		
5.9.1.4: Metallic Objects. For electrical projects, identify any metallic pipelines or cables within 25 feet of the project.		

[29] For fire risk specific to state responsibility areas or lands classified as very high fire hazard severity zones, see Section 5.20, Wildfire.

5.9.1.5: Pipeline History (for Natural Gas Projects). Provide a narrative describing the history of the pipeline system(s) to which the project would connect, list of previous owner and operators, and detailed summary of the pipeline systems' safety and inspection history.		
5.9.2 Regulatory Setting		
5.9.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for hazards, hazardous materials, and public safety.		
5.9.2.2: Touch Thresholds. Identify applicable standards for protection of workers and the public from shock hazards.		
5.9.3 Impact Questions		
5.9.3.1: Impact Questions. The impact questions include all hazards and hazardous materials impact questions in the current version of CEQA Guidelines, Appendix G. **5.9.3.2:** Additional CEQA Impact Questions: a) Would the project create a significant hazard to air traffic from the installation of new power lines and structures? b) Would the project create a significant hazard to the public or environment through the transport of heavy materials using helicopters? c) Would the project expose people to a significant risk of injury or death involving unexploded ordnance? d) Would the project expose workers or the public to excessive shock hazards?		
5.9.4 Impact Analysis		
5.9.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.9.4.2: Hazardous Materials. Identify the hazardous materials (i.e., chemicals, solvents, lubricants, and fuels) that would be used during construction and operation of the project. Estimate the quantity of each hazardous material that would be stored on site during construction and operation.		
5.9.4.3: Air Traffic Hazards. If the project involves construction of above-ground structures (including structure replacement) within the airport land use plan area, provide a discussion of how the project would or would not conflict with height restrictions identified in the airport land use plan and how the project would comply with any FAA or military requirements for the above ground facilities.		
5.9.4.4: Accident or Upset Conditions. Describe how the project facilities would be designed, constructed, operated, and maintained to		

minimize potential hazard to the public from the failure of project components as a result of accidents or natural catastrophes.		
5.9.4.5: Shock Hazard. For electricity projects, identify infrastructure that may be susceptible to induced current from the proposed project. Describe strategies (e.g., cathodic protection) that the project would employ to reduce shock hazards and avoid electrocution of workers or the public.		
For Natural Gas and Gas Storage:		
5.9.4.6: Health and Safety Plan. Include in the Health and Safety Plan, plans for addressing gas leaks, fires, etc. Identify sensitive receptors, methods of evacuation, and protection measures. The Plan will be provided as an Appendix to the PEA.		
5.9.4.7: Health Risk Assessment. Provide a Health Risk Assessment including risk from potential gas leaks, fires, etc. Identify sensitive receptors that would be affected and potential impacts on them if there is a gas release.[30]		
5.9.4.8: Gas Migration. Describe potential for and effects of gas migration through natural and manmade pathways. a) Provide Applicant Proposed Measures for avoiding gas emissions at the surface from gas migration pathways. b) Provide Applicant Proposed Measures for avoiding emissions of mercaptan and/or other odorizing agents.		
5.9.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.10 Hydrology and Water Quality

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.10.1 Environmental Setting		
5.10.1.1: Waterbodies. Identify by milepost all ephemeral, intermittent, and perennial surface waterbodies crossed by the project. For each, list its water quality classification, if applicable.		
5.10.1.2: Water Quality. Identify any downstream waters that are on the state 303(d) list and identify whether a total maximum daily load (TMDL) has been adopted or the date for adoption of a TMDL. Identify existing sources of impairment for downstream waters. Describe any management plans that are in place for downstream waters.		
5.10.1.3: Groundwater Basin. Identify all known EPA and state groundwater basins and aquifers crossed by the project.		

[30] Refer to the requirements for Health Risk Assessments in Section 5.3.4.4.

5.10.1.4: Groundwater Wells and Springs. Identify the locations of all known public and private groundwater supply wells and springs within 150 feet of the project area.		
5.10.1.5: Groundwater Management. Identify the groundwater management status of any groundwater resources in the project area and any groundwater resources that may be used by the project. Describe if groundwater resources in the basin have been adjudicated. Identify any sustainable groundwater management plan that has been adopted for groundwater resources in the project area or describe the status of groundwater management planning in the area.		
5.10.2 Regulatory Setting		
5.10.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding hydrologic and water quality.		
5.10.3 Impact Questions		
5.10.3.1: Impact Questions. The impact questions include all hydrology and water quality impact questions in the current version of CEQA Guidelines, Appendix G. **5.10.3.2:** Additional CEQA Impact Questions: None.		
5.10.4 Impact Analysis		
5.10.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in the current version of CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.10.4.2: Hydrostatic Testing. Identify all potential sources of hydrostatic test water, quantity of water required, withdrawal methods, treatment of discharge, and any waste products generated.		
5.10.4.3: Water Quality Impacts. Describe impacts to surface water quality, including the potential for accelerated soil erosion, downstream sedimentation, and reduced surface water quality.		
5.10.4.4: Impermeable Surfaces. Describe increased run-off and impacts on groundwater recharge due to construction of impermeable surfaces. Provide the acreage of new impermeable surfaces that will be created as a result of the project.		
5.10.4.5: Waterbody Crossings. Identify by milepost all waterbody crossings. Provide the following information for crossing: a) Identify whether the waterbody has contaminated waters or sediments. b) Describe the waterbody crossing method and any approaches to avoid the waterbody. c) Describe typical additional work area and staging area requirements at waterbody and wetland crossings.		

d) Describe any dewatering or water diversion that will be required during construction near the waterbody. Identify treatment methods for any dewatering. e) Describe any proposed restoration methods for work near or within the waterbody.		
5.10.4.6: Groundwater Impacts. If water would be obtained from groundwater supplies, evaluate the project's consistency with any applicable sustainable groundwater management plan.		
5.10.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.11 Land Use and Planning

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.11.1 Environmental Setting		
5.11.1.1: Land Use. Provide a description of land uses within the area traversed by the project route as designated in the local General Plan (e.g., residential, commercial, agricultural, open space, etc.).		
5.11.1.2: Special Land Uses. Identify by milepost and segment all special land uses within the project area including: a) All land administered by federal, state, or local agencies, or private conservation organizations b) Any designated coastal zone management areas c) Any designated or proposed candidate National or State Wild and Scenic Rivers crossed by the project d) Any national landmarks		
5.11.1.3: Habitat Conservation Plan. Provide a copy of any Habitat Conservation Plan applicable to the project area or proposed project. Also required for Section 5.4, Biological Resources.		
5.11.2 Regulatory Setting		
5.11.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for land use and planning.		
5.11.3 Impact Questions		
5.11.3.1: Impact Questions. The impact questions include all land use questions in the current version of CEQA Guidelines, Appendix G. **5.11.3.2:** Additional CEQA Impact Questions: None.		
5.11.4 Impact Analysis		
5.11.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		

5.11.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.12 Mineral Resources

This section will include, but is not limited to, the following:	**PEA Section and Page Number**	**Applicant Notes, Comments**
5.12.1 Environmental Setting		
5.12.1.1: Mineral Resources. Provide information on the following mineral resources within 0.5 mile of the proposed project area: a) Known mineral resources b) Active mining claims c) Active mines d) Resource recovery sites		
5.12.2 Regulatory Setting		
5.12.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for minerals.		
5.12.3 Impact Questions		
5.12.3.1: Impact Questions. The impact questions include all mineral resource impact questions in the current version of CEQA Guidelines, Appendix G. **5.12.3.2:** Additional CEQA Impact Questions: None.		
5.12.4 Impact Analysis		
5.12.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
5.12.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.13 Noise

This section will include, but is not limited to, the following:	**PEA Section and Page Number**	**Applicant Notes, Comments**
5.13.1 Environmental Setting		
5.13.1.1: Noise Sensitive Land Uses. Identify all noise sensitive land uses within 1,000 feet of the proposed project. Provide GIS data for sensitive receptors within 1,000 feet of the project.		
5.13.1.2: Noise Setting. Provide the existing noise levels (Lmax, Lmin, Leq, and Ldn sound level and other applicable noise parameters) at noise sensitive areas near the proposed project. All noise measurement data and the methodology for collecting the data will be provided in a noise study as an Appendix to the PEA.		

5.13.2 Regulatory Setting		
5.13.2.1: Regulatory Setting. Identify applicable state, and local laws, policies, and standards for noise.		
5.13.3 Impact Questions		
5.13.3.1 Impact Questions. The impact questions include all noise questions in the current version of CEQA Guidelines, Appendix G. **5.13.3.2:** Additional CEQA Impact Questions: None.		
5.13.4 Impact Analysis		
5.13.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.13.4.2: Noise Levels a) Identify noise levels for each piece of equipment that could be used during construction. b) Provide a table that identifies each phase of construction, the equipment used in each construction phase, and the length of each phase at any single location (see example in Table 7 below). c) Estimate cumulative equipment noise levels for each phase of construction. d) Include phases of operation if noise levels during operation have the potential to frequently exceed pre-project existing conditions. e) Identify manufacturer's specifications for equipment and describe approaches to reduce impacts from noise.		

Table 7. Construction Noise Levels

Equipment Required	Equipment Noise Levels (Leq; 50 feet)	Phase Noise Level (Leq; 50 feet)	Phase Duration at Each Location	Receptor Nearest to Construction Phase	Noise Level at Nearest Receptor (Leq)	Exceeds Noise Standard at Nearest Receptor?	Distance to Not Exceed Standard
Site Preparation/Grading							
Dozer	78 dBA	82 dBA	5 days	Residence on Main Street; 100 feet from Substation Site	76 dBA	Yes	112 feet
Gradall	79 dBA						
Dump Truck	73 dBA						
Construct Tower Foundation							
Auger Rig	77 dBA	82 dBA	11 days	School on Education Avenue; 130 feet from Tower A12	73 dBA	No	N/A
Dump Truck	73 dBA						
Excavator	77 dBA						
Concrete Truck	75 dBA						

For Natural Gas:		
5.13.4.3: Compressor Station Noise. Provide site plans of compressor stations or other noisy, permanent equipment, showing the location of the nearest noise sensitive areas within 1 mile of the proposed ROW. If new compressor station sites are proposed, measure or estimate the existing ambient sound environment based on current land uses and		

activities. For existing compressor stations (operated at full load), include the results of a sound level survey at the site property line and nearby noise-sensitive areas. Include a plot plan that identifies the locations and duration of noise measurements.		
5.13.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.14 Population and Housing

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.14.1 Environmental Setting		
5.14.1.1: Population Estimates. Identify population trends for the areas (county, city, town, census designated place) where the project would take place.		
5.14.1.2: Housing Estimates. Identify housing estimates and projections in areas where the project would take place.		
5.14.1.3: Approved Housing Developments a) Provide the following information for all housing development projects within 1 mile of the proposed project that have been recently approved or may be approved around the PEA and application filing date: i. Project name ii. Location iii. Number of units and estimated population increase iv. Approval date and construction status v. Contact information for developer (provided in the public outreach Appendix) b) Ensure that the project information provided above is consistent with the PEA analysis of cumulative project impacts.		
5.14.2 Regulatory Setting		
5.14.2.1: Regulatory Setting. Identify any applicable federal, state or local laws or regulations that apply to the project.		
5.14.3 Impact Questions		
5.14.3.1: Impact Questions. The impact questions include all population and housing impact questions in the current version of CEQA Guidelines, Appendix G. **5.14.3.2:** Additional CEQA Impact Questions: None.		
5.14.4 Impact Analysis		
5.14.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		

Include the following information in the impact analysis:		
5.14.4.2: Impacts to Housing. Identify if any existing or proposed homes occur within the footprint of any proposed project elements or right-of-way. Describe housing impacts (e.g., demolition and relocation of residents) that may occur as a result of the proposed project.		
5.14.4.3: Workforce Impacts. Describe on-site manpower requirements, including the number of construction personnel who currently reside within the impact area, who would commute daily to the site from outside the impact area or would relocate temporarily within the impact area. Chapter 4 of this document can be referenced as applicable. Identify any permanent employment opportunities that would be create by the project and the workforce conditions in the area that the jobs would be created.		
5.14.4.4: Population Growth Inducing. Provide information on the project's growth inducing impacts, if any. The information will include, but is not necessarily limited to, the following: a) Any economic or population growth in the surrounding environment that will directly or indirectly result from the project b) Any obstacles to population growth that the project would remove c) Any other activities directly or indirectly encouraged or facilitated by the project that would cause population growth leading to a significant effect on the environment, either individually or cumulatively		
5.14.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.15 Public Services

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.15.1 Environmental Setting		
5.15.1.1 Service Providers a) Identify the following service providers that serve the project area and provide a map showing the service facilities that could serve the project: i. Police ii. Fire (identify service providers within local and state responsibility areas) iii. Schools iv. Parks v. Hospitals		

b) Provide the documented performance objectives and data on existing emergency response times for service providers in the area (e.g., police or fire department response times).		
5.15.2 Regulatory Setting		
5.15.2.1 Regulatory Setting. Identify any applicable federal, state or local laws or regulations for public services that apply to the project.		
5.15.3 Impact Questions		
5.15.3.1: Impact Questions. The impact questions include all public services impact questions in the current version of CEQA Guidelines, Appendix G. **5.15.3.2:** Additional CEQA Impact Questions: None.		
5.15.4 Impact Analysis		
5.15.4.1 Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.15.4.2: Emergency Response Times a) Describe whether the project would impede ingress and egress of emergency vehicles during construction and operation. b) Include an analysis of impacts on emergency response times during project construction and operation, including impacts during any temporary road closures. Describe approaches to address impacts on emergency response times.		
5.15.4.3: Displaced Population. If the project would create permanent employment or displace people, evaluate the impact of the new employment or relocated people on governmental facilities and services and describe plans to reduce the impact on public services.		
5.15.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.16 Recreation

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.16.1 Environmental Setting		
5.16.1.1: Recreational Setting a) Describe the regional and local recreation setting in the project area including: i. Any recreational facilities or areas within and surrounding the project area (approximately 0.5-mile buffer) including the recreational uses of each facility or area		

ii. Any available data on use of the recreational facilities including volume of use b) Provide a map (or maps) showing project features and recreational facilities and provide associated GIS data.		
5.16.2 Regulatory Setting		
5.16.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding recreation.		
5.16.3 Impact Questions		
5.16.3.1: Impact Questions. The impact questions include all recreation impact questions in the current version of CEQA Guidelines, Appendix G. **5.16.3.2:** Additional CEQA Impact Questions: a) Would the project reduce or prevent access to a designated recreation facility or area? b) Would the project substantially change the character of a recreational area by reducing the scenic, biological, cultural, geologic, or other important characteristics that contribute to the value of recreational facilities or areas? c) Would the project damage recreational trails or facilities?		
5.16.4 Impact Analysis		
5.16.4.1: Impact Analysis: Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
5.16.4.2: Impact Details. Clearly identify the maximum extent of each impact, and when and where the impacts would or would not occur. Organize the impact assessment by project phase, project component, and/or geographic area, as necessary.		
5.16.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.17 Transportation

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.17.1 Environmental Setting		
5.17.1.1: Circulation System. Briefly describe the regional and local circulation system in the project area, including modes of transportation, types of roadways, and other facilities that contribute to the circulation system.		
5.17.1.2: Existing Roadways and Circulation a) Identify and describe existing roadways that may be used to access the project site and transport materials during		

construction or are otherwise adjacent to or crossed by linear project features. Provide the following information for each road: i. Name of the road ii. Jurisdiction or ownership (i.e., State, County, City, private, etc.) iii. Number of lanes in both directions of travel iv. Existing traffic volume (if publicly available data is unavailable or significantly outdated, then it may be necessary to collect existing traffic counts for road segments where large volumes of construction traffic would be routed or where lane or road closures would occur) v. Closest project feature name and distance b) Provide a supporting map (or maps) showing project features and the existing roadway network identifying each road described above. Provide associated GIS data. The GIS data should include all connected road segments within at least 5 miles of the project.		
5.17.1.3: Transit and Rail Services a) Identify and describe transit and rail service providers in the region. b) Identify any rail or transit lines within 1,000 feet of the project area. c) Identify specific transit stops, and stations within 0.5 mile of the project. Provide the frequency of transit service. d) Provide a supporting map (or maps) showing project features and transit and rail services within 0.5 mile of the project area. Provide associated GIS data.		
5.17.1.4: Bicycle Facilities a) Identify and describe any bicycle plans for the region. b) Identify specific bicycle facilities within 1,000 feet of the project area. c) Provide a supporting map (or maps) showing project features and bicycle facilities. Provide associated GIS data.		
5.17.1.5: Pedestrian Facilities a) Identify and describe important pedestrian facilities near the project area that contribute to the circulation system, such as important walkways. b) Identify specific pedestrian facilities that would be near the project, including on the road segments identified per 5.17.1.2. c) Provide a supporting map (or maps) showing project features and important pedestrian facilities. Provide associated GIS data.		

5.17.1.6: Vehicle Miles Traveled (VMT). Provide the average VMT for the county(s) where the project is located.		
5.17.2 Regulatory Setting		
5.17.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards regarding transportation.		
5.17.3 Impact Questions		
5.17.3.1: Impact Questions. All impact questions for this resource area in the current version of CEQA Guidelines, Appendix G. **5.17.3.2:** Additional CEQA Impact Questions: a) Would the project create potentially hazardous conditions for people walking, bicycling, or driving or for public transit operations? b) Would the project interfere with walking or bicycling accessibility? c) Would the project substantially delay public transit?		
5.17.4 Impact Analysis		
5.17.4.1: Impact Analysis. Provide an impact analysis for each significance criteria identified in Appendix G of the CEQA Guidelines for transportation and any additional impact questions listed above[31].		
Include the following information in the impact analysis:		
5.17.4.2: Vehicle Miles Traveled (VMT) a) Identify whether the project is within 0.5 mile of a major transit stop or a high-quality transit corridor. b) Identify the number of vehicle daily trips that would be generated by the project during construction and operation by light duty (e.g., worker vehicles) and heavy-duty vehicles (e.g., trucks). Provide the frequency of trip generation during operation. c) Quantify VMT generation for both project construction and operation. d) Provide an excel file with the VMT assumptions and model calculations, including all formulas and values. e) Evaluate the project VMT relative to the average VMT for the area in which the project is located.		
5.17.4.3: Traffic Impact Analysis. Provide a traffic impact study. The traffic impact study should be prepared in accordance with guidance from the relevant local jurisdiction or Caltrans, where appropriate.		
5.17.4.4: Hazards. Identify any traffic hazards that could result from construction and operation of the project. Identify any lane closures and traffic management that would be required to construct the project.		

[31] Discuss with CPUC during Pre-filing whether a traffic study is needed.

5.17.4.5: Accessibility. Identify any closures of bicycle lanes, pedestrian walkways, or transit stops during construction or operation of the project.		
5.17.4.6: Transit Delay. Identify any transit lines that could be delayed by construction and operation of the project. Provide the maximum extent of the delay in minutes and the duration of the delay.		
5.17.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.18 Tribal Cultural Resources[32]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.18.1 Environmental Setting		
5.18.1.1: Outreach to Tribes. Provide a list of all tribes that are on the Native American Heritage Commission (NAHC) list of tribes that are affiliated with the project area. Provide a discussion of outreach to Native American tribes, including tribes notified, responses received from tribes, and information of potential tribal cultural resources provided by tribes. Any information of potential locations of tribal cultural resources should be submitted in an Appendix under clearly marked confidential cover. Provide copies of all correspondence with tribes in an Appendix.		
5.18.1.2: Tribal Cultural Resources. Describe tribal cultural resources (TCRs) that are within the project area. a) Summarize the results of attempts to identify possible TCRs using publicly available documentary resources. The identification of TCRs using documentary sources should include review of archaeological site records and should begin during the preparation of the records search report (see Attachment 3). During the inventory phase, a formal site record would be prepared for any resource identified unless tribes object. b) Summarize attempts to identify TCRs by speaking directly with tribal representatives.		
5.18.1.3: Ethnographic Study. The ethnographic study should document the history of Native American use of the area and oral history of the area.		
5.18.2 Regulatory Setting		
5.18.2.1: Regulatory Setting. Identify any applicable federal, state or local laws or regulations for tribal cultural resources that apply to the project.		

[32] For a description of historical resources and requirements for cultural resources that are not tribal cultural resources, refer to Section 5.5 Cultural Resources.

5.18.3 Impact Questions		
5.18.3.1: Impact Questions. The impact questions include all tribal cultural resources impact questions in the current version of CEQA Guidelines, Appendix G. **5.18.3.2:** Additional CEQA Impact Questions: None.		
5.18.4 Impact Analysis		
5.18.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.18.4.2: Information Provided by Tribes. Include an analysis of any impacts that were identified by the tribes during the Applicant's outreach.		
5.18.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.19 Utilities and Service Systems

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.19.1 Environmental Setting		
5.19.1.1: Utility Providers. Identify existing utility providers and the associated infrastructure that serves the project area.		
5.19.1.2: Utility Lines. Describe existing utility infrastructure (e.g., water, gas, sewer, electrical, stormwater, telecommunications, etc.) that occurs in the project ROW. Provide GIS data and/or as-built engineering drawings to support the description of existing utilities and their locations.		
5.19.1.3: Approved Utility Projects. Identify utility projects that have been approved for construction within the project ROW but that have not yet been constructed.[33]		
5.19.1.4: Water Supplies. Identify water suppliers and the water source (e.g., aqueduct, well, recycled water, etc.). For each potential water supplier, provide data on the existing water capacity, supply, and demand.		
5.19.1.5: Landfills and Recycling. Identify local landfills that can accept construction waste and may service the project. Provide documentation of landfill capacity and estimated closure date. Identify any recycling centers in the area and opportunities for construction and demolition waste recycling.		

[33] Note that this project information should be consistent with the cumulative project description included in Chapter 7.

5.19.2 Regulatory Setting		
5.19.2.1: Regulatory Setting. Identify any applicable federal, state or local laws or regulations for utilities that apply to the project.		
5.19.3 Impact Questions		
5.19.3.1: Impact Questions. All impact questions for this resource area in the current version of CEQA Guidelines, Appendix G. **5.19.3.2:** Additional CEQA Impact Question: Would the project increase the rate of corrosion of adjacent utility lines as a result of alternating current impacts?		
5.19.4 Impact Analysis		
5.19.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.19.4.2: Utility Relocation. Identify any project conflicts with existing utility lines. If the project may require relocation of existing utilities, identify potential relocation areas and analyze the impacts of relocating the utilities. Provide a map showing the relocated utility lines and GIS data for all relocations.		
5.19.4.3: Waste a) Identify the waste generated by construction, operation, and demolition of the project. b) Describe how treated wood poles would be disposed of after removal, if applicable. c) Provide estimates for the total amount of waste materials to be generated by waste type and how much of it would be disposed of, reused, or recycled.		
5.19.4.4: Water Supply a) Estimate the amount of water required for project construction and operation. Provide the potential water supply source(s). b) Evaluate the ability of the water supplier to meet the project demand under a multiple dry year scenario. c) Provide a discussion as to whether the proposed project meets the criteria for consideration as a project subject to Water Supply Assessment Requirements under Water Code Section 10912. d) If determined to be necessary under Water Code Section 10912, submit a Water Supply Assessment to support conclusions that the proposed water source can meet the project's anticipated water demand, even in multiple dry year scenarios. Water Supply Assessments should be approved by		

the water supplier and consider normal, single-dry, and multiple-dry year conditions.		
5.19.4.5: Cathodic Protection. Analyze the potential for existing utilities to experience corrosion due to proximity to the proposed project. Identify cathodic protection measures that could be implemented to reduce corrosion issues and where the measures may be applied.		
5.19.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.20 Wildfire

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.20.1 Environmental Setting		
5.20.1.1: High Fire Risk Areas and State Responsibility Areas a) Identify areas of high fire risk or State Responsibility Areas (SRAs) within the project area. Provide GIS data for the Wildland Urban Interface (WUI) and Fire Hazard Severity Zones (FHSZ) mapping along the project alignment. Include areas mapped by CPUC as moderate and high fire threat districts as well as areas mapped by CalFire. b) Identify any areas the utility has independently identified as High FHSZ known to occur within the proposed project vicinity.		
5.20.1.2: Fire Occurrence. Identify all recent (within the last 10 years) large fires that have occurred within the project vicinity. For each fire, identify the following: a) Name of the fire b) Location of fire c) Ignition source and location of ignition d) Amount of land burned e) Boundary of fire area in GIS		
5.20.1.3: Fire Risk. Provide the following information for assessment of baseline fire risk in the area: a) Provide fuel modeling using Scott Burgan fuel models, or other model of similar quality. b) Provide values of wind direction and speed, relative humidity, and temperature for representative weather stations along the alignment for the previous 10 years, gathered hourly. c) Digital elevation models for the topography in the project region showing the relationship between terrain and wind patterns, as well as localized topography to show the effects of terrain on wind flow, and on a more local area to show effect of slope on fire spread.		

d) Describe vegetation fuels within the project vicinity and provide data in map format for the project vicinity. USDA Fire Effects Information System or similar data source should be consulted to determine high-risk vegetation types. Provide the mapped vegetation fuels data in GIS format.		
5.20.1.4: Values at Risk. Identify values at risk along the proposed alignment. Values at risk may include: Structures, improvements, rare habitat, other values at risk, (including utility-owned infrastructure) within 1000 feet of the project. Provide some indication as to its vulnerability (wood structures vs. all steel features). Communities and/or populations near the project should be identified with their proximity to the project defined.		
5.20.1.5: Evacuation Routes. Identify all evacuation routes that are adjacent to or within the project area. Identify any roads that lack a secondary point of access or exit (e.g., cul-de-sacs).		
5.20.2 Regulatory Setting		
5.20.2.1: Regulatory Setting. Identify applicable federal, state, and local laws, policies, and standards for wildfire.		
5.20.2.2: CPUC Standards. Identify any CPUC standards that apply to wildfire management of the new facilities.		
5.20.3 Impact Questions		
5.20.3.1: Impact Questions. All impact questions for this resource area in the current version of CEQA Guidelines, Appendix G. **5.20.3.2:** Additional CEQA Impact Questions: None.		
5.20.4 Impact Analysis		
5.20.4.1: Impact Analysis. Provide an impact analysis for each checklist item identified in CEQA Guidelines, Appendix G for this resource area and any additional impact questions listed above.		
Include the following information in the impact analysis:		
5.20.4.2: Fire Behavior Modeling. For any new electrical lines, provide modeling to support the analysis of wildfire risk.		
5.20.4.3: Wildfire Management. Describe approaches that would be implemented during operation and maintenance to manage wildfire risk in the area. Provide a copy of any Wildfire Management Plan.		
5.20.5 CPUC Draft Environmental Measures		
Refer to Attachment 4, CPUC Draft Environmental Measures.		

5.21 Mandatory Findings of Significance[34]

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
5.21.1: Impact Assessment for Mandatory Findings of Significance. Provide an impact analysis for each of the mandatory findings of significance provided in Appendix G of the CEQA Guidelines. The impact analysis can reference relevant information and conclusion from the biological resources, cultural resources, air quality, hazards, and cumulative sections of the PEA, where applicable.		

6 Comparison of Alternatives

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
6.1: Alternatives Comparison a) Compare the ability of each alternative described in Chapter 4 against the proposed project in terms of its ability to avoid or reduce a potentially significant impact. The alternatives addressed in this section will each be: i. Potentially feasible ii. Meet the underlying purpose of the proposed project iii. Meet most of the basic project objectives, and iv. Avoid or reduce one or more potentially significant impacts. b) The relative effect of the various potentially significant impacts may be compared using the following or similar descriptors and an accompanying analysis: i. Short-term versus long-term impacts ii. Localized versus widespread impacts iii. Ability to fully mitigate impacts c) Impacts that the Applicant believes would be less than significant with mitigation may also be included in the analysis, but only if the steps listed above fail to distinguish among the remaining few alternatives.		
6.2: Alternatives Ranking. Provide a detailed table that summarizes the Applicant's comparison results and ranks the alternatives in order of environmental superiority.[35]		

[34] PEAs need only include a Mandatory Findings of Significance section if CPUC CEQA Unit Staff determine that a Mitigated Negative Declaration may be the appropriate type of document to prepare for the project, as determined through Pre-filing consultation. If no such determination has been made, then a Mandatory Findings of Significance section and the requirements below are not required.

[35] If the proposed project does not rank #1 on the list, the Applicant should provide the rationale for selecting the proposed project.

7 Cumulative and Other CEQA Considerations

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
7.1 Cumulative Impacts		
7.1.1: List of Cumulative Projects a) Provide a detailed table listing past, present, and reasonably foreseeable future projects within and surrounding the project area (approximately 2-mile buffer)[36]. The following information should be provided for each project in the table: i. Project name and type ii. Brief description of the project location(s) and associated actions iii. Distance to and name of the nearest project component iv. Project status and anticipated construction schedule v. Source of the project information and date last checked (for each individual project), including links to any public websites where the information was obtained so it can be reviewed and updated (the project information should be current when the PEA is filed) b) Provide a supporting map (or maps) showing project features and cumulative project locations and/or linear features. Provide associated GIS data.		
7.1.2: Geographic Scope. Define the geographic scope of analysis for each resource topic. The geographic scope of analysis for each resource topic should consider the extent to which impacts can be cumulative. For example, the geographic scope for cumulative noise impacts would be more limited in scale than the geographic scope for biological resource impacts because noise attenuates rapidly with distance. Explain why the geographic scope is appropriate for each resource.		
7.1.3: Cumulative Impact Analysis. Provide an analysis of cumulative impacts for each resource topic included in Chapter 5. Evaluate whether the proposed project impacts are cumulatively considerable[37] for any significant cumulative impacts.		
7.2 Growth-Inducing Impacts		
7.2.1: Growth-Inducing Impacts. Provide an evaluation of the following potential growth-inducing impacts:		

36 Information on cumulative projects may be obtained from federal, state, and local agencies with jurisdiction over planning, transportation, and/or resource management in the area. Other projects the Applicant is involved in or aware of in the area should be included.

37 "Cumulatively considerable" means that the incremental effects of an individual project are significant when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects.

a) Would the proposed project foster any economic or population growth, either directly or indirectly, in the surrounding environment? b) Would the proposed project cause any increase in population that could further tax existing community service facilities (i.e., schools, hospitals, fire, police, etc.)? c) Would the proposed project remove any obstacles to population growth? d) Would the proposed project encourage and facilitate other activities that would cause population growth that could significantly affect the environment, either individually or cumulatively?		

8 List of Preparers

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
8.1: List of Preparers. Provide a list of persons, their organizations, and their qualifications for all authors and reviewers of each section of the PEA.		

9 References

This section will include, but is not limited to, the following:	PEA Section and Page Number	Applicant Notes, Comments
9.1: Reference List a) Organize all references cited in the PEA by section within a single chapter called "References." b) Within the References chapter, organize all of the Chapter 5 references under subheadings for each resource area section.		
9.2: Electronic References a) Provide complete electronic copies of all references cited in the PEA that cannot be readily obtained for free on the Internet. This includes any company-specific documentation (e.g., standards, policies, and other documents). b) If the reference can be obtained on the Internet, the Internet address will be provided.		

PEA Checklist Attachments

Attachment 1: GIS Data Requirements

This Attachment includes specific requirements and format of GIS data that is intended to be applicable to all PEAs. The specific GIS data requirements may be updated on a project-specific basis during Pre-filing coordination with CPUC's CEQA Unit Staff.

1. GIS data will be provided in an appropriate format (i.e., point, line, polygon, raster) and scale to adequately verify assumptions in the PEA and supporting materials and determine the level of environmental impacts. At a minimum, all GIS data layers will include the following metadata properties:
    a. The source (e.g., report reference), date, title, and preparer (name or company)
    b. Description of the contents and any limitations of the data
    c. Reference scale and accuracy of the data
    d. Complete attributes that correspond to the detailed mapbook, project description, and figures presented in the PEA and/or supporting application materials, including unique IDs, labels, geometry, and other appropriate project details
2. Where precise boundaries of project features may change (e.g., staging areas and temporary construction work areas), the Applicant will provide GIS data layers with representative boundaries to evaluate potential environmental impacts as a worst-case scenario.
3. Provide GIS data for:
    a. All proposed <u>and alternative</u> project facilities including but not limited to existing and proposed/alternative ROWs; substations and switching stations; pole/tower locations; conduit; vaults, pipelines; valves; compressor stations; metering stations; valve stations, gas wellheads; other project buildings, facilities, and components (both temporary and permanent); telecommunication and distribution lines modifications or upgrades related to the project; marker ball and lighting locations; and mileposts, facility perimeters, and other demarcations or segments as applicable
    b. All proposed areas required for construction and construction planning, including all proposed and alternative disturbance areas (both permanent and temporary); access roads; geotechnical work areas; extra work areas (e.g., staging areas, parking areas, lay-down areas, work areas at and around specific pole/tower sites, pull and tension sites, helicopter landing areas); airport landing areas; underground installation areas (e.g. trenches, vaults, underground work areas); horizontal directional drilling, jack and bore, or tunnel areas; blasting areas; and any areas where special construction methods may need to be employed
    c. Within the PEA checklist there are also specific requirements for environmental resources within Chapter 5. All environmental resource GIS data must meet the minimum mapping standards specified in this Attachment.

