2024 CALIFORNIA GAS REPORT

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PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES

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

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2024 CALIFORNIA GAS REPORT

FOREWORD

FOREWORD

The *2024 California Gas Report* (CGR) presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2040. 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 Utilities Department, 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.

A working committee comprised of representatives from each utility was responsible for compiling the 2024 CGR. The membership of this committee is listed in the Respondents Section at the end of this report.

2024 CALIFORNIA GAS REPORT

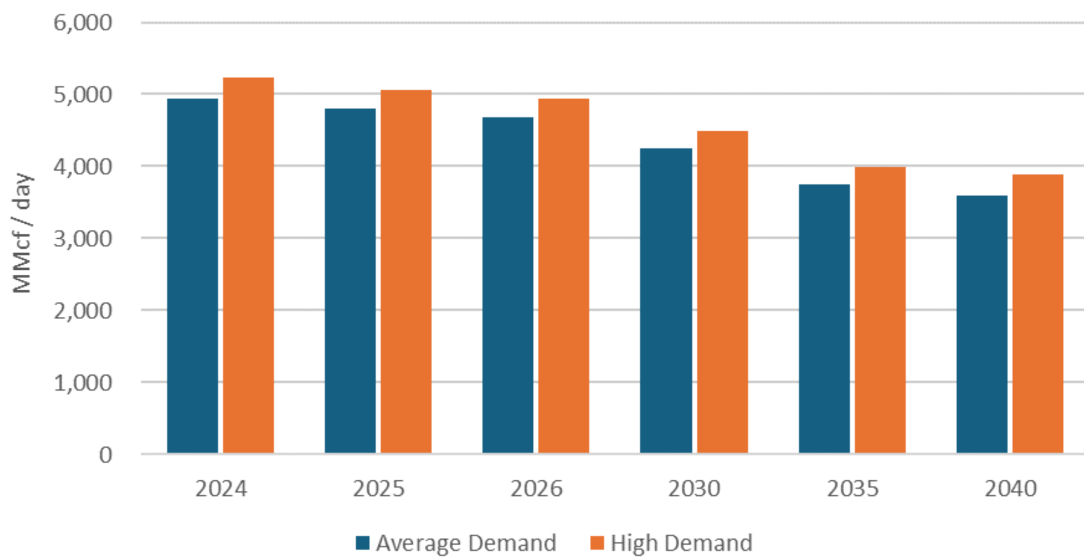
EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

FORECAST RESULTS

California demand for natural gas is forecasted to decline through 2040. The graph below summarizes statewide gas demand under the Average Demand case and the High Demand case. The Average Demand case refers to the expected gas demand for an average temperature year and normal hydroelectric generation (hydro) year, and the High Demand case refers to expected gas demand for a cold temperature year and dry hydro conditions. Under the Average Demand case, gas demand for the entire state is projected to average 4,931 million cubic feet of gas per day (MMcf/d) in 2024 decreasing to 3,593 MMcf/d by 2040, a decline of 2.0 percent per year.

FIGURE 1 – CALIFORNIA GAS DEMAND OUTLOOK



Compared to the Average Demand case scenario, the Northern California High Demand scenario is 11 percent higher in year 2024 while the Southern California High Demand scenario is 3.0 percent higher for the same year due to differing climate zones and respective energy generation (EG) assumptions.

FORECAST ASSUMPTIONS

The forecasts that comprise the 2024 CGR are based on assumptions regarding various state policies including energy efficiency, fuel substitution, electric generation/integrated resource planning, and system planning. More detailed discussion of each can be found in the Northern California and Southern California sections of the 2024CGR.

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 2024 through 2040 for average temperature and normal hydro years (Average Demand) and cold weather and dry hydro years (High Demand).

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 Utilities 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 1 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2024-2028, MMcf/d

	2024	2025	2026	2027	2028
California's Supply Sources					
Utility					
California Sources	88	88	88	88	88
Out-of-State	4,639	4,550	4,476	4,372	4,270
Utility Total	4,727	4,638	4,564	4,460	4,358
Non-Utility Served Load (1)	514	477	443	400	375
Statewide Supply Sources Total	**5,241**	**5,115**	**5,007**	**4,860**	**4,733**
California's Requirements					
Utility					
Residential	1,063	1,027	1,014	995	972
Commercial	472	466	458	453	446
Natural Gas Vehicles	59	62	66	70	73
Industrial	894	895	895	900	895
Electric Generation (2)	1,567	1,509	1,456	1,370	1,301
Enhanced Oil Recovery Steaming	24	24	23	22	22
Wholesale/International+Exchange	269	270	268	268	267
Company Use and Unaccounted-for	69	65	64	63	62
Utility Total	4,417	4,318	4,244	4,140	4,038
Non-Utility					
Enhanced Oil Recovery Steaming	56	52	49	44	42
EOR Cogeneration/Industrial	3	3	2	2	2
Electric Generation	455	423	392	354	331
Non-Utility Served Load (1)	514	477	443	400	375
Statewide Requirements Total (3)	**4,931**	**4,795**	**4,687**	**4,540**	**4,413**

Notes:
(1) Consists of California production and deliveries by El Paso, Kern/Mojave and TGN pipelines to industrial, Enhanced Oil Recovery (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 2 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2029-2040, MMcf/d

	2029	2030	2031	2035	2040
California's Supply Sources					
Utility					
California Sources	88	88	88	88	88
Out-of-State	4,183	4,154	3,780	3,403	3,266
Utility Total	4,271	4,242	3,868	3,491	3,354
Non-Utility Served Load (1)	354	329	307	252	239
Statewide Supply Sources Total	**4,624**	**4,571**	**4,175**	**3,743**	**3,593**
California's Requirements					
Utility					
Residential	950	925	899	784	663
Commercial	440	433	426	391	355
Natural Gas Vehicles	77	80	84	95	102
Industrial	890	884	880	861	839
Electric Generation (2)	1,243	1,249	1,230	1,014	1,047
Enhanced Oil Recovery Steaming	21	21	20	18	16
Wholesale/International+Exchange	268	268	268	269	274
Company Use and Unaccounted-for	62	62	61	58	58
Utility Total	3,951	3,922	3,868	3,491	3,354
Non-Utility					
Enhanced Oil Recovery Steaming	39	37	35	29	28
EOR Cogeneration/Industrial	2	2	2	1	1
Electric Generation	312	290	271	222	209
Non-Utility Served Load (1)	354	329	307	252	239
Statewide Requirements Total (3)	**4,304**	**4,251**	**4,175**	**3,743**	**3,593**

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 TAKEN
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2024-2028, MMcf/d

Utility	2024	2025	2026	2027	2028
Northern California					
California Sources (1)	22	22	22	22	22
Out-of-State	2,398	2,326	2,283	2,218	2,160
Northern California Total	2,420	2,348	2,305	2,240	2,182
Southern California					
California Sources (2)	66	66	66	66	66
Out-of-State	2,241	2,224	2,193	2,153	2,111
Southern California Total	2,307	2,290	2,259	2,219	2,177
Utility Total	4,727	4,638	4,564	4,460	4,358
Non-Utility Served Load (3)	514	477	443	400	375
Statewide Supply Sources Total	**5,241**	**5,115**	**5,007**	**4,860**	**4,733**

Utility	2029	2030	2031	2035	2040
Northern California					
California Sources (1)	22	22	22	22	22
Out-of-State	2,090	2,113	1,779	1,442	1,277
Northern California Total	2,112	2,135	1,801	1,464	1,299
Southern California					
California Sources (2)	66	66	66	66	66
Out-of-State	2,093	2,041	2,000	1,961	1,989
Southern California Total	2,159	2,107	2,066	2,027	2,055
Utility Total	4,271	4,242	3,868	3,491	3,354
Non-Utility Served Load (3)	354	329	307	252	239
Statewide Supply Sources Total	**4,624**	**4,571**	**4,175**	**3,743**	**3,593**

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.

TABLE 4 – STATEWIDE ANNUAL GAS REQUIREMENTS[1]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2024-2028, MMcf/d

	2024	2025	2026	2027	2028
Utility					
Northern California					
Residential	493	465	462	451	439
Commercial - Core	216	213	211	209	206
Natural Gas Vehicles - Core	8	8	8	9	9
Natural Gas Vehicles - Noncore	4	4	4	4	5
Industrial - Noncore	468	471	475	480	478
Wholesale	9	9	9	9	9
SMUD Electric Generation	96	89	88	74	74
Electric Generation (2)	740	696	653	611	570
Exchange (California)	33	33	33	33	33
Company Use and Unaccounted-for	44	40	40	39	39
Northern California Total (3)	2,110	2,028	1,985	1,920	1,862
Southern California					
Residential	570	562	552	543	533
Commercial - Core	206	203	197	194	190
Commercial - Noncore	50	50	50	50	50
Natural Gas Vehicles - Core	48	50	53	56	59
Industrial - Core	51	50	49	49	48
Industrial - Noncore	375	374	371	370	369
Wholesale (excluding EG)	227	228	226	226	226
SDG&E, Vernon & Ecogas EG	117	113	112	104	99
Electric Generation (EG) (4)	615	611	602	581	558
Enhanced Oil Recovery Steaming	24	24	23	22	22
Company Use and Unaccounted-for	25	24	24	24	23
Southern California Total	2,307	2,290	2,259	2,219	2,177
Utility Total	4,417	4,318	4,244	4,140	4,038
Non-Utility Served Load (5)	514	477	443	400	375
Statewide Gas Requirements Total (6)	**4,931**	**4,795**	**4,687**	**4,540**	**4,413**

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 5 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR, 2029-2040, MMcf/d

	2029	2030	2031	2035	2040
Utility					
Northern California					
Residential	420	399	377	275	149
Commercial - Core	203	198	193	168	135
Natural Gas Vehicles - Core	10	10	11	12	14
Natural Gas Vehicles - Noncore	5	5	5	6	7
Industrial - Noncore	473	469	465	451	432
Wholesale	9	9	9	9	8
SMUD Electric Generation	74	74	74	74	74
Electric Generation [2]	527	578	596	400	410
Exchange (California)	33	33	33	33	33
Company Use and Unaccounted-for	39	40	39	36	36
Northern California Total [3]	1,792	1,815	1,801	1,464	1,299
Southern California					
Residential	530	525	522	509	514
Commercial - Core	187	185	183	174	170
Commercial - Noncore	50	50	50	50	50
Natural Gas Vehicles - Core	62	65	68	76	81
Industrial - Core	48	47	47	46	44
Industrial - Noncore	368	368	367	365	364
Wholesale (excluding EG)	226	227	227	228	233
SDG&E, Vernon & Ecogas EG	97	94	86	86	90
Electric Generation (EG) [4]	545	503	474	454	473
Enhanced Oil Recovery Steaming	21	21	20	18	16
Company Use and Unaccounted-for	23	22	22	22	22
Southern California Total	2,159	2,107	2,066	2,027	2,055
Utility Total	3,951	3,922	3,868	3,491	3,354
Non-Utility Served Load [5]	354	329	307	252	239
Statewide Gas Requirements Total [6]	**4,304**	**4,251**	**4,175**	**3,743**	**3,593**

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 TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE (4) AND DRY HYDRO YEAR, 2024-2028, MMcf/d

	2024	2025	2026	2027	2028
California's Supply Sources					
Utility					
California Sources	88	88	88	88	88
Out-of-State	4,932	4,819	4,726	4,605	4,483
Utility Total	5,020	4,907	4,814	4,693	4,571
Non-Utility Served Load (1)	514	477	443	400	375
Statewide Supply Sources Total	**5,534**	**5,385**	**5,257**	**5,094**	**4,946**
California's Requirements					
Utility					
Residential	1,143	1,107	1,094	1,075	1,052
Commercial	490	484	476	471	463
Natural Gas Vehicles	59	62	66	70	73
Industrial	896	897	897	902	897
Electric Generation (2)	1,746	1,670	1,597	1,495	1,405
Enhanced Oil Recovery Steaming	24	24	23	22	22
Wholesale/International+Exchange	280	277	275	275	274
Company Use and Unaccounted-for	71	67	66	65	64
Utility Total	4,710	4,587	4,494	4,373	4,251
Non-Utility					
Enhanced Oil Recovery Steaming	56	52	49	44	42
EOR Cogeneration/Industrial	3	3	2	2	2
Electric Generation	455	423	392	354	331
Non-Utility Served Load (1)	514	477	443	400	375
Statewide Requirements Total (3)	**5,224**	**5,065**	**4,937**	**4,774**	**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.

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

TABLE 7 – STATEWIDE TOTAL SUPPLY SOURCES AND REQUIREMENTS
COLD TEMPERATURE (4) AND DRY HYDRO YEAR, 2029-2040, MMcf/d

	2029	2030	2031	2035	2040
California's Supply Sources					
Utility					
California Sources	88	88	88	88	88
Out-of-State	4,377	4,385	4,035	3,645	3,545
Utility Total	4,465	4,473	4,123	3,733	3,633
Non-Utility Served Load (1)	354	329	307	252	239
Statewide Supply Sources Total	**4,818**	**4,803**	**4,430**	**3,985**	**3,872**
California's Requirements					
Utility					
Residential	1,030	1,004	978	862	739
Commercial	457	451	443	408	372
Natural Gas Vehicles	77	80	84	95	102
Industrial	892	886	882	863	841
Electric Generation (2)	1,329	1,372	1,378	1,151	1,223
Enhanced Oil Recovery Steaming	21	21	20	18	16
Wholesale/International+Exchange	275	275	275	276	281
Company Use and Unaccounted-for	63	64	63	59	60
Utility Total	4,145	4,153	4,123	3,733	3,633
Non-Utility					
Enhanced Oil Recovery Steaming	39	37	35	29	28
EOR Cogeneration/Industrial	2	2	2	1	1
Electric Generation	312	290	271	222	209
Non-Utility Served Load (1)	354	329	307	252	239
Statewide Requirements Total (3)	**4,498**	**4,483**	**4,430**	**3,985**	**3,872**

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-TAKEN
COLD TEMPERATURE [4] AND DRY HYDRO YEAR, 2024-2028, MMcf/d

Utility	**2024**	**2025**	**2026**	**2027**	**2028**
Northern California					
California Sources [1]	22	22	22	22	22
Out-of-State	2,622	2,532	2,471	2,389	2,313
Northern California Total	2,644	2,554	2,493	2,411	2,335
Southern California					
California Sources [2]	66	66	66	66	66
Out-of-State	2,310	2,287	2,255	2,216	2,170
Southern California Total	2,376	2,353	2,321	2,282	2,236
Utility Total	5,020	4,907	4,814	4,693	4,571
Non-Utility Served Load [3]	514	477	443	400	375
Statewide Supply Sources Total	**5,534**	**5,385**	**5,257**	**5,094**	**4,946**

Utility	**2029**	**2030**	**2031**	**2035**	**2040**
Northern California					
California Sources [1]	22	22	22	22	22
Out-of-State	2,225	2,285	1,976	1,628	1,501
Northern California Total	2,247	2,307	1,998	1,650	1,523
Southern California					
California Sources [2]	66	66	66	66	66
Out-of-State	2,152	2,101	2,059	2,017	2,044
Southern California Total	2,218	2,167	2,125	2,083	2,110
Utility Total	4,465	4,473	4,123	3,733	3,633
Non-Utility Served Load [3]	354	329	307	252	239
Statewide Supply Sources Total	**4,818**	**4,803**	**4,430**	**3,985**	**3,872**

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.

TABLE 9 – STATEWIDE ANNUAL GAS REQUIREMENTS (1)
COLD TEMPERATURE (7) and DRY HYDRO YEAR, 2024-2028, MMcf/d

	2024	2025	2026	2027	2028
Utility					
Northern California					
Residential	531	503	501	490	477
Commercial - Core	225	222	220	218	215
Natural Gas Vehicles - Core	8	8	8	9	9
Natural Gas Vehicles - Noncore	4	4	4	4	5
Industrial - Noncore	469	472	477	482	479
Wholesale	10	10	10	9	9
SMUD Electric Generation	96	89	88	74	74
Electric Generation (2)	914	852	792	731	673
Exchange (California)	33	33	33	33	33
Company Use and Unaccounted-for	46	42	41	40	40
Northern California Total (3)	2,334	2,234	2,173	2,091	2,015
Southern California					
Residential	612	604	594	585	575
Commercial - Core	215	211	205	202	198
Commercial - Noncore	50	51	51	51	51
Natural Gas Vehicles - Core	48	50	53	56	59
Industrial - Core	51	51	50	50	49
Industrial - Noncore	375	374	371	370	369
Wholesale (excluding EG)	238	234	232	232	232
SDG&E, Vernon & Ecogas EG	119	116	114	106	100
Electric Generation (EG) (4)	617	613	603	583	559
Enhanced Oil Recovery Steaming	24	24	23	22	22
Company Use and Unaccounted-for	25	25	25	24	24
Southern California Total	2,376	2,353	2,321	2,282	2,236
Utility Total	4,710	4,587	4,494	4,373	4,251
Non-Utility Served Load (5)	514	477	443	400	375
Statewide Gas Requirements Total (6)	**5,224**	**5,065**	**4,937**	**4,774**	**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 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 10 – STATEWIDE ANNUAL GAS REQUIREMENTS [1]
COLD TEMPERATURE [7] AND DRY HYDRO YEAR, 2029-2040, MMcf/d

	2029	2030	2031	2035	2040
Utility					
Northern California					
Residential	459	438	415	313	186
Commercial - Core	211	207	202	176	144
Natural Gas Vehicles - Core	10	10	11	12	14
Natural Gas Vehicles - Noncore	5	5	5	6	7
Industrial - Noncore	475	470	467	452	433
Wholesale	9	9	9	9	9
SMUD Electric Generation	74	74	74	74	74
Electric Generation [2]	611	699	742	536	586
Exchange (California)	33	33	33	33	33
Company Use and Unaccounted-for	40	41	40	37	38
Northern California Total [3]	1,927	1,987	1,998	1,650	1,523
Southern California					
Residential	571	567	563	549	553
Commercial - Core	195	193	191	181	177
Commercial - Noncore	51	51	51	51	51
Natural Gas Vehicles - Core	62	65	68	76	81
Industrial - Core	49	48	48	46	45
Industrial - Noncore	368	368	367	365	364
Wholesale (excluding EG)	233	233	233	234	239
SDG&E, Vernon & Ecogas EG	98	95	87	87	90
Electric Generation (EG) [4]	546	504	475	454	473
Enhanced Oil Recovery Steaming	21	21	20	18	16
Company Use and Unaccounted-for	24	23	23	22	22
Southern California Total	2,218	2,167	2,125	2,083	2,110
Utility Total	4,145	4,153	4,123	3,733	3,633
Non-Utility Served Load [5]	354	329	307	252	239
Statewide Gas Requirements Total [6]	**4,498**	**4,483**	**4,430**	**3,985**	**3,872**

Notes:

(1) Includes transportation gas.