Attachment 2: Biological Resource Technical Report Standards

Definitions

The following biological resources will be considered within the scope of the PEA and the Biological Resources Technical Report:

Sensitive Vegetation Communities and Habitats

a) Sensitive vegetation communities/habitats identified in local or regional plans, policies, or regulations, or designated by CDFW38 or USFWS
b) Areas that provide habitat for locally unique biotic species/communities (e.g., oak woodlands, grasslands, and forests)
c) Habitat that contains or supports rare, endangered, or threatened wildlife or plant species as defined by CDFW and USFWS
d) Habitat that supports CDFW Species of Special Concern
e) Areas that provide habitat for rare or endangered species and that meet the definition in CEQA Guidelines Section 15380
f) Existing game and wildlife refuges and reserves
g) Lakes, wetlands, estuaries, lagoons, streams, and rivers
h) Riparian corridors

Special-Status Species

a) Species listed or proposed for listing as threatened or endangered under the federal Endangered Species Act (ESA) (50 CFR § 17.12 [listed plants], 17.11 [listed animals] and various notices in the Federal Register [proposed species])
b) Species that are candidates for possible future listing as threatened or endangered under the federal ESA (61 FR § 40, February 28, 1996)
c) Species listed or proposed for listing by the State of California as threatened or endangered under the California ESA (14 CCR § 670.5)
d) Plants listed as rare or endangered under the California Native Plant Protection Act (California Fish and Game Code, Section 1900 et seq.)
e) Species that meet the definitions of rare and endangered under CEQA. CEQA Guidelines Section 15380 provides that a plant or animal species may be treated as "rare or endangered" even if not on one of the official lists.
f) Plants considered by the California Native Plant Society (CNPS) to be "rare, threatened or endangered in California" (California Rare Plant Rank 1A, 1B, 2A, and 2B) as well as California Rare Plant Rank 3 and 4 plant species
g) Species designated by CDFW as Fully Protected or as a Species of Special Concern
h) Species protected under the Federal Bald and Golden Eagle Protection Act
i) Birds of Conservation Concern or Watch List species
j) Bats considered by the Western Bat Working Group to be "high" or "medium" priority (Western Bat Working Group 2015)

[38] CDFW's Rarity Ranking follows NatureServe's Heritage Methodology (Faber-Langendoen, et al. 2016) in which communities are given a G (global) and S (state) rank based on their degree of imperilment (as measured by rarity, trends, and threats). Communities with a Rarity Ranking of S1 (critically imperiled), S2 (imperiled), or S3 (vulnerable) are considered sensitive by CDFW.

Biological Resource Technical Report Minimum Requirements

Report Contents

The Biological Resource Technical Report will include the following information at a minimum.

a) **Preliminary Agency Consultation.** Describe any pre-survey contact with agencies. Describe any agency approvals that were required for biologists or agency protocols that were applied to the survey effort. Provide copies of correspondence and meeting notes with the names and contact information for agency staff and the dates of consultation as an appendix to the Biological Resources Technical Report.
b) **Records Search.** Provide the results of all database and literature searches for biological resources within and surrounding the project area. Identify all sources reviewed (e.g., CNDDB, CNPS, USFWS, etc.).
c) **Biological Resource Survey Method.** Identify agency survey requirements and protocols applicable to each biological survey that was conducted. Identify the areas where each survey occurred. Identify any limitations for the surveys (e.g., survey timing or climatic conditions) that could affect the survey results.
d) **Vegetation Communities and Land Cover.** Identify all vegetation communities or land cover types (e.g., disturbed or developed) within the biological survey area. The biological survey area should include a 1,000-foot buffer from project facilities to support CPUC's evaluation of indirect effects.
e) **Aquatic Resources.** Identify any wetlands, streams, lakes, reservoirs, estuarine, or other aquatic resources within the biological survey area. Provide a wetland delineation and all data sheets including National Wetlands Inventory maps (or the appropriate state wetland maps, if National Wetlands Inventory maps are not available) that show all proposed facilities and include milepost locations for proposed pipeline routes. Provide a copy of agency verification of the wetland delineation if the delineation has been verified by the U.S. Army Corps of Engineers or CDFW. If the delineation has not been verified, describe the process and timing for obtaining agency verification.
f) **Habitat Assessments.** Evaluate the potential for suitable habitat in the biological survey area for each species identified in the database and literature search.
g) **Native Wildlife Corridors and Nursery Sites.** Identify any wildlife corridors or nursery sites that occur within the biological survey area.
h) **Survey Results.** Describe all survey results and include a copy of any focused (e.g., rare plant, protocol special-status wildlife) biological resources survey reports.

Mapping and GIS Data

Provide detailed maps (at approximately 1:3,000 scale or similar), and all associated GIS data for the Biological Resources Technical Report and any supporting biological survey reports, including:

a) Biological survey area for each survey that was conducted
b) Vegetation communities and land cover types
c) Aquatic resource delineation
d) Special-status plant locations
e) Special-status wildlife locations
f) Avian point count locations
g) Critical habitat
h) California Coastal Commission or Bay Conservation and Development Commission jurisdictional areas

Attachment 3: Cultural Resource Technical Report Standards

Cultural Resource Inventory Report

Provide a cultural resource inventory report that includes archaeological, unique archaeological, and built-environment resources within all areas that could be affected by the proposed project including areas of indirect effect. The inventory report will include the results of both a literature search and pedestrian survey. The contents will address the requirements in *Archaeological Resource Management Reports: Recommended Contents and Guidelines*. The methodology and results of the inventory should be sufficient to provide the reader with an understanding of the nature, character, and composition of newly discovered and previously identified cultural resources so that the required recommendations about the resource(s) CRHR eligibility are clearly understood. No information regarding the location of the cultural resources will be included in these descriptions. The required Department of Parks and Recreation (DPR) 523 forms, including location information and photographs of the resources, are to be included in a removable confidential appendix to the report.[39]

The inventory report will meet the following requirements:

a) The report should clearly discuss the methods used to identify unique archaeological resources (e.g., how the determination was made about the resources' eligibility).
b) The report should identify large resources such as districts and landscapes where resources indicate their presence, even if federal agencies disagree. It is understood that often only a few contributing elements may be in the project area, and that the boundaries of the large resource may need to be revisited as part of future projects. It is acknowledged that boundaries of districts and landscapes can be difficult to define and there is not always good recorded data on these resources.
c) In the case of archaeological resources, the report should discuss whether each one is also a unique archaeological resource and explain why or why not.
d) Descriptions of resources should include spatial relationships to other nearby resources, raw materials sources, and natural features such as water sources and mountains.
e) The evidence that indicates a particular function or age for a resource should be explicitly described with a clear explanation, not simply asserted.

Cultural Resource Evaluation Report

Provide a cultural resource evaluation report. The report contents required by the state of California are outlined in the *Archaeological Resource Management Reports: Recommended Contents and Guidelines*. The evaluation report should also include:

a) Resource descriptions and evaluations together, and not in separate volumes or report sections. This will facilitate understanding of each resource.
b) An evaluation of each potential or eligible California Register of Historical Resources (CRHR) resource within the public archaeology laboratory (PAL) for all seven aspects of integrity[40] using specific examples for each resource. This evaluation needs to be included in the evaluation

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[39] Any aspect of the PEA and associated data that Applicants believe to be confidential will be provided in full but may be marked confidential if allowed pursuant to General Order 66 or latest applicable Commission rule (e.g., see Public Records Act Proceeding R.14-11-001).

[40] The seven aspects of integrity are location, design, setting, materials, workmanship, feeling, and association, as defined in "***Types of Historical Resources and Criteria for Listing in the California Register of Historical Resources***" [14 CCR 4852(c)]).

report for all resources that could be affected by the project even if the resources were not previously evaluated. Previous evaluations should be reviewed to address change over time.

c) An evaluation of each potential or eligible CRHR resource within the PAL under all four criteria using specific examples for each resource. This evaluation needs to be included in the evaluation report for all resources that could be affected by the project even if the resources were not previously evaluated. The cultural resources professional should make their own recommendation regarding eligibility, which does not need to agree with previous recommendations for CRHR or NRHP, as long as it is clearly explained.
d) For **prehistoric archaeological resources**, Criteria 1, 2 and 3[41] should be explicitly considered. Research efforts to search for important events and persons related to the resource must be described. This evaluation needs to be included in the evaluation report for all resources that could be affected by the project even if the resources were not previously evaluated. The cultural resources professional should make their own recommendation, which does not need to agree with previous recommendations for CRHR or NRHP eligibility, as long as it is clearly explained.
e) While **potential unique archaeological resources** could be identified in the records search report or inventory report, the justification for each individual resource to be considered a resource under CEQA should be presented in this report.
f) If surface information collected during survey is sufficient to make an eligibility recommendation, this reasoning should be outlined explicitly for each resource. This is particularly the case for resources that are believed to have buried subsurface components.
g) If archaeological testing or additional historical research was required in order to evaluate a resource, the evaluation report will be explicit about why the work was required, the results for each resource, and the subsequent eligibility recommendation.
h) For large projects with multiple similar resources where the eligibility justifications for similar resources are essentially identical, it is acceptable to discuss these resources as a group. However, eligibility justifications for each individual resource is preferred, so if the grouping strategy is used, the criteria used to group resources must be clearly justified.
i) Large resources such as districts and landscapes may be challenging to fully evaluate in the context of a single project. CPUC encourages the identification and evaluation of these resources with the understanding that often only a few contributing elements may be located within the project area, and that the boundaries of the large resource may need to be revisited as part of future projects. It is understood that a full evaluation of the resource may be beyond the scope of one project. Regardless, the potential for the project to affect any resources within a district or landscape must be defined.

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[41] Criteria for Designation on the California Register are as follows (defined in http://ohp.parks.ca.gov/?page_id=21238):
- Criterion 1: Associated with events that have made a significant contribution to the broad patterns of local or regional history or the cultural heritage of California or the United States.
- Criterion 2: Associated with the lives of persons important to local, California or national history.
- Criterion 3: Embodies the distinctive characteristics of a type, period, region or method of construction or represents the work of a master or possesses high artistic values.
- Criterion 4: Has yielded, or has the potential to yield, information important to the prehistory or history of the local area, California or the nation.

Attachment 4: CPUC Draft Environmental Measures

About this Attachment: The following CPUC Draft Environmental Measures are provided for consideration during PEA development. They should be discussed with the CPUC's CEQA Unit Staff during Pre-filing, especially with respect to the development of Applicant Proposed Measures. The CPUC Draft Environmental Measures may form the basis for mitigation measures in the CEQA document if appropriate to the analysis of potentially significant impacts. These and other CPUC Draft Environmental Measures may be formally incorporated into Chapter 5 of future versions of the PEA Checklist.

5.1 Aesthetics

Aesthetics Impact Reduction During Construction

All project sites will be maintained in a clean and orderly state. Construction staging areas will be sited away from public view where possible. Nighttime lighting will be directed away from residential areas and have shields to prevent light spillover effects. Upon completion of project construction, project staging and temporary work areas will be returned to pre-project conditions, including re-grading of the site and re-vegetation or re-paving of disturbed areas to match pre-existing contours and conditions.

5.3 Air Quality

Dust Control During Construction

The Applicant shall implement measures to control fugitive dust in compliance with all local air district(s) standards. Dust control measures shall include the following at a minimum:

- All exposed surfaces with the potential of dust-generating shall be watered or covered with coarse rock to reduce the potential for airborne dust from leaving the site.
- The simultaneous occurrence of more than two ground disturbing construction phases on the same area at any one time shall be limited. Activities shall be phased to reduce the amount of disturbed surfaces at any one time.
- Cover all haul trucks entering/leaving the site and trim their loads as necessary.
- Use wet power vacuum street sweepers to sweep all paved access road, parking areas, staging areas, and public roads adjacent to project sites on a daily basis (at minimum) during construction. The use of dry power sweeping is prohibited.
- All trucks and equipment, including their tires, shall be washed off prior to leaving project sites.
- Apply gravel or non-toxic soil stabilizers on all unpaved access roads, parking areas, and staging areas at project sites.
- Water and/or cover soil stockpiles daily.
- Vegetative ground cover shall be planted in disturbed areas as soon as possible and watered appropriately until vegetation is established.
- All vehicle speeds shall be limited to fifteen (15) miles per hour or less on unpaved areas.
- Implement dust monitoring in compliance with the standards of the local air district.
- Halt construction during any periods when wind speeds are in excess of 50 mph.

5.5 Cultural Resources

Human Remains (Construction and Maintenance)

Avoidance and protection of inadvertent discoveries that contain human remains shall be the preferred protection strategy with complete avoidance of such resources ensured by redesigning the project. If human remains are discovered during construction or maintenance activities, all work shall be diverted from the area of the discovery, and the CPUC shall be informed immediately. The Applicant shall contact the County Coroner to determine whether or not the remains are Native American. If the remains are determined to be Native American, the Coroner will contact the Native American Heritage Commission (NAHC). The NAHC will then identify the person or persons it believes to be the most likely descendant of the deceased Native American, who in turn would make recommendations for the appropriate means of treating the human remains and any associated funerary objects.

If the remains are on federal land, the remains shall be treated in accordance with the Native American Graves Protection and Repatriation Act (NAGPRA). If the remains are not on federal land, the remains shall be treated in accordance with Health and Safety Code Section 7050.5, CEQA Section 15064.5(e), and Public Resources Code Section 5097.98.

5.8 Greenhouse Gas Emissions

Greenhouse Gas Emissions Reduction During Construction

The following measures shall be implemented to minimize greenhouse gas emissions from all construction sites:

- If suitable park-and-ride facilities are available in the project vicinity, construction workers shall be encouraged to carpool to the job site.
- The Applicant shall develop a carpool program to the job site.
- On road and off-road vehicle tire pressures shall be maintained to manufacturer specifications. Tires shall be checked and re-inflated at regular intervals.
- Demolition debris shall be recycled for reuse to the extent feasible.
- The contractor shall use line power instead of diesel generators at all construction sites where line power is available.
- The contractor shall maintain construction equipment per manufacturing specifications.

5.19 Utilities and Service Systems

Notify Utilities with Facilities Above and Below Ground

The Applicant shall notify all utility companies with utilities located within or crossing the project ROW to locate and mark existing underground utilities along the entire length of the project at least 14 days prior to construction. No subsurface work shall be conducted that would conflict with (i.e., directly impact or compromise the integrity of) a buried utility. In the event of a conflict, areas of subsurface excavation or pole installation shall be realigned vertically and/or horizontally, as appropriate, to avoid other utilities and provide adequate operational and safety buffering. In instances where separation between third-party utilities and underground excavations is less than 5 feet, the Applicant shall submit the intended construction methodology to the owner of the third-party utility for review and approval at least 30 days prior to construction. Construction methods shall be adjusted as necessary to assure that the integrity of existing utility lines is not compromised.

5.20 Wildfire

Construction Fire Prevention Plan

A project-specific Construction Fire Prevention Plan for both construction and operation of the project shall be submitted for review prior to initiation of construction. A draft copy of the Plan shall be provided to the CPUC and state and local fire agencies at least 90 days before the start of any construction activities in areas designated as Very High or High Fire Hazard Severity Zones. Plan reviewers shall also include federal, state, or local agencies with jurisdiction over areas where the project is located. The final Plan shall be approved by the CPUC at least 30 days prior to the initiation of construction activities. The Plan shall be fully implemented throughout the construction period and include the following at a minimum:

- The purpose and applicability of the Plan
- Responsibilities and duties
- Preparedness training and drills
- Procedures for fire reporting, response, and prevention that include:
  - Identification of daily site-specific risk conditions
  - The tools and equipment needed on vehicles and to be on hand at sites
  - Reiteration of fire prevention and safety considerations during tailboard meetings
  - Daily monitoring of the red-flag warning system with appropriate restrictions on types and levels of permissible activity
- Coordination procedures with federal and local fire officials
- Crew training, including fire safety practices and restrictions
- Method(s) for verifying that all Plan protocols and requirements are being followed

A project Fire Marshal or similar qualified position shall be established to enforce all provisions of the Construction Fire Prevention Plan as well as perform other duties related to fire detection, prevention, and suppression for the project. Construction activities shall be monitored to ensure implementation and effectiveness of the Plan.

Fire Prevention Practices (Construction and Maintenance)

The Applicant shall implement ongoing fire patrols during the fire season as defined each year by local, state, and federal fire agencies. These dates vary from year to year, generally occurring from late spring through dry winter periods. During Red Flag Warning events, as issued daily by the National Weather Service, all construction/maintenance activities shall cease, with an exception for transmission line testing, repairs, unfinished work, or other specific activities which may be allowed if the facility/equipment poses a greater fire risk if left in its current state.

All construction/maintenance crews and inspectors shall be provided with radio and cellular telephone access that is operational in all work areas and access routes to allow for immediate reporting of fires. Communication pathways and equipment shall be tested and confirmed operational each day prior to initiating construction/maintenance activities at each work site. All fires shall be reported to the fire agencies with jurisdiction in the area immediately upon discovery of the ignition.

All construction/maintenance personnel shall be trained in fire-safe actions, initial attack firefighting, and fire reporting. All construction/maintenance personnel shall be trained and equipped to extinguish small fires in order to prevent them from growing into more serious threats. All construction/maintenance personnel shall carry at all times a laminated card and be provided a hard hat sticker that list pertinent telephone numbers for reporting fires and defining immediate steps to take if a fire starts. Information on laminated contact cards and hard hat stickers shall be updated and redistributed to all construction/maintenance personnel and outdated cards and hard hat stickers shall be destroyed prior to the initiation of construction/maintenance activities on the day the information change goes into effect.

Construction/maintenance personnel shall have fire suppression equipment on all construction vehicles. Construction/maintenance personnel shall be required to park vehicles away from dry vegetation. Water tanks and/or water trucks shall be sited or available at active project sites for fire protection during construction. The Applicant shall coordinate with applicable local fire departments prior to construction/maintenance activities to determine the appropriate amounts of fire equipment to be carried on vehicles and, should a fire occur, to coordinate fire suppression activities.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's Own Motion into Natural Gas Prices During Winter 2022-2023 and Resulting Impacts to Energy Markets.	I.23-03-008 (Filed March 20, 2023)

JOINT RESPONSE OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G) TO ORDER INSTITUTING INVESTIGATION ON THE COMMISSION'S OWN MOTION INTO NATURAL GAS PRICES DURING WINTER 2022-2023 AND RESULTING IMPACTS TO ENERGY MARKETS

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Dated: April 19, 2023

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Pursuant to the California Public Utilities Commission (Commission) Order Instituting Investigation on the Commission's Own Motion into Natural Gas Prices During Winter 2022-2023 and Resulting Impacts to Energy Markets, Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E), hereby submit their response to preliminary matters identified in the OII.[1]

I. INTRODUCTION AND BACKGROUND

SoCalGas and SDG&E appreciate the opportunity to provide these comments in response to the questions posed by the Commission regarding the recent spike in natural gas prices in winter 2022-2023. SoCalGas and SDG&E share the Commission's interest in understanding the factors underlying the recent market events to inform development of policies and reforms that

1 Pursuant to Rule 1.8(d) of the CPUC Rules of Practice and Procedure, SoCalGas has been authorized to submit this Joint Response on behalf of SDG&E.

might serve to protect against the risk of future similar events and mitigate adverse impacts on consumers.

SoCalGas operates an integrated gas transmission system on behalf of both SoCalGas and SDG&E (SoCalGas System), consisting of pipeline and storage facilities designed to transport natural gas supply to primary load centers in Los Angeles and San Diego. Initially, the SoCalGas System received and redelivered gas from the east to the load centers in the Los Angeles Basin, Imperial Valley, San Joaquin Valley, north coastal areas, and San Diego County. As SoCalGas sought to diversify sources of natural gas supply, it built interconnections to concurrently accept natural gas deliveries from the North.

SoCalGas also operates four underground storage facilities in its service territory—Honor Rancho, La Goleta, Playa del Rey, and Aliso Canyon. The SoCalGas System was designed to operate using a combination of underground storage and pipeline supplies to meet customer demand, as flowing natural gas travels slowly at approximately 20-30 miles per hour and SoCalGas's natural gas receipt points, located at the fringes of the service territory, are too far from the load centers to fully support customers' changing needs throughout the operating day. Storage facilities provide supply to customers in response to daily, hourly, and seasonal gas demand, provide a local and strategic supply source, and increase systemwide capacity and flexibility.

California currently receives over 95% of its natural gas supply from out-of-state sources as California-produced local supplies continue to trend downwards.[2] The SoCalGas System is

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[2] California-sourced production delivered to SoCalGas has declined from 232 MMcfd in 2007 (and 9% of total throughput) to just 86 MMcfd in 2021 (4% of total throughput). (*See* California Gas and Electric Utilities, *2022 California Gas Report* [hereinafter, 2022 California Gas Report], at 41, available at: https://www.socalgas.com/sites/default/files/Joint_Utility_Biennial_Comprehensive_California_Gas_

also at the terminus of several interstate pipelines delivering gas into California and underground storage serves as the system's largest contingency resource for flexibility and resiliency, mitigating impacts caused by disruptions in delivery of interstate gas supply. Storage facilities also provide system and market flexibility by providing balancing services and a physical price hedge on gas commodity costs.

Developing and maintaining gas infrastructure (e.g., pipelines, compressors, and storage) is critical to maintaining gas and electric service reliability during peak demand periods and mitigating price volatility. The availability of interstate and intrastate pipeline capacity during periods of high demand provides access to out-of-state supplies that can help mitigate prices and support reliability. To preserve available capacity on its system, SoCalGas strives to schedule its planned system maintenance, which requires taking capacity offline, during off-peak periods. This past winter, SoCalGas System's available capacity to receive gas supplies from out-of-state delivered by Backbone Transportation Service (BTS) customers[3] averaged 2,996 thousand dekatherm per day (MDthd),[4] and SoCalGas observed an average system utilization rate of

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Report_2022.pdf; California Gas and Electric Utilities, *2008 California Gas Report*, at 26, available at: https://www.socalgas.com/regulatory/documents/cgr/2008_CGR.pdf.)

3 "Backbone Transmission Service Customers" are commonly referred to as shippers who transport gas from SoCalGas System Receipt Points and California Producer interconnects to the SoCalGas City Gate storage fields and end user contracts. All gas delivered to the SoCalGas System must be scheduled under a Backbone Transmission Service Contract.

4 Excluding local production receipt capacity. This means if customers deliver that much supply to the SoCalGas System, and there is sufficient customer demand, SoCalGas can redeliver that gas supply to customers. Supplies delivered to the SoCalGas system, however, do not reach these available receipt levels for a variety of reasons, including that customers may choose to use SoCalGas's balancing service rather than deliver supplies, California production has declined over time, system demand frequently does not require maximum delivery of supply, or flowing supplies may not be available due to weather patterns or maintenance impacting the interstate pipelines upstream of the SoCalGas system.

approximately 89%.[5] Storage inventory also mitigates prices and supports reliability. At the start of the winter season, SoCalGas's storage inventory was at a 6-year high[6] and was nearly full at 88 Bcf.[7] Without this storage inventory, considering the infrastructure constraints on interstate pipelines, price volatility at the SoCal Border and SoCal Citygate trading points may have been greater this past winter.

SoCalGas operated its system safely and reliably during winter 2022-2023 without declaring any system-wide curtailments, or curtailments on the southern portion of SoCalGas's System (Southern System).[8] This was despite a series of winter storms which brought sustained cold and high demand over several weeks this past winter[9] and below-average temperatures in the West, stretching from Western Canada to California, which started earlier than in past years and lasted much longer throughout the winter season. This past winter season was the coldest in SoCalGas's service territory in almost 40 years and SDG&E's service territory in at least 50

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5 Customers do not typically fully balance their supply with their demand even given SoCalGas's balancing rules. While a review of scheduled deliveries shows that customers have used on average 80% of interstate available receipt capacity, SoCalGas adopted utilization factors of 85% and 90% in its 2022-2023 Winter Technical Assessment. These factors reflect SoCalGas's expectation of tighter balancing requirements through this winter season in response to the storage capabilities and supply outlook.

6 Of the 92.06 Bcf of allowable working storage on SoCalGas's system, 82.5 Bcf is currently allocated to core and 9.56 Bcf is currently allocated to the Balancing Function.

7 SoCalGas's total available storage inventory capacity this winter was 92 Bcf. Pursuant to D.21-11-008, the current maximum allowable inventory at Aliso Canyon inventory is 41.16 Bcf.

8 The SoCalGas Southern System is the portion of its transmission system serving Riverside, San Bernardino, Imperial, and San Diego counties. The primary source of supply is the El Paso Natural Gas system at Ehrenberg. The Southern System has no direct access to flowing supplies from other SoCalGas system receipt points other than limited receipts from the TGN system at Otay Mesa and has no direct access to SoCalGas storage assets.

9 SoCalGas declared a weather-related Southern System Curtailment Watch effective December 13, 2022, which ended December 17, 2022, and a Systemwide Curtailment Watch effective March 2, 2023, which concluded later the same day.

years. SoCalGas made storage inventory withdrawals throughout the season[10] and utilized operator tools such as Low Operational Flow Orders (OFOs). OFOs are issued to incentivize customers to procure additional flowing supply to meet their daily demand when the system forecast of storage withdrawals used for balancing exceeds the withdrawal capacity allocated to the balancing function. In addition to, and separate from, operating an integrated gas transmission system, SoCalGas procures natural gas for retail core customers of both SoCalGas and SDG&E.[11] Pursuant to D.07-12-019, Ordering Paragraph 4, the retail core portfolios of SoCalGas and SDG&E were consolidated into one single portfolio managed by SoCalGas's Gas Acquisition Department, effective April 1, 2008.[12] SDG&E's Energy Procurement department is separately responsible for the procurement of natural gas used in the production of electricity for SDG&E.

To build awareness of expected higher gas prices this past winter, SoCalGas leveraged existing direct customer communications channels, engaged media outlets, and conducted numerous outreach efforts through community organizations and local officials. These communications provided information regarding helpful resources, tools, programs and services available to customers to help with the gas prices.

As presented at the Commission's *en banc* hearing, the U.S. Energy Information Administration (EIA) identified several factors as contributing to the sharp increase in gas prices. These factors include widespread, below-normal temperatures in the West (Western Canada to California), high natural gas consumption, interstate natural gas pipeline constraints, lower

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[10] Aliso Canyon storage availability subject to the Aliso Canyon Withdrawal Protocol.

[11] SoCalGas and SDG&E's procurement activities are done in compliance with all relevant Commission Affiliate Transaction Rules. (*See* D.97-12-088; D.01-09-056; D.06-12-029; D.07-12-019.)

[12] D.07-12-019 at 114, OP 4.

imports from Canada, and low natural gas storage inventories in the Pacific Region. Another potential factor that was discussed at the *en banc* was the significant constraint that existed on El Paso Natural Gas Company's (EPNG) transmission system. Additional factors discussed at the *en banc* included decreased availability of hydroelectric power due to prolonged drought resulting in increased competition for natural gas for electric generation, increased reliance on natural gas-powered generation to support increasing levels of intermittent generation, and changes to gas storage levels in Pacific Gas and Electric Company's (PG&E) territory following reclassification of 51 Bcf of natural gas from working gas to base gas.

There are specific concrete steps – both in the near term and the longer term – that can be taken to help avoid or mitigate future similar market events. In the near term, the Commission could mitigate the risk of another gas price spike this coming summer and next winter by authorizing increased inventory at SoCalGas's Aliso Canyon facility, as proposed in SoCalGas and SDG&E's Petition for Modification filed on April 19, 2023, and eliminating the Aliso Canyon Withdrawal Protocol. This could help provide a buffer against supply constraints and elevated prices during winter peak season or high summer demand days. In addition, in the near term, SoCalGas is planning additional customer communications by expanding text (SMS) message options for high natural gas price alerts to customers, to provide additional awareness to support customers with energy and bill management during the winter season.

In the longer term, the Commission could help protect against price spikes by providing avenues for utilities to diversify supplies and reduce reliance on out-of-state gas supplies through facilitating the development and procurement of clean fuels such as clean renewable hydrogen[13]

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[13] D.22-12-055 at 9, fn. 2 ("'Clean Hydrogen' is defined as hydrogen produced with a carbon intensity equal to or less than two kilograms of carbon dioxide-equivalent produced at the site of production per kilogram of hydrogen produced.").

and renewable natural gas (RNG). The Commission should also review the current interstate pipeline capacity approval process to determine whether modifications are warranted.

Finally, to help mitigate the impact on consumers if gas price spikes do occur, SoCalGas and SDG&E offer bill related reforms and rate-design tools. First, SoCalGas and SDG&E propose that the natural gas California Climate Credit (CCC) be returned to customers in a winter month rather than April of each year. Second, the utilities could proactively offer their levelized payment plan program that allows eligible arrearages to be amortized into future bill payments that are level each month, with an adjustment every six months. For customers who may have difficulty with a single high bill, the utilities could proactively offer their payment plans which are available to extend payment due dates, or to make installment payments over several months. Third, SoCalGas and SDG&E recommend the use of existing gas utility procurement tariff tools, such as amortization, to assist in mitigating the impact to customers during periods of gas market price volatility. In addition, the utilities could explore a potential temporary cap on the commodity cost passed through to customers during a price spike event, subject to subsequent recovery.

II. PROCEDURAL ISSUES

SoCalGas and SDG&E provide the following comments on procedural issues raised by the OII.

A. Categorization.

The OII preliminarily determines that the category for this proceeding is quasi legislative. SoCalGas and SDG&E agree with this categorization to the extent that the Commission is examining the causes and contributing factors of recent gas market volatility in the context of considering new rules and policies to help mitigate future similar market events and insulate consumers from elevated prices.

B. Evidentiary hearings.

The OII anticipates many of the issues in this proceeding can be addressed through filed comments, public meetings, and/or workshops and preliminarily determined that evidentiary hearings are not needed. SoCalGas and SDG&E agree that the issues raised in the OII may be resolved without the need for evidentiary hearings. If resolution of any of the issues identified in the Scoping Ruling necessitates that the Commission make findings on disputed issues of material fact, however, evidentiary hearings may be required. Depending on the nature of any disputed facts, the Commission may be able to adopt appropriate rules and policies without reaching a determination on disputed factual issues.

C. Confidentiality and Market Sensitive Information.

The OII presents several questions related to gas procurement, operations, and market conditions in the winter months of 2022-2023. To respond to questions and related discovery respondents may be required to provide information that is market-sensitive or otherwise necessitates confidential treatment. In addition, SoCalGas and SDG&E, will need to take care to maintain restrictions on communications and the exchange of market sensitive information between their gas acquisition and gas operations departments to comply with applicable rules. It is unclear at this time what information the Commission will require for purposes of this proceeding. Accordingly, SoCalGas and SDG&E anticipate that they will assess confidentiality and apply appropriate protocols to protect confidential information as the need arises and in response to specific information requests.

III. RESPONSES TO QUESTIONS

The OII provides that Respondents' and other parties' comments submitted in response to the OII should present information regarding market activity that may have affected gas prices during the period November 1, 2022 through March 31, 2023, and should specifically address the questions presented in the OII.[14] SoCalGas and SDG&E's responses to the questions are provided below and are based on information available to SoCalGas and SDG&E at this time.

1. What factors caused or contributed to observed gas price increases beginning on November 1, 2022? Comments shall address market fundamentals as well as other applicable factors.

The Energy Information Administration's (EIA) identified the following factors contributing to natural gas price increases this past winter:[15]

- Widespread, below-normal temperatures in the West (Western Canada to California) which led to high natural gas consumption;
- Pipeline constraints, including resulting from system maintenance in West Texas;
- Lower natural gas imports from Canada; and
- Low natural gas storage levels in the Pacific region.[16]

The EIA found that these simultaneous events increased demand at the same time that supply was limited due to substantial capacity constraints.

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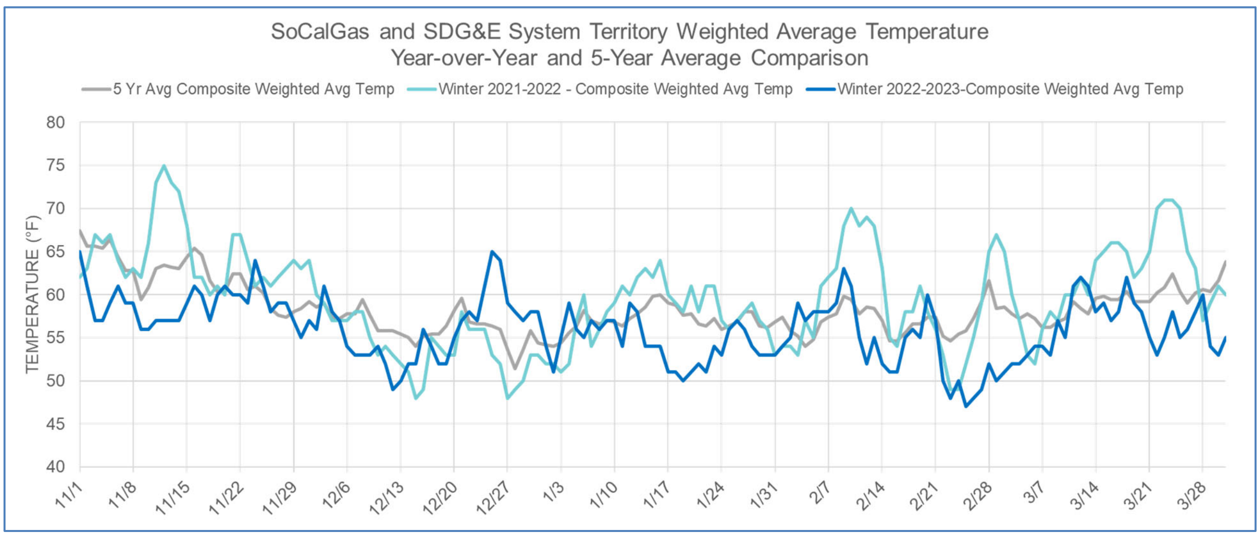
14 Investigation (I.) 23-03-008, *Order Instituting Investigation on the Commission's Own Motion into Natural Gas Prices During Winter 2022-2023 and Resulting Impacts to Energy Markets*, March 20, 2023 (hereinafter, OII), at 10-11.

15 EIA Natural Gas Weekly Update, December 22, 2022, available at: https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/12_22/; EIA, Daily natural gas spot prices in western United States exceed $50.00/MMBtu in December, January 24, 2023, available at: https://www.eia.gov/todayinenergy/detail.php?id=55279.

16 SoCalGas notes that, within its service territory, storage inventory was at a 6-year high on November 1, 2022. However, this could have been higher but for the current maximum inventory limitation at Aliso Canyon.

In SoCalGas's and SDGE's combined service territory, below-normal temperatures were observed to have begun much earlier this past winter starting in November (59 ˚F monthly average), with the system average temperatures approximately 6˚F colder than the prior year, and 3˚F colder than the 5-year composite average leading to **higher natural gas fueled heating demand for the region almost every day from November 1 through March 31, 2023**.[17] The cold temperatures also persisted for much longer throughout the winter season, with March 2023 ending at 56 ˚F, which was also 6˚F colder than the prior year, and 3˚F colder than the 5-year composite average, as shown in Figure 1.

Figure 1



A Heating Degree Day (HDD) is accumulated for every degree Fahrenheit (˚F) the daily average temperature is below a standard reference temperature (SoCalGas and SDG&E: 65 ˚F; PG&E 60˚F) and is 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

17 Over two-thirds of the winter season's daily demand exceeded the 5-year daily demand average, and over three-fourths of the winter season's daily demand exceeded prior winter's (2021/2022) daily demand.

would accumulate 15 HDD, and PG&E would accumulate 10 HDD. From November 2022 through March 2023, the total HDDs for SoCalGas was 1,436 and 1,495 for SDG&E (see Table 1 and 2 below), which are higher than the total HDDs of the 5-month period of a 1-in-35 cold year[18] weather design in the 2022 California Gas Report. Based on SoCalGas HDD data from 1950-present, this 5-month period was the coldest in SoCalGas's service territory since the 1984-1985 winter season. Based on SDG&E HDD data from 1972-present, this 5-month period was the coldest in SDG&E's service territory.

Table 1

SoCalGas Monthly Heating Degree Day (HDD) Weather Designs								
	Cold		Average	Hot			Recorded	
Month	1-in-35 Design	1-in-10 Design		1-in-10 Design	1-in-35 Design		2022/2023 Winter	Note
Nov-2022	146	138	123	108	101		188	Colder than 1-in-35 year
Dec-2022	334	316	282	248	230		300	
Jan-2023	300	284	253	222	206		339	Colder than 1-in-35 year
Feb-2023	257	243	217	191	177		312	Colder than 1-in-35 year
Mar-2023	196	185	165	145	135		297	Colder than 1-in-35 year
Nov. - Mar.	**1,233**	**1,167**	**1,041**	**915**	**849**		**1,436**	Colder than 1-in-35 year

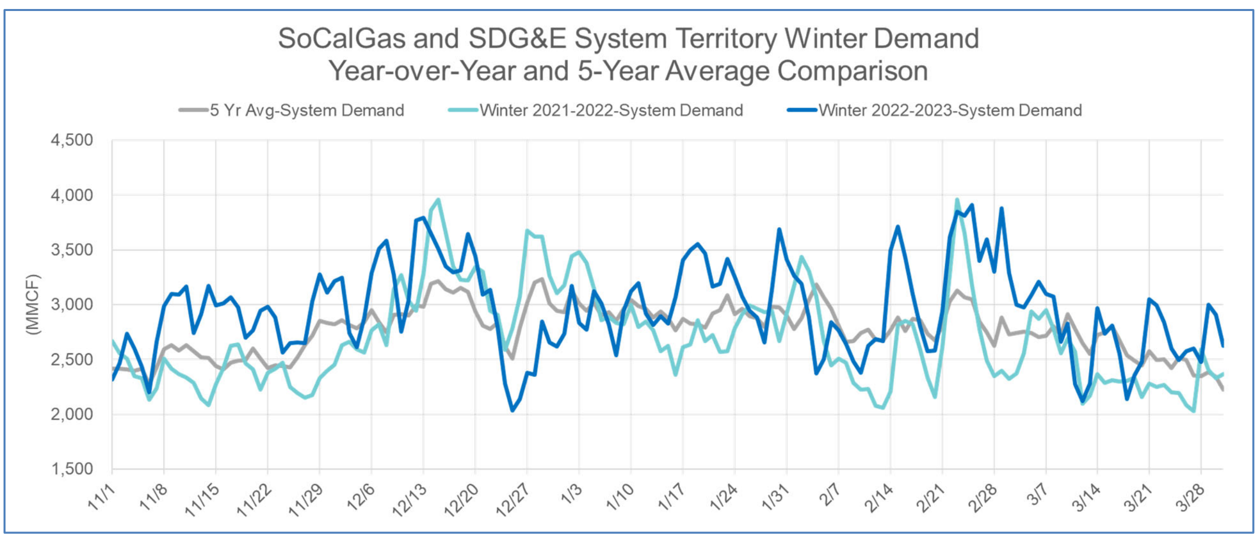
Table 2

SDG&E Monthly Heating Degree Day (HDD) Weather Designs								
	Cold		Average	Hot			Recorded	
Month	1-in-35 Design	1-in-10 Design		1-in-10 Design	1-in-35 Design		2022/2023 Winter	Note
Nov-2022	122	116	103	91	84		217	Colder than 1-in-35 year
Dec-2022	301	285	255	224	208		303	Colder than 1-in-35 year
Jan-2023	278	264	235	207	192		336	Colder than 1-in-35 year
Feb-2023	244	231	206	181	168		335	Colder than 1-in-35 year
Mar-2023	195	185	165	145	135		304	Colder than 1-in-35 year
Nov. - Mar.	**1,141**	**1,080**	**964**	**849**	**788**		**1,495**	Colder than 1-in-35 year

18 A statistical likelihood of occurrence of 1-in-35 on an annual basis.

Earlier than typical cold temperatures throughout the SoCalGas and SDG&E territories led to increased November demand for residential and commercial building space heating by 24% against the 5-year average. Natural gas use also increased for electricity production by 19% in that same period against the 5-year average. In SoCalGas and SDG&E's service territories, total gas demand over the winter season (November 1 through March 31) was over 186 MMcfd higher than the 5-year average, which is equivalent to the daily usage of approximately 1.6 million single family homes,[19] with residential and commercial building space heating up 12% relative to the 5-year average and natural gas used for electricity production up 14% relative to the 5-year average. Figure 2 and Table 3 show SoCalGas's and SDG&E's combined winter system demand against winter 2021-2022 demand and 5-year average demand as comparison points.

Figure 2



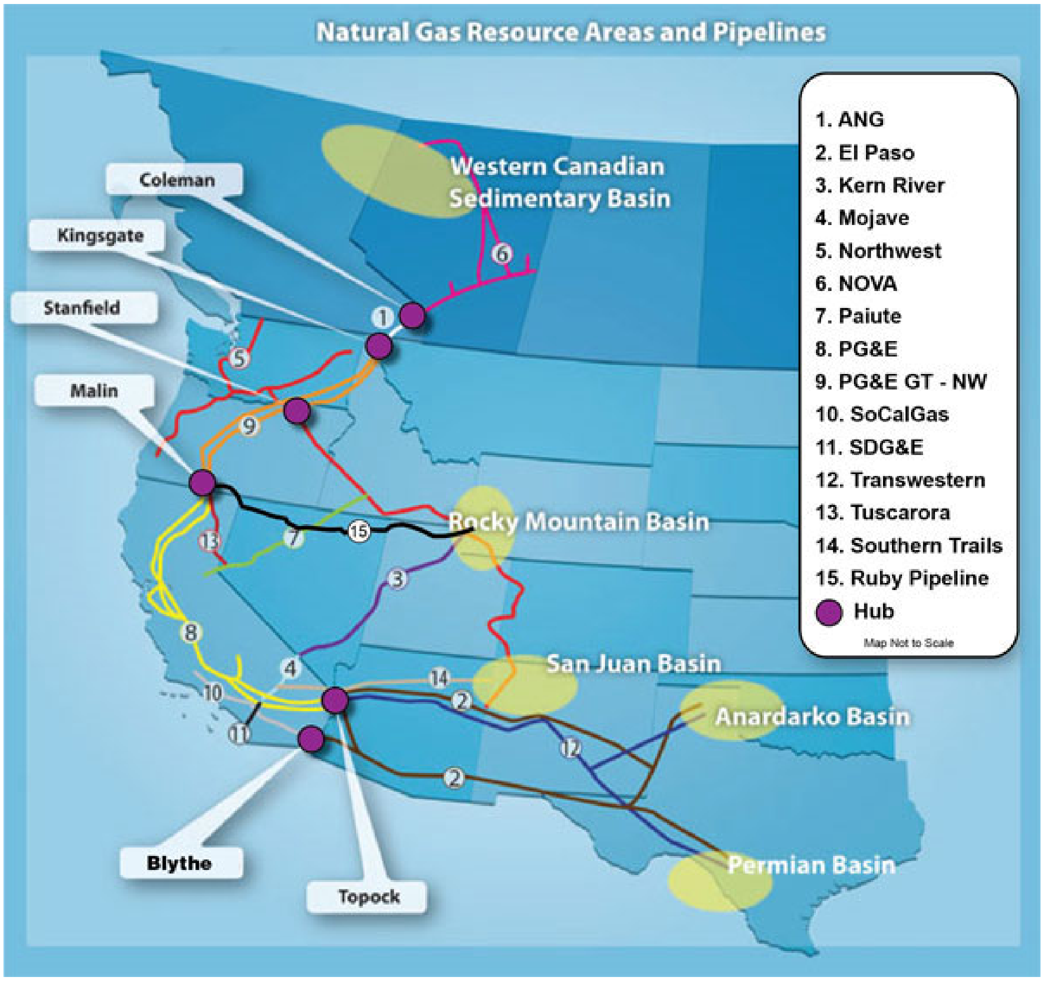
19 2022 California Gas Report at 119, Table 27.

Table 3

SoCalGas and SDG&E Territory Monthly Average Winter Demand (MMcf)					
	Nov	Dec	Jan	Feb	Mar
5 Yr Avg	2,517	2,935	2,926	2,849	2,606
2021-2022	2,358	3,106	2,864	2,716	2,398
2022-2023	2,828	3,039	3,082	3,050	2,773

SoCalGas and SDG&E receive gas supplies from several sedimentary basins in the Western U.S. and Canada including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), Rocky Mountains, Western Canada, and local California supplies, which are shown in Figure 3.

Figure 3[20]



Canadian and Rocky Mountain supplies declined in December 2022, affecting Pacific Northwest and Northern California supplies, and additional interstate maintenance activities also reduced the amount of gas that could be supplied from West Texas and/or San Juan Basin to the western region.[21]

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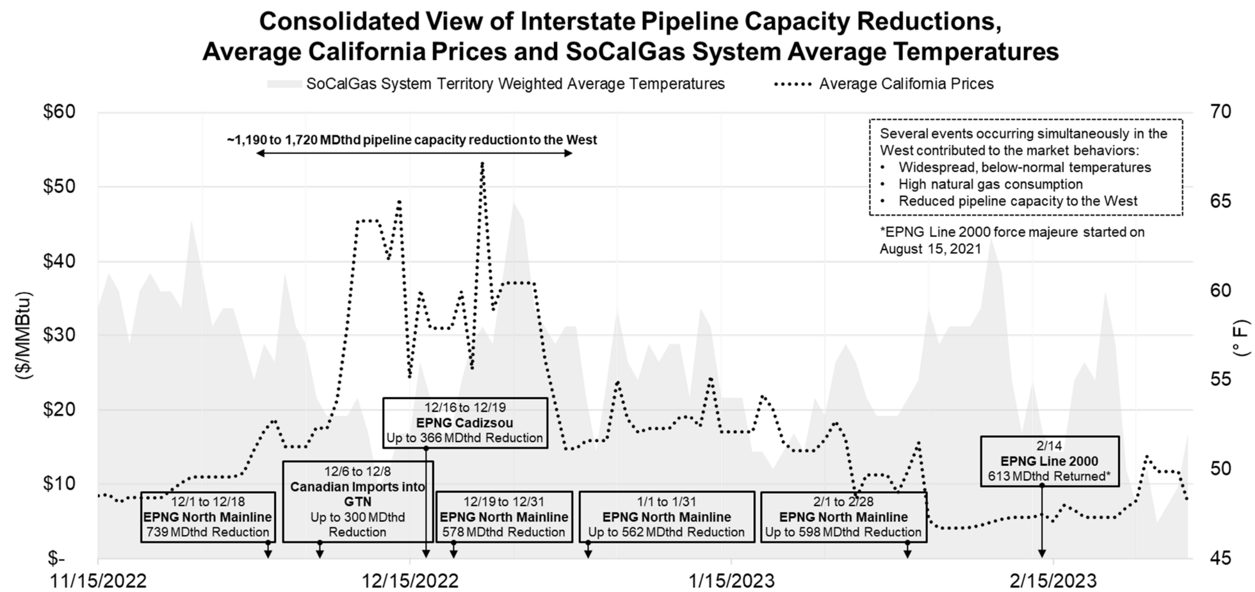
20 CEC, available at: https://www.energy.ca.gov/media/4503. This schematic is illustrative and represents a high-level overview of the pipeline systems.

21 EIA, *Daily natural gas spot prices in western United States exceed $50.00/MMBtu in December*, January 24, 2023, available at: https://www.eia.gov/todayinenergy/detail.php?id=55279.

EPNG's Line 2000 force majeure outage began on August 15, 2021 and reduced the amount of gas that could be supplied from West Texas to the western region by approximately 600 MDthd (representing approximately 20% of SoCalGas's and SDG&E's combined average daily winter demand) and was not returned to service until February 14, 2023. Several additional maintenance outages on EPNG's system began in December 2022. EPNG's additional maintenance reductions in addition to its Line 2000 force majeure, which were observed to have impacted supplies flowing to the Southwest at Ehrenberg, included maintenance on their North Main Line and at Cadiszou. EPNG indicated on their electronic bulletin board reductions from November 2022 to January 2023 ranging from approximately 273-739 MDthd and 194-366 MDthd respectively, and reductions at Ehrenberg from 479-694 MDthd.

Figure 4 below consolidates a view of average California natural gas prices, SoCalGas System composite temperatures, and significant interstate pipeline capacity reductions identified over the late November 2022 through February 2023 winter period. This figure indicates a correlation between natural gas price increases to colder temperatures and interstate pipeline constraints to supplies from West Texas.

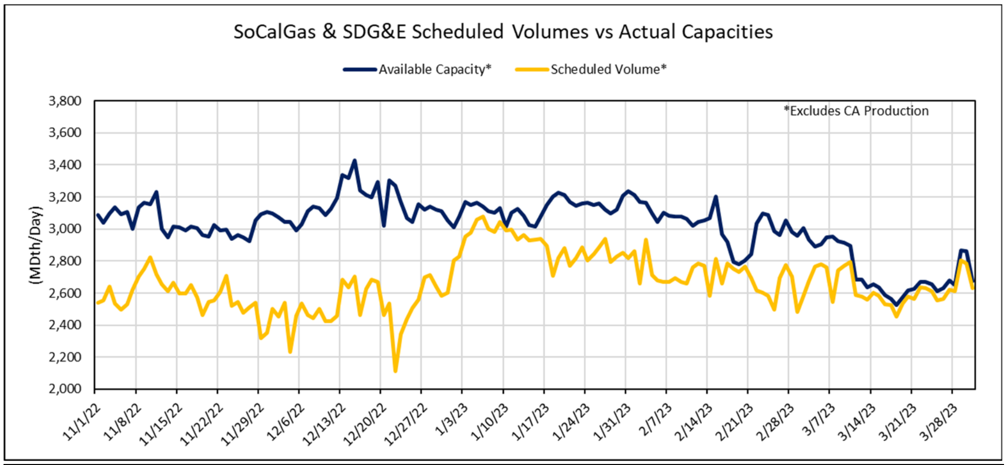
Figure 4[22]



This past winter, SoCalGas System available pipeline capacity averaged at 2,996 Mdthd, consistent with SoCalGas's longstanding practice of scheduling planned system maintenance activities on pipeline and storage infrastructure to off-peak periods, when practicable, to minimize net impacts to system capacity during peaks and to safeguard reliability. The SoCalGas System observed an 82% system utilization rate by BTS customers bringing in gas supplies in early winter (November-December) which improved to approximately 89% system utilization for the total winter season (see Figure 5).

22 Average California Prices were compiled from Natural Gas Intelligence (NGI) published daily indexes for Malin, Southern Border PG&E, PG&E Citygate, SoCal Citygate and SoCal Border Avg. for the relevant time period.

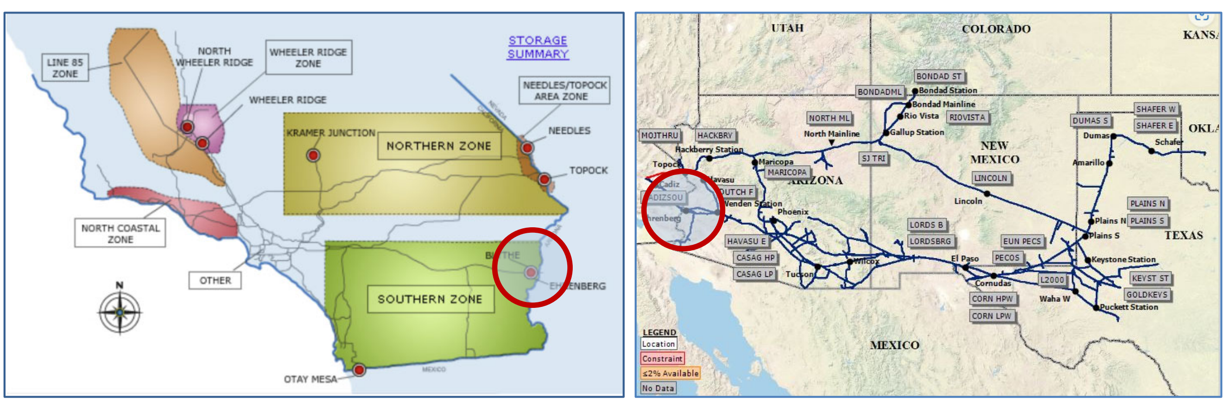
Figure 5



SoCalGas relies heavily on the EPNG system, especially when it comes to the Southern System which lacks storage assets and has less access to flowing supplies. Not only does the EPNG system provide supply availability, but it is also critical in meeting the reliability of the Southern System and the demand of those customers connected to it, including the entire SDG&E territory (see Figure 6).

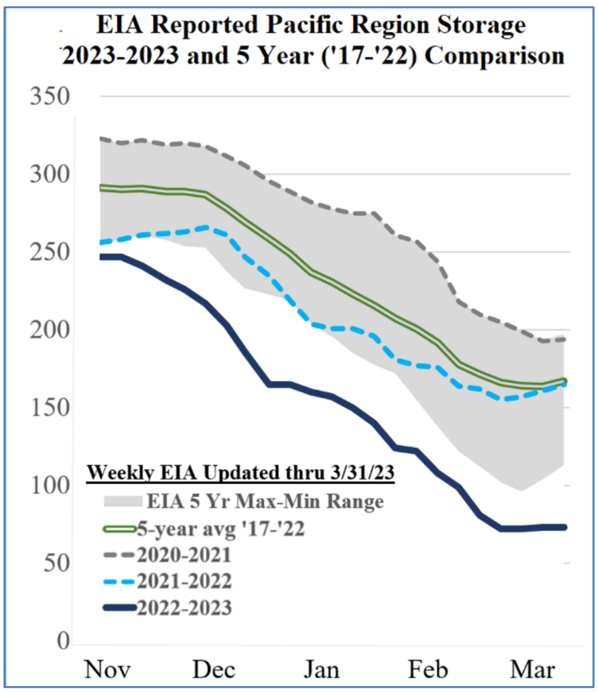
Figure 6

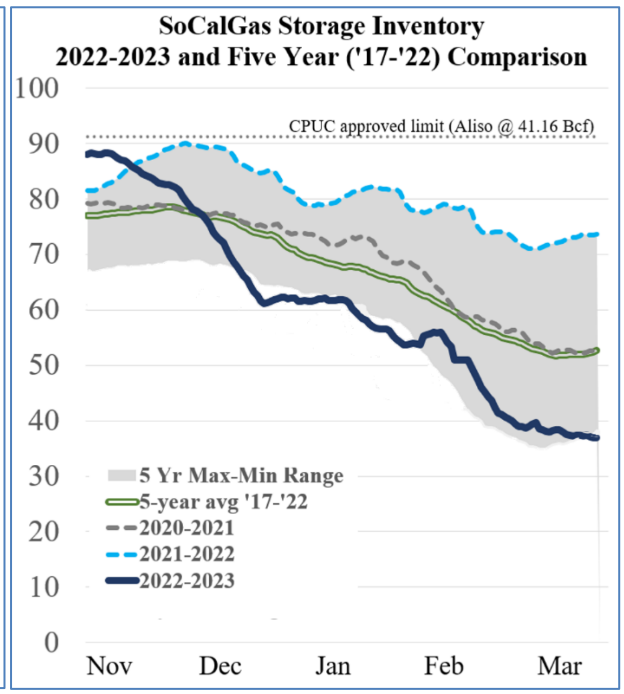
SoCalGas and EPNG Transmission Systems



Natural gas storage inventories in the Pacific Region were -15% (below) their 5-year average at the start of the winter season (see Figure 7).[23] However, SoCalGas's storage levels on November 1, 2022[24] were the highest in the last 6 years (88 Bcf) and close to the maximum level SoCalGas is currently permitted to store at its storage facilities.[25] As described herein, below-normal temperatures were observed to have begun much earlier this past winter starting in early November. Nonetheless, SoCalGas had sufficient inventory to meet reliability requirements for the winter.

Figure 7





23 *See* EIA, *Weekly Natural Gas Storage Report*, April 13, 2023, https://ir.eia.gov/ngs/ngs.html.

24 SoCalGas typically injects natural gas into storage during the months of April through October and usually withdraws natural gas from storage during the months of November through March.

25 SoCalGas's storage capacity limits are regulated by CalGEM and the CPUC. As of October 2022, SoCalGas had about 88 BCF in its storage inventory (inclusive of Aliso Canyon), including inventory space used for system balancing, and the inventory held by wholesale customers and core aggregators in November 2022, which has been its highest level in the past six years.

Longstanding western drought conditions resulted in historically low reservoir levels, which in turn affected potential hydro production, thus increasing reliance on gas-fired generation. It can also be observed that, as the western region decarbonizes and increases its reliance on intermittent energy sources (renewables), while displacing baseload resources with no replacement (e.g., coal plant retirements), the amount of natural gas usage for power across the West has increased.[26]

Natural gas storage in PG&E's territory is another consideration that was discussed at the Commission's *en banc*. In June 2021, PG&E reclassified 51 Bcf of natural gas in its storage system from working gas to base gas. As PG&E explained during the Commission's *en banc*, "the working natural gas inventory effectively has been acting as base[27] gas even before the reclassification formalized this change."[28] A recent California Energy Markets article highlighted analyst concerns related to storage levels in the Western Region:

> The status of Western natural gas storage and what currently low levels might portend for reliability moving into the traditional injection season is an ongoing concern for analysts, some of whom contend reliability is now a year-round concern.
>
> Of particular concern is Pacific Gas & Electric natural gas storage, which analysts have said is now low, giving "little room for error" in balancing.
>
> Energy GPS analysts said it is unlikely for that system to fully recover from reclassification and the draw on demand by next winter. They said the combination of "one of the coldest winters in the past three decades" and "a lack of hydro power

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26 Natural Gas Intelligence, *North American Coal Retirements, Asian LNG Demand Drive Global Natural Gas Rebound in 2023, GECF Says*, April 10, 2023, https://www.naturalgasintel.com/north-american-coal-retirements-asian-lng-demand-drive-global-natural-gas-rebound-in-2023-gecf-says/.

27 EIA defines Base (cushion) gas as the volume of gas needed as a permanent inventory to maintain adequate reservoir pressures and deliverability rates throughout the withdrawal season.

28 PG&E, *En Banc on Current Gas Market Conditions and Impacts of Gas Prices on Electricity*, February 7, 2023, at slide 5, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/meeting-documents/20230207-en-banc/20230207-en-banc---pge-presentation.pdf?sc_lang=en&hash=69FAF2D890D4A5C6F75785ECD7E575F1.

> generation in the Pacific Northwest" has increased the amount of natural gas used for power across the West.[29]

In addition to these regional issues, tight international gas markets have also impacted U.S. natural gas prices.

2. Did any of the entities under our regulatory jurisdiction play a role in causing the increase in California border prices between November 1, 2022 and March 31, 2023?

Market prices may be influenced by the individual and collective activities of market participants, which in the western U.S. gas market includes both Commission jurisdictional and non-jurisdictional entities. These include but are not limited to: gas producers, marketers, banks, private equity, hedge funds, exchange-traded funds (ETFs), electric generators, electric utilities, natural gas utilities, municipalities, pipelines, independent storage operators (ISPs), asset managers, industrial users, and independent traders. In addition, see response to Question 1 above regarding potential factors that contributed to the price spike.

***3. What actions can the CPUC* or other entities take to avoid the likelihood that similar price spikes will occur in the future?**

SoCalGas and SDG&E recommend parties in this proceeding consider the long-term actions that the Commission and/or other entities could take to mitigate the likelihood of similar price spikes occurring in the future. In the interim, SoCalGas and SDG&E propose immediate short-term actions the Commission could take to potentially mitigate these issues from occurring in the near future. Specifically, SoCalGas and SDG&E recommend increasing available gas

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29 California Energy Markets, *Analysts Point to Western Natural Gas Storage-Level Concerns*, March 31, 2023, https://www.newsdata.com/california_energy_markets/regional_roundup/analysts-point-to-western-natural-gas-storage-level-concerns/article_e6b16f96-cff2-11ed-b4ef-5bedee55afa7.html.

supply by eliminating the Aliso Canyon Withdrawal Protocol (ACWP) and increasing the maximum allowable inventory level at Aliso Canyon.

a. Near term mitigation solutions.

i. <u>The Commission should authorize SoCalGas to increase inventory levels at Aliso Canyon to 68.6 BCF.</u>

On April 19, 2023, SoCalGas and SDG&E filed a Joint Petition for Modification (PFM or Petition) of Decision (D.) 21-11-008, which establishes an interim limit for Aliso Canyon storage capacity at 41.16 billion cubic feet (Bcf).[30] SoCalGas and SDG&E are requesting the Commission take expedited action to increase the inventory limit at Aliso Canyon to 68.6 Bcf, a limit deemed safe by the California Geologic Energy Management Division (CalGEM),[31] to help mitigate against future price spikes.[32] The Commission has recognized that the natural gas inventory level at Aliso Canyon has an economic impact on market prices and natural gas and electricity costs paid by customers.[33] On October 1, 2021, a Proposed Decision (PD) was issued in I.17-02-002 that set the interim inventory level of Aliso Canyon at 68.6 BCF, based in part upon the available pipeline receipt capacity as recommended by Commission staff. The Assigned Commissioner issued an Alternate PD (APD) which set the interim maximum inventory level of Aliso Canyon at 41.16 Bcf. The APD was then approved by the Commission as D.21-11-018. In setting the Aliso Canyon inventory level at 41.16 Bcf, D.21-11-008 made

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30 I.17-02-002, *Southern California Gas Company (U 904 G) Petition for Modification of Decision*, April 19, 2023.

31 Staff of the CPUC, *Aliso Canyon I.17-02-002 Phase 2: Modeling Report*, January 26, 2021, at 9.

32 I.17-02-002, *Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) Joint Petition for Modification of Decision*, April 19, 2023; *Joint Motion of Southern California Gas Company (U 904 G) and San Diego Gas & Electric Company (U 902 G) to Shorten Time to Respond to Petition for Modification of Decision*, April 19, 2023.

33 D.21-11-008 at 8.

clear that the limit was temporary and would be revisited as necessary: "When it becomes appropriate to revisit the maximum allowable inventory, we will do so."[34] It seems that now is the appropriate time to revisit the maximum allowable inventory at Aliso Canyon.

As Mark Pocta of the Commission's Public Advocates Office highlighted during the Commission's *en banc*:

> The Commission set a range back in 2021 for Aliso Canyon. They could operate between zero and 41 Bcf. At that time, there was a concurrent proposed decision by administrative law judge that would have proposed to accept the interim range and how a maximum from zero to 68.6 Bcf. So you saw that under SoCal charts, so that additional capacity would provide more storage capacity for the market. So again, the utilization of Aliso Canyon, is another matter that the Commission will need to consider closely moving forward.[35]

The chart in Figure 8 below illustrates what the potential maximum inventory would have been with Aliso Canyon at 68.6 Bcf.

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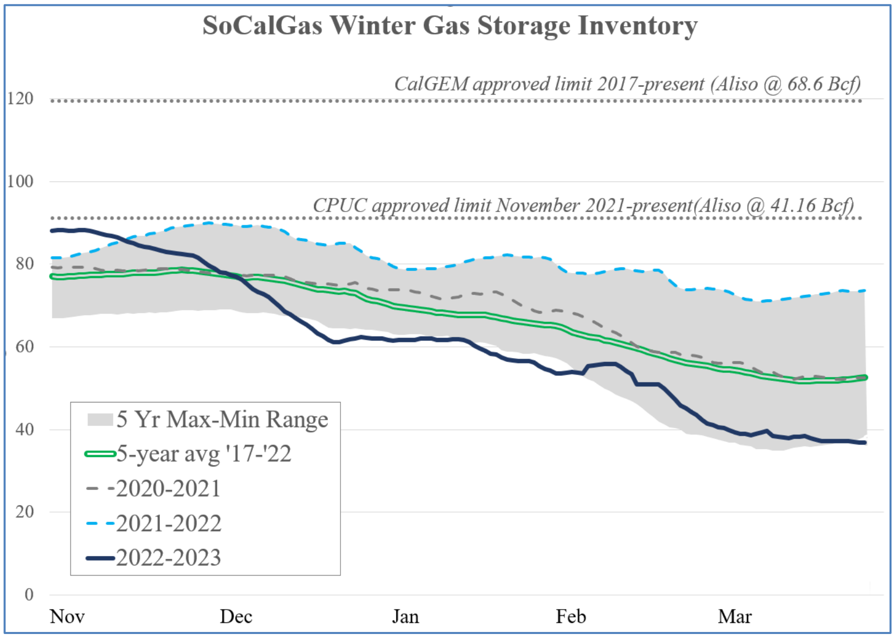
[34] *Id*. at 20.

[35] CPUC, *En Banc, Current Gas Market Conditions & Impacts of Gas Prices on Electricity Markets*, February 7, 2023, Cal Advocates Presentation by Marc Pocta, at 1:04:29-1:06:56, recording available at: https://www.adminmonitor.com/ca/cpuc/en_banc/20230207/.

Figure 8



The gas purchased and stored at Aliso Canyon was purchased at prices lower than what was available at market prices this past winter. The additional source of supply from Aliso Canyon likely contributed to a dampening effect on price volatility at the SoCal Border and SoCal Citygate trading points. In other words, if it were not for the availability of Aliso Canyon's supply, prices might have been even higher.

If the maximum allowable inventory at Aliso Canyon was set to 68.6 Bcf, as opposed to the current 41.16 Bcf, the additional supply might have mitigated intrastate pipeline capacity constraints inhibiting out-of-state supplies. In addition, starting the winter season with higher storage inventories would support higher withdrawal capacities for the latter part of the winter season. Higher storage volumes generally equate to higher storage withdrawal rates. This would serve to dampen price volatility and provide additional price hedging benefits to customers on the SoCalGas System. Notably, on November 1, 2022, Aliso Canyon had a total inventory of

40.345 Bcf.[36] In SoCalGas's Summer 2022 Technical Assessment, SoCalGas found that it would have 66.3 Bcf of excess supply (excluding Otay Mesa supply) under the best-case supply scenario,[37] which it could use to inject at Aliso Canyon but for the limitation of 41.16 Bcf.[38] Actual receipt capacity during the summer 2022 operating season exceeded the best-case supply scenario presented in the Technical Assessment.[39] Accordingly, but for the 41.16 Bcf limitation at Aliso Canyon, there may have been additional inventory at Aliso Canyon on November 1, 2022 and throughout the winter season, including inventory allocated to the Unbundled Storage Program.

In order to mitigate against potential similar price spikes in the future, the Commission should allow SoCalGas to increase Aliso Canyon's inventory to 68.6 Bcf. Further, SoCalGas's 2023 Summer Technical Assessment provides that SoCalGas expects to have sufficient capacity and supply to fill its storage fields by the end of the 2023 summer season.[40] SoCalGas's

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[36] SoCalGas ceases injecting prior to reaching the 41.16 Bcf current inventory limitation to verify it does not exceed the limitation and to mitigate against the potential for high operational flow orders (OFO).

[37] SoCalGas, *SoCalGas Summer 2022 Technical Assessment*, March 30, 2022, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=242505&DocumentContentId=76010. SoCalGas Operations does not purchase and store gas supply for the use of any customer. SoCalGas' Gas Acquisition department purchases supplies for storage only for the SoCalGas retail core and the SDG&E wholesale core market segment, excluding those core customers served by Core Transport Agents as part of a Core Aggregation Transportation (CAT) program and other wholesale providers. SoCalGas Operations can only make pipeline and storage capacity available to market participants; the Technical Assessment found that sufficient capacity would be available to fill storage to the cited levels if market participants made use of that capacity to deliver gas supply.

[38] *Id*. at 7.

[39] The best-case supply scenario in the Summer 2022 Technical Assessment assumed 559.8 Bcf of supply for the entire summer season, excluding Otay Mesa supply. (*See SoCalGas Summer 2022 Technical Assessment* at 7.) Actual receipt capacity for the summer 2022 season was 620.6 Bcf.