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

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

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

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

(6) Does not include off-system deliveries.

(7) 1-in-35 cold year temperature for SoCalGas; 1-in-10 cold year temperature for PG&E.

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 11 – 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 12– 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 (3,4)	132	406	151	9	245	0	0	0	943
Noncore C&I, EG/EOR/Wholesale/Internation	(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 (5)									
Core	0	8	33	379	(7)	0	0	165	578
Noncore Industrial/Wholesale/EG (6)	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 (7)	14	0	0	0	0	0	0	0	14
Non-Utilities Served Load (8,9)									
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									
Core	25	0	0	0	0	0	0	0	25
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	27	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) Includes UEG, COGEN, EOR, and deliveries to SoCalGas' Wholesale, Resale and International Customers.
(3) Includes NGV volumes. Core supplies represent accrued values.
(4) Kern River volumes include aggregated flowing supplies from Ruby and Mojave.
(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) Source: California Energy Commission.
Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Source: California Energy Commission; EIA.
(9) Deliveries to end users by non-CPUC jurisdictional pipelines. California Production is preliminary.

TABLE 13 – RECORDED 2021 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 (3,4)	217	334	184	20	210	0	(15)	0	950
Noncore C&I, EG/EOR/Wholesale/Internation	(131)	504	173	206	618	85	18	0	1,473
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	326	1,840
Total	23	385	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	1,272	543	1,578	1,463	127	3	485	5,890
San Diego Gas & Electric Company									
Core	31	48	27	3	30	0	(2)	0	137
Noncore Commercial/Industrial	(11)	44	15	18	54	7	2	0	128
Total	20	91	42	21	84	7	0	0	265
Southwest Gas Corporation									
Core	24	0	0	0	0	0	13	0	37
Noncore Commercial/Industrial	2	0	0	0	0	0	0	0	2
Total	26	0	0	0	0	0	13	0	39

Notes:
(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes UEG, COGEN, EOR, and deliveries to SoCalGas' Wholesale, Resale and International Customers.
(3) Includes NGV volumes. Core supplies represent accrued values.
(4) Kern River volumes include aggregated flowing supplies from Ruby and Mojave.
(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) Source: California Energy Commission.
Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Source: California Energy Commission; EIA.
(9) Deliveries to end users by non-CPUC jurisdictional pipelines. California Production is preliminary.

TABLE 14 – RECORDED 2022 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 (3,4)	144	338	150	31	221	0	33	0	917
Noncore C&I, EG/EOR/Wholesale/Internation	(53)	483	311	189	521	50	(31)	0	1,499
Total	91	821	461	220	742	50	2	0	2,416
Pacific Gas and Electric Company (5)									
Core	0	38	0	391	(4)	0	0	160	585
Noncore Industrial/Wholesale/EG (6)	23	323	145	1,023	14	0	0	176	1,704
Total	23	361	145	1,414	10	0	0	336	2,289
Other Northern California									
Core (7)	0	0	0	0	0	0	0	0	0
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	256	32	0	0	638	20	0	0	1,017
TOTAL SUPPLIER	370	1,214	606	1,634	1,390	70	2	336	5,722
San Diego Gas & Electric Company									
Core	21	49	22	4	32	0	5	0	133
Noncore Commercial/Industrial	(5)	45	29	18	49	5	(3)	0	141
Total	16	94	51	22	81	5	2	0	274
Southwest Gas Corporation									
Core	26	0	0	0	0	0	0	0	26
Noncore Commercial/Industrial	1	0	0	0	0	0	0	0	1
Total	27	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) Includes UEG, COGEN, EOR, and deliveries to SoCalGas' Wholesale, Resale and International Customers.
(3) Includes NGV volumes. Core supplies represent accrued values.
(4) Kern River volumes include aggregated flowing supplies from Ruby and Mojave.
(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) Source: California Energy Commission.
Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Source: California Energy Commission; EIA.
(9) Deliveries to end users by non-CPUC jurisdictional pipelines. California Production is preliminary.

TABLE 15 – RECORDED 2023 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 (3,4)	261	391	153	19	226	0	(54)	0	996
Noncore C&I, EG/EOR/Wholesale/Internation	(170)	545	282	147	573	99	56	0	1,539
Total	91	936	435	166	799	99	2	0	2,535
Pacific Gas and Electric Company (5)									
Core	0	34	0	398	(1)	0	0	171	601
Noncore Industrial/Wholesale/EG (6)	22	398	170	1,085	22	0	0	253	1,949
Total	22	431	170	1,482	21	0	0	424	2,550
Other Northern California									
Core (7)	0	0	0	0	0	0	0	0	0
Non-Utilities Served Load (8,9)									
Direct Sales/Bypass	249	32			601	48			930
TOTAL SUPPLIER	362	1,399	605	1,648	1,421	147	2	424	6,015
San Diego Gas & Electric Company	37	55	22	3	32	0	(8)	0	141
Core	(28)	41	23	14	50	10	8	0	120
Noncore Commercial/Industrial									
Total	9	97	45	17	82	10	0	0	261
Southwest Gas Corporation									
Core	29	0	0	0	0	0	0	0	29
Noncore Commercial/Industrial	1	0	0	0	0	0	0	0	1
Total	30	0	0	0	0	0	0	0	30

Notes:
(1) Includes storage activities, volumes delivered on Questar Southern Trails for SoCalGas and PG&E.
(2) Includes UEG, COGEN, EOR, and deliveries to SoCalGas' Wholesale, Resale and International Customers.
(3) Includes NGV volumes. Core supplies represent accrued values.
(4) Kern River volumes include aggregated flowing supplies from Ruby and Mojave.
(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) Source: California Energy Commission.
Includes Southwest Gas Corporation and Tuscarora deliveries in the Lake Tahoe and Susanville areas.
(8) Source: California Energy Commission; CALGem.
(9) Deliveries to end users by non-CPUC jurisdictional pipelines. 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 five years. Daily sendout from SoCalGas, PG&E, and from customers not served by these utilities were used to construct the following tables.

TABLE 16 - ESTIMATED CALIFORNIA HIGHEST SUMMER SENDOUT, 2019-2023, MMcf/d

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
2019	09/04/2019	2,606	2,907	5,513	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
2022	09/06/2022	2,620	3,229	5,849	1,080	6,929
2023	08/16/2023	2,627	3,015	5,642	1,109	6,751

TABLE 17 - ESTIMATED CALIFORNIA HIGHEST WINTER SENDOUT, 2019-2023, MMcf/d

Year	Date	PG&E (1)	SoCal Gas (2)	Utility Total (4)	Non-Utility (3)	State Total
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
2022	02/23/2022	3,439	3,953	7,392	838	8,230
2023	01/30/2023	3,607	3,736	7,343	903	8,246

Notes:

(1) PG&E Pipe Ranger.

(2) SoCalGas Envoy.

(3) Source: Provided by the CEC. Data are from Geologic Energy Management Division (CalGEM), 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 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.

CORE SUPPLY STANDARDS

The following tables are presented pursuant to Gas Planning OIR decision (D.22-07-002).

TABLE 18 - STATEWIDE FIRM CORE GAS INTERSTATE PIPELINE CAPACITY (% of AVERAGE DAILY DEMAND)

Time of the Year	PG&E	SoCalGas
Winter (PG&E: Dec-Feb, SoCalGas: Nov-Mar)	100%-162%	100%-120%
Shoulder (Mar & Nov)	80%-162%	100%-120%
Summer (Apr-Oct)	80%-105%	90%-120%

TABLE 19 - PG&E FIRM CORE GAS STORAGE ALLOCATION

Firm Core Gas Storage Allocation from PG&E	
Gas Inventory (Bcf)	6.7
Maximum November Withdrawal (MMcf/d)	205
Maximum Dec-Feb Withdrawal (MMcf/d)	409
Maximum March Withdrawal (MMcf/d)	205
Average Apr-Oct Injection (MMcf/d)	33
Maximum Nov-Mar Injection (MMcf/d)	0

TABLE 20 - SOCALGAS FIRM CORE GAS STORAGE ALLOCATION

Firm Core Gas Storage Allocation from SoCalGas	
Gas Inventory (Bcf)	82.5
Winter Withdrawal (MMcf/d)	2,000
Summer Withdrawal (MMcf/d)	400
Winter Injection (MMcf/d)	155
Summer Injection (MMcf/d)	445

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2024 CALIFORNIA GAS REPORT

STATEWIDE MARKET CONDITIONS

MARKET CONDITIONS

The role of natural gas in the energy mix remains significant and it is expected to continue to play a vital role in meeting customers' energy needs, considering emissions reduction targets by 2030 and expected increased reliance on intermittent renewable resources. Record high natural gas production, flat consumption, and rising natural gas inventories in 2023 and 2024 contributed to lower prices in 2023 compared to 2022. The Energy Information Administration's (EIA) reported national benchmark price at Henry Hub averaged about $2.57/Million British Thermal Units (MMBtu) in 2023, approximately 62% lower than the 2022 average natural gas price.

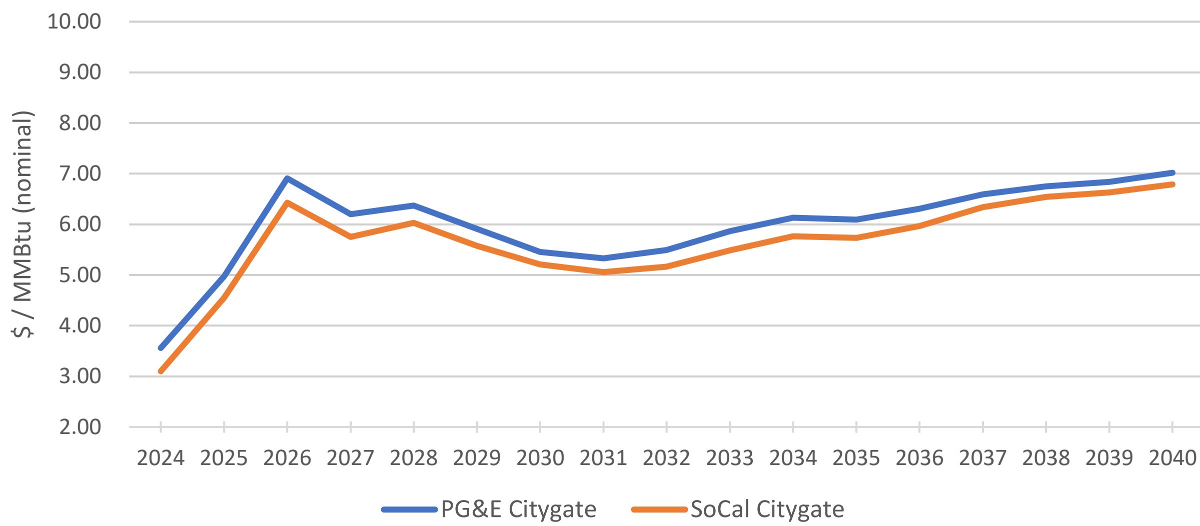
Going forward over the next several years, the level of gas prices can be impacted by the direction of developments in four key areas. These include natural gas production; local and national temperatures; natural gas storage; and liquefied natural gas (LNG) developments. Gas storage for all regions across the U.S. are currently holding inventories above the 2019-2023 five-year average; however, inventories could adjust downward in response to demand for natural gas as they declined to low levels during the summer of 2022 amid strong demand for electric generation.

LNG export demand has grown rapidly in the United States over recent historical years. In 2023, the United States emerged as the largest LNG exporter worldwide according to S&P Global. According to the Institute for Energy Economics and Financial Analysis, there is an impending surge in LNG development. The global LNG industry is on track to add almost five times as much new liquefaction capacity from 2025 through 2028 compared to the previous four-year period. In the United States, five LNG projects totaling more than seventy-one million metric tons per annum in liquefaction capacity are currently under construction. The five projects consist of Plaquemines LNG, Golden Pass LNG, Rio Grande LNG, Port Arthur LNG, and an expansion project at Corpus Christi LNG. If the anticipated LNG export capacity growth plays out, natural gas prices are expected to experience upward pressure as demand increases. Meanwhile, if LNG exports are interrupted, domestic natural gas prices likely would decline as domestic supplies increase.

DEVELOPMENT OF THE GAS PRICE FORECAST

The 2024 near term gas price average at the California Citygates[1] is a little above $3.00/MMBtu. By the end of the decade, gas prices are projected to reach between $5.00 and $6.00 MMBtu before reaching between $6.00 and $7.00 MMBtu by 2040. The 2024 CGR gas price forecast is based on a February 2024 forecast from S&P Global Commodity Insights.

FIGURE 2 – FORECASTED NATURAL GAS PRICES



It is important to recognize that natural gas price forecasts are inherently uncertain. PG&E, SoCalGas, and the respondents of the 2024 CGR, separately and collectively, do not warrant the accuracy of the gas price projections and 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 in-state California

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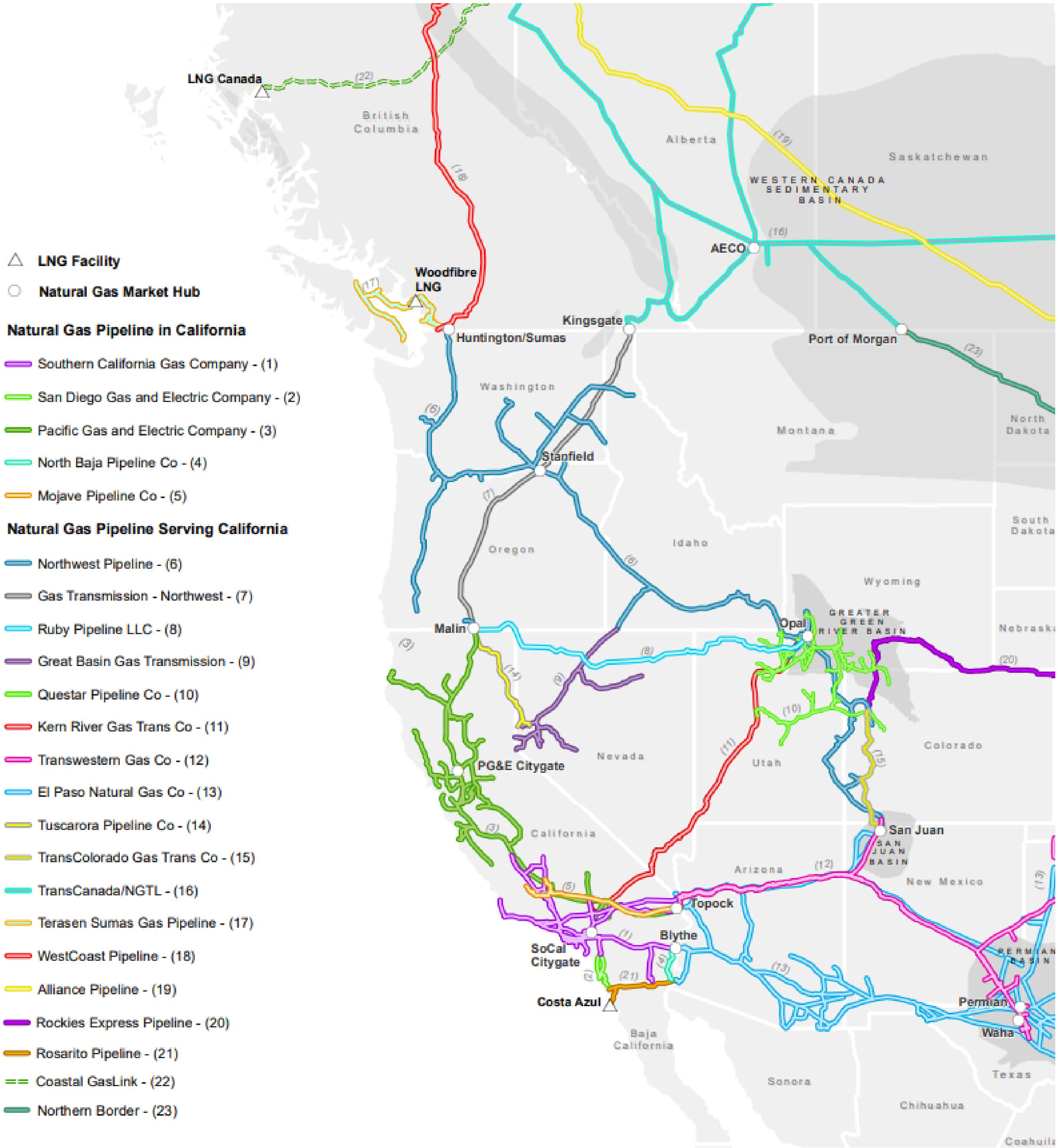
[1] The two Citygate price hubs are the Southern California Gas Company Citygate (SoCal Citygate) and the Pacific Gas and Electric Citygate (PG&E Citygate).