[40] SoCalGas, *SoCalGas Summer 2023 Technical Assessment -Revised*, April 13, 2023, at 7, available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=249688&DocumentContentId=84327. (On April 14, 2023, as a courtesy, SoCalGas served the Summer 2023 Technical Assessment on parties to I.17-02-002).

Technical Assessment shows excess pipeline supply of approximately 53 Bcf over the 2023 summer season, some of which could potentially be stored at Aliso Canyon if the Commission's inventory limitation of 41.16 Bcf were lifted.[41] For example, if the maximum allowable inventory limitation at Aliso Canyon was increased to 68.6 Bcf, SoCalGas expects it would have sufficient excess supply to fill Aliso Canyon by November 1, 2023.[42] Notably, increasing the maximum inventory at Aliso Canyon to 68.6 Bcf would also enable SoCalGas to reinstate the Unbundled Storage Program,[43] providing SoCalGas customers the opportunity to contract for 27 Bcf of storage inventory that could be filled during lower priced months and withdrawn during higher priced months. Further, increasing the storage inventory at Aliso Canyon and eliminating the ACWP, as discussed further below, could help mitigate OFOs. For example, a Low OFO occurs when the Forecasted Total Daily Customer imbalance is greater than the Storage withdrawal limit for Load Balancing. Increasing the inventory at Aliso Canyon, which would increase the Load Balancing storage inventory allocation,[44] and eliminating the Aliso Canyon Withdrawal Protocol, which would include Aliso Canyon's withdrawal capacity in the OFO calculation, could help mitigate OFOs. In addition, if the Unbundled Storage Program is reinstated and customers contract for storage, those customers may be able to use storage to mitigate OFO penalties.

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[41] *Ibid*.

[42] *Ibid*.

[43] D.20-02-045.

[44] If the maximum allowable inventory at Aliso Canyon is increased to 68.6 Bcf, 0.44 Bcf of additional storage inventory would be allocated to Load Balancing and 27 Bcf would be allocated to the Unbundled Storage Program.

ii. The Commission should eliminate the ACWP to provide additional flexibility and supply in winter months.

On April 19, 2023, SoCalGas requested the Commission immediately eliminate the ACWP to help mitigate against price volatility.[45] The ACWP currently prohibits SoCalGas from making withdrawals from Aliso Canyon, including in peak winter months, except under specified conditions. These conditions were designed to permit SoCalGas to make withdrawals only to address certain operationally constrained conditions and maintain reliability.

Specifically, the ACWP provides that SoCalGas may withdraw from Aliso Canyon if any of the following conditions are met: (1) Preliminary low Operational Flow Order (OFO) calculations for any cycle result in a Stage 2 low OFO or higher for the applicable gas day; (2) Aliso Canyon is above 70% of its maximum allowable inventory between February 1 and March 31; in such case, SoCalGas may withdraw from Aliso Canyon until inventory declines to 70% of its maximum allowable inventory; (3) The Honor Rancho and/or La Goleta fields decline to 110% of their month-end minimum inventory requirements during the winter season; and/or (4) There is an imminent and identifiable risk of gas curtailments created by an emergency condition that would impact public health and safety or result in curtailments of electric load that could be mitigated by withdrawals from Aliso Canyon.[46] The ACWP provides that it "shall remain in effect, subject to modification, through the completion of the CPUC Investigation (I.) 17-02-002 **or such time as determined based on conditions**."[47]

45 SoCalGas Letter to Deputy Executive Director for Energy and Climate Policy, Re: Aliso Canyon Withdrawal Protocol, April 19, 2023.

46 CPUC, *Aliso Canyon Withdrawal Protocol*, July 23, 2019, at 1, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf

47 *Id*. at 3 (emphasis added).

The current ACWP was made effective July 23, 2019, with noticing and reporting requirements updated April 1, 2020.[48] When the Commission updated the ACWP conditions in July 2019, it explained that it did so for several reasons, including a focus on improving price stability in the Southern California region.[49] In particular, the Commission noted that combined natural gas pipeline outages and operational restrictions on Aliso Canyon led to extraordinarily high natural gas and electricity prices.[50] Subsequently, the Commission found that the changes to the ACWP contributed to natural gas and electricity prices remaining relatively stable during summer 2019.[51] Specifically, the Commission noted:

> Summer 2019 was the first season without abnormal gas price volatility since October 2017, when the region began experiencing the combined impacts of the Line 235-2 rupture and the Aliso Canyon storage field restrictions. Generally, moderate weather, high production from out-of-state gas and oil wells, ample hydroelectric energy, **and revisions to the Aliso Canyon Withdrawal Protocol contributed to a stabilizing of average gas prices**.[52]

48 *Ibid*.

49 CPUC, Letter Re: Aliso Canyon Withdrawal Protocol to Stakeholders and Parties to Proceedings I.17-02-002, A.18-07-024, and A.17-10-007, July 23, 2019, at 1, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2019/coverletter-alisocanyonwithdrawalprotocol-2019-07-23.pdf.

50 CPUC, Letter Re: CPUC Proposed Revisions to Aliso Canyon Withdrawal Protocol to Stakeholders and Parties to Proceedings I.17-02-002, A.18-07-024, and A.17-10-007, July 1, 2019, at 1, available at:https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2019/alisocanyonwithdrawalprotocol-letter-2019-07-01.pdf.

51 Staff of the CPUC, *Summer 2019 SoCalGas Conditions and Operations Report*, July 20, 2020, at 4, available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/summerlookback2019report-final.pdf.

52 *Id*. at 14 (emphasis added).

The California Independent System Operator (CAISO) also acknowledged the positive impacts of revising the ACWP.[53] While the market saw positive impacts because of the changes, the existence of the ACWP continues to limit the availability of the facility to the market. Market participants with gas in storage are not able to rely on the availability of the gas in storage at Aliso Canyon, which may artificially increase the demand and price for flowing supplies. Higher inventory and access to Aliso Canyon would remove some of the supply uncertainty from the market. Therefore, to help mitigate price spikes in the future, the Commission should immediately eliminate the Protocol. SoCalGas also notes that if the ACWP remains in place, the Unbundled Storage Program will not be as useful to the market since it prevents unbundled storage customers from accessing their supplies in storage.

iii. SoCalGas will expand use of text messaging to keep customers informed of elevated gas costs and support options.

In addition, SoCalGas is planning additional customer communications by expanding text (SMS) message options for high natural gas price alerts to customers who opt-in, as means to provide additional awareness to support customers with energy and bill management during the winter season. For additional detail on customer communications please see response to Question 7 below.

b. Longer term mitigation solutions.

The Commission should also consider longer-term actions it and/or other entities could take to mitigate the likelihood of similar price spikes occurring in the future. These include

[53] CAISO, *2020 Summer Loads and Resources Assessment*, May 15, 2020, at 13 ("Specifically, on July 23, 2019 the CPUC made revisions to the Aliso Canyon Withdrawal Protocol to remove its classification as "an asset of last resort" to provide SoCalGas with more flexibility to use Aliso Canyon to balance the system and ease energy price spikes."), available at: https://www.caiso.com/Documents/2020SummerLoadsandResourcesAssessment.pdf.

options to diversify gas supply and increase availability and utilization of interstate pipeline capacity.

i. The Commission should promote diversification of supply and reduce reliance on imports with clean renewable hydrogen and renewable natural gas.

California currently receives over 95% of its natural gas supply from out-of-state sources. This reliance makes California especially vulnerable to interstate infrastructure constraints, including those experienced during this winter season. The Commission could help protect against price spikes by providing avenues for utilities to diversify supplies and reduce reliance on out of state gas supplies through facilitating the development of clean fuels such as clean renewable hydrogen and RNG.

SoCalGas's mission is to build the cleanest, safest, most innovative energy infrastructure company in America, and we are working to realize this future through innovation and decarbonization. In 2021, SoCalGas announced its aspiration to achieve net zero greenhouse gas (GHG) emissions in our operations by 2045.[54] SoCalGas also released its Clean Fuels Whitepaper, a comprehensive technical analysis that examines pathways to achieve California's carbon neutrality goals through a more integrated, resilient, and reliable and affordable energy system, which showed the essential role clean fuels can play in our energy future.[55]

The use of hydrogen, either blended with natural gas, or delivered via a dedicated pipeline, is one important component of SoCalGas's strategy to achieve net zero emissions in its

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54 SoCalGas, *ASPIRE 2045: Sustainability and Climate Commitment to Net Zero*, available at: https://www.socalgas.com/sites/default/files/2021-03/SoCalGas_Climate_Commitment.pdf.

55 SoCalGas, *The Role of Clean Fuels and Gas Infrastructure in Achieving California's Net Zero Climate Goal*, October 2021, available at: https://www.socalgas.com/sites/default/files/2021-10/Roles_Clean_Fuels_Full_Report.pdf

operations and the energy it delivers by 2045. Hydrogen can leverage the current natural gas system through blending hydrogen alongside natural gas in existing gas transmission and delivery infrastructure. In fact, in December 2022, the Commission ordered the four main gas utilities to either file a new or amend an existing application proposing hydrogen blending pilot projects;[56] an amended application filed in a pre-existing proceeding is expected by the end of 2023.[57] In the same month, the Commission approved SoCalGas's request to track costs for advancing the first phase of the Angeles Link Project,[58] a proposed clean renewable hydrogen pipeline system that could deliver clean, reliable, renewable energy to the Los Angeles region. As envisioned, Angeles Link could be the nation's largest clean renewable hydrogen pipeline system and support significantly reducing greenhouse gas emissions from electric generation, industrial processes, heavy-duty trucks, and other hard-to-electrify sectors of the Southern California economy. SoCalGas recognizes the Commission's pending SB 380 proceeding investigating the feasibility of reducing or eliminating the use of Aliso Canyon for natural gas storage, while maintaining energy and electric reliability for the Los Angeles region at just and reasonable rates.[59] While Aliso Canyon is critical today to meet these objectives and an increased inventory limit will further enhance the value it provides, introducing a clean renewable hydrogen energy transport system into the Los Angeles Basin would provide a clean alternative fuel to help to alleviate natural gas demand served by Aliso Canyon in the long term, supporting (along with other clean energy projects and reliability efforts, such as those being

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56 D.22-12-057.

57 A.22-09-006, *Assigned Commissioner's Scoping Memorandum and Ruling*, March 3, 2023; available at https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M502/K980/502980995.PDF.

58 D.22-12-055.

59 I.17-02-002, *Order Instituting Investigation*, February 17, 2017.

evaluated in the SB 380 Proceeding) a path to its ultimate closure while maintaining energy system reliability.

California's Renewable Gas Standard (RGS), established in D.22-02-025 pursuant to Senate Bill (SB) 1440, also provides an opportunity to reduce California's reliance on out-of-state gas by at least 12% of core throughput by 2030. To achieve the procurement goals established by D.22-02-025, the Commission should identify and remove barriers of entry that are inhibiting the development of California biomethane producing facilities in this space. Supporting the development of projects that meet the RGS eligibility criteria established by the Commission would provide utilities with access to in-state gas that could help mitigate the exposure to out-of-state gas supplies while advancing California's net zero goals, all while providing local climate benefits.

ii. The Commission should review interstate pipeline capacity procurement process.

The Commission should review the current interstate pipeline capacity approval process to determine whether modifications are warranted to allow gas utilities to submit competitive bids in open seasons and secure interstate capacity. In D.04-09-022, the Commission recognized the need for a clearly articulated interstate pipeline capacity approval process, which is flexible and provides for expeditious processing and appropriate regulatory oversight, to provide the utilities with the opportunity to acquire needed core capacity in the most efficient and most cost-effective manner.[60] The decision established a pre-approval process for interstate pipeline capacity contracts within a contract length limit of 3 years and capacity amount limits (100

[60] D.04-09-022 at 85-86, FOF 4.

MMcfd for SoCalGas and PG&E and 20 MMcfd for SDG&E).[61] The Commission should review the pre-approval contract criteria and determine whether it is still appropriate. Potential modifications could include allowing gas utilities to enter into contract transportation capacity contracts with longer delivery periods, so that gas utilities can submit competitive bids in open seasons and secure interstate capacity. The inability to submit competitive bids has the potential to increase costs and risk securing interstate capacity. This is most important for interstate capacity contracts for the Southern System where there is a greater reliance on flowing supplies.

4. What actions can the CPUC take to mitigate the harm to ratepayers if such price spikes do recur?

SoCalGas and SDG&E have and continue to utilize a wide array of tools, with Commission assistance where needed, to assist customers as they navigate this unusual period (e.g., early and frequent communication, promotion of energy efficiency measures, bill assistance through payment plans, the Gas Assistance Fund, and supporting the acceleration of the climate credit). In addition, customer programs such as energy efficiency and demand response can mitigate harm to ratepayers. SoCalGas and SDG&E's energy efficiency offerings and market support for new energy efficiency solutions affordably reduce energy consumption and emissions for SoCalGas customers, and result in customer savings. In addition, gas demand response programs may provide load shifting from times when gas prices are high to other times when gas prices are lower, the delta in prices translating to cost savings for customers.

The California Cap-and-Trade Program is a state program designed to reduce greenhouse gas emissions. Each year the state auctions a limited number of emissions permits so that California can meet its goal of reducing overall emissions. The Commission directs investor-

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[61] *Id*. at 86, FOF 9.

owned utilities to distribute some of the auction proceeds generated by the Cap-and-Trade Program as a credit (California Climate Credit or CCC) to residential customers, and for clean energy and energy efficiency programs. D.15-10-032, and as affirmed in D.18-03-017, authorized greenhouse gas (GHG) allowance proceeds, net of reasonable GHG compliance costs and expenses, to be returned to residential customers as a natural gas “California Climate Credit” each April beginning in 2016. Accordingly, a portion of the funds raised through the program are distributed annually in April to SoCalGas and SDG&E customers in the form of bill credits.

In response to the unprecedented market conditions and the resulting impact on customer gas rates, the Commission voted to accelerate the annual credit to February or March, depending on customers' individual billing cycles. D.23-02-014 clarified that, for gas utilities, the acceleration of the April 2023 CCC applied to the natural gas credit only and the normal schedule for CCC disbursements for residential customers would resume as of May 2023. To mitigate against potential future winter price spikes, SoCalGas recommends the Commission authorize distribution of the CCC in a winter month rather than April of each year. SoCalGas and SDG&E recommend the natural gas CCC be provided to customers in January or February given that those months are usually colder and there is typically more price volatility, as opposed to March or November. SoCalGas also supports Senate Bill 429 which would require the cap-and-trade climate credit to be returned to residential customers in the month of February.

Another action that has already been proposed, but which has added relevance within the context of this OII, is SoCalGas’s residential transportation rate design proposal in the pending Cost Allocation Proceeding.[62] In that proceeding, SoCalGas has proposed an enhanced two-tier, income-based residential fixed charge. The fixed customer charge for non-CARE customers

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[62] A.22-09-015.

would increase in a phased-in approach from its current $5 per month to $10 per month in 2025, $15 per month in 2026, and $20 per month in 2027. SoCalGas also proposes to establish a separate, lower CARE fixed customer charge which, when taking into account the 20% CARE discount, will be effectively 50% below the non-CARE fixed customer charge.[63] In the long run, enhanced fixed charges will help to remedy the inherent cost shift as some customer loads begin to shift away from gas service via fuel substitution (e.g., appliance electrification), and for customers who partially electrify promotes paying a fair share of the fixed costs associated with maintaining their gas service.[64] But in the short run, many customers who are most exposed to high volumetric rates would see an annual average bill decrease with this proposal, while crucially having the effect of reducing month-to-month bill volatility by decreasing winter bills and collecting more transportation-related revenue requirement in the non-winter months. Commission action on this proposal would be an additional tool to support affordability during the peak demand season, while maintaining conservation price signals.

SoCalGas has and continues to inform and offer several ways to help customers through our bill and home improvement assistance programs, bill forgiveness plan, and the level-pay program. In addition, SoCalGas has, in 2023, contributed $11 million in shareholder funding to provide additional relief to low-income families, seniors, and small restaurant owners, impacted by the unprecedented regional natural gas market prices, as follows:

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63 A.22-09-015, Chapter 13, Prepared Direct Testimony of Iftekharul (Sharim) Chaudhury on Behalf of Southern California Gas Company and San Diego Gas & Electric Company, Rate Design, at 14-27.

64 A.22-09-015, Chapter 14, Prepared Direct Testimony of N. Jonathan Peress on Behalf of Southern California Gas Company and San Diego Gas & Electric Company, Long-Term Policy and Energy Transition, at 14.

- $6 million towards the Gas Assistance Fund, a program administered by the United Way to provide one-time grants to income-qualified customers to help pay their natural gas bills.
- $4 million from its donor-advised fund towards re-launching Fueling Our Communities, a collaborative program with local food banks and non-profit organizations to provide free meals and groceries to thousands of Californians facing food insecurity.
- $1 million from its donor-advised fund towards the Restaurants Care Resilience Fund to help small restaurants with improvements, upgrades, employee retention, and to manage debt, losses and rising costs.

SoCalGas has also pushed broad proactive communications with information on programs, tools and tips to manage bills and reduce gas use. Those communications are discussed in greater detail in response to Question 7.

SoCalGas and SDG&E also recommend the use of existing gas utility procurement tariff tools to assist in mitigating the impact to customers during periods of gas market price volatility. For example, amortizing Core Procurement Gas Account (CPGA) imbalances over a period of time can be a useful tool to help mitigate the impact to customers during periods of price volatility. In addition, the utilities could also explore a potential temporary cap on the Core Procurement Charge (CPC) passed through to customers in bundled core rates during price spike events, subject to subsequent recovery.

The CPC is an estimate of the wholesale natural gas market's monthly commodity cost of gas which is placed in rates for residential and non-residential bundled core customers. As described in SoCalGas's G-CP Tariff, components of the monthly CPC include the following: (1) the weighted average estimated cost of gas (WACOG) for the current month including reservation charges associated with interstate pipeline capacity contracts entered into by SoCalGas, and the carrying cost of storage inventory; (2) authorized franchise fees and uncollectible expenses; (3) authorized core brokerage fee; (4) any adjustments for over or under collection imbalance in the CPGA imbalance band;[65] (5) backbone transportation service charges; and (6) an adjustment for the Gas Cost Incentive Mechanism (GCIM) reward/penalty.[66]

In D.96-08-037, the Commission provided that the dynamism of the natural gas markets, combined with the traditional ratemaking method for bundled core gas rates (setting an effective rate for a two-year period as part of SoCalGas's Biennial Cost Allocation Proceeding (BCAP)), resulted in differences between the spot market price of natural gas and what consumers were paying month to month.[67] The Commission also provided that it was appropriate to bring rates more closely into alignment with changes in underlying market costs to improve price signals for consumers.[68] Accordingly, D.96-08-037 authorized the adoption of tariff Schedule G-CP and modified the timing of gas price forecasts from every two years to monthly.[69]

In D.98-07-068, the Commission authorized modifications to the calculation of SoCalGas's forecasted portfolio WACOG using best estimates of the weighted volumes and prices of flowing supplies from the different supply basins delivered to the California Border for purposes of setting the CPC, approval to file the G-CP Tariff on the last business day of the month to become effective on the first calendar day of the following month, and established a CPGA imbalance band of +/-1% of the actual annual commodity gas purchases for the preceding 12-month period ending March 31 of each year, wherein adjustments would be made to the monthly CPC only if the CPGA imbalance falls outside of the band. [70]

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65 The CPGA component is an adder in the case of an under-collection and a subtracter in the case of an over-collection.

66 SoCalGas Tariff Schedule No. G-CP, Core Procurement Service, at Sheet 1, available at: https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/tariffs/GAS_G-SCHEDS_G-CP.pdf.

67 D.96-08-037 at 4.

68 *Id*. at 6.

69 *Id*. at 10, OP 1.

70 D.98-07-068 at 3, OP 1-3.

Pursuant to D.98-07-068, upon exceeding the +/-1% of actual annual commodity costs imbalance (tolerance) band, SoCalGas places into future rates (amortizes) a component of CPGA over or under-collection imbalance. A CPGA over-or -under collection imbalance represents the difference at the end of each month between forecasted and estimated gas costs placed into rates and recovered from customers versus SoCalGas's actual procurement costs from purchasing natural gas. An under-collection results when forecasted gas costs are lower than actual gas procurement costs and conversely, an over collection results when forecasted gas costs are higher than actual gas procurement costs.

SoCalGas and SDG&E recommend the use of existing gas utility procurement tariff tools, such as amortization, to assist in mitigating the impact to customers during periods of gas market price volatility. For example, amortizing CPGA imbalances over a period of time may help mitigate the impact to customers. In addition, deferring the amortization to periods of less price volatility would avoid adding additional costs during higher prices. The utilities could also explore a potential temporary cap on the CPC cost passed through to customers in bundled core rates during price spike events. Evaluating and defining a potential temporary cap would include defining relevant parameters (e.g., "price spike event"), determining which pricing locations should be considered (e.g., individual trading points, regional markets, etc.), developing a mechanism for utilities to collect the costs exceeding the CPC cap that were not collected during the price spike event, and analyzing the extent to which a potential temporary price cap might mute price signals that could potentially reduce consumption.

Another way to mitigate the impact of high customers' bills, once it is understood that gas procurement rates will be unusually high, is for the utilities to proactively offer their levelized payment plan which may include qualifying arrearages. In addition, payment plan offerings could be proactively offered to extend a payment due date, or to make installment payments over several months. For example, if a customer's bill exceeds a pre-defined threshold, the utilities could offer an easy way to spread payment of that one high bill over several subsequent months. Any actions taken by the Commission related to the recommendations in this question should not impair the utilities' financial health and obligations.

In addition, D.21-10-012 directed utilities to commence marketing, education, outreach, and enrollment for the Percentage of Income Payment Plan (PIPP) pilot within 45 days of the approval of the PIPP advice letters filed.[71] Based on the date of Resolution E-5200, which approved IOUs' advice letters, marketing, education, and outreach (ME&O) began on January 30th, 2023. Though the PIPP outreach efforts began after the high bill period had mostly passed, there is an opportunity to utilize future PIPP outreach to mitigate high gas prices for eligible customers[72] prior to the next winter season. The PIPP Pilot sets the target enrollment level at 50% of the pilot participation cap effective six months after enrollment begins. D.21-10-012 set an overall pilot size of 15,000 customers, with SoCalGas and SDG&E having a participation cap of 5,000 and 1,000, respectively.[73] As such, SoCalGas and SDG&E must enroll 2,500 and 500 customers, respectively, in PIPP by the end of July. Should there be remaining availability in the Pilot prior to the winter months, future phases of outreach can be tailored towards eligible customers with previously high bills, or those residing in climate zones most impacted by high bills during peak heating months. Leveraging an existing program such as PIPP is a quick and

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[71] D.21-10-012 at 38.

[72] *See Id*. at 24-25 (PIPP enrollment is limited to customers who are enrolled in the California Alternate Rates for Energy (CARE) program and who either (i) are located in one of the zip codes with the highest rates of recurring disconnections prior to the disconnections moratorium, or (ii) have been disconnected 2 or more times during the 12 months prior to the disconnections moratorium.)

[73] *Id.* at 14.

feasible option to mitigate high bills for eligible customers given that system changes to automate billing have been implemented, and cost recovery has already been established.

5. Is there any information that the CPUC should collect or examine to further understand market dynamics?

The Commission should examine market events outside of California, including eastern US, Canada, the situation in Ukraine, and U.S. producing basins. High prices were not limited to California. Indeed, elevated prices were experienced in the production basins of Canada and the Rockies, which are sources of considerable volumes relied upon by California consumers. Mark Pocta of the Commission's Public Advocates Office highlighted the unusualness of the price spikes in the producing regions: "…. a little bit different observation here is … in the past just the price for almost at the border. But we really never experienced them to the extent in the producing regions."[74] Elevated natural gas prices were also observed globally. The natural gas market is a national (and increasingly even global) market. To fully understand the market dynamics this winter, it is important to examine what occurred outside of California.

6. Are there any gas and electric market interactions that affect costs to consumer that the CPUC should examine and/or investigate?

The Commission should collaborate with relevant stakeholders to further understand the implications of decarbonization and extreme weather events on natural gas markets and prices. As extreme weather events and decarbonization policies influence electric resource portfolios and electric system reliability needs, a more holistic view of integrated energy planning and analysis is needed going forward as the energy transition changes the way we produce, deliver and consume energy, and its corresponding impact on energy markets. SoCalGas recommends

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[74] CPUC, *En Banc, Current Gas Market Conditions & Impacts of Gas Prices on Electricity Markets*, February 7, 2023, Cal Advocates Presentation by Marc Pocta, at 1:02:06-1:02:20, recording available at: https://www.adminmonitor.com/ca/cpuc/en_banc/20230207/.

the Commission coordinate with relevant stakeholders to review Electric Generation (EG) gas demand in the west, how that demand was met during this period, whether it is transient or systemic in nature, and whether it contributed to price volatility in the Rockies and other western delivery points. In addition, the Commission should explore whether elevated EG consumption of natural gas impacted the supply/demand balance for the Southern California system (e.g., how reduction of CAISO imports may have impacted gas demand on the SoCalGas system by increasing reliance on in-state natural gas fired EGs).

Extreme weather events result in elevated natural gas demand by EGs. For example, the extreme weather event in the Summer of 2022 presented California grid operators the challenge of meeting unprecedented record demand. On September 6, 2022, record peak demand hit ~52,000 MW for the CAISO service territory with natural gas generation contributing roughly half of supply to meet gross peak demand.[75] Natural gas proved essential because of its flexibility in meeting demand that cannot be met with renewables. Important long-term trends in California energy markets, their relationship to cost allocation and rate design for natural gas in California, specifically the relationship between natural gas generation and core customers (mainly residential and commercial buildings) and how this relationship is anticipated to evolve as part of the energy transition and impact affordability is discussed at length in SoCalGas's testimony in its pending Cost Allocation Proceeding.[76] As the testimony outlines, natural gas generation continues to be a major customer segment on the natural gas system, accounting for around 28% of overall SoCalGas system throughput forecast underlying 2022 rates, while only

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75 CAISO, *Summer Market Performance Report*, September 2022, at 139 http://www.caiso.com/Documents/SummerMarketPerformanceReportforSeptember2022.pdf

76 *See* A.22-09-015, Chapter 14, Prepared Direct Testimony of N. Jonathan Peress on Behalf of Southern California Gas Company and San Diego Gas & Electric Company, Long-Term Policy and Energy Transition.

contributing around 3% of SoCalGas's revenue requirement in the same period.[77] Core customers account for around 39% of overall SoCalGas system throughput and contribute around 82% of SoCalGas's revenue requirement.[78] Advancing rate design and cost allocation strategies is paramount to ensure equitable and affordable outcomes as the state transitions to a net zero economy. While the substance of these issues is scoped into the cost allocation proceeding as well as the gas system OIR, an understanding of the market dynamics and how decarbonization policies impact traditional ratemaking and cost allocation and ultimately market design are relevant to the issues and line of inquiry raised in this OII.

And while natural gas generators have always been a major customer demand on the SoCalGas system, as the electric grid integrates greater levels of intermittent renewables, natural gas generators are needed to provide critical load following and system flexibility, and thus their demand profile has become more volatile and less predictable, presenting challenges for natural gas utilities. However, at the same time that levels of intermittent renewable energy are increasing, natural gas generation capacity is decreasing. The Commission should consider how this impacts pricing and affordability. For example, by 2021 in-state renewable capacity increased 20% since 2017 and tripled relative to 2006 levels, while in state natural gas generation capacity has fallen ~20% since reaching its highest capacity in 2014.[79] And while gas imports on September 6, 2022 were a key contributor in maintaining grid reliability providing approximately 10% of the CAISO's peak load, increasing decarbonization targets adopted by

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[77] *Id*. at 5.

[78] *Ibid*.

[79] CEC, *Electric Generation Capacity and Energy*, *In-State Electric Generation by Fuel Type (GWh)* (data based on CEC-1304 QFER Database as of May 11, 2021), available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy

western states may further constrain the future availability of natural gas resources, which are vital for providing critical load following and system balancing particularly when renewables are experiencing diminished output and/or are unavailable. 2022 Southern California Edison (SCE) Day-Ahead prices, load, and renewable outputs reveal that price spikes occur on high demand days during evening ramp when the sun is setting, implying that California has insufficient dispatchable resources. During extreme weather event days, the morning spike and mid-day dip are overshadowed by prices as high as $1,344/MW or 13.4 cents/kwh in the evening.[80] Occurrences of scarcity pricing are likely to increase in frequency as western states decarbonize and more natural gas generators retire.

Decarbonization policies will exacerbate this challenge as greater parts of the economy electrify. Over time, depending on the degree of fuel substitution that occurs, the winter natural gas-fired EG load could become a proportionately larger contributor to peak gas system design conditions – and may even become the largest contributing segment. Indeed, the CARB's 2022 Scoping Plan retains the existing natural gas capacity to meet reliability needs out through 2045, as well as adding 9GW of dedicated hydrogen thermal generation to provide the operational attributes necessary to address system balancing needs.[81] This modeling result acknowledges the need for operational flexibility of a just in time fuel source that becomes more important as electric load increases and intermittent resources make up a larger share of the resource portfolio. Without adequate firm dispatchable generation both in state and regionally, scarcity pricing for

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80 CAISO, OASIS Locational Marginal Prices for SCE DLAP, available at: http://oasis.caiso.com/mrioasis/logon.do.

81 CARB, *Final 2022 Scoping Plan Update and Appendices*, November 16, 2022, AB 32 GHG Inventory Sectors Modeling Data Spreadsheet, available at: https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx and https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents.

dispatchable natural gas generation will continue to present affordability challenges for an economy that increasingly relies on electrification. The relationship between gas generation resource availability both near-term and long-term and the resulting pricing impacts should be further examined to ensure affordability as we make progress towards our decarbonization goals.

The Commission should also examine the current misalignment between the CAISO Day-Ahead market and the natural gas procurement cycles. Gas nominations are performed before Electric Generators know what their gas obligations are. This can result in OFO non-compliance charges (or potential non-compliance charges) to be captured in bid costs which will impact electric prices. Better alignment between the two markets would help with the uncertainty that we have today.

7. What were the utility communications to customers about the high gas prices, and what changes, if any, should be made in the future?

SoCalGas Response

a. Winter 2022-2023 customer communications and outreach.[82]

With customers facing higher than average bills due to higher natural gas commodity prices throughout 2022, proactive high bill customer communications[83] ran across various channels with messages acknowledging higher gas prices, offering ways SoCalGas can help with either energy efficiency, income qualified assistance programs, and tools such as our *Ways to Save* and *Bill Tracker Alerts*, to manage usage and bills through winter months and cooler

[82] *See* Attachment A for a compilation of SoCalGas's winter 2022-2023 customer communications and outreach.

[83] Historically SoCalGas has developed annual strategic winter customer communications in preparation for our "high bill season" (November through March). Primary messages have included, but not been limited to, natural gas conservation, energy savings tips, appliance safety, and customer assistance programs.

temperatures. Based on SoCalGas's research and industry survey soliciting customer feedback,[84] SoCalGas designed its Winter 2022- 2023 high bills communications campaign to focus on proactive, supportive, and multi-language (English and Spanish) messages. The specific objectives of SoCalGas's communications campaign included: 1) helping customers plan and prepare for higher winter bills and drive awareness around gas price volatility, 2) driving awareness of tips, tools, programs, and services to support the variety of customer needs, and 3) providing information related to energy savings, safety, and conservation solutions for natural gas.

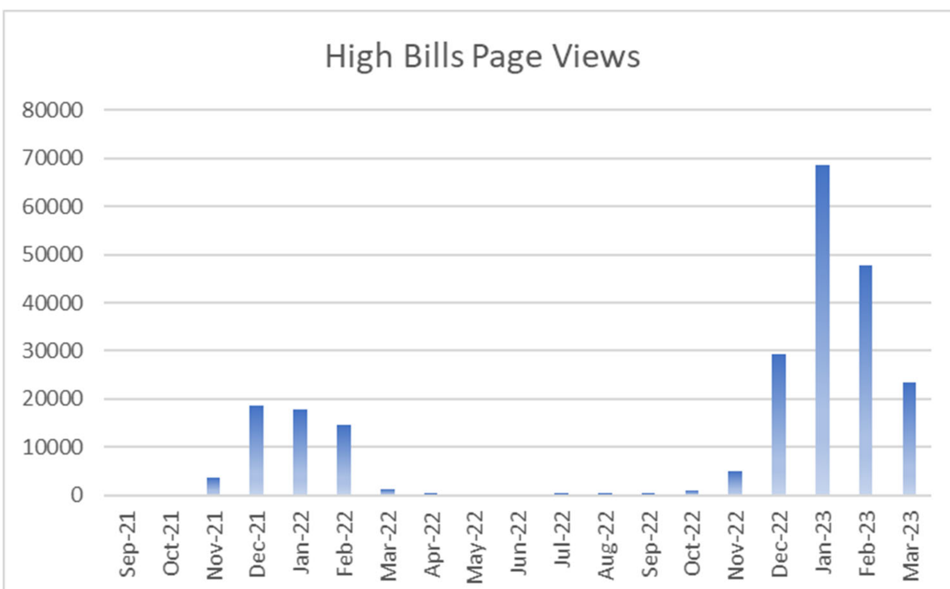
In support of these objectives, SoCalGas used a variety of communication channels (beginning in September 2022 and continuing through March 2023) including but not limited to: socalgas.com, printed on-bill messages, Interactive Voice Response (IVR), My Account, chatbot, Amazon Alexa, non-bill emails, social media, stakeholder outreach. These channels were utilized to reach a majority of customers through the various touchpoints in both English and Spanish as applicable, and provided relevant messages regarding gas price forecasts, and ways in which SoCalGas could help customers manage usage and bills through energy conservation, assistance programs, bill payment options, and tools such as our Ways to Save application,

[84] In July 2022, SoCalGas conducted qualitative research consisting of six virtual focus groups to gather feedback from geographically diverse customers experiencing higher than typical natural gas bills due to commodity costs that could help inform our winter messaging campaign. Specific objectives included: 1) understanding customer awareness and perceptions around rising commodity costs, 2) obtain feedback on messaging and outreach, 3) identify areas of confusion, and 4) generate suggestions for improvement. The six sessions consisted of the following customer segments: two sessions with Residential Customers (one each in English and Spanish); two sessions with Low-Income Residential Customers (one each in English and Spanish); and two sessions with Small Business Customers (conducted in English). In addition to the direct customer research, as a member of American Gas Association (AGA), SoCalGas pursued an opportunity for a member survey to gain additional insights regarding planned messages or communications to customers about high commodity costs for natural gas, the channels that were being utilized, and how far into the future our expectations are being communicated regarding commodity prices.

which provides customized recommendations to help lower energy usage, and Bill Tracker Alerts, which help customers monitor consumption and view projected charges on upcoming bills.