(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



STATEWIDE MARKET CONDITIONS

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 provide supply reliability. Additionally, storage allows gas customers to take advantage of low prices and store gas for periods with higher prices. Various regulations and standards[2] 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 21 – STATEWIDE NATURAL GAS STORAGE CAPABILITIES, 2023

	Inventory (Bcf)	Injection (MMcf/d)	Withdrawal (MMcf/d)	Cite
Northern California				
Independent Storage Providers				1
Lodi Gas Storage	31	550	750	
Wild Goose Storage	75	525	950	
Gill Ranch	15	165	162	
Central Valley	11	300	300	
PG&E-Utility Storage***	37	315	766	2
Northern California Total	169	1,855	2,928	
Southern California				
SoCalGas	120	790 (summer) 500 (winter)	1,240 (summer) 2,400 (winter)	3
California Total	289	2,645 (summer) 2,355 (winter)	4,168 (summer) 5,328 (winter)	

Citations

1) Capacities derived from information provided by Independent Storage Providers

2) ***Firm maximum inventory level

3) SoCalGas/SDG&E Triennial Cost Allocation Proceeding, D 20-02-045

[2] 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. Currently, incentives such as Low Carbon Fuel Standards (LCFS) and renewable identification number (RIN) credits are successfully supporting the use of RNG in the transportation sector. As policies evolve and new programs are created, such as California's recently approved Renewable Gas Standard (RGS),[3] we expect RNG to play a growing role in serving customers' energy needs beyond the transportation sector.

As California continues towards achieving a decarbonized energy system, hydrogen (H2) will become an important fuel source in achieving the State's emissions goals. There is growing potential for generating clean renewable green hydrogen[4] and delivering it using existing gas utility infrastructure to help meet California's dynamic energy needs.

[3] *See* CPUC Decision (D).22-02-025.

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

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2024 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. PG&E's natural gas system spans central and northern California, with a service area that stretches from Eureka to Bakersfield and from the Pacific Ocean to the Sierra Nevada. Our system consists of approximately 44,000 miles of gas distribution pipelines, 6,400 miles of gas transmission pipelines, two fully owned underground storage facilities[5], 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 interconnections with interstate pipelines, California gas fields and California RNG facilities to PG&E's local transmission and distribution systems, other local distribution companies and operators.

PG&E provides natural gas procurement, transportation, and storage services to approximately 4.52 million commercial and industrial customers[6]. PG&E also provides gas transportation and storage services to a variety of gas-fired 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 services from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are 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, utilize the PG&E system to meet their gas needs in Southern California.

[5] PG&E has a pending application with the CPUC to sell the Pleasant Creek storage facility under application (Link).

[6] PG&E does not provide procurement services for noncore customers.

The Northern California section of this report includes details of the following Northern California forecasts and is consistent with the forecasting requirements in the CPUC Decision 22-07-002 issued in the Long-Term Gas System Planning Order Instituting Rulemaking (OIR)[7]:

- Average Demand Annual Forecast
- High Demand Annual Forecast (1-in-10 Cold and 1-in-10 Dry)
- Core Peak Demand and Supply Forecast on an Abnormal Peak Day (APD)
- 1-in-2-Year Cold Winter Day Forecast (High Demand Day in an Average Demand Year)
- 1-in-10-Year Peak Winter Day Forecast (High Demand Day in a 1-in-10 Cold and 1-in-10 Dry Demand Year)
- Dry Year Summer Day High Demand Estimate (High Demand Day in a 1-in-10 Dry Demand Year)

The Northern California section also includes discussions on gas demand sensitivity, policies and legislative developments impacting gas demand, and a chapter on gas supply, pipeline capacity, storage, and related policies.

The following is a summary of key takeaways:

The Northern California Gas Demand Forecast Reflects the Impact of California's Existing Decarbonization Policies: PG&E's average-year demand[8] is forecasted to decline at an annual average rate of 3.0 percent between 2024 and 2040. The decline in forecasted gas demand is in response to the state's decarbonization policies and is driven by reductions in Core and EG demand:

- **Core**: The decline reflects reduced demand due to energy efficiency, building electrification (BE) from switching from natural gas appliances to electric, and climate change. Proposed regional and state zero-emission appliance standards have also been factored into the core demand forecast. The modeled effects of the proposed zero-

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[7] 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, Rulemaking 20-01-007.

[8] Gas demand projection for an average temperature year and normal hydroelectric generation year.

emission appliance standards include potential uncertainties such as legal challenges and technical or supply chain constraints.

- **Electric Generation**: The decline reflects the impact of renewable generation and energy storage additions to achieve a California Independent System Operator (CAISO) wide greenhouse gas (GHG)-free electric system by 2045 but uncertainty in resource locations and transmission constraints limit decline.

The Northern California Gas Demand Forecast Does Not Necessarily Achieve 100% Decarbonization of the Gas System: It is important to note that the California Gas Demand Forecast is not constrained to meet a net-zero gas system by 2045. Such a forecast would need to include, but would not be limited to, additional building decarbonization. Additionally, higher levels of RNG and hydrogen, and emerging technologies such as carbon capture and sequestration (CCS), could be deployed to meet the higher demand forecasted in the 2024 CGR. PG&E expects to work with the CPUC and other stakeholders within the Long-Term Gas Planning OIR to advance California's transition away from fossil natural gas (to electrification and cleaner fuels) in an affordable fashion.

The Forecasted Demand is Subject to Significant Uncertainties: Key forecast uncertainties include the pace and magnitude of BE, Northern and Southern California gas price differentials, the impact of climate change on forecasted gas and electric load and hydroelectric generation, import availability, and planned electric generation buildout and transmission limitations.

PG&E is Taking Action 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, converting facilities from more impactful fuel sources, and conducting methane abatement.

2. Decrease costs by limiting system expansion, strategically reducing capital and operational expenses, strategically pruning the gas system, and through electrification.

3. Increase demand through strategic investment in the gas system to increase load by providing cleaner fuels to hard-to-electrify customers.

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. To successfully implement the State's environmental goals, issues such as obligation to serve, treatment of capital versus expense dollars, and non-traditional funding must be addressed and resolved in a manner that supports affordably meeting PG&E's and California's climate objectives.

Regulatory bodies and investor-owned utilities (IOU) should continue to 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 OIR 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 RNG to contribute towards access to clean, reliable, and affordable energy. The current investment and incentives for RNG principally favor the transportation sector, resulting in little RNG availability to comply with the recently enacted RGS[9]. If this is to change, California will have to take several actions, mainly (a) incentivize the interconnection costs, (b) help streamline the interconnection process, and (c) incentivize diversified technology and fuel sources so that utilities will have access to cost-effective RNG to comply with the RGS.

[9] CPUC Decision 22-02-025 (454335009.PDF (ca.gov))

ANNUAL GAS DEMAND

This chapter contains PG&E's annual[10] gas demand forecasts (average and high demand[11]), a description of the forecast methodology, details on average demand forecast by customer sector, and details on key assumptions driving the forecast. The chapter concludes with an analysis of forecast uncertainty, providing potential changes in Core and EG gas demand if key forecast drivers were to materialize differently than assumed in the 2024 CGR.

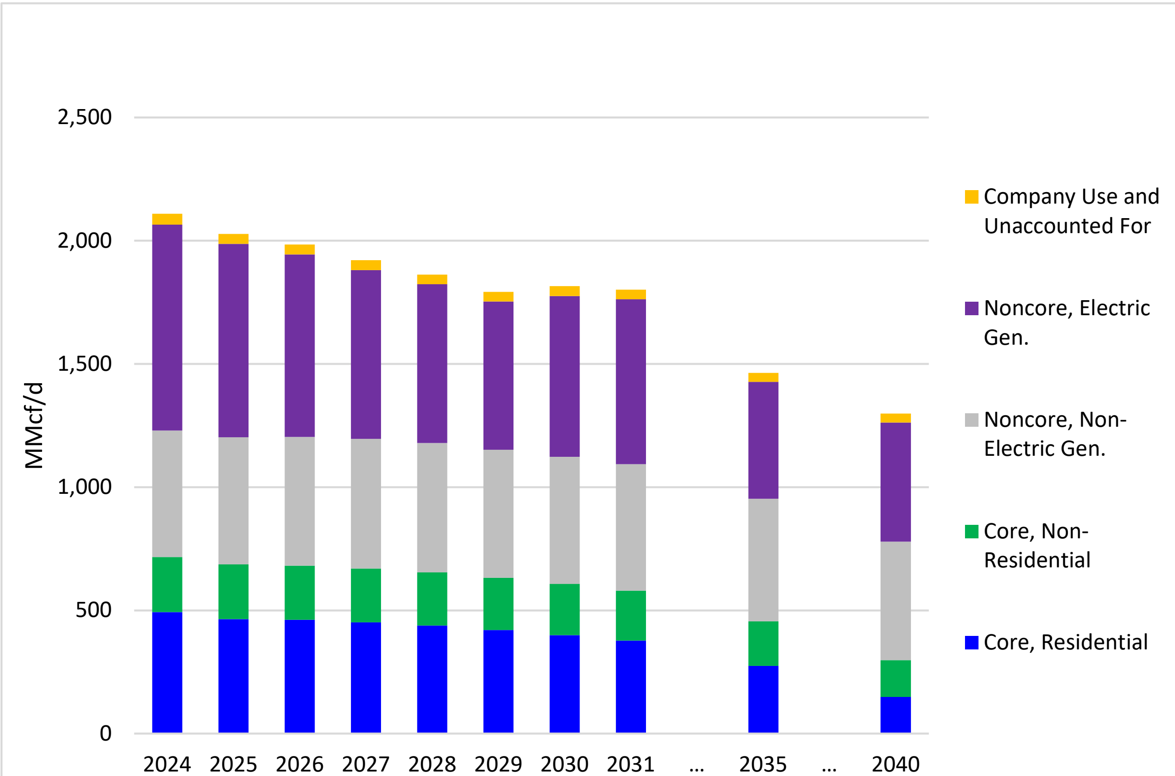
AVERAGE DEMAND SUMMARY

PG&E's average demand throughput[12] is forecasted to decline at an annual average rate of 3.0[13] percent between 2024 and 2040. The Core sector is forecasted to decline at an average annual rate of 5.3 percent. The Noncore sector is forecasted to decline at a rate of 2.1 percent annually, driven in part by a decrease in throughput for electric generation. The decline in throughput from Noncore, Industrial customers is relatively small at a rate of less than 0.4 percent annually.