- *Website*—SoCalGas has maintained and updated a resource webpage at socalgas.com/ManageHigherBills with information regarding how SoCalGas can help residential, income qualified and small business customers manage higher bills. It also provides information regarding the factors leading to higher bills, current and historical monthly natural gas prices, bill details, energy savings tools and programs to help manage monthly bills. SoCalGas has seen significant increases in website visits and engagement compared to winter 2021-2022. Specifically, when compared to January 2022 to January 15, 2023, roughly 63% of the visitors to this webpage were new visitors. In addition, we can see that consistently the top five engagement topics are 1) Level Pay Plan, 2) Programs & Services, 3) Log in/Register MyAccount, 4) Energy Savings Tips/Tools, and 5) Assistance Programs.

Figure 9



(Data as of March 2023)

- *Pop-up ads*—In addition, website promotions on the socalgas.com homepage were run through pop-up digital ads in January and February 2023 to provide additional awareness to any visitor to the homepage during the run times and linked back to the resource page mentioned above. Key messaging in January was higher gas prices and in February the focus was on understanding bills.

- *Emails*—Non-bill related direct customer emails were sent in the months of December 2022 and January 2023 reaching roughly 4.1 million customers per email deployment, per residential, CARE and small business customers from December 2022 – January 2023. The December email focused on winter preparation, providing customers awareness of expected higher bills due to price of natural gas and expected transportation rate increase. Accompanying these key messages, SoCalGas offered tips to save on energy use, customer assistance programs, bill payment options, and tools to help manage usage into the winter season. The January email also provide the same helpful energy savings tips, program, and services to help manage bills, but followed a focus on the transparent message regarding the unprecedented colder weather, leading to increase usage and expectations of "much higher than expected" natural gas prices and the impact on customer bills.

- *Interactive Voice Response (IVR)*—Through our customer contact center IVR system, SoCalGas placed messages following prompts for billing inquiries regarding the natural gas prices and again offering way to help with assistance programs and bill payment options. These messages were launched as early as the end of September 2022 and continued to be maintained and updated as relevant to address the customers' needs based on calls with Customer Service Representatives (CSRs) and foreseen impacts as necessary.

- *MyAccount*—From Dec 2022 – March 2023 the SoCalGas My Account system was visited by roughly 3.4 million customers per month, with 97% of them residential and 3% business customers. Within the My Account Dashboard, messages are placed periodically to inform customers of important system or service updates and opportunities. My Account is available to residential and business customers, and both are served as part of the overall communications strategy to share key information regarding expected higher gas prices, billing resources, and programs.

- *Social Media*—The social media strategy consisted of a minimum of weekly postings in alignment with winter preparations, conservation messages, assistance programs and billing payment options or tools to help manage usage. Planned communications started September 2022 - March 2023 and ran on the SoCalGas Facebook, Instagram, and/or Twitter handles as relevant. Topics included energy saving/conservation tips, assistance programs, weather triggered tips, climate credit, and our debut of a social media winter conservation series titled "Dan The Weatherman".

- *Media* – Planned media and public information was guided by the utilization of the SoCalGas Newsroom (newsroom.socalgas.com) blog stories and proactive Press Releases. Since the end of December 2022 to March 2023, four blog stories were posted and provided updates and information on higher natural gas prices including, third party sourced validation regarding contributing sources for higher natural gas prices across the west coast, details on gas market volatility, updates on monthly gas prices for months of February and March, along with all resources for billing support, payment options, and energy conservation to help customer manage bills. Additionally, since November 2022 at least five press releases have been sent via PR Newswire and providing community outreach ahead of winter, expected customer bill impacts, contributing factors for higher natural gas market prices, and significant SoCalGas contributions to provide additional financial relief to our most vulnerable and income qualified customers.

Aside from the general public communications, targeted communications were provided to maximize awareness of higher gas price impacts across specific customer segments. These communications had been developed and targeted specifically to these customer segments:

- *High Bill Investigation (HBI) Customers*—Historically, SoCalGas has conducted an annual email-based communications campaign at the start of winter (Dec/Jan - weather pending) providing energy savings tips, programs, and services to help manage energy use and bills during the winter and colder weather months. This campaign targeted customers from the prior season who had been issued a "high bill investigation" service order requiring a service technician to inspect the customers appliances for any natural gas leaks or abnormal usage that might have resulted in the high bill. In November 2022, SoCalGas initiated an early deployment of this email campaign and expanded the targeted list to include customers who called our customer contact center about (HBI) and those who received a follow up letter from a Customer Service Representative (CSR). This strategy allowed the targeted customer list to expand by nearly 40% and reached roughly 65,000 customers by the end of November in doing so.
- *Income Qualified Customers*—Customers eligible for subsidized or low-cost services due to certain qualifications receive text (SMS) messages based on assumed consent. These customers receive CARE program messages in effort to continue to raise awareness and encourage participation in the income qualified program. These communications are divided into three groups: 1) new customers, 2) existing customers not enrolled in CARE, and 3) customers eligible to recertify for the program to continue to receive the 20% monthly bill discount. This channel and was leveraged to bring awareness to potentially vulnerable customers of higher expected bills due to increases in natural gas prices while also offering a direct assistance program to help manage bills.

In addition, in October and November of 2022, SoCalGas partnered with local organizations to share important resources and provide 500 Google Nest thermostats in preparation for winter. Organizations included Southeast Community Development Corporation, Alma Family Services, and All Peoples Community Center. Media coverage consisted of English, Spanish and Asian media including, KNBC (NBC), KTLA, KVEA (Telemundo 52), KMEX (Univision), NTDTV (New Tang Dynasty Television), and PR NEWSWIRE: KYLA, KRON4, FOX5.

SoCalGas also maintains strong community partnerships and engagement throughout our service territory. At the start of 2023, SoCalGas accelerated its outreach efforts through Regional Public Affairs, Account Representatives, and third-party contracts. SoCalGas also engaged foodservice organizations, restaurant associations, trade professionals, and community-based organizations (CBOs). Through these connections SoCalGas contacted over 50 organizations/associations with critical awareness and factors leading to higher natural gas prices and bill impacts. Higher gas prices also impacted our natural gas vehicle (NGV) fueling stations and clean transportation customers. Communications were not only posted directly at the NGV fueling stations but, through the SoCalGas clean transportation team, we had reached roughly 325 clean natural gas (CNG) customers and third-party contractors.

Communications with public officials was another key component of SoCalGas's customer and stakeholder outreach strategy. SoCalGas issued communications to all 223 municipalities and 12 counties within the SoCalGas service territory. This included communications to mayors, city councils, supervisors, city managers, etc. Communications through direct calls and in person presentations at city council meetings have continued to provide community awareness, resources and updates on natural gas prices and ways SoCalGas can help our customers. SoCalGas has supported various cities convening special informational sessions related to gas prices by providing subject matter experts from its gas acquisition, customer service and public affairs groups to provide resources and information needed to aid in the public communications. In addition, SoCalGas coordinated and conducted Commission staff briefings to various staff members throughout January. The briefings were attended by experts from SoCalGas's gas acquisition, customer service, and public communications departments. SoCalGas provided information regarding market volatility for western gas prices leading into January, historical winter gas demand, SoCalGas winter storage levels, customer service trends and impacts as well as an overview of its customer communication and outreach efforts. Lastly, SoCalGas participated in a special legislative staff update regarding winter gas prices on February 9, 2023. Over 90 people attended this event, with representatives from 30 Assembly offices, 20 Senate offices, and three different committees.

Figure 10 provides a timeline of SoCalGas's communications and outreach efforts.

Figure 10

Timeline

October/November	December	January 2023	January/February
10/17 • Residential Bill Ready Notifications updated **10/28 and 11/14** **Media/Outreach:** English, Spanish & Chinese (TV/News) • Google Thermostat giveaway events with local nonprofits **11/15** **Stakeholder Communications** • RPA E-Mail to all Cities & Counties • AE Non- Core C&I Notifications (Email) **11/26** • Annual High Bills Email Campaign • USPS Informed Delivery Campaign **11/28** • Annual Winter Safety & Savings paid media campaign	**12/1 – 12/13** • All Customer Email (Residential CARE, Non-CARE, and Small Business) Email **12/6 – 12/9** **Employee Communications** • VP Letter High Bills – Gillian Wright • Gaslines Story • Connected Newsletter **12/8** • CARE paid media campaign **Stakeholder Communications** • RPA- Ventura Newsletter **12/20 & 12/29** **Stakeholder Communications** • RPA E-Mail to all Cities & Counties **12/29** **Media** • News Blog & social media (FB/Twitter) **Continued** • USPS Informed Delivery Campaign • Annual Winter Safety & Savings paid media campaign	**1/3** **Employee Communications** • Gaslines Story – Higher Winter Bills Update **1/4 – 1/15** • All Customer Email (Residential CARE, Non-CARE, and SMB) **1/4** • **NEW** Winter Conservation Social Series – "Dan The Weatherman" **1/5** **Stakeholder Communications** • RPA E-Mail to all Cities, Counties, Chambers & EDC's **1/6** **Media** • Press Release – Gas Assistance Fund/High Bills • AE Core Procurement Rate Comms **1/8** • California Arrearage Payment Program (CAPP) Funding – Bill message	**1/12** **Employee Communications** • Lunch & Learn – High Bill Factors **1/13** **Media** • News Blog- Understanding Natural Gas Prices **1/23** **Paid Media Campaign** • Annual Winter Safety & Savings **1/30** • Percentage of Income Payment Plan (PIPP) Pilot Comms. **2/1 - 2/27** **Media** • News Blog: Market Prices For Natural Gas (2/1) • Press Release: Climate Credit (2/2) • Press Release: Customer Natural(2/15 • Press Release: Gas Assistance Fund/High Bills (2/27) **2/22 Paid Media Campaign** • Customer Assistance Programs mass media advertising for CARE, ESAP, & Medical Baseline

Ongoing socalgas.com, My Account, IVR, and On-bill messages + Organic Social Media and Newsroom Updates (September 2022 – March 2023)

b. ***<u>Options for future additional customer communications and outreach.</u>***

SoCalGas appreciates the opportunity to provide comments regarding future communications to customers about high gas prices. In the near term, SoCalGas is planning additional customer communications by expanding text (SMS) message options for high natural gas price alerts to customers that opt-in, as means to provide additional awareness to support customers with energy and bill management during the winter season. Additional options for future customer communications include:

- Expanding customer feedback and qualitative research to include additional participants and customer segments to gain further insights on messaging, channels, and other tools.
- Enhancing presentation and organization of digital communications (e.g., socalgas.com, educational videos, and social media) to provide helpful information to customers across various customer segments.
- Dedicated promotional communications regarding SoCalGas's Bill Tracker Alert to encourage early adoption, including use of direct communication channels, social media, and leveraging cross promotional communications where applicable.

<u>SDG&E Response</u>

a. ***<u>Winter 2022-2023 customer communications and outreach</u>.***[85]

Beginning last October, SDG&E has been executing a broad, multi-channel, customer education and engagement campaign to be transparent, drive awareness and offer assistance. SDG&E launched a comprehensive, integrated communications campaign starting in October 2022 to prepare customers for potentially high winter bills, which continued through Q1 2023. A variety of tactics – including press releases, media interviews, direct emails to customers, organic and paid social media posts, digital and print ads, multi-lingual fliers, new and revamped web

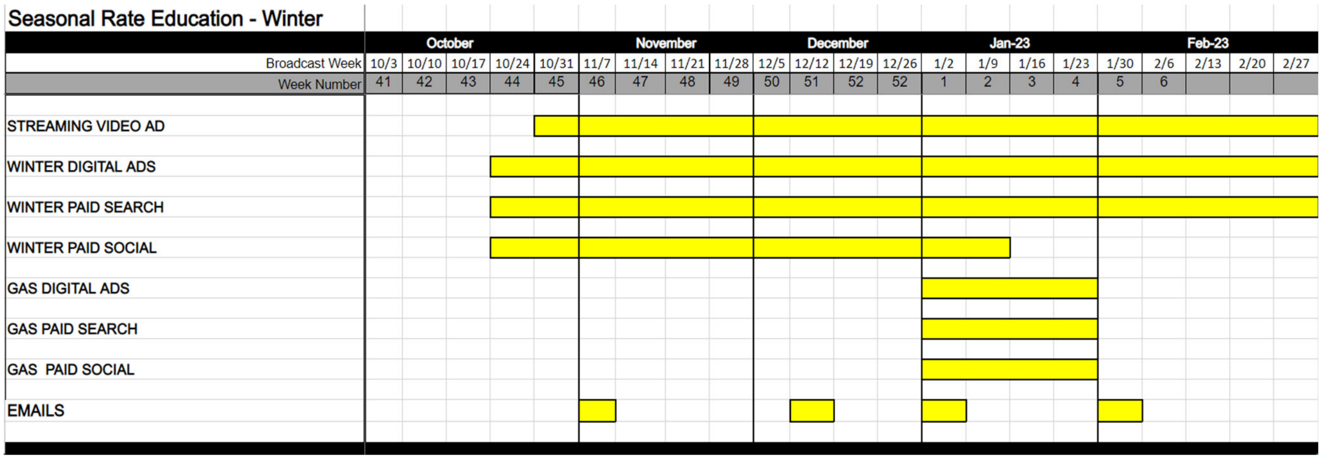
85 See Attachment B for a compilation of SDG&E's winter 2022-2023 customer communications and outreach.

content – were used to disseminate relevant and useful information to customers, broadcast, online and print media, local community leaders (including elected officials and municipal staff), and community-based organizations (CBOs). Using plain and straightforward language, SDG&E informed customers about the unprecedented natural gas commodity market volatility, what they can do to save on their gas heating bill, and what assistance programs are available to help them if they are struggling to pay their bill. Support included:

- *Dedicated Leadership Strike-team:* SDG&E's cross-functional "strike-team" featured leaders across several departments who executed a comprehensive and thoughtful plan to drive awareness of gas rates, deliver a multi-pronged communications and media campaign, provide ongoing support and follow-up directly on all escalated customer complaints. This team met weekly throughout Q1 to ensure customers with complaints were provided with options including payment arrangements, the federal Low Income Home Energy Assistance Program (LIHEAP), which provides hundreds of dollars to customers to pay for energy bills and weatherization measures, Neighbor to Neighbor (N2N), which is SDG&E's shareholder funded program to help customers pay overdue bills, as well as enrollment in California Alternative Rates for Energy (CARE) and the Family Electric Rate Assistance (FERA) programs, which reduce customers' bills.

- *Paid Advertising:* SDG&E began programmatic digital advertising on October 24, 2022 which promoted winter-specific savings tips to help manage their gas and electric bills. The ads connected customers to sdge.com/MyEnergy to learn more about bill and energy management resources like Energy Alerts and Level Pay program, gas-specific tips, and available assistance programs. On January 2, 2023, additional advertisement messages ran specifically focused on alerting customers to higher natural gas pricing and bills. Figure 11 outlines the timeline for advertising per channel, including the customer emails.

Figure 11



As part of its paid media campaign, SDG&E began programmatic digital advertising on October 24, 2022, which promoted winter-specific savings tips to help manage their gas and electric bills. The ads connected customers to sdge.com/MyEnergy to learn more about bill and energy management resources like Energy Alerts and Level Pay program, gas-specific tips, and available assistance programs. On January 2, 2023, additional advertisement messages ran specifically focused on alerting customers to higher natural gas pricing and bills. As part of the campaign:

- *Emails*: SDG&E also delivered 6.8 million emails, with higher than usual open rates, tailored for residential and business customers to help them plan and prepare for higher winter bills. Additionally. SDG&E leveraged monthly energy bill forecast/usage alerts for all customers who have provided e-mail contact information.

- *Social Media*: The social media strategy consisted of a minimum of weekly postings in alignment with winter preparations, conservation messages, assistance programs and billing payment options or tools to help manage usage. Planned communications started November 2022 - April 2023 and ran on all SDG&E channels and means at its disposal to disseminate information, including Facebook, Twitter, Instagram, and Nextdoor, which resulted in retweets by the CPUC and local leaders. About 200+ social media posts were created, translated, published and shared in English and Spanish to our 1.2M+ followers.

- *Website*: SDG&E's primary homepage graphic was updated to prominently highlight the historic natural gas market conditions as well as assistance programs. A banner message was added to the top of every webpage. Additionally, functionality and design improvements were made to its customer assistance program landing page, sdge.com/assistance, which is a one-stop shop for customers to learn about payment plans, debt relief, bill discounts and other resources. In addition to sdge.com/MyEnergy, this landing page was heavily publicized across communications channels and materials. A page dedicated to explaining what goes into customer rates, sdge.com/rates, also saw "New Users" account for ~47% of total Pageviews in January, February, and March. The top five engagement topics on the rates page are 1) Energy Rates and Who Sets Them 2) Your SDG&E Bill and Why Rates Are Higher 3) Making Bills More Affordable 4) 2024-2027 Electric and Gas Budget Proposal 5) Valuable Benefits to Customers

- *Media*: Due to the company's aggressive and proactive media outreach over a period of months, all local major news outlets, as well as many smaller community publications, ran or aired multiple rounds of stories on the topic throughout the peak of the commodity price spike, and then ran more stories as SDG&E communicated that commodity prices were starting to come down. Updates were also made available at its NewsCenter at sdgenews.com.

- *Interactive Voice Response (IVR)*— SDG&E placed an upfront message on our Customer Contact Center IVR to increase customer awareness of high natural gas prices.

- *Customer Contact* – SDG&E provided frequent updates and additional training to Customer Care agents including talking points, coaching, and training to answer customer questions and provide recommendations to reduce their bill to support customer understanding.

- *Collaboration with Community Based Organizations*: A key part of SDG&E's strategy to extend the reach of its communications was through collaborations with local leaders and community-based groups, such as 2-1-1 San Diego and 2-1-1 Orange County. SDG&E created a social media toolkit, which focused on rate education and customer programs including CARE, FERA, ESA, AMP, LIHEAP and Level Pay Plan, and shared it with SDG&E's Energy Solutions Partner Network, which consists of more than 200 CBOs. This toolkit was used to amplify messaging to customers throughout SDG&E's service territory and provided contact and enrollment information for these programs.

- *Access and Functional Needs Support:* SDG&E conducted extensive community outreach, which included a call campaign to ~500 customers with Access and Functional Needs (AFN), who were also identified as being high natural gas users, to ensure they were aware of the gas rates, educate them on the key drivers and provide information on available programs that can help lower their usage and manage their monthly bills. SDG&E also partnered with the San Diego Food Bank to provide warming items (blankets, beanies, socks and gloves) at two food distributions, which were well attended and received positive customer feedback. SDG&E staff joined SD Food Bank and provided information on available Customer Assistance Programs and bill payment support programs. Additionally, care was taken to make sure customers with AFN received the communications either directly through SDG&E or through trusted sources, such as CBOs whose mission is to serve them. Customer communications, social media posts, and press materials were consistently translated into Spanish, the most prevalent foreign language spoken in SDG&E's service territory. An assistance program flier was translated into other prevalent languages, in addition to Spanish.

- *Rate Education Seminars:* Additionally, SDG&E hosted rate education seminars for both large business customers and SDG&E's Energy Solutions Partner Network of CBOs. More than 100 organizations attended these sessions to learn more about the key drivers of the rate increase, SDG&E's response to further support customers, and programs available to assist customers with lowering their monthly bill.

- *Local Government Engagement:* SDG&E communicated with all municipalities in our service territory, including cities and counties, and held one-on-one briefings with elected officials to update them on the steep rise in wholesale natural gas rates. This included communications to all mayors, city councils, county supervisors and city managers. Communications included resources for customers including tips on how to save energy and available assistance, including bill payment, discount and debt relief programs. Additionally, SDG&E spoke during public city council meetings, at events, and in community forums to communicate with both community leaders and the public. We have engaged in many follow-up conversations and sent subsequent communications to elected officials to ensure all questions and concerns are addressed around gas rates, and provided regular updates as we saw changes to the market.

- *Program Enhancements and Promotion:* SDG&E heavily promoted available programs, in particular, the LIHEAP and N2N programs, as well as enhancing the N2N program. Some examples include:

    - Adding $5M in shareholder funding to N2N program fund for a total of $6M in funding available to customers

    - Enhancing the N2N program to make enrollment easier for customers, including enhancements listed in Table 4 below.

- *My Account:* From Dec 2022 – March 2023 the SDG&E My Account system was visited by roughly 475,000 customers per month, with 96% of them residential and 4% business customers.

Table 4

Old Program	New Program
Indirect enrollment only (must call 2-1-1 to obtain # of local agencies)	Customers can call SDG&E, visit a branch office or apply online, in addition to 2-1-1
Incentive capped at $300 or $400 for MBL	Incentive level increased to $600 per household
Must be at least 90 days past due (disconnection notice)	Only 60 days past due (late notice)
Customers must attempt to apply for LIHEAP before applying to NTN	Any active, residential primary account eligible
Customers with remaining debt must agree to payment plan	No payment plan required
No interaction with disconnection process	NTN embedded into disconnection process through ESS

- Held[86] 9 events at SDG&E's branch offices, resulting in more than 800 attendees and over 500 LIHEAP enrollments, in coordination with Campesinos Unidos, Inc. of San Diego (CUI) to enroll eligible customers in LIHEAP and Neighbor to Neighbor.

- SDG&E sent over 43,500 dedicated emails to customers with qualifying arrears to promote the events. Targeted by zip codes, SDG&E posted the week of each event on NextDoor.

- Partnering with CUI to attend workshops at CUI's offices to enroll eligible customers in LIHEAP on Saturdays.

- Met with community organizations, such as the Chaldean Community Council, to ensure local access to available programs and funding.

- During Q1, SDG&E sent CARE & FERA outreach emails to potentially eligible customers, continued paid search and promoted customer assistance on social media outlets and bill messaging.

- Dedicated emails and letters were sent to 25,000 customers in arrears promoting customer assistance offerings, including NTN and LIHEAP.

86 As of 3/30/2023.

From Dec 2022 – March 2023 the SDG&E My Account system was visited by roughly 475,000 customers per month, with 96% of them residential and 4% business customers.

b. Future communications and outreach

SDG&E continues its annual rate education to help customers plan and prepare for seasonal bills. The multi-channel approach will evolve based on the marketing effectiveness of the 2022-2023 campaign, incorporating lessons learned from customer response, key KPIs and targeted customer research. SDG&E will also continue to explore new opportunities to enhance its seasonal campaigns, including:

- Expand content marketing opportunities through video, web copy and social influencers.
- Continued promotion of Bill Alert notification enrollment and functionality, providing customers with more choices and control over bill notifications and energy usage.
- In an effort to expand time-sensitive messaging, SDG&E will continue to explore new media tactics that can be turned on and in-market quickly.

IV. CONCLUSION

SoCalGas and SDG&E appreciate the opportunity to provide these comments in response to the OII and share the Commission's interest in protecting against the risk of future similar events and mitigating adverse price impacts on consumers.

Respectfully submitted,

/s/ Setareh Mortazavi

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Dated: April 19, 2023

ATTACHMENT A

SoCalGas's winter 2022-2023 customer communications and outreach

ATTACHMENT A

SoCalGas 2022-2023 High Bills Communications

Emails:

1. **November/December 2022 –** Email sent on 11/26/2022 to 65K customers and then retargeted to 29K customers on 12/10/2022.

SoCalGas

Dear Customer,

Cold weather has arrived, and we are here to help you prepare with energy-saving tools, conservation tips, and assistance programs that could help you manage your monthly bill, while still providing a warm and cozy environment this season.

The cost of natural gas has been higher nationwide, resulting in higher-than-average monthly natural gas prices. Heating is one of the top energy expenses for most customers during colder months and can account for more than half of your total natural gas bill.

Here are a few tips to help you manage your gas usage this winter:

- Wash and rinse clothes in cold water, take shorter hot showers, and lower your water heater temperature.
- Sign up for email and text Bill Tracker Alerts through My Account to help monitor your natural gas consumption throughout your billing period.
- Complete your Energy Profile with our Ways to Save tool to get a personalized household energy analysis and savings plan to help you keep track of your energy-efficiency progress and ultimately help you lower your bills.
- Eligible customers may sign up for a Level Pay Plan, which averages their annual natural gas use and costs over 12 months.

Learn More

Por favor visite nuestro sitio web para obtener información en español.

Connect with Us*

2. **December 2022 –** Email sent to 4.1M residential, CARE, and small business customers combined with valid emails on file.

SoCalGas

Prepare for the Winter Season

SoCalGas can help customers prepare for and navigate the upcoming colder weather and the potential increasing cost of energy.

During this winter season, customers may be receiving higher bills due to several factors including the cost of energy. Peak winter bills are expected to increase by 25-30%[1] compared to the 2021-2022 season. This increase is due to continued higher price of natural gas[2] and increases in transportation rates.

To help you manage your monthly bill this winter, we offer **energy-savings tools, programs, tips, and resources** that could help you save money and reduce energy use through the colder months.

Winter Outlook

Heating your home during colder temperatures could lead to more natural gas use and can account for more than half of your bill. Compared to other fuel sources, a natural gas heating system is still the most affordable and efficient way to heat your home or business.

Financial assistance is available to qualifying customers through our **customer assistance programs**. Plus, we offer rebates on energy-efficient appliances, energy saving tips, and **bill payment options** that may be right for you.

To help plan your usage, you can reference **current and historical natural gas prices**. You can also sign up for **Bill Tracker Alerts** to monitor your gas consumption to avoid surprises on your bill.

We offer more resources to help you understand your bill, payment options, and natural gas safety this winter.

Learn More

Información en español

3. **January 2023 –** Email sent to 4.1M residential, CARE and small business customers combined with valid emails on file.

SoCalGas

Dear Customer,

There's no easy way to put this: January bills are likely to be higher than usual. An unprecedented cold snap across the nation in part has caused natural gas market prices in the West to more than double between December and January – much higher than expected. As a result, SoCalGas residential customers can expect the typical January bill likely to be more than double the typical bill last January, assuming the same amount of natural gas is used.

Many SoCalGas employees are your neighbors and community members, and we are here to help you best manage your energy consumption, while balancing usage and comfort. To help keep monthly bills as low as possible, we offer tips, tools, and programs designed to assist you in finding what works best for your home or business.

- **Bill Tracker Alerts** are a great way to monitor your consumption to help gauge the amount of your next bill and enrollment is easy. Completing an energy profile through our **Ways to Save** online tool provides you with a personalized plan to track progress and determine the best approach to help lower your energy usage. If you would like to spread out your monthly costs, check out our **Level Pay Plan**, which averages your natural gas usage and costs over 12 months.

- Qualifying residential customers may also be eligible for a variety of options through our **customer assistance programs**. The CARE program offers a 20% bill discount, the Energy Savings Assistance Program offers no-cost home improvements, and customers with a qualifying medical condition may be eligible for additional natural gas at the lowest baseline rate through the Medical Baseline Allowance Program.

We offer **bill payment options**, conservation tips, rebates, and resources to help all customers in customizing their usage and savings approach. For more information, please visit **socalgas.com/ManageHigherBills**.

Información en español

Respectfully,

4. **January 2023 –** Sample email sent to assigned commercial and industrial customers directly from Account Representatives.

Dear Customer,

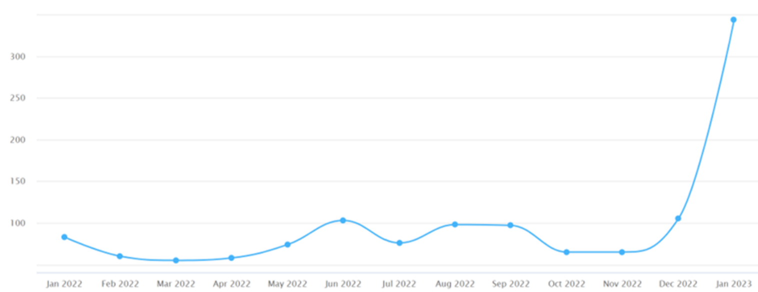
SoCalGas is reaching out to inform all customers that natural gas prices are going to be even higher than usual this January due to several unprecedented factors beyond our control. Customers can expect much higher than usual natural gas prices on the West Coast.

In addition to our annual transportation rate updates (effective January 1, 2023), you will notice a significant rise in our monthly core procurement rate for January 2023. The core procurement rate is the cost of natural gas purchased by SoCalGas on behalf of its customers. Due to a rise in the market price of natural gas, customers may see a winter gas bill double or higher compared to one year ago.

The high bills are a result of historically high natural gas prices in the western United States. SoCalGas doesn't set the price for natural gas. Instead, natural gas prices are determined by national and regional markets. SoCalGas buys natural gas in those markets on behalf of residential and small business customers, and the cost of buying that gas is billed to those customers with no markup, meaning SoCalGas does not profit from gas commodity prices going up.

Natural gas prices change monthly, and you can view current and historical prices to help plan your usage.

Current and Historical Natural Gas Prices:



According to the US Energy Information Administration (EIA), a number of factors are contributing to higher natural gas commodity prices.

- Widespread, below-normal temperatures on much of the West Coast, including Washington and Oregon;
- High natural gas demand for heating by customers in areas with below normal temperatures;
- Reduced natural gas supplies to the West Coast from Canada and the Rocky Mountains;
- Reduced interstate pipeline capacity to the West Coast because of pipeline maintenance activities in West Texas; and
- Low natural gas storage levels on the West Coast.

A detailed report about these market conditions can be found here: https://www.eia.gov/naturalgas/weekly/.

In short, this combination of factors means that demand for natural gas on the West Coast is unusually high at the same time that supplies are reduced. These conditions could continue through the winter months.

Our focus is always on safe, reliable, and affordable natural gas service to our customers, and we are very empathetic to the real impact higher bills can have. We are alerting you so that together we can manage and mitigate impact.

SoCalGas offers many accessible tools to help you cut down on energy usage and help lower your bills amidst the rising costs. Please do not hesitate to contact me to discuss how to reduce energy use by installing energy-efficient equipment, review SoCalGas' rate tariffs to find one that best fits your needs for cost and reliability, and/or answer questions you may have about your natural gas bill.

Sincerely,
SAE Name
Phone

Email

5. **February 2023 –** Clean Fuels customer email sent to assigned customers and contractors directly from Account Representatives.

SoCalGas

February 1, 2023

Dear Customer:

Natural gas prices continue to remain higher than average in the month of February.

Prices at SoCalGas public-access compressed natural gas stations will range from $XX-$XX in February.

We understand that higher fuel and energy costs can be burdensome for you and your business. SoCalGas works diligently to secure the best possible prices for the natural gas we purchase on our customers' behalf, but the market price of natural gas remains high.

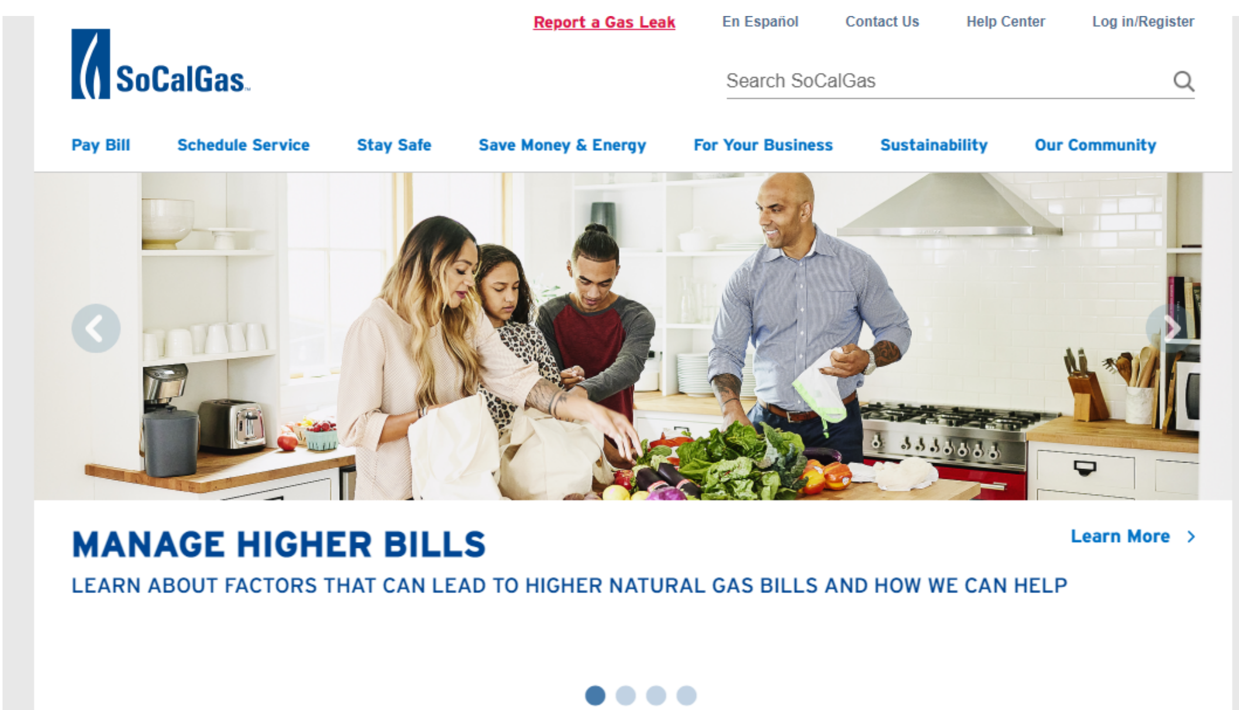
Click here to view our current transportation rate schedule. For more information on natural gas prices and predictions, visit https://www.eia.gov/naturalgas/weekly/

If you have any questions, you can always contact me at (phone) and (email).