The projected decline in total demand could result in gas system operating and maintenance costs being allocated over lower usage, causing customer gas rates to increase. Consequently, PG&E is actively developing programs to reduce gas system costs but will need statewide utility stakeholders to partner in work to mitigate customer rate increases.

[10] Monthly forecasts are available in PG&E's workpapers.
[11] The average demand gas forecasts are for an average temperature year and average hydroelectric generation for the most recent 15 historical years (2009-2023). The high demand year forecast presents demand under cold temperature and dry hydroelectric generation to provide more information about gas throughput under stressed conditions.
[12] Forecasts are presented in tabular form at the end of the Northern California section.
[13] Includes PG&E and SMUD forecasts.

FIGURE 4: Northern California On-System Gas Demand Average
YEAR FORECAST



Changes in the major components of on-system gas demand are illustrated in Figure 9 above. Core demand decline is driven by increasing energy efficiency, increasing BE, and a warming climate. Noncore, non-EG demand is forecasted to remain largely flat over the forecast horizon, as potential demand growth is partly offset by increasing gas prices.

The EG demand forecast is largely a function of electric energy demand, the future CAISO generation portfolio, transmission constraints (including imports from other balancing authorities) and gas prices. PG&E's EG demand forecast incorporates the impact of renewable generation and electric storage forecast from the 2023 CPUC Preferred System Plan (PSP) developed as part of the CPUC's Integrated Resource Planning (IRP) process.[14] It also reflects the impact of higher burner-tip gas prices for Northern California electric generators relative to Southern California.

AVERAGE DEMAND MARKET SECTOR FORECASTS

Residential

Northern California residential demand is forecasted to decrease from 493 MMcf/d in 2024 to 149 MMcf/d in 2040, primarily driven by a decrease in use per customer from increased BE and improvements in appliance and building shell efficiencies. The number of residential household billings in the PG&E service area is forecasted to decline slightly from 2024 to 2040, with declines in the 2030s offsetting slight increases in the 2020s. PG&E expects continued efficiency improvements, coupled with the following emerging trends, to decrease long-term residential gas demand.

1. PG&E currently records over 50 ordinances in its service area that require or give preference to all-electric new construction.[15] Not all construction types are covered by these ordinances, and there is regional variation (residential versus non-residential, exceptions and partial electrification allowed by some ordinances). While the number of households is forecasted to grow slightly at 0.5 percent annually, PG&E's BE forecast assumes that many of these households will install electric-only appliances. This assumption is supported by new Title 24 building energy code requirements and local ordinances as well as the removal of gas line extension allowances, discounts, and refunds as decided in the Building Decarbonization OIR.[16]

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[14] CPUC IRP Proceeding: https://www.cpuc.ca.gov/irp/; 2023 PSP final Decision: Results (ca.gov)

[15] California Energy Codes & Standards, accessed May 21, 2024, https://localenergycodes.com/content/adopted-ordinances

[16] The removal of gas line extension allowances, discounts, and refunds is expected to save California ratepayers approximately $120 million annually.

2. In addition to new construction BE, this forecast anticipates that existing households will begin to convert appliances from gas to electric driven by state, regional, and local policies, customer cost savings, or other mechanisms.

3. The warming climate will reduce winter heating needs, gradually decreasing residential gas sales.

Total annual residential demand is projected to continue declining, driven by efficiency gains, building and appliance electrification, and warming temperatures. By 2040, annual residential gas throughput is projected to be 70% lower than forecasted 2024 throughput, with most of the decrease driven by a higher BE assumption as we approach the 2040s.

Commercial

Northern California commercial demand, excluding NGVs, is forecasted to decrease from 216 MMcf/d in 2024 to 135 MMcf/d in 2040. The number of commercial customers in the PG&E service area is projected to grow on average by about 0.1 percent annually from 2024-2040. Like to the residential customer class, PG&E expects new construction and retrofit BE, 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 an average of 2.9 percent per year over the next 16 years, with the decline accelerating in later years. Core NGVs remain a minor component that is forecasted to grow at about 4 percent per year.

Industrial

Northern California industrial demand is forecasted to decrease nominally from 468 MMcf/d in 2024 to 432 MMcf/d in 2040. Gas requirements for PG&E's industrial sector are affected by the level and the 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. Recorded data shows a drop-off in industrial usage beginning in 2020 corresponding to the impacts of COVID on large industrial users, such as refineries, which seem to have largely recovered. While, as that example illustrates, the industrial sector has the potential for high year-to-year variability, over the long term industrial gas consumption is expected to decrease slowly, with decreasing customer counts and higher gas prices adding to a mild decline continuing from about 2018.[17] As with the commercial category of NGV, the industrial category NGV sees moderate growth from a small base, with some as yet unquantified possibilities for additional growth as described in “Gas Demand Trends and Strategy” below.

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 hydrogen in the future. Although these conversions are in the planning stage and could increase industrial gas use, natural gas demand from the industrial sector is expected to decline by 0.5 percent annually over the next 16 years.

Electric Generation

Northern California EG demand[18] is forecasted to steadily decline over the forecast horizon, with a small increase in 2030-2031 due to the retirement of Diablo Canyon[19] (although demand in those years is still forecasted to be lower than present-day conditions). The average projected gas demand during 2024-2029 is 715 MMcf/d, during 2030-2035 declines to 573 MMcf/d, and further declining to 456 MMcf/d over the final 5 years of the forecast.

The EG gas demand forecast is subject to significant uncertainty due to factors including:

- Future burner-tip gas prices;[20]
- CAISO import availability.
- Timing and location of new renewable electricity generation; and

[17] 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. This forecast does not assume any specific requirements for electrification of industrial processes.

[18] Northern California Electric generation demand includes demand from gas-fired cogeneration and power plants connected to PG&E’s gas system.

[19] CPUC Decision (R-23-01-007) Conditionally Approving Extended Operations at Diablo Canyon Nuclear Power Plant Pursuant to Senate Bill 846, 12/14/2023. OP 1. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K496/521496261.pdf

[20] Burner tip gas prices are the combination of the commodity price and transportation rate.

- Variable precipitation affecting hydroelectric generation; Variable precipitation affecting hydroelectric generation.

To assess the broad impact of these uncertainties, this report discusses a sensitivity analysis conducted with PG&E's EG model in the "Analysis of Forecast Uncertainty" section.

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 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 Lines 300 A and B and approximately 4.2 percent in Line 401. 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 an average load of 96 MMcf/d and a decline to 74 MMcf/d by 2028, which is embedded in this forecast.

FORECAST METHODOLOGY 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.

Forecasts of EG gas demand by power plants connected to PG&E's gas system are developed by modeling the Western Electricity Coordinating Council (WECC) electricity market using PLEXOS software. PLEXOS is a production cost modeling tool that estimates the generation by, and 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 while accounting for high-level transmission limitations.

Temperature Assumptions

Space heating accounts for a high percentage of gas use. Therefore, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. PG&E's Average Demand forecast assumes that temperatures in the forecast period will be equivalent to the average of observed temperatures during the past 21 years, with the addition of a temperature adjustment for climate change. Adding the climate change adjustment has little impact on 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 2040 the total December/January heating degree days (HDD) are projected to be 9 percent lower than the 21-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 High Demand (Cold Weather, Dry Hydro) 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. 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 every month.

Hydroelectric Conditions Assumptions

Annual water runoff for hydroelectric plants has varied by 50 percent above and below the long-term annual average.[21] PG&E uses a vintage approach to WECC hydroelectric generation by assuming average generation for the most recent fifteen historical years, 2009-2023, in the Average Demand forecast. PG&E uses the High Demand (Cold, Dry Hydro) forecast to illustrate the impacts from reduced in-state hydroelectric availability on EG demand. PG&E

[21] Additional details in "Analysis of Forecast Uncertainty" Section of this chapter.

uses the hydroelectric generation conditions for the calendar years 2015 and 2021 to represent the "1-in-10" dry hydro case.

Gas Price and Rate Assumptions

Inputs for gas prices and transportation rate assumptions are important for forecasting gas demand. This is especially true for particularly price-sensitive market sectors, such as the industrial or EG sectors. PG&E used the gas commodity price forecast described in detail in the Executive Summary of this report. It combines transportation rates with the gas commodity price forecast. PG&E's forecast presented in the report 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 Demand Assumptions

As described above, PG&E's Average Year forecast is developed from econometric regression models for non-EG sectors. This forecast is modified by forecasts of policy and technology adoption. The major modifiers are BE and energy efficiency (EE). Since the CEC staff recommended against the use of the managed gas scenarios presented in the 2023 IEPR for gas system planning,[22] the demand forecast for Northern California utilizes PG&E's 2024 Annual Load Forecast (ALF) BE forecast. This BE forecast is between the widely varying 2023 IEPR Additional Achievable Fuel Substitution (AAFS) Scenarios 2 and 3 and uses recent data, incorporating input from PG&E's subject matter experts to reflect the high level of uncertainty inherent in existing BE. BE quantities in this forecast have accompanying gas reduction quantities. These gas reductions are included in the forecasts as a modifier to the base models.

PG&E also includes the impact of EE in its gas forecasts. PG&E's model requires the inputs of two categories of energy efficiency, "Additional Achievable Energy Efficiency" (AAEE) savings and "Committed" savings. AAEE represents energy savings from programs that had not yet been funded and new codes and standards (C&S). Committed represents savings

[22] CEC Adopted 2023 Integrated Energy Policy Report with Errata, February 2024, p. 150. https://efiling.energy.ca.gov/GetDocument.aspx?tn=254463

from measures resulting from C&S already in process but implemented during the forecast period. The AAEE forecast used by PG&E is the EE forecast from its 2024 ALF which is based on 2022 IEPR AAEE scenarios. PG&E estimates the EE already embedded in historical patterns reflected in the base forecast and, using the AAEE forecast, calculates the additional energy efficiency expected to materialize over the forecast years. These incremental energy efficiency quantities are then applied as modifiers on top of the base forecast.

Finally, there is a smaller adjustment to the forecast 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. The demand forecast of these customers is reflected in the Industrial sector forecast.

Electric Load Assumptions

PG&E's EG forecasts rely on the "Planning" case electricity demand forecast from the CEC's 2023 Integrated Energy Policy Report (IEPR). The 2023 IEPR Planning case captures an increasing electric load as electric vehicles are projected to become more commonplace. For Northern California, the electric demand forecast also includes BE from PG&E's 2024 ALF consistent with the "Gas Demand Assumptions" section above. For Southern California, PG&E utilized the BE assumption developed and used by SoCalGas. This assumption utilizes only the "Programmatic[23]" component of the 2023 IEPR's AAFS 3 forecast. The AAFS 3 "Programmatic" assumption is substantially lower in magnitude than PG&E's 2024 ALF. PG&E elected to use this assumption for Southern California to develop a consistent set of statewide forecasts.

[23] Adopted 2023 Integrated Energy Policy Report with Errata, February 2024, p. 117. https://efiling.energy.ca.gov/GetDocument.aspx?tn=254463

Electric Generation and Electric Transmission Assumptions

With increasing electric load and state-wide GHG emission reduction targets, California's portfolio of generation resources is expected to change significantly over the forecast horizon to 2040. Generation resource addition and retirement assumptions are from the CPUC's 2023 PSP[24], with reductions to near-term build rates to match historical rates (and capture delays due to issues such as supply chain, COVID-19, etc.). The 2023 PSP proposes a resource mix that includes new renewable and energy storage resources that meet a GHG target of 30 million metric tons (MMT) by 2030 and 25 MMT by 2035.

Gas-fired plants that employ once-through cooling (OTC) are assumed to retire by the compliance dates set by the California State Water Resources Control Board (SWRCB) in conjunction with the CPUC direction.[25] The latest OTC policy allows for the operation of six units in Southern California to be extended from 2023 through 2026 provided they enter the Electricity Supply Strategic Reliability Reserve Program. Since this reserve is intended to be dispatched to meet critical reliability conditions not reflected in this forecast, these units are assumed not to operate after December 31, 2023 in PLEXOS. Additionally, PG&E assumes that all cogeneration plants in the state retire by 2040, consistent with 2023 PSP assumptions. To capture recent trends in import availability into CAISO, the PG&E forecast assumes CAISO imports are capped at 2023 actuals.

Diablo Canyon Power Plant Retirement Dates

For the 2024 CGR, PG&E assumed that Diablo Canyon Power Plant (DCPP) Reactor 1 would retire on November 1, 2029, and DCPP Reactor 2 would retire on November 1, 2030, as approved by the CPUC.[26] This is in contrast with the 2022 CGR which assumed DCPP Reactor

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[24] 2022-2023 Integrated Resource Planning Inputs & Assumptions, October 2023. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf

[25] California State Water Resources Control Board policy effective August 15, 2023 https://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc-policy-2023/otc-policy-2023.pdf

[26] OP 1. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K496/521496261.pdf

1 retires on November 2, 2024, and DCPP Reactor 2 retires on August 26, 2025. This assumption originated from Senate Bill (SB) 846[27] which set a process into effect for extending Diablo Canyon operations for at least five additional years.

It is worth noting that while DCPP is assumed to remain online for a longer period previously forecasted, the electric portfolio developed in the 2023 PSP identifies replacement resources as if DCPP retired according to its originally planned deadlines per SB 846. This was intended to ensure that the extension of DCPP did not further delay California's decarbonization trajectory beyond known resource delays.

HIGH DEMAND SCENARIO: COLD/DRY HYDRO

The Average Demand forecast presented above is a reasonable projection for an uncertain future. However, a point forecast presented in the Average case 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 case for cold temperature conditions and dry hydroelectric conditions.

The High Demand Scenario forecast assumes that winter temperatures over the time horizon will have a 1-in-10 likelihood of occurrence. The cold weather assumption increases gas and 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 2015 and 2021.

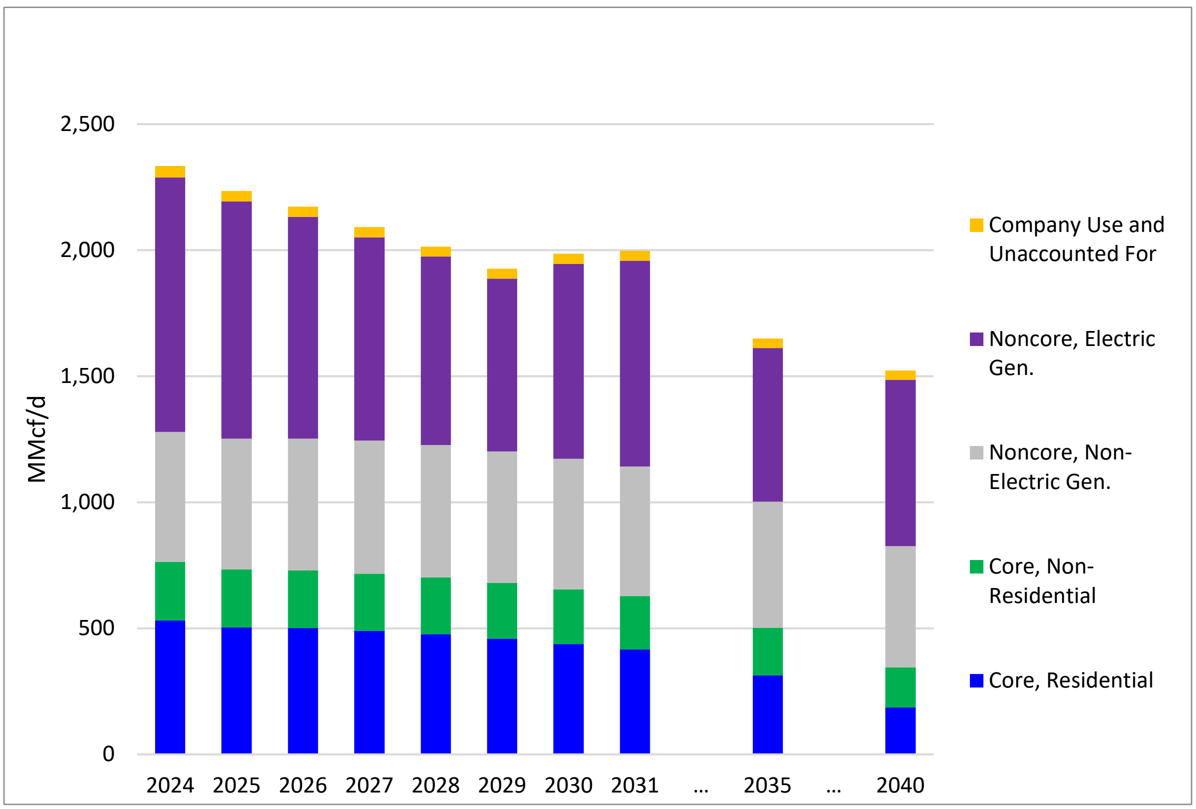
Total gas demand for the High Demand Scenario forecast averages approximately 11 percent higher than the Average Demand forecast. The cold weather impact drives gas throughput higher due to the increased need for space heating. Winter monthly Core throughput is projected to increase on average by 10 percent, ranging from 7 to 15 percent. The non-core

[27] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB846

industrial segment demonstrates little correlation to temperature leading to an insignificant demand increase relative to the Average case.

This forecast projects that EG gas demand increases by about 20 percent on average over the Average Demand outlook. In this forecast, the generation from Northern California hydroelectric resources is about half of the 15-year average assumed in the Average Demand outlook, which increases EG gas demand. Hydroelectric conditions can vary widely throughout the WECC and illustrate another degree of uncertainty in EG gas demand forecasting.

FIGURE 5: NORTHERN CALIFORNIA ON-SYSTEM GAS DEMAND - HIGH DEMAND YEAR



ANALYSIS OF FORECAST UNCERTAINTY

Gas demand forecasts are driven by the assumptions utilized. There is inherent uncertainty in these assumptions that can result in actual gas demand deviating from the forecast. PG&E has developed this section to help illustrate how changes in key assumptions could potentially impact gas demand. This section starts with a discussion on BE, one of the largest drivers, which impacts both the Core and EG sectors. It then concludes with a discussion of some other drivers of EG forecast uncertainty.

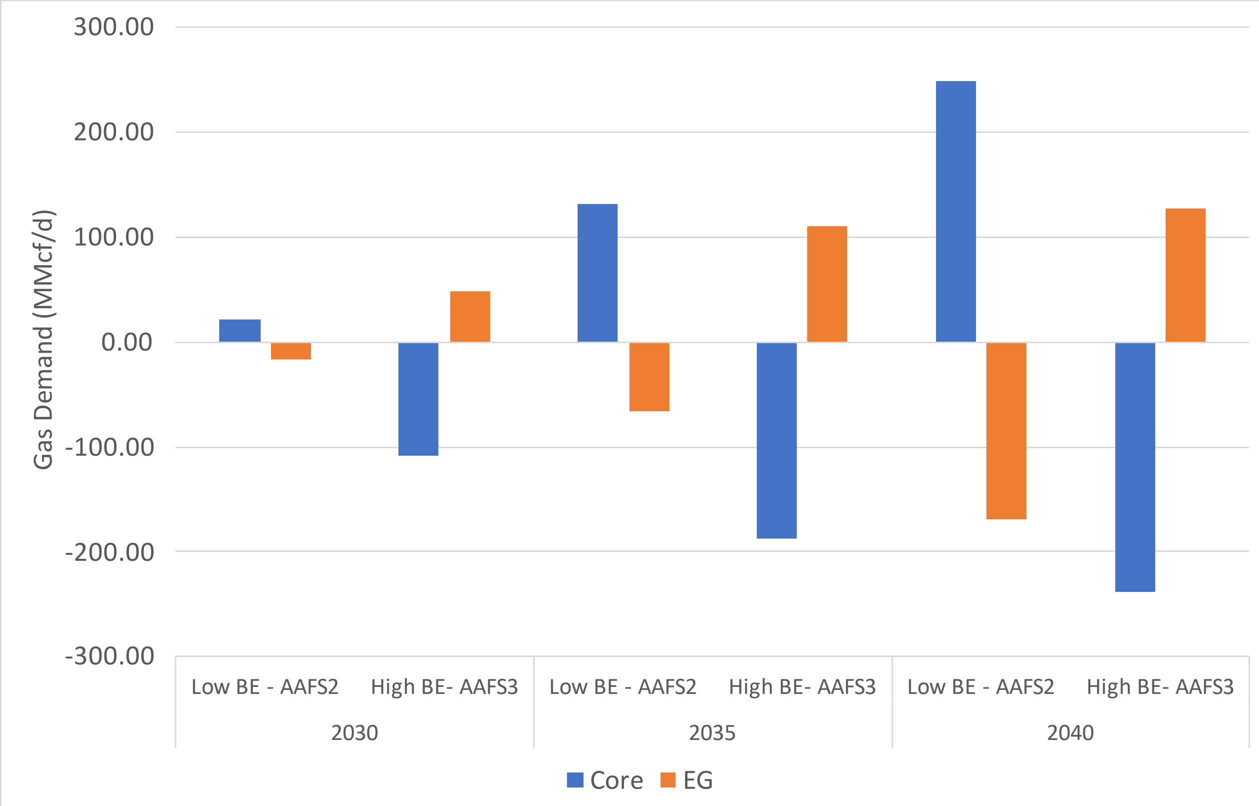
Building Electrification Forecast Uncertainty on Core and Electric Generation Sectors

BE is one of the most impactful drivers of future forecasted gas demand in California. As noted in the sections above, PG&E utilized the BE assumption from its 2024 ALF for Northern California. To quantify the uncertainty in gas demand associated with BE, in the figure below PG&E shows how Core and EG demand change[28] relative to the Average Demand Year forecast for selected years. To quantify the changes, the 2023 CEC IEPR AAFS 2 and AAFS3 cases were used.

The AAFS2 case represents a "low" case where there are virtually no future appliance bans or building codes. The AAFS 3 case represents a "high" case where appliance bans and building codes are 100% realized. Since BE impacts are expected to ramp up over time, the difference between these scenarios in the near-term is much lower than it is in the long-term. In the longer term, BE has the potential to be the single largest driver of Core throughput reduction.

[28] To quantify the EG gas demand change, all other modelling assumptions (including renewable resources) were kept the same as the Average Demand scenario.

FIGURE 6 – CHANGE IN NORTHERN CALIFORNIA CORE AND NON-CORE EG DEMAND UNDER 2023 IEPR BE SCENARIOS



Additional Uncertainty Factors Affecting Electric Generation

To assess the impact of changing assumptions contributing to forecasted EG gas demand, an assessment of the sensitivity of several key drivers was assessed (in isolation). The drivers focused on in this uncertainty analysis include:

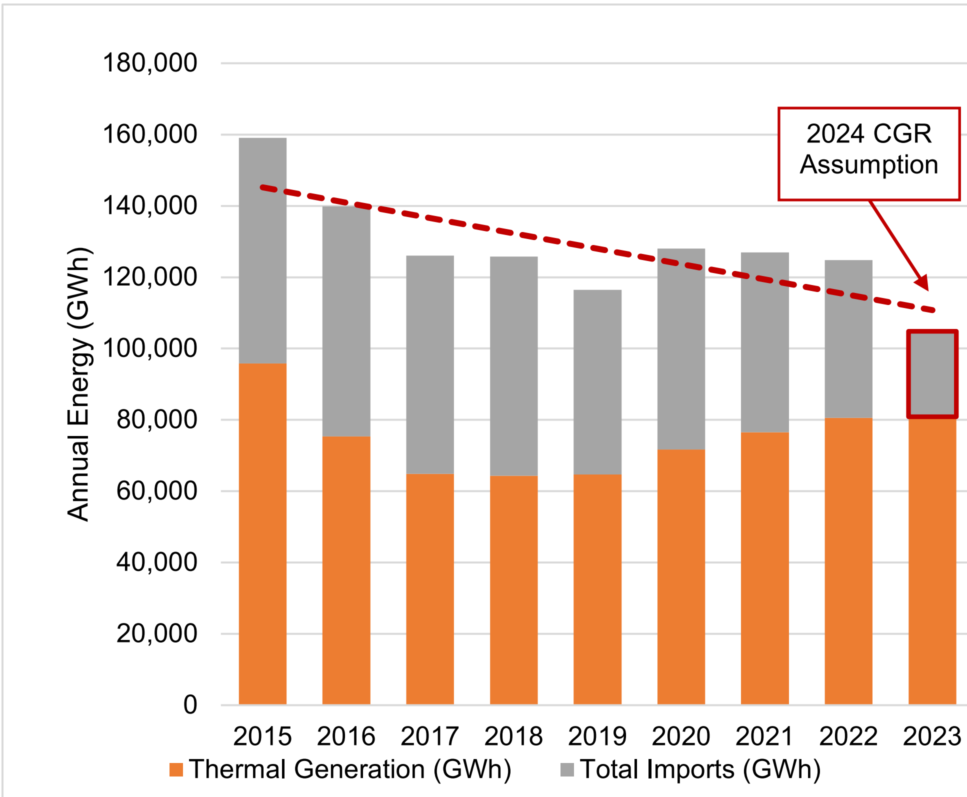
CAISO NG Prices

Gas prices across the state have shown significant volatility in the past, due to extreme conditions (weather, supply chain, demand from another sector, gas production, gas storage inventories, etc.) within and outside of CAISO. To assess the dynamics of this price volatility, PG&E tested EG demand when relative prices narrowly change. When prices changed by, say 5% to 10%, EG demand moved in the opposite direction. EG demand changed by 10% to 30% and depends on many factors. Some