Sincerely,

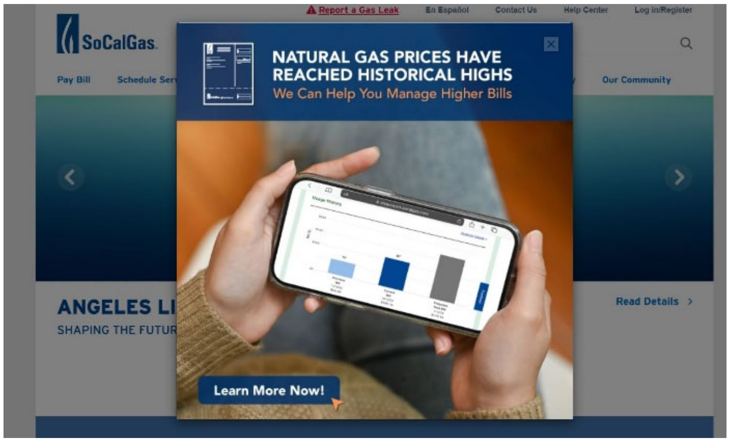
SAE Name
Phone
Email

SoCalGas.com Homepage Marquee:

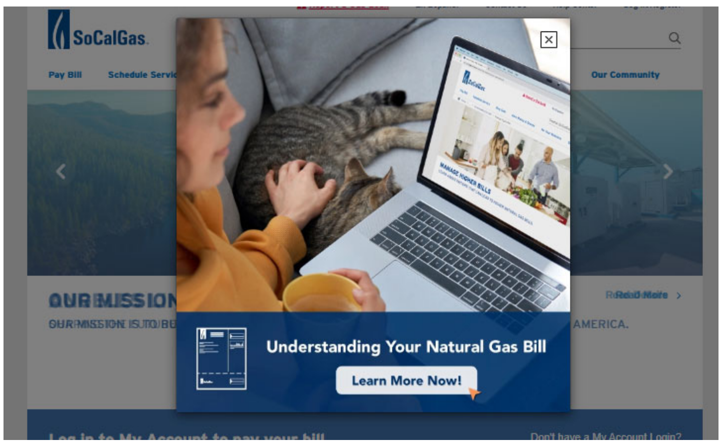


Homepage Pop-up Ads:

January homepage pop-up:



February homepage pop-up:



Web - socalgas.com/ManageHigherBills:

Beginning Fall 2022, all customer communications and messages encouraged audiences to visit socalgas.com/ManageHigherBills to for energy savings tips, tools, factors leading to higher bills and ways SoCalGas can help with assistance programs and bill management services. The page was updated as needed with relevant information and houses graphical depiction of gas prices month over month along with other billing details. Sample image of main landing page:

MANAGE HIGHER BILLS

LEARN ABOUT FACTORS THAT CAN LEAD TO HIGHER NATURAL GAS BILLS.

Natural gas prices have reached unprecedented levels on the West Coast. SoCalGas continues to diligently work to secure cost-effective natural gas supplies on behalf of our residential and small business customers. The price of natural gas is determined by broader regional, national, and global markets and is passed on directly to our customers without markup. SoCalGas does not profit from the movement of gas commodity prices. We are here to help our customers understand their bill while preparing for the colder weather and increasing cost of energy. Visit our SoCalGas Newsroom for the latest stories and announcements.

How We Can Help

- We offer energy-savings tools, program tips, and services to help our customers save money, use less energy, and lower their monthly bills year-round.
- If you need financial assistance, we offer a wide range of programs and services that may help you save money on your natural gas bills.
- Residential and small business customers may also qualify for COVID-19 support or assistance.
- Sign up for email and text Bill Tracker Alerts through My Account to help monitor your natural gas consumption throughout the billing period.
- Eligible customers may sign up for a Level Pay Plan, which averages their annual natural gas use and costs over 12 months. Customers then pay an average bill amount each month instead of actual charges.

What Could Be Causing My SoCalGas Bill to Be Higher?

- Factors that could impact your bill include the cost of natural gas, weather, an increase in your appliance usage, your billing cycle, and past due bills. Learn more.
- The cost of natural gas has been higher nationwide, resulting in higher-than-average monthly natural gas prices.
- The price of natural gas is determined by regional and national markets and passed on directly to our customers. We do not set the cost of natural gas and do not earn additional profits from higher supply prices.
- SoCalGas is committed to delivering affordable natural gas to our customers. We continue to use a suite of tools to secure the best prices for the natural gas we purchase.
- New gas transportation rates, approved by the CPUC, went into effect on January 1, 2023. Residential average transportation rates increased by about 6% and small business transportation rate increased by about 5% on average. These transportation rate changes will allow us to continue upgrading our infrastructure, retain responsible, well-trained employees, and support the growth of diverse energy options.

Current and Historical Natural Gas Prices:

- Natural gas prices change monthly, and you can view current and historical prices to help plan your usage.

Understanding Your Bill

We are all looking for ways to save time and energy and reduce expenses. Understanding your monthly SoCalGas bill can help.

What is the California Climate Credit?

This month your natural gas bill will include a credit of $50.77 identified as the "California Climate Credit." Your household and millions of others throughout the state will receive this credit on your utility bills. **If you are also a customer of Southern California Edison, San Diego Gas & Electric, or Pacific Gas & Electric you will receive an additional credit from them. According to the California Public Utilities Commission, your combined credit on your gas and electric bills can range from $90 to $120.**

The California Climate Credit is part of California's efforts to fight climate change. This credit is from a state program that requires power plants, natural gas providers, and other large industries that emit greenhouse gases to buy carbon pollution permits. The credit on your bill is your share of the payments from the State's program.

The Climate Credit is one of many programs resulting from landmark legislation called the Global Warming Solutions Act of 2006. Together, these programs are cutting pollution, creating jobs, and investing in cleaner energy and transportation.

Your Climate Credit is designed to help you join in these efforts. For more information about the Climate Credit, visit www.cpuc.ca.gov/climatecredit. For more information about climate change science and programs to reduce carbon pollution, visit www.caclimateinvestments.ca.gov.

What Charges Make Up My SoCalGas Bill?

Our rates are regulated and approved by the California Public Utilities Commission (CPUC). Natural gas bills consist of three cost components:

1. **Natural Gas Commodity Charge** – The cost of natural gas purchased by SoCalGas on behalf of its customers.
2. **Natural Gas Transportation Rates** – The cost to deliver natural gas to a customer's home or business.
3. **Public Purpose Surcharge** – A CPUC mandated charge to fund public purpose programs such as California Alternate Rates for Energy (CARE), the Energy Savings Assistance Program, energy efficiency, and research.

Taxes and fees vary depending on customer location and applicable regulations.

Learn more about how these charges are reflected on your bills.

April 2023 Rates

<u>My Account (Residential and Business):</u>

When customers logged into SoCalGas My Account to see their personalized energy information, a message about winter pricing was posted to make customers aware of higher prices and emphasize that assistance was available.

<u>IVR (Interactive Voice Response) On Hold Messaging for Customer Contact Center:</u>

Messages on IVR have been running since early Fall 2022 and have been updated as necessary to provide the most current information to customers. Below is a sample of these messages in English and Spanish. In January and February, the on-hold message was also updated to provide customers with information about natural gas bills and available resources prior to connecting with a Customer Service Representative.

IVR Message	Completed (updated week of 11/28 to current message)	<u>English:</u> Colder weather has arrived and you may notice a higher gas bill. This season, higher bills are primarily due to the cost of natural gas increasing nationwide combined with increased natural gas usage on cooler days. SoCalGas is here to help you manage higher bills with our customer assistance programs, Ways to Save tools, and Level Pay Plan. Learn more at socalgas.com/ManageHigherBills <u>Spanish:</u> Ha llegado el clima frío y es posible que note una factura de gas más alta. Esta temporada, las facturas más altas se deben principalmente al aumento del costo del gas natural a nivel nacional combinado con un incremento de uso de gas natural en los días más fríos. SoCalGas está aquí para ayudarle a administrar facturas más altas con nuestros programas de asistencia al cliente, las herramientas de ahorro de energía “Formas de Ahorrar,” y el Plan de Pagos Nivelado. Obtenga más información en socalgas.com/FacturasAltas.	All customers calling the CCC who select the "billing" path

Sample On-bill Message:

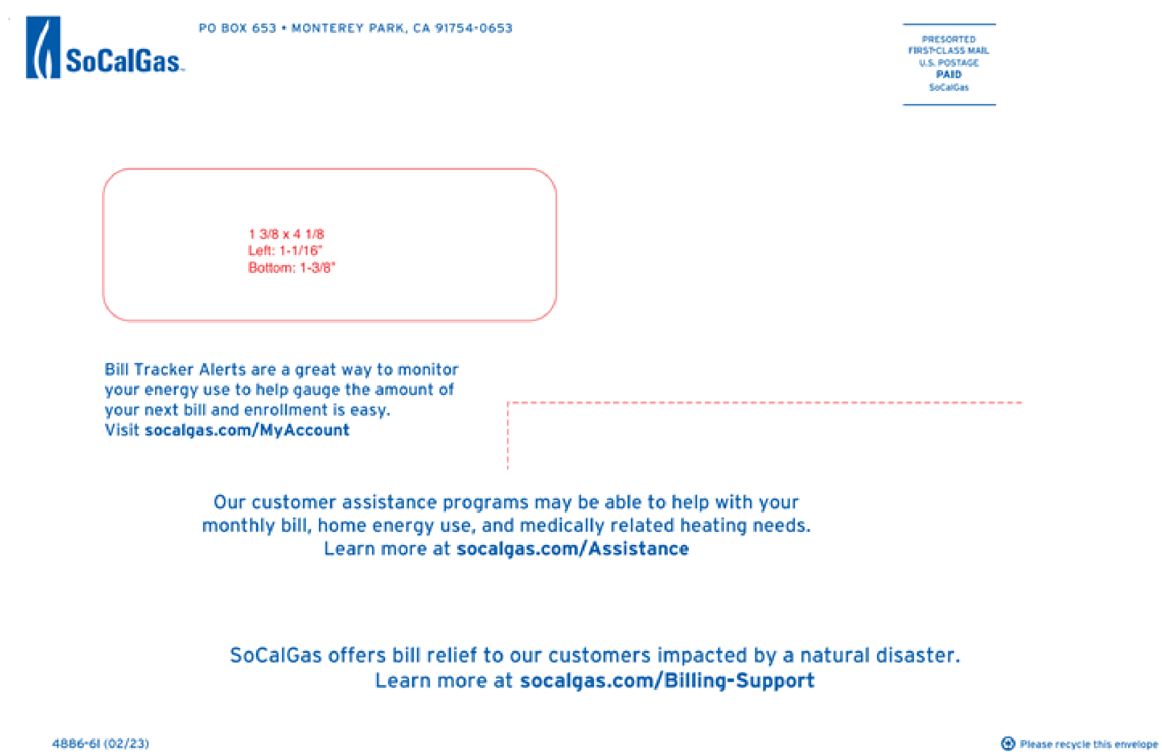
January 2023 sent to all residential customers receiving a paper bill (~2,380,151 customers). Bill messages varied and were placed throughout Fall/Winter months as space allowed.

Customer Affordability Message # XXXX, January 2023, All Residential, Cycles 1-21

"This winter, bills may be higher due to the increasing cost of natural gas nationwide combined with higher usage. We can help you manage your bills with our assistance programs, Ways to Save tools, and Level Pay Plan at socalgas.com/ManageHigherBills"

Bill Envelope Messages:

February 2023 bill envelope messages sample below, while various messages ran on the bill envelopes throughout the Fall/Winter months as space allowed.



Monthly CARE Text Messages:

SoCalGas customers that are eligible for subsidized or low-cost services due to certain qualifiers received text (SMS) messages based on assumed consent. These CARE program messages aim to raise awareness and encourage participation in the income qualified program. These communications are divided into three groups: 1) new customers, 2) existing customers not enrolled in CARE, and 3) customers eligible to recertify for the program to continue to receive the 20% monthly bill discount and were leveraged with high gas prices awareness during winter months.

New Customers

Existing Customers Not On CARE

Recertify Customers

Public Handout:

A postcard sized hand out was created to distribute as needed to the public during public events. It was also provided as needed at SoCalGas's Energy Resource Center to customers inquiring about high bills on site. (Spanish versions available upon request)

SoCalGas

SoCalGas Is Here To Help You Manage Higher Bills

This winter natural gas prices had reached unprecedented levels on the West Coast. SoCalGas continues to diligently work to secure cost-effective natural gas supplies on behalf of our residential and small business customers. The price of natural gas is determined by broader regional, national, and global markets and is passed on directly to our customers without markup. SoCalGas does not profit from the movement of gas commodity prices.

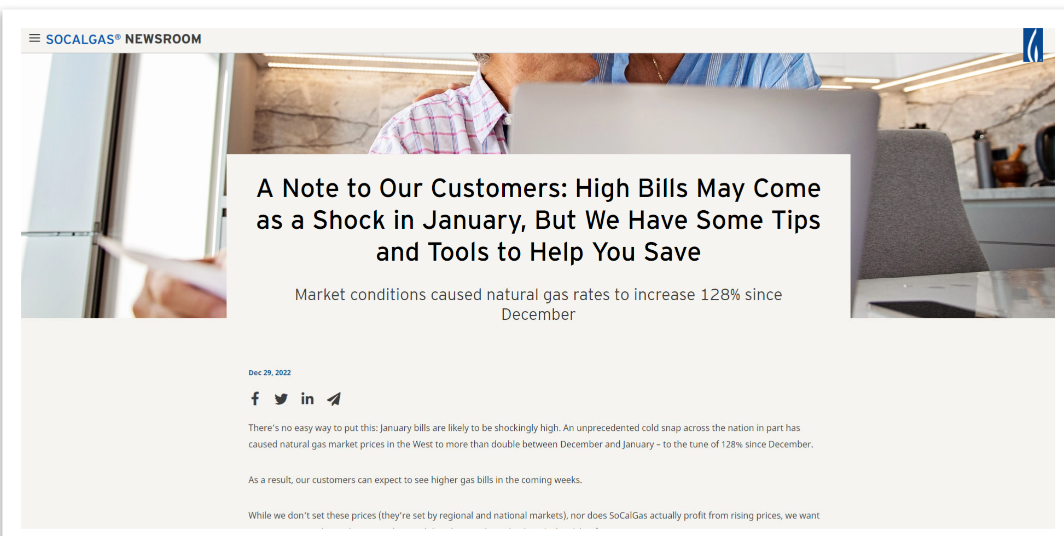
To learn more about:

- How We Can Help
- Current and Historical Natural Gas Prices
- Understanding Your Bill
- Factors Affecting Your Monthly Bills
- Tools and Assistance Programs

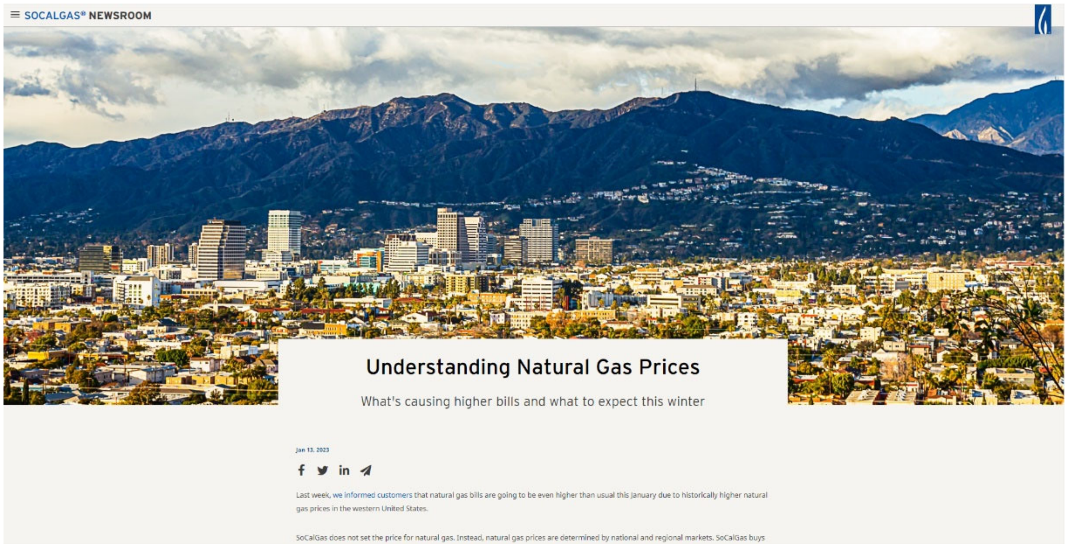
Visit **socalgas.com/ManageHigherBills** OR Scan here:

SoCalGas.com/Newsroom – Sample News Stories

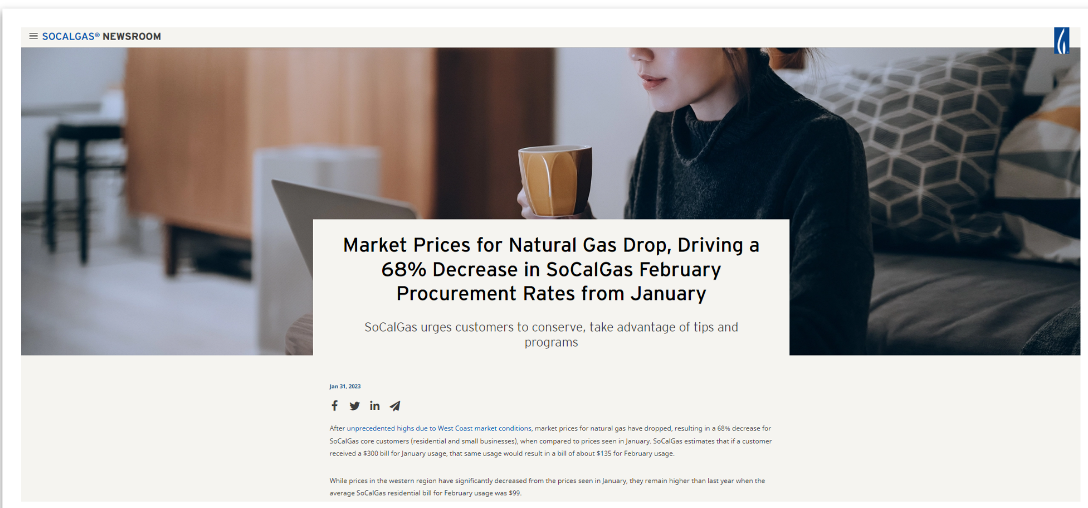
1. A Note to Our Customers: High Bills May Come as a Shock in January, But We Have Some Tips and Tools to Help You Save – Posted: December 29, 2022



2. Understanding Natural Gas Prices – Posted: January 13, 2023



3. Market Prices for Natural Gas Drop, Driving a 68% Decrease in SoCalGas February Procurement Rates from January – Posted: January 31, 2023



4. Market Prices for Natural Gas Drop Again, Driving a More Than 80% Decrease in SoCalGas March Procurement Rates from January's High – Posted: March 28, 2023

≡ SOCALGAS® NEWSROOM

Market Prices for Natural Gas Drop Again, Driving a More Than 80% Decrease in SoCalGas March Procurement Rates from January's High

Feb 28, 2023

Southern California Gas Co. (SoCalGas) today announced that market prices for natural gas have dropped for the second month in a row, resulting in an 83% decrease in March's procurement rate for SoCalGas core customers (residential and small businesses), when compared

<u>Sample Press Releases</u>

1. [SoCalGas Provides Resources to Help Customers Save Money Ahead of Winter]() – Posted November 14, 2022

SoCalGas

MEDIA CONTACT
Candice Lee
Office of Media and Public Information
(213) 709-5295
clee4@socalgas.com

NEWS RELEASE

SoCalGas Provides Resources to Help Customers Save Money Ahead of Winter

SoCalGas partners with Google Nest, Southeast Community Development Corporation, Alma Family Services, and All People's Community Center to prepare customers for rising costs, also donating 500 energy efficient smart thermostats

LOS ANGELES, November 14, 2022 – In anticipation of cooler winter temperatures, Southern California

2. SoCalGas Triples Contribution to Gas Assistance Fund to Help Customers Impacted by Historically High Natural Gas Prices – Posted: January 6, 2023

SoCalGas

MEDIA CONTACT
Brian Haas
Office of Media and Public Information
(213) 244-2442
bhaas2@socalgas.com

NEWS RELEASE

SoCalGas Triples Contribution to Gas Assistance Fund to Help Customers Impacted by Historically High Natural Gas Prices

Company encourages customers to take advantage of conservation tips and programs to help reduce their bills

LOS ANGELES – January 6, 2023 – Southern California Gas Co. (SoCalGas) today announced a $1 million contribution to the Gas Assistance Fund, a program that helps income-qualified customers pay their natural gas bills beginning Jan. 17. Customers will be facing bills that could be double or higher compared to last year's winter bills.

The high bills are a result of historically high natural gas prices in the western United States. SoCalGas

3. CPUC Approves Accelerated Climate Credit for SoCalGas Residential Customers – Posted: February 2, 2023

MEDIA CONTACT
Brian Haas
Office of Media and Public Information
(213) 244-2442
bhaas2@socalgas.com

NEWS RELEASE

CPUC Approves Accelerated Climate Credit for SoCalGas Residential Customers

SoCalGas residential customers will receive a one-time California Climate Credit of $50.77 in February or March, depending on their billing cycle

LOS ANGELES – February 2, 2023 – The California Public Utilities Commission (CPUC) today approved the acceleration of the California Climate Credit for Southern California Gas Company (SoCalGas) customers in response to the unprecedented natural gas prices impacting the Western United States. SoCalGas' residential customers will receive a credit of $50.77 in their February or March bill.

The California Climate Credit is a state program designed to reduce greenhouse gas emissions. Some of

4. SoCalGas Updates Customers on Current Natural Gas Prices – Posted: February 15, 2023

SoCalGas

MEDIA CONTACT
Brian Haas
Office of Media and Public Information
(213) 244-2442
bhaas2@socalgas.com

NEWS RELEASE

SoCalGas Updates Customers on Current Natural Gas Prices

Market conditions improve: critical out-of-state pipeline service restored; experts also cite improved weather conditions and related decrease in natural gas demand as contributing to lower market prices

SoCalGas continues to encourage customers to conserve as natural gas markets remain sensitive to changing weather and maintenance updates

LOS ANGELES – February 15, 2023 – Southern California Gas Company (SoCalGas) today provided customers with an update on natural gas prices across the West Coast. After a significant drop from unprecedented January natural gas commodity prices, market prices for March, 2023 are currently trending closer to 2022 prices.

5. SoCalGas Announces $10 Million to Support Low-Income Families, Seniors and Small Restaurant Owners Impacted by Unprecedented Regional Gas Market Prices – Posted: February 27, 2023

SoCalGas

MEDIA CONTACT
Chris Gilbride
Office of Media and Public Information
(213) 244-2442
cgilbride@socalgas.com

NEWS RELEASE

SoCalGas Announces $10 Million to Support Low-Income Families, Seniors and Small Restaurant Owners Impacted by Unprecedented Regional Gas Market Prices

Thousands newly eligible for winter bill assistance after SoCalGas bolsters United Way's Gas Assistance Fund with historic $5 million contribution

$4 million will revive Fueling Our Communities – a collaboration with local nonprofits that has provided free meals and groceries to tens of thousands of Californians since 2020

Media and Outreach Events:

October/November 2022 - SoCalGas partnered with local organizations to share important resources and provide 500 Google Nest thermostats in preparation for winter. Partnering organizations included: Google, Southeast Community Development Corporation, Alma Family Services, All Peoples Community Center. Sample social/digital media coverage:

[Winter Conservation/Tips Video 1]() – Posted via Facebook and Twitter on January 4, 2023

[Winter Conservation/Tips Video 2]() – Posted via Facebook and Twitter on February 15, 2023

Winter Conservation/Tips Video 3 – Posted Via Facebook and Twitter on March 3, 2023

Social Media Sample of Posts (Facebook, Twitter and Instagram):

Social media campaign ran from December 2022 - March 2023 to help customers plan and prepare for higher winter bills and drive awareness around natural gas price volatility, tips, tools, programs, and services to support the variety of customer needs, and provide energy savings, safety, and conservation solutions for natural gas.

December 2022:

Weather Trigger: December 1, 2022

SoCalGas @socalgas · Dec 1

It's getting colder! Here are some tips that can help save energy and money when the temperature drops. For more, visit socalgas.com/Save

Conservation Tip: December 7, 2022

SoCalGas @socalgas · 20h

Save up to 10% a year on heating & cooling by simply turning your thermostat back 5-8 degrees from where you normally set it for 8 hours/day (when safe to do so). Get more energy-saving tips: socalgas.com/SavingTips

Weather Trigger: December 9, 2022

SoCalGas @socalgas · 6s

With rainy and cool weather expected this weekend and lows dropping into the 30s early next week, here are some tips that can help you save money by reducing energy consumption. For more, visit socalgas.com/Winter

Assistance Programs: December 12, 2022

SoCalGas @socalgas · 21h

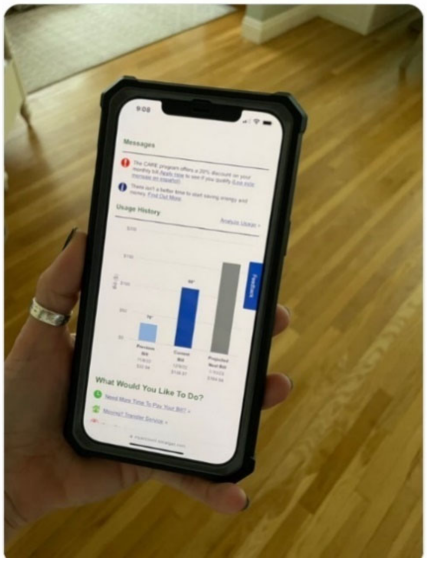
#DidYouKnow that you may be eligible to receive professional, energy-saving home improvements from an authorized contractor at no cost through the Energy Savings Assistance Program?!

Apply today:
socalgas.com/save-money-and...

Tip Tuesday: December 20, 2022

SoCalGas @socalgas · 30s ···

#TipTuesday: Monitor your natural gas consumption, take steps to help reduce your usage, and avoid surprises on your bill. Customers with an Advanced Meter can sign up for weekly Bill Tracker Alerts through My Account – learn more: socalgas.com/pay-bill/my-ac...



High Bills Messaging: December 29, 2022

SoCalGas @socalgas · Dec 29, 2022 ···

As market conditions cause natural gas prices to rise, we offer our customers several tools to reduce energy use and help lower bills this winter. For more information, please visit: bit.ly/3Q0DGVv

Promote

1,014 3 6 11

January 2023:

Understanding Your Bill: January 3, 2023

SoCalGas @socalgas · 4m

In the new year, we are all looking for ways to save time, energy, and reduce expenses. Understanding your monthly SoCalGas bill can help – learn more @ socalgas.com/ManageHigherBi...

Dan The Weatherman - Saving Tips: January 4, 2023

SoCalGas @socalgas · Jan 4

With more moderate to heavy rain and cooler temperatures on the way this week, make sure you follow these simple tips that could save as much as 22% on energy costs. For more tips, head to socalgas.com/Winter

Gas Assistance Fund: January 6, 2023

SoCalGas @socalgas · 21m

We continue to encourage customers to conserve and take advantage of cost savings tips and programs as winter weather and complex natural gas market conditions are likely to lead to higher bills for customers in the coming weeks.

newsroom.socalgas.com
SoCalGas Triples Contribution to Gas Assistance ...
Company encourages customers to take advantage of conservation tips and programs to help reduce ...

Energy Tips, Rebates, and Financing: January 9, 2023

SoCalGas @socalgas · 1m

To help customers manage energy usage and possibly save on bills, check out the latest energy-efficient appliances. We're here to help with our appliance buying guide. Look for energy tips, available rebates, low-interest financing, and more.

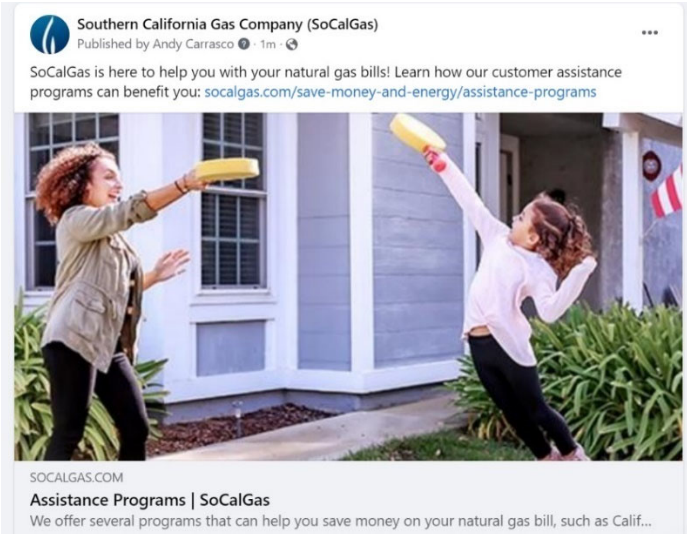
Click here: socalgas.com/save-money-and...

Gas Assistance Fund: January 10, 2023

Southern California Gas Company (SoCalGas)
Published by Andy Carrasco · 4m

Apply for a one-time grant to help you pay your natural gas bill. The Gas Assistance Fund is now available for qualifying customers. Learn more at socalgas.com/GAF

Assistance programs: January 12, 2023



Tip Tuesday: January 16, 2023

Weather Trigger: January 19, 2023

Tip Tuesday: January 24, 2023

SoCalGas @socalgas · 3m

#TipTuesday: We offer various Customer Assistance Programs that could help you with your natural gas bills, provide energy-saving home improvements, and more. Visit: socalgas.com/Assistance

Assistance Programs: January 27, 2023

SoCalGas @socalgas · 3m

During winter, customers can experience a 3-7 times increase in their natural gas usage. Check out these savings tips that can help reduce your energy bill!

socalgas.com/Save

Promote

1 1 29

Assistance Programs: January 31, 2023

SoCalGas @socalgas · 5m

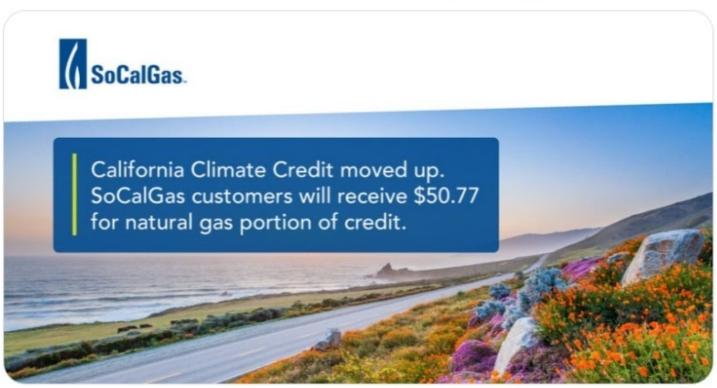
We are here to help our customers with various resources. Visit socalgas.com/Save to learn more about our energy savings tips, customer assistance programs, rebates, and more.

February 2023:

Climate Credit: February 9, 2023

SoCalGas @socalgas · 14m

We support @CaliforniaPUC accelerating the April CA Climate Credit. Residential customers will receive the credit in February or March depending on your gas billing cycle. The electric portion will come from customer's respective electric provider. More: cpuc.ca.gov/climatecredit/



Weather Trigger: February 14, 2023

SoCalGas @socalgas · Feb 14

With #temperatures dropping to the 20s for the coasts and valleys and single digits for the mountains and deserts the next few mornings, here are some tips that can help you save money by reducing #energy consumption. Head to socalgas.com/Winter for more ways to save.

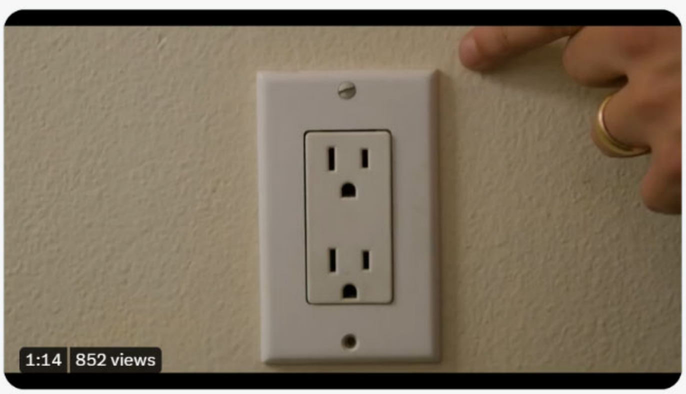
Promote

18 · 7 · 9 · 2,861

Saving Tips: February 15, 2023

SoCalGas @socalgas · Feb 15

During the #winter months, heat loss can have a noticeable impact on a home's energy bills. Here are a few tips on insulating your home that could help lower energy costs by up to 20%. For more tips that could help reduce your #energy consumption, head to socalgas.com/Winter



Promote

21 · 10 · 10 · 3,448

Dan The Weatherman - Saving Tips: February 15, 2023

SoCalGas @socalgas · Feb 15

During the #winter months, heat loss can have a noticeable impact on a home's energy bills. Here are a few tips on insulating your home that could help lower energy costs by up to 20%. For more tips that could help reduce your #energy consumption, head to socalgas.com/Winter

28 14 15 4,834

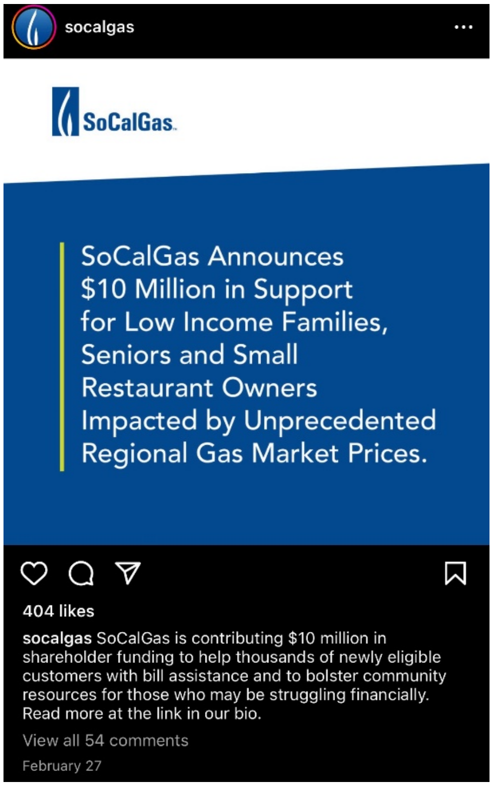
Weather Trigger: February 21, 2023

SoCalGas @socalgas · 2m

A winter storm is bringing cold and wet weather to southern California for the rest of the week. Here are a few winter weather tips that can help you reduce your overall energy consumption. For more, visit socalgas.com/Winter

Promote

$10M in Support: February 21, 2023



Tip Tuesday: February 28, 2023

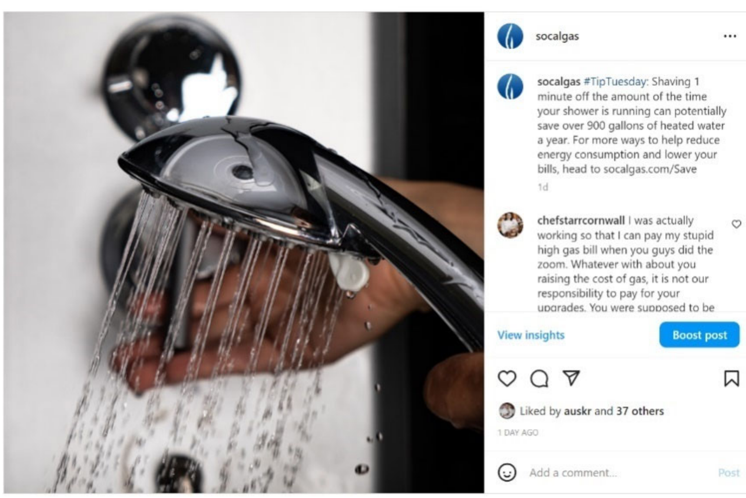
March 2023:

Market Price for Natural Gas Drop: March 1, 2023

Dan The Weatherman - Saving Tips: March 3, 2023

Assistance Programs: March 6, 2023

Tip Tuesday: March 7, 2023



Gas Assistance Fund: March 16, 2023

SoCalGas
@socalgas

More customers can now qualify to receive a one-time grant for up to $400 to help them pay their natural gas bill. Eligible applicants age 55+ or w/ an older adult living in their household, could receive up to $500! Learn more abt the Gas Assistance Fund: socalgas.com/GAF

Weather Trigger: March 20, 2023

SoCalGas @socalgas · 28m
With more rain, mountain snow, and below average temperatures on the way for the first half of the week, here are some tips that can help you save money by reducing energy consumption. Head to socalgas.com/Winter for more ways to save.

ATTACHMENT B

SDG&E's winter 2022-2023 customer communications and outreach

ATTACHMENT B

SDG&E 2022-2023 High Bills Communications

Email One

Below is a sample email sent to residential customers November 8 through November 11. The email was tailored for either bundled or unbundled residential and small and medium businesses.

Para ver en español, haga clic aquí

SDGE

Get to know your power

At SDG&E, we know you count on us every day for the energy you need to power your homes and lives. We also recognize many Californians are facing higher than usual bills across a range of products and services, including energy bills. So as the weather cools off and the likelihood that you may use more energy to heat your home increases, we want to help you plan and prepare for higher energy costs this winter.

Given the feedback we heard from customers last winter about avoiding surprises, we also wanted to make you aware that SDG&E will update its energy pricing on January 1, 2023. Unfortunately, natural gas prices in the worldwide wholesale market have reached a 14-year high and continue to impact not only the cost of fuel to heat homes and run appliances but also the price to generate electricity. Energy prices are also forecasted to increase due to the ongoing need to make safety, reliability and climate resiliency investments that include battery storage, electric vehicle infrastructure and wildfire protection.

We recognize there is never a good time for higher energy bills, even when they reflect the extensive work needed for a stronger, healthier and safer energy future. But it's our responsibility to be transparent with you. While our pricing won't be finalized until the end of the year, we have performed preliminary forecasts for January 1, 2023, pricing that we can share with you. This forecast could change between now and the end of the year when our pricing is finalized. As a reminder, winter pricing is effective November 1 through May 31.

Based on our preliminary forecast, the average residential customer could see an increase of $28 on their monthly electric bill and an increase of $6 on their monthly natural gas bill, January 1, 2023. Actual customer bills will vary based on a number of factors, including a customer's usage and pricing plan, as well as weather and market conditions.

Assistance programs and resources

SDG&E offers a variety of programs to provide direct assistance to customers in need, including a monthly discount program and payment arrangements. To learn more, visit *sdge.com/assistance*.

In addition, below are a few tips to help manage energy use and keep bills as low as possible before temperatures drop. More information and resources are available on *sdge.com/myenergy*.

- You can cut a load of laundry's energy use in half by using warm water instead of hot water; using cold water will save even more.
- Check your furnace filter as dirty air filters can increase energy costs.
- Wrap old water heaters with proper insulating jackets and set the temperature to 120 degrees F (or lower).
- For customers on a Time-of-Use plan, utilize the delay start button on your dishwasher and washing machine to run outside the on-peak hours of 4 p.m. to 9 p.m.

As we continue to analyze how January 1 rate changes may impact bills, you should expect to hear from us again in the coming months. To learn more about what goes into your bill, why it's rising and what we are trying to do about it, please visit *sdgeratesinfo.com*.

Email Two

Sent to assigned commercial and industrial customers in December 2022.

FINAL – Approved 12-13-2022

Account Executive Email – December Rate Communications

Updated December 13, 2022

Audience: Assigned accounts – to be personalized by Account Executives

Distribution – Starting December 14, 2022

Subject line: SDG&E winter energy pricing update

Body:

Dear (customer name),

As part of our ongoing commitment to be transparent about our rates and bills, I am writing to provide you with an update on the latest trends in the natural gas market and how this, coupled with cold weather, could impact SDG&E bills. We also want to remind you that gas and electric prices will increase on January 1, 2023. Click here to learn more.

Natural gas market prices have remained elevated and volatile across the U.S. this year. While natural gas prices briefly dipped, we saw a significant increase between November and December. Natural gas rates increased by 19%. This spike is driven by increases in the market price of natural gas. As a reminder, what SDG&E pays to buy natural gas on behalf of our customers is a direct passthrough and SDG&E makes no profit on these purchases of natural gas.

Based on the latest market dynamics – frigid weather across the West, low storage levels, and other factors impacting supply and demand – current forecasts suggest that natural gas market prices may continue to increase through January. This would result in even higher bills relative to last winter. Bill impacts will vary based on a customer's usage and pricing plan, as well as weather and market conditions.

Now's an excellent time to take advantage of ways to control your energy use. We're here to help you be successful this winter. Please feel free to reach out directly to me should you have questions, require additional information, or would like to schedule a briefing.

Sincerely,

[Account executive name]

Email three

Below is a sample email sent to residential customers December 14 through December 15. The email was tailored based on a customer's pricing plan for both residential and small and medium business.

With the sun setting earlier, combined with winter temperatures, that may mean running your lights and heater more, which can lead to higher energy bills. Energy bills may also be higher than expected due to the increase in natural gas market prices. Natural gas market prices have remained elevated and volatile across the U.S. this year. Between November and December, we saw residential natural gas rates increase by 19% driven by a spike in the market price of natural gas.

As a reminder, the price of natural gas purchased to serve our customers is a straight passthrough and SDG&E makes no profit. As we move into January, when weather in our region is typically the coldest and natural gas usage is the generally the highest, current forecasts suggest the market price of natural gas could increase further, resulting in even higher customer bills relative to last winter.

Now's an excellent time to take advantage of ways to control your energy use. We're here to help you be successful this winter so we have gathered a few winter energy tips to help you save.* We also want to remind you that gas and electric prices will increase on January 1, 2023. *Click here learn more*. We will communicate to you in January once rates are final.

Energy savings tips

- Caulk and weather-strip around drafty doors and windows. Use a door sweep, door sock or towel at the bottom of doors with a gap.
- Log on or enroll in *My Account* to view and compare your energy use by months, days or hours, to identify patterns in your energy usage and opportunities to make changes.
- Take our quick 5-minute survey to see where your electricity is going and get a plan to help you save. *Take the survey*

For more savings tips, visit sdge.com/MyEnergy

Email four"

Sent to all residential and business customers in January 2023

Para ver en español, haga clic aquí

SDGE

Many customers are facing higher bills, and we recognize our responsibility to be transparent with you as prices change. As a follow-up to our communications these past two months about higher natural gas and electricity pricing, we want you to know that new pricing became effective on January 1, 2023.

Natural gas pricing

Since our last communication, natural gas prices have increased dramatically, primarily driven by frigid temperatures across most of the country and on-going supply challenges.

Effective January 1, 2023, a typical residential customer can expect an increase of ~$120 on their monthly natural gas bill relative to last January.

Residential natural gas usage is typically the highest in January when the weather in our region has historically been the coldest. Actual electric and gas customer bills will vary based on a number of factors, including usage and pricing plan, weather and natural gas market conditions. Natural gas rates are updated monthly on customers' bills, whereas major changes to electric rates typically occur once or twice a year. If prices for natural gas go down, customers see that adjusted monthly on their bill. SDG&E does not mark up the market cost for gas and does not make a profit from rising gas.

Electric pricing

A typical residential customer can expect an increase of approximately ~$24 on their monthly electric bill. This change is primarily driven by the increased cost of purchasing electricity along with investments in safety and reliability and increasing state-mandated costs. Actual customer bills will vary based on a number of factors, including usage and pricing plan, weather and market conditions.

Resources to help you manage higher bills

We're here to help if you need it. We have programs and resources available to help you manage your energy use and provide direct assistance, including payment arrangements, Level Pay program and monthly discounts. You can also avoid surprises on your bill by signing up for My Account to receive Energy Alerts. Please visit sdge.com/MyEnergy for energy saving tips, financial assistance, and rebate information.

Investing in the future

You count on us every day for the energy you need, and our job is to continue to deliver clean, reliable energy that is resilient to increasingly extreme climate conditions and temperatures. We have an obligation to prepare for the future, so we are taking the steps to strengthen our energy infrastructure by:

- Hardening our electric grid against climate threats such as wildfires
- Modernizing the grid to accommodate more renewables, energy storage, microgrids, electric vehicles, and all-electric buildings in order to meet California's ambitious goals to reduce greenhouse gas emissions

Responsible investments today will help to create a future that is cleaner, safer and reduce outages. However, these climate resiliency investments, along with the surge in natural gas costs, impact rates.

Email five

Sent to assigned commercial and industrial customers in January 2023.

January 1, 2023 Winter Communications – C&I Account Executive Communications

Update January 4, 2023

Background: This email will be personalized by the Account Executives and sent to their respective accounts.

UNBUNDLED ONLY – CCA and DA ACCOUNTS

Subject line: New 2023 energy pricing now effective

Body:
Dear [customer name],

As promised, I am writing to share with you the new electric and natural gas rates that took effect on January 1, 2023.

As you may recall, we started communicating our January 1, 2023, bill forecast with our customers these past couple of months. Since our last communication, natural gas prices in the wholesale market have continued to rise, in part because of the frigid temperatures that blanketed much of the country during the last two weeks of 2022.

The ongoing rise in natural gas prices account for the majority of the increases in both our electric and natural gas rates, which were finalized at the end of December. We recognize there is never a good time for higher energy bills, even when they reflect the extensive work needed for a stronger, healthier and safer energy future. But it's our responsibility to be transparent with you.

Gas rate changes

Based on the latest market dynamics – frigid weather across the West, low storage levels, and other factors impacting supply and demand – natural gas market prices have reached historic highs resulting in significantly higher bills relative to last winter. Actual bill impacts will vary based on a customer's usage and pricing plan, as well as weather and natural gas market conditions. Natural gas rates are updated monthly on customers' bills. If prices for natural gas go down, customers see that adjusted monthly on their bill. SDG&E does not mark up the market cost for gas and does not make a profit from rising gas prices.

- Core Commercial & Industrial (C&I) customers – The estimated class average transportation rate increases by 7 cents per therm, from 61 cents/therm to 68 cents /therm. The estimated PPPS rate decreases by 2 cents per therm, from 10 cents/therm to 8 cents/therm. The commodity price of the rate increased from $1.05 per therm to 3.45 per therm for the month of January.

- Noncore C&I customers (Distribution) – The estimated class average transportation rate increases by 13 cents per therm, from 16 cents /therm to 29 cents therm. The estimated PPPS rate decreases by 2 cents per therm, from 11 cents/therm to 9 cents/therm.

Electric rate changes
The following are SDG&E's Utility Distribution Company (UDC) class average electric rates effective January 1, 2023. Your specific rate and bill impact may be higher or lower depending on your service voltage, pricing plan and usage pattern.

SDG&E's UDC class average rates includes the cost of electricity delivery and service (transmission, distribution, and public purpose programs). It **does not** include charges for electric generation, the cost to purchase electricity on your behalf by either your Community Choice Aggregator (CCA) or Direct Access provider, or your PCIA rates which vary by customer depending on what vintage rate you are on. For information on the cost of electric generation, please contact your CCA or DA provider.

- Medium/large commercial and industrial unbundled customers – The class average UDC total rate increased by approximately 2.6 cents/kWh, from 14.6 cents/kwh to 17.2 cents/kWh.

- Small commercial unbundled customers – The class average UDC total rate increased by approximately 3.0 cents/kWh, from 19.8 cents/kWh to 22.8 cents/kWh

Now's an excellent time to take advantage of ways to control your energy use. We're here to help you be successful this winter. Please feel free to reach out directly to me should you have questions, require additional information, or would like to schedule a briefing.

To learn more about what goes into your bill, why it's rising and what we are trying to do about it, please visit sdgeratesinfo.com.

Sincerely,

AE Name

Email six

Sent to all residential and small/medium bussiness customers Janury 30 through February 2, 2023.

SDGE™

As a follow-up to the email we sent in early January about historically high natural gas pricing in the West, we are contacting you to provide an update.

Compared to January's historic gas market prices, **the price of gas has decreased by nearly 68% from $3.45 per therm to $1.11 per therm, effective February 1**. As a result, the expected average gas bill for residential customers (commodity plus delivery charges and other mandated fees and taxes) is expected to decrease to $110 in February, from approximately $225 in January. Your actual bill will vary and depending on your billing cycle and your household's energy usage you may not see the lower gas price reflected on your bill until sometime in February or early March.

SDG&E expects to provide you with a credit on the gas portion of your bill in February and your electric portion of your bill in March with **the acceleration of the California Climate Credit**. These credits and the decrease in gas pricing will hopefully provide you with a meaningful reduction in winter bills.

While we are optimistic about gas prices in the coming months, the market is still volatile. Gas prices are updated monthly based on forecasted market conditions and reflected in the price customers pay. Even with lower pricing, it's important to remember that weather conditions and usage can still lead to higher bills than you're used to, especially as we turn up the heat when the temperature drops. We also want you to know that we have programs and resources to help you manage your energy use and provide direct assistance should you need it.

Resources to help

- **A variety of** *customer assistance programs* may be available for qualifying residential customers, including a monthly discount of 30% or more with the CARE program, emergency payment assistance, and debt forgiveness. The Neighbor-to-Neighbor program, funded entirely by SDG&E shareholder dollars (not customer dollars), provides eligible customers up to $300 to offset their outstanding bills. The federally funded Low-Income Home Energy Assistance Program (LIHEAP) offers financial help ranging from a few hundred to a few thousand dollars, depending on household income, size and past due balances.
- *Energy Alerts* **are an easy way to monitor your energy use** and bill before it arrives. Customize your notifications for when your bill reaches a dollar amount you set or get weekly. Or, you can get notified of your usage and projected bill each week or halfway through your bill cycle.
- *Level Pay* **can help make your energy bill more predictable**. Level Pay averages your energy bill every three months so you can budget more easily.
- **Take our** *Home Energy Survey* to help you identify key ways energy inefficiencies in your home could be costing you money. You can also **save on products** that can improve your home's comfort, health and energy efficiency with the *Golden State Rebate program*.

For more information on energy savings tips and resources to help you manage your energy use and bill, please visit *sdge.com/myenergy*.

Email seven

Sent to all residential and small/medium business customers in March

Para ver en español, haga clic aquí

Relief is in sight as natural gas prices continue to decline for the second month as we head into March, with the cost per therm at $0.60 compared to $3.45 per therm in January.

The typical residential customer's gas bill (commodity plus delivery charges and other mandated fees and taxes) is expected to decrease to ~$85 in March, from ~$225 in January.
There's also good news for customers with electric service as they can also expect to see the California Climate Credit of $60.70 on their bill.

SDG&E commits $16 million to help customers

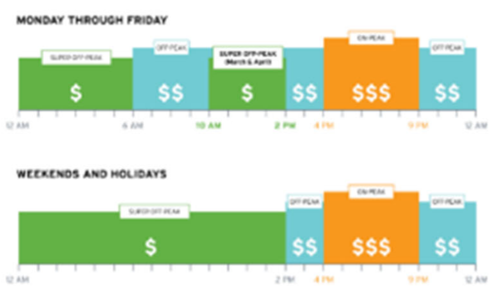
Even with this welcome news of lower gas pricing and electric climate credit, we recognize that customers are facing higher-than-usual bills across a range of products and services, including utilities. To support our community, SDG&E announced that it is providing $16 million in shareholder funding to help customers with bill assistance and bolster community resources for residents who may be struggling financially.

Available resources to help with your bill

- With the additional funding provided by SDG&E, the *Neighbor-to-Neighbor program* now provides eligible customers up to $600 to offset their outstanding bills. SDG&E customers may apply if they are experiencing serious illness, temporary unemployment, disability or unusual hardship.
- A new no-cost energy efficiency upgrade program for renters and owners of single-family homes is now available. *Residential Energy Solutions* has no income restrictions and has the potential to help local families achieve long-term savings on their energy bills.
- *Energy Alerts* are an easy way to monitor your energy use and bill before it arrives. Customize your notifications for when your bill reaches a dollar amount you set or get weekly.

Additional Super Off-peak hours in March and April

As a customer with electric service, there is more good news in March. Because you are on a Time-of-Use pricing plan with super off-peak hours, you have more opportunities to save. For March and April, there are additional super off-peak hours from 10 am to 2 pm where energy is priced the lowest. During these times, try to shift using major appliances to maximize savings.



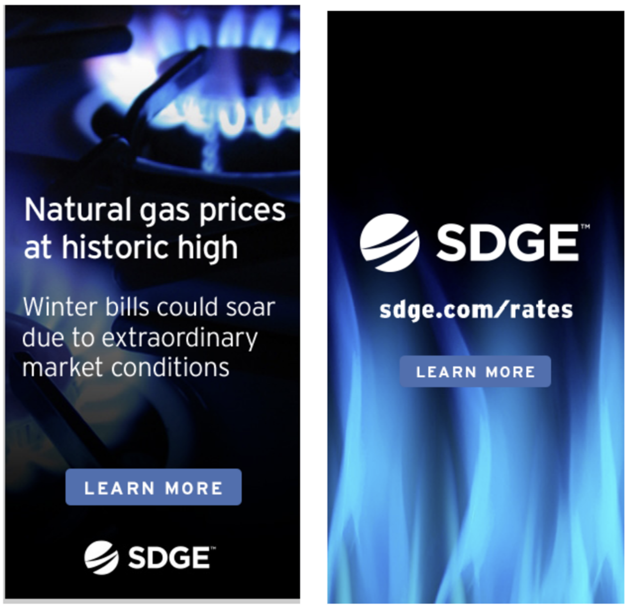
For more information on energy savings tips and resources to help you manage your energy use and bill, please visit sdge.com/MyEnergy.

Digital Ads

Ran from November 2022 – February 2023 and connected customers to sdge.com/MyEnergy.

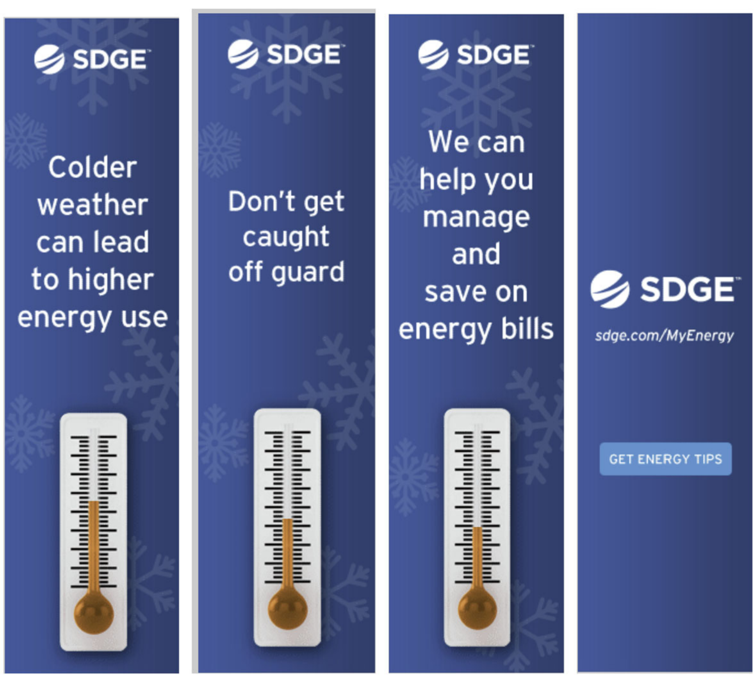
Digital Ads

Ran in January 2023 and connected customers to sdge.com/Rates



Digital Ads

Ran during the last week of February 2023 during a period of unusually cold weather.



Videos 1

Sixty second video, both English and Spanish versions, providing natural gas tips that ran in paid advertising from January through February 2023

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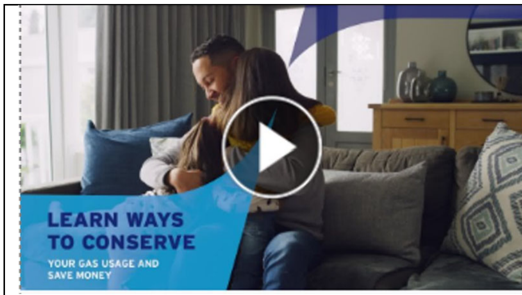

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Videos 2

Sixty second video, both English and Spanish versions, that ran in a paid digital campaign from November 2022 – January 2023, featuring electric tips to save on winter energy bills.

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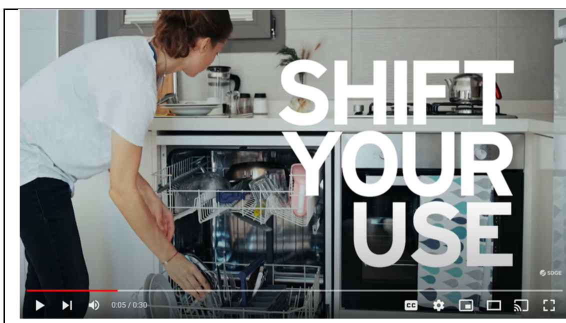

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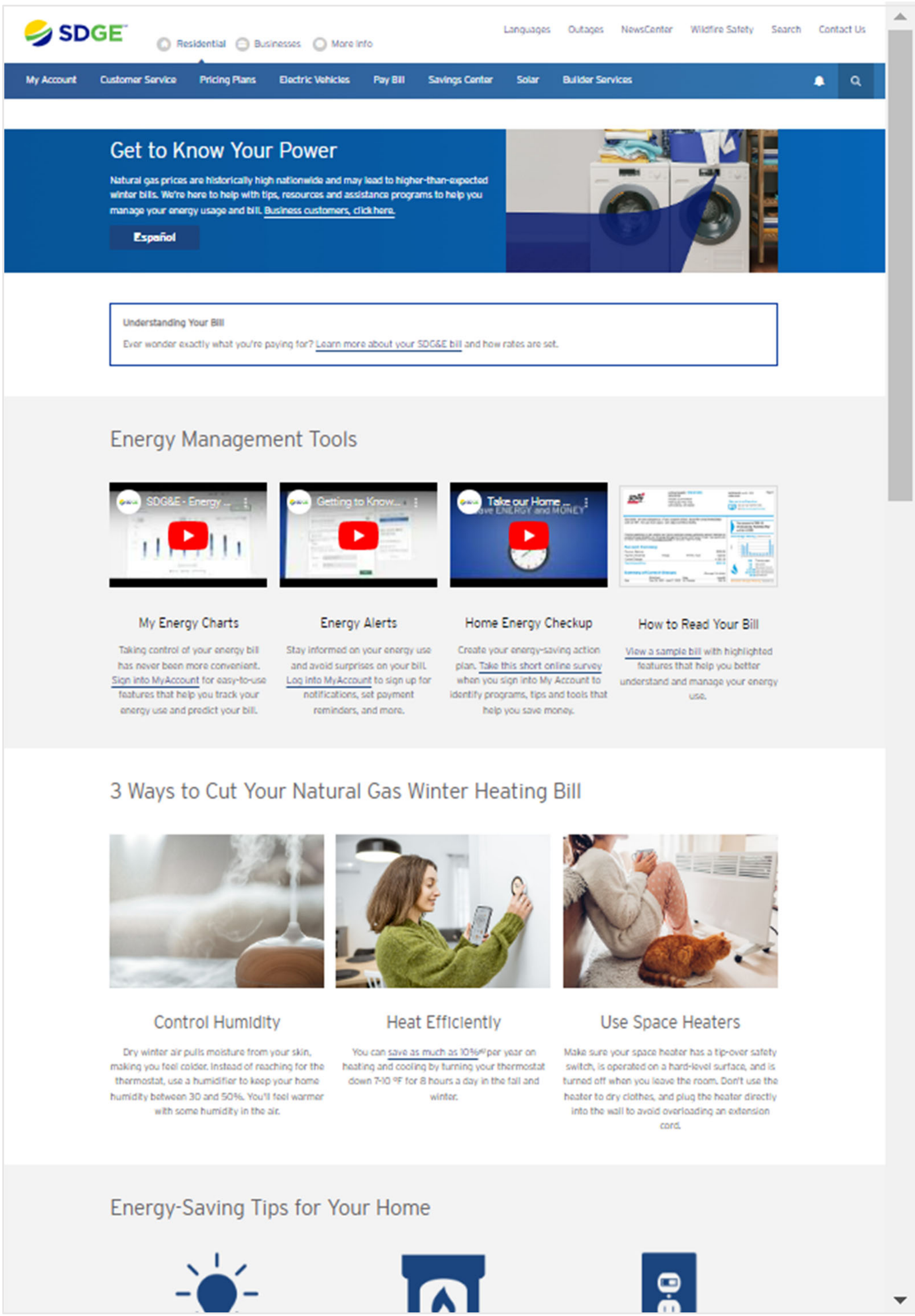
Web – sdge.com/MyEnergy

Throughout the campaign customers were encouraged to visit sdge.cm/MyEnergy to for tips and resources for saving energy and money, including specific tips related to winter heating. The page also includes information on assistance programs and other resources.

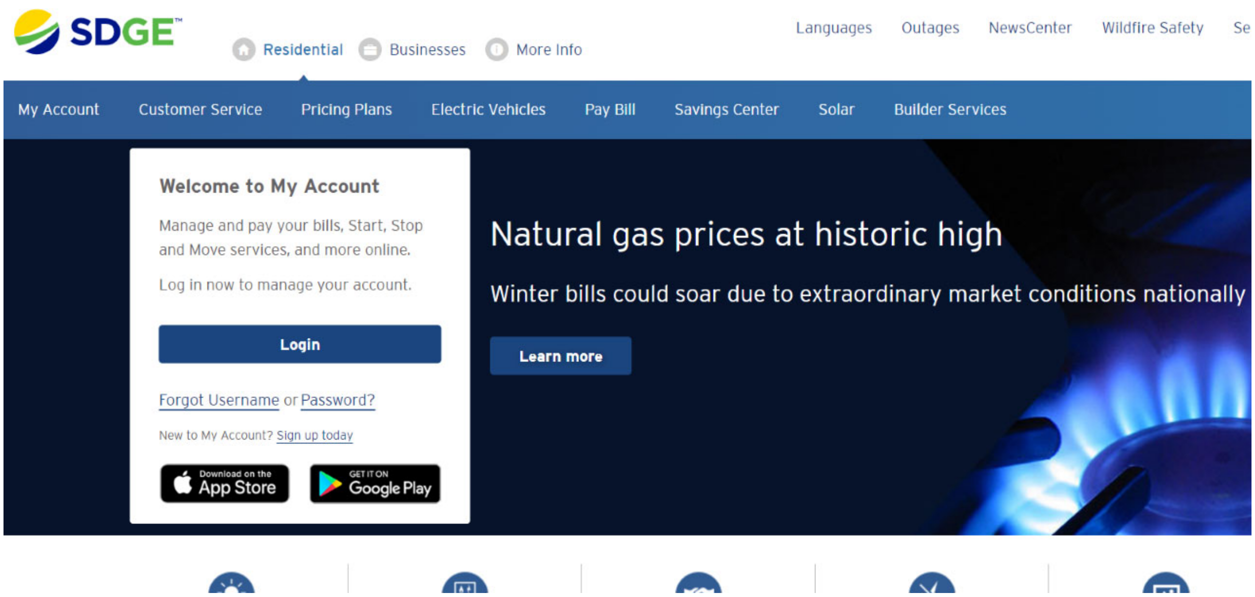


My Account App One

When customers log into My Account to see their personalized energy information, a message about winter pricing was also posted to make them aware of higher prices and reinforce that assistance was available.

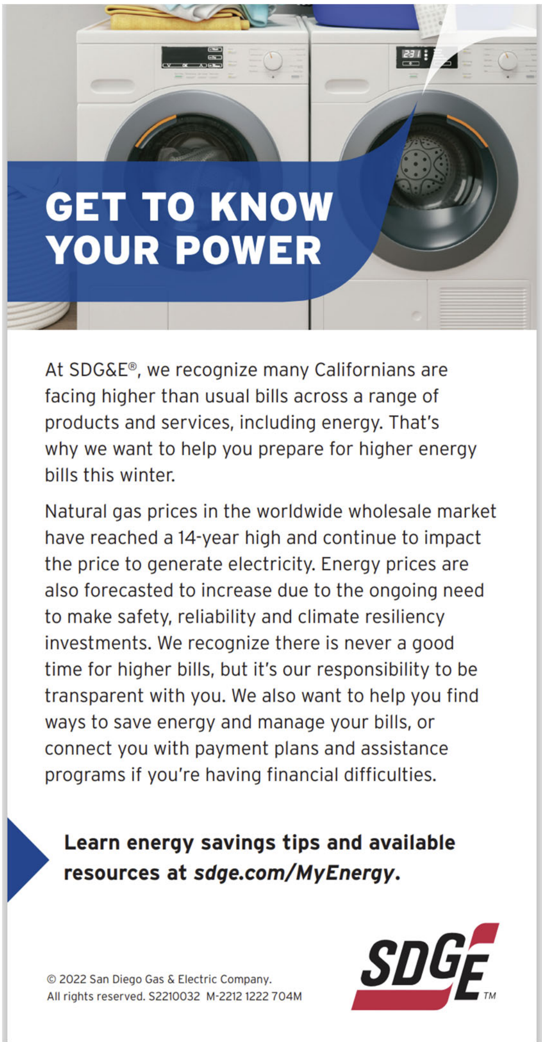
	**Winter Pricing Update** Natural gas prices are at a historic high in the West and winter bills could soar. We are here to help. For information on debt forgiveness, one-time payments, monthly bill discounts and more please, <u>Click here</u>.

Homepage Banner One



Bill Package Messaging

The following bill insert was included in the December bill package, which is distributed to some 700,000 customers.



On Hold Messaging for Customer Care Center

In January and February, the on hold message was updated to provide customers with information about natural gas bills and available resources prior to connecting with a Customer Care Center representative.

January:

Winter 2023 – Front End IVR for Higher Natural Gas Prices
January 4, 2023

2023 Winter Message (117 words)
Thank you for calling SDG&E. We are currently experiencing high call volume. Are you calling regarding a higher-than-expected energy bill? On January first, SDG&E updated its pricing for electricity and natural gas. Nationwide, natural gas prices are at historic levels, and winter bills could soar due to the extraordinary market condition. We have resources and assistance programs to help. Visit sdge.com/assistance to learn more. You can also keep track of your energy use and avoid surprises on your bill with Energy Alerts. Log on to My Account to customize your preferences, all online and at your convenience. Otherwise, please remain on the line, and we'll be with you as soon as possible. We apologize for the wait.

Sample Press Releases

NEWS RELEASE

Media Contact: Anthony Wagner
San Diego Gas & Electric
858-649-3570
AWagner1@sdge.com
Twitter: @sdge

AMID SOARING NATURAL GAS PRICES NATIONWIDE, SDG&E OFFERS CUSTOMERS BILL-SAVING TIPS AND TOOLS

Due to ongoing market volatility, residential natural gas rate increased 19% between November and December

SAN DIEGO, December 13, 2022 – As wholesale natural gas prices nationwide continue to soar higher and as cold weather leads to higher gas usage for heating, San Diego Gas & Electric is offering customers tips and tools to help them save on their energy bill, while cautioning that natural gas prices could rise even higher into January

NEWS RELEASE

Media Contact: Anthony Wagner
San Diego Gas & Electric
858-649-3570
sdge.com
Twitter: @sdge

SDG&E ADOPTS NEW RATES IMPACTED BY HISTORICALLY HIGH NATURAL GAS PRICES AFFECTING CUSTOMERS NATIONWIDE

A wide range of assistance programs available to help

SAN DIEGO, January 4, 2023 –San Diego Gas & Electric implemented new natural gas and electric rates effective Jan. 1, 2023, that reflect the increasing costs of providing clean, safe and reliable energy services. The most significant contributor to the increases is the ongoing, steep rise in the natural gas market, which has impacted energy bills across the nation. Natural gas is not just used for heating and cooking, it’s also used to generate 40% of this nation’s electricity.

NEWS RELEASE

Media Contact: Anthony Wagner
San Diego Gas & Electric
858-649-3570
sdge.com
Twitter: @sdge

SDG&E ANNOUNCES FEBRUARY NATURAL GAS COMMODITY PRICE TO DECLINE 68% COMPARED TO JANUARY

Average natural gas bills in February expected to decrease by $115

SAN DIEGO, January 31, 2023 – After hitting historic highs this winter due to unprecedented market conditions in the Western United States, San Diego Gas & Electric announced today that the February natural gas commodity price has declined by 68% percent compared to January 2023, plunging from $3.45 per therm to $1.11 per therm.

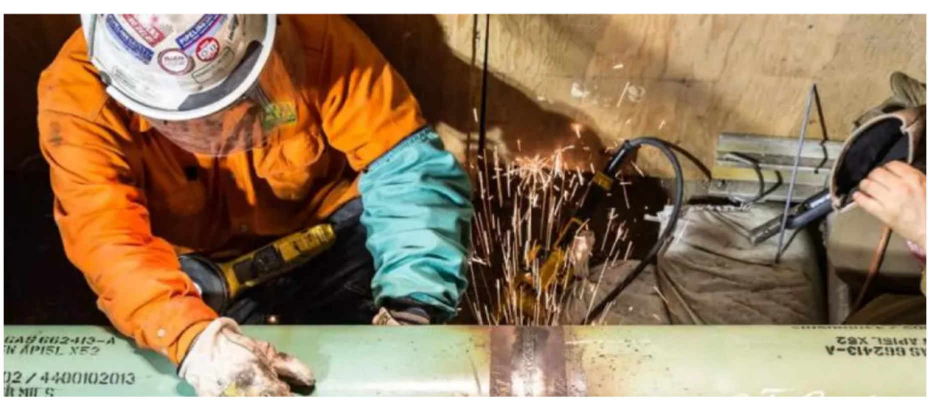
The typical residential customer's gas bill (commodity plus delivery charges and other mandated fees and taxes) is expected to decrease to ~$110 in February, from ~$225 in January. Nevertheless, the average residential gas bill this February is still substantially

Sample News Stories

LA JOLLA LIGHT

NEWS

Natural gas prices are way up, so brace for higher SDG&E bills



7 SAN DIEGO LOCAL SPORTS ENTERTAINMENT WEATHER TRAFFIC THE SCENE CORONAVIRUS NEWSLETTE... 55° LIVE

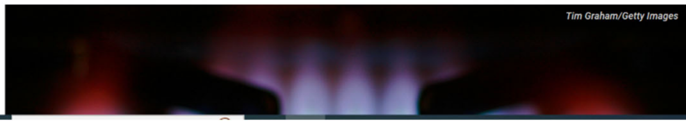
TRENDING Today in San Diego Podcast Claim Against SDPD Apply for Innovation Grants NBC 7 Streaming KNSD Accessibility

SAN DIEGO

SDG&E Offers Money Saving Tips Amid 19% Increase in Natural Gas Prices

If SDG&E pays $1 for natural gas in the commodity market, that's what SDG&E customers pay, the company said

By City News Service • Published December 13, 2022 • Updated on December 13, 2022 at 2:30 pm



Trending Stories

SAN DIEGO COUNTY BOARD OF SUPERVISORS

How Much Did San Diego Pay While Nathan Fletcher Allegedly Preyed on Staff?

FOX 5 Watch News Sports Weather Seen On FOX 5 Contests About Jobs Search

LOCAL

SDG&E warns natural gas prices could rise into the new year

by: Jafet Serrato
Posted: Dec 13, 2022 / 12:59 PM PST
Updated: Dec 13, 2022 / 01:34 PM PST

The logo for San Diego Gas & Electric, or SDG&E, which provides natural gas service to San Diego County.

WORKING FOR YOU

SDG&E gas bills expected to more than double this month

"If it keeps going up, I don't know what I'm gonna do," said SDG&E customer, Tammy Smith.

Author: Shannon Handy
Published: 5:40 PM PST January 4, 2023
Updated: 5:41 PM PST January 4, 2023

LIFE

Natural Gas Prices Increasing 19% in Cold Weather, SDG&E Provides Tips to Save

by Debbie L. Sklar December 13, 2022

Share this:

The San Diego Union-Tribune

PODCASTS AND LIVESTREAMS

SDG&E natural gas prices will double in January. Here's what you need to know.

(U-T)

Get the story behind the story every day. Host Kristy Totten interviews Union-Tribune reporters, newsmakers and experts about what matters in San Diego.

BY KRISTY TOTTEN
JAN. 9, 2023 6:53 PM PT

SUBSCRIBERS ARE READING >

Social Media Sample Posts, including those shared by the CPUC and Local Elected Officials

Social Media – Exhibit

Organic social media campaign ran from December 2022 – February 2023 and connected customers to sdge.com/MyEnergy and the NewsCenter sdgenews.com. Our social media posts were RT'd by the CPUC and local elected officials.

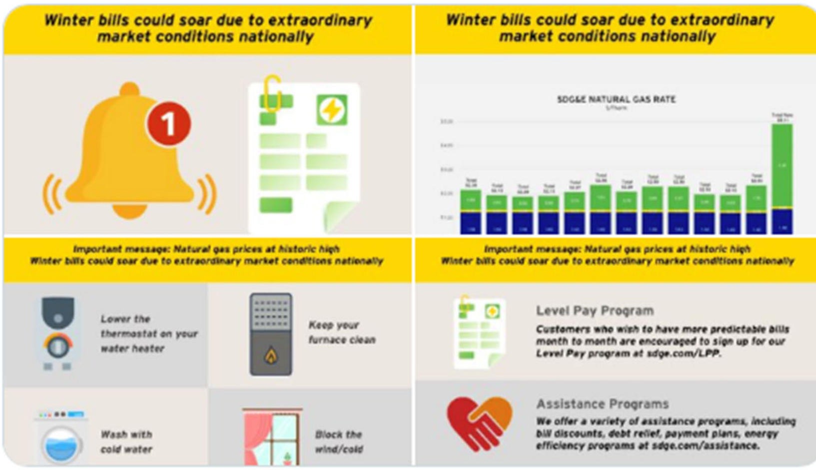
California PUC Retweeted

SDG&E @SDGE · Jan 4

🔔 Rate transparency is something we take seriously. New rates are impacted by historically high natural gas prices affecting customers nationwide.

📲 We are offering customers bill-saving tips & tools at: ow.ly/nYtn5OMivoN

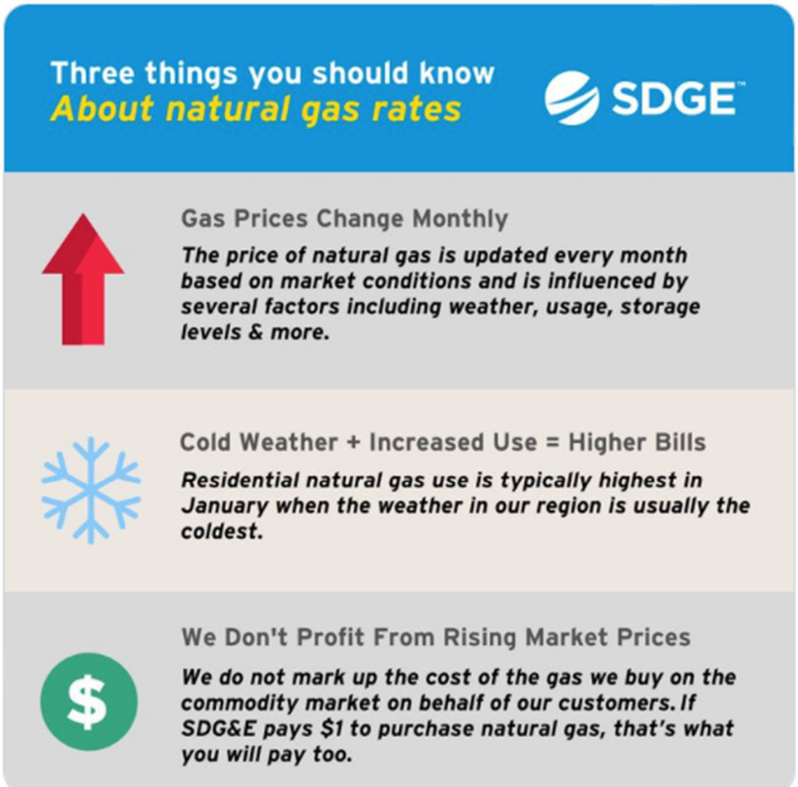
⚡ Additional resources: sdge.com/myenergy



California PUC Retweeted

SDG&E @SDGE · Jan 4

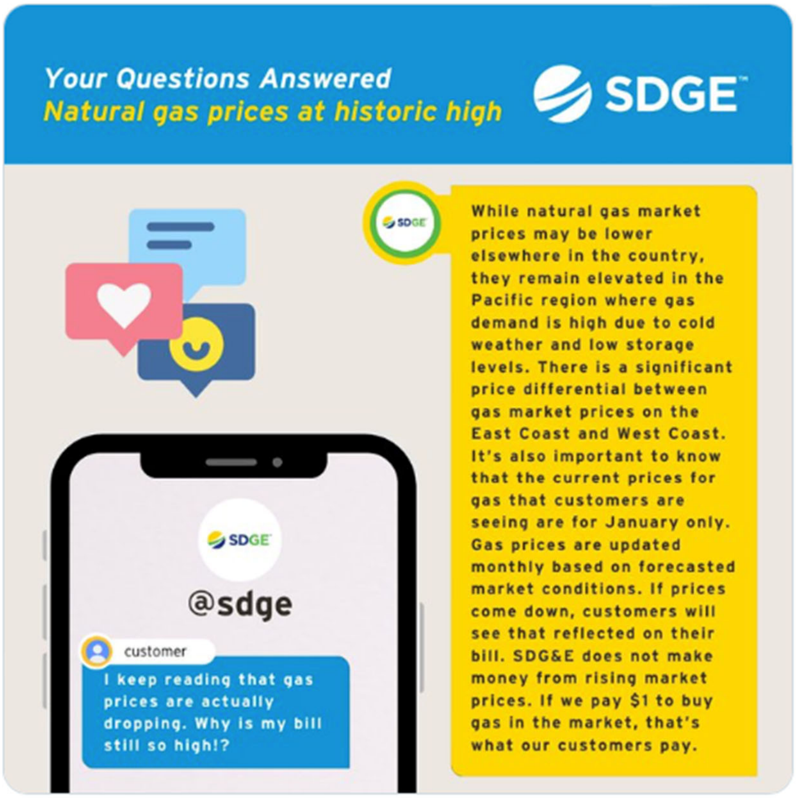
🔔 Three things you should know about natural gas rates. Learn more at ow.ly/nYtn5OMivoN.



California PUC Retweeted

SDG&E @SDGE · Jan 6

🔔 Your natural gas questions answered. Learn more at ow.ly/nYtn50MivoN.



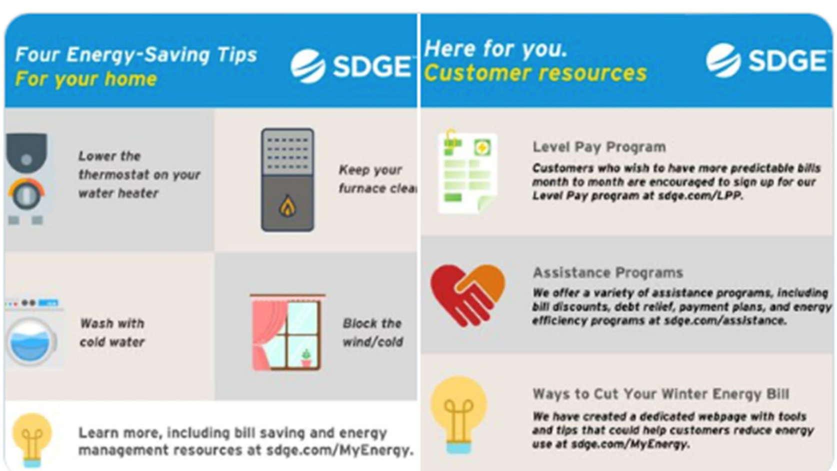
California PUC Retweeted

SDG&E @SDGE · Jan 9

🔔 Below are a few tips to help you reduce your gas usage this winter.

📲 Learn more about the programs we have available to help our customers, including debt relief and bill discounts: sdge.com/assistance

⚡ Additional bill-saving tips: sdge.com/myenergy



California PUC Retweeted

SDG&E @SDGE · Jan 10

Entirely funded by shareholder dollars, $1 million is now available through our Neighbor-to-Neighbor (N2N) program that provides up to $300 in one-time grants to help offset past-due bills for customers experiencing financial hardship. Learn more atow.ly/b8i650Mn0QT.

California PUC Retweeted

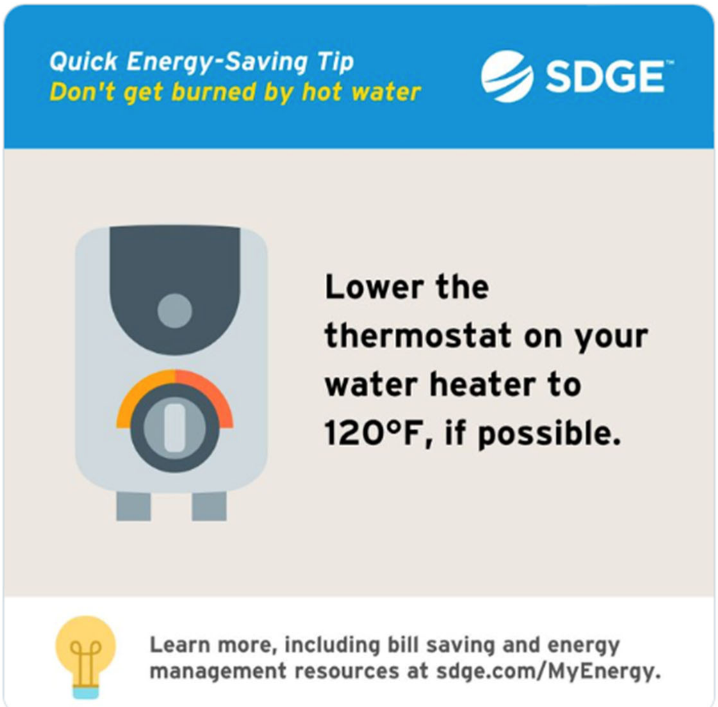
SDG&E @SDGE · Jan 10

$1 millón de fondos de accionistas ahora están disponibles a través del programa Neighbor-to-Neighbor que ofrece subvenciones únicas de hasta $300 para ayudar a compensar las facturas vencidas de los clientes que están experimento dificultades financieras.
ow.ly/luLa50Mn1VP

California PUC Retweeted

SDG&E @SDGE · Jan 18

🔔 Take control of your energy bill this winter by reducing your gas usage with this tip.
📲 Here are ways we are helping our customers: sdge.com/assistance
⚡ Additional bill-saving tips: sdge.com/MyEnergy
💬 Natural gas prices FAQs: ow.ly/NpBA50Mua0L



California PUC Retweeted

SDG&E @SDGE · Jan 19

🔔 Below are a few tips to help you reduce your gas usage this winter.
📲 Ways we are helping our customers, including assistance programs: sdge.com/assistance.
⚡ Additional bill-saving tips: sdge.com/MyEnergy.
💬 Natural gas prices FAQs: ow.ly/NpBA50Mua0L.

California PUC Retweeted

SDG&E @SDGE · Jan 19

🔔 A continuación se presentan consejos para ayudarle a reducir su consumo de gas este invierno.
📲 Formas en que estamos ayudando a nuestros clientes: sdge.com/assistance
⚡ Consejos para ahorrar: sdge.com/MiEnergia
💬 Preguntas frecuentes: ow.ly/xyjg50MucXf

California PUC Retweeted

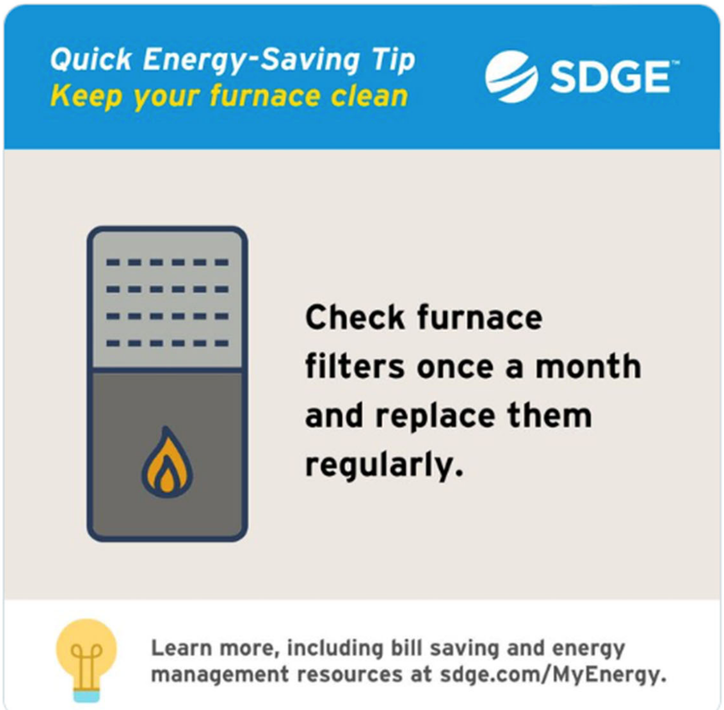
SDG&E @SDGE · Jan 23

🔔 Take control of your energy bill this winter by reducing your gas usage with this tip.

📲 Here are ways we are helping our customers: sdge.com/assistance

⚡ Additional bill-saving tips: sdge.com/MyEnergy

💬 Natural gas prices FAQs: ow.ly/NpBA50Mua0L



California PUC Retweeted

SDG&E @SDGE · Jan 24

🤝 Additional ways we are helping our customers: sdge.com/assistance.

💬 Natural gas prices FAQs: ow.ly/NpBA50Mua0L.

sdgenews.com
Have Questions about Natural Gas Prices? We've...
In recent days, we have received several questions about natural gas prices. We have answers to you...

California PUC Retweeted

SDG&E @SDGE · Jan 30

🤝 Here for you.

📲 Here are ways we are helping our customers, including assistance programs:sdge.com/assistance

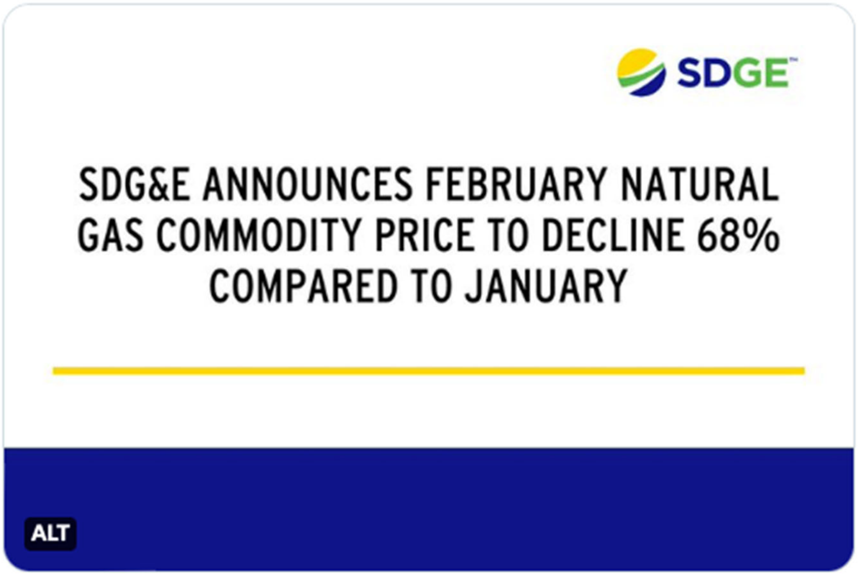
⚡ Additional bill-saving tips:sdge.com/MyEnergy

💬 Natural gas prices FAQs:ow.ly/NpBA50Mua0L

California PUC Retweeted

SDG&E @SDGE · Jan 31

🔔 After hitting a historic high in January due to unprecedented natural gas market conditions in the Western U.S., today we announce that the February natural gas commodity price has declined by 68% percent compared to January 2023: ow.ly/5wXn50MF45y.



California PUC Retweeted

SDG&E @SDGE · Feb 2

🔔 Following a decision made today by the @californiapuc, 2 of the 3 scheduled installments of the CA Climate Credit have been moved up to provide winter bill relief to SDG&E customers: ow.ly/6ojZ50MHi2U.

California PUC Retweeted

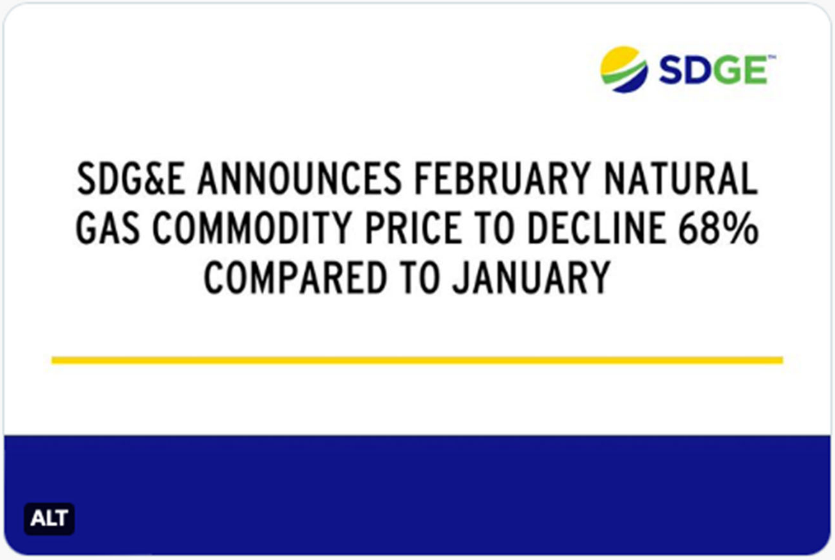
SDG&E @SDGE · Feb 6

Residential customers with natural gas service will see a $43.40 credit on their February bill. Learn more about the CA Climate Credit, how you're helping to fight climate change and when the next climate credit is expected to hit your bill this year at ow.ly/6ojZ50MHi2U.

Councilmember Jennifer Campbell Retweeted

SDG&E @SDGE · Jan 31

🔔 After hitting a historic high in January due to unprecedented natural gas market conditions in the Western U.S., today we announce that the February natural gas commodity price has declined by 68% percent compared to January 2023: ow.ly/5wXn50MF45y.



Councilmember Jennifer Campbell Retweeted

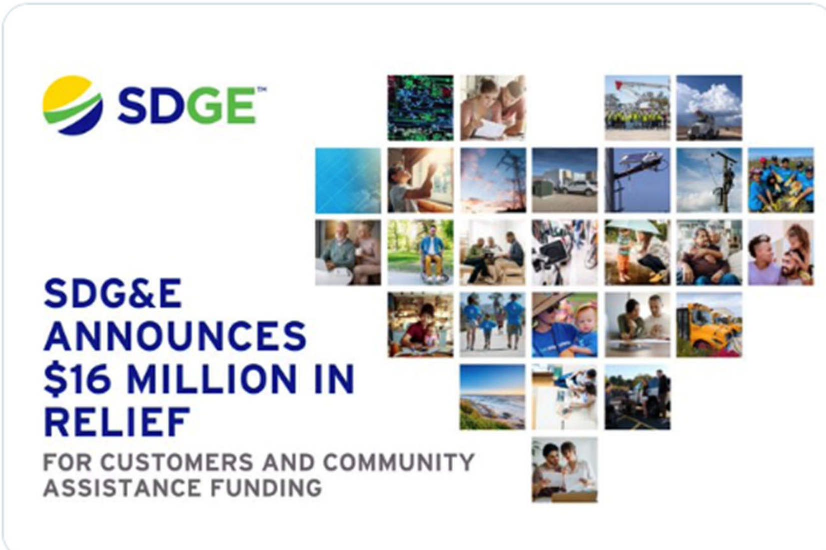
SDG&E @SDGE · Feb 2

🔔 Following a decision made today by the @californiapuc, 2 of the 3 scheduled installments of the CA Climate Credit have been moved up to provide winter bill relief to SDG&E customers: ow.ly/6ojZ50MHi2U.

Councilmember Jennifer Campbell Retweeted

SDG&E @SDGE · Feb 27

💙🤝💚 Today, we are proud to announce that we are providing $16 million in shareholder funding to help customers with bill assistance & bolster community resources for residents who may be struggling financially. ow.ly/z7vY50N3zkC



Councilmember Jennifer Campbell Retweeted

SDG&E @SDGE · Feb 28

🔔 After hitting a historic high in Jan. due to unprecedented natural gas market conditions in the West, today we announce that the March natural gas commodity price has declined by ~ 83% compared to Jan., plunging from $3.45 per therm to $0.60 per therm. ow.ly/MBvs50N5j4l

10 5 13 3,974

Bilingual (ENG/SPA) Social Media CBO Tool Kit:

SDGE™

SDG&E Community Partners: Social Media Toolkit

Socios de la comunidad SDG&E: Kit de herramientas para redes sociales

We have many SDG&E, federal, state and local assistance programs to help with your monthly utility bills

While the decline in natural gas commodity cost is welcome news, we recognize that many customers are still struggling with high bills. We continue to work diligently to connect customers with assistance programs and develop solutions to provide financial relief.

As a trusted community partner, we thank you in advance for sharing these social media posts with your audience to help amplify a wide range of customer assistance programs and resources that are available to help your clients/constituency manage their energy bill.

In your posts, please feel free to tag us on our social media accounts found below and route your audience to sdge.com/assistance for more information.

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Tenemos muchos programas de asistencia SDG&E, federales, estatales y locales para ayudarlo con sus facturas mensuales de servicios públicos

Aunque la reducción en el costo del producto básico de gas natural es una buena noticia, reconocemos que muchos de nuestros clientes todavía están luchando con facturas altas. Continuamos trabajando con diligencia para conectar a los clientes con programas de asistencia disponibles y desarrollar soluciones para brindar alivio financiero.

Como socio comunitario confiable, le agradecemos de antemano por compartir estas publicaciones en las redes sociales con su audiencia para ayudar a amplificar una amplia gama de programas de asistencia y recursos que están disponibles para ayudar a sus clientes y constituyentes a administrar su factura de energía.

En sus publicaciones, no dude en etiquetarnos en nuestras cuentas de redes sociales que se encuentran a continuación y dirigir a su audiencia a ***sdge.com/assistance*** *para obtener más información.*

If you have any questions, please don't hesitate to contact Rick Cervantes at rcervant@sdge.com.

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/SANDIEGOGASANDELECTRIC | @SDGE | @SDGE | /COMPANY/SDGE | /SANDIEGOGASELECTRIC

Sample Posts

1. 🔔 A message from our community partner, @SDGE: We recognize that many customers are still struggling with high bills, and we continue to work diligently to connect customers with assistance programs & develop solutions to provide financial relief. Here are a few of our assistance programs that are available to you. Learn more at sdge.com/assistance.

   🔔 *Un mensaje de nuestro socio comunitario, @SDGE: Reconocemos que muchos clientes todavía están luchando con facturas altas y seguimos trabajando diligentemente para conectar a los clientes con programas de asistencia y desarrollar soluciones para brindar alivio financiero. Estos son algunos de nuestros programas de asistencia que están disponibles para usted. Obtenga más información en sdge.com/assistance.*

   English Graphic (*Please feel free to include additional customer assistance program social media graphics from the appendix found at the end of the document.*):

   Spanish Graphic (*No dude en incluir imágenes de redes sociales adicionales de programas de asistencia en el apéndice que se encuentra al final del documento.*):

2. 🔔 A message from our community partner, @SDGE: Under the federally funded Low-Income Home Energy Assistance Program (LIHEAP), about $10 million is available to help SDG&E customers who are past due on their bill payments. About $7 million of that amount was allocated for 2021-2022 and is expected to expire by June 30, 2023. See if you qualify and learn more at sdge.com/LIHEAP.

🔔 *Un mensaje de nuestro socio comunitario, @SDGE: Bajo el Programa de Asistencia de Energía para Hogares de Bajos Ingresos (LIHEAP, por sus siglas en inglés), financiado con fondos federales, cerca de $10 millones están disponibles para ayudar a los clientes de SDG&E que están atrasados en el pago de sus facturas. Aprox. $7 millones de esa cantidad se asignaron para el 2021 al 2022 y se espera que expiren el 30 de junio de 2023. Vea si califica y obtenga más información en sdge.com/LIHEAP.*

English Graphic:

Spanish Graphic:

3. 🔔 A message from our community partner, @SDGE: We continue to work diligently to connect customers with assistance programs and develop solutions to provide financial relief like the Neighbor-to-Neighbor Fund. Learn more at sdge.com/assistance.

🔔 *Un mensaje de nuestro socio comunitario, @SDGE: Continuamos trabajando con diligencia para conectar a los clientes con programas de asistencia disponibles y desarrollar soluciones para brindar alivio financiero como el fondo de vecino a vecino. Obtenga más información en sdge.com/assistance.*

English Graphic:

Spanish Graphic:

SDGE News articles posted to sdgenews.com

The following articles and corresponding were posted to SDG&E's News center webpage, which is accessible on sdge.com or directly at sdgenews.com.

Publication Date	Headline
June 22, 2022	Energy Market Trend: Natural Gas Prices Continue to Rise | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post #1 • Social Media Post #2-
Dec 13, 2022	Amid Soaring Natural Gas Prices Nationwide, SDG&E Offers Customers Bill-Saving Tips and Tools | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post Example #1 (English / Spanish)
Jan 3, 2023	SDG&E Adopts New Rates Impacted By Historically High Natural Gas Prices Affecting Customers In The Pacific Region | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post Example #1 • Social Media Post Example #2
Jan 4, 2023	SDG&E adopta nuevas tarifas afectadas por precios históricamente altos del gas natural que afectan a clientes en el oeste del país | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post Example #1 • Social Media Post Example #2
Jan 13, 2023	SDG&E's Commentary in the San Diego Union-Tribune Outlines Reasons for High Bills and Customer Assistance Programs | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post Example #1
Jan 17, 2023	Have Questions about Natural Gas Prices? We've Got Answers | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post Example #1 (English / Spanish) • Social Media Post Example #2 (English / Spanish)
Jan 31, 2023	SDG&E Announces February Natural Gas Commodity Price To Decline 68% Compared To January | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post Example #1
Jan 31, 2023	SDG&E anuncia que el precio del producto básico del gas natural de febrero disminuirá un 68% en comparación con enero | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post Example #1

Feb 16, 2023	SDG&E Provides Update On Natural Gas Prices – Critical Out-Of-State Pipeline Service Restored | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) –
Feb 28, 2023	SDG&E Announces March Natural Gas Commodity Price To Decline By ~ 83% Compared To January | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post Example #1
Feb 28, 2023	SDG&E anuncia que el precio del producto básico del gas natural de marzo disminuirá aprox. un 83% en comparación con enero | SDGE | San Diego Gas & Electric - News Center (sdgenews.com) • Social Media Post Example #1

LIHEAP and Neighbor to Neighbor (N2N) programs

The following summary tables below provide more details regarding the increases for both the LIHEAP and NTN programs:

LIHEAP Pledge Counts (cumulative)

Month	2022	2023	% Difference
January	503	490	-2.6
February	873	1,272	+45.7
March	1,456	2,079	+42.8

LIHEAP Pledge Amount (cumulative)

Month	2022	2023	% Difference
January	$399,622	$444,170	+11.1
February	$635,114	$1,087,589	+71.2
March	$1,014,278	$1,853,213	+82.7

NTN Pledge Counts (cumulative)

Month	2022	2023	% Difference
January	19	69	+263.2
February	44	129	+193.2
March	66	505	+665.2

NTN Pledge Amount (cumulative)

Month	2022	2023	% Difference
January	$3,134	$19,492	+522.0
February	$7,086	$37,895	+434.8
March	$10,235	$223,402	+2,082.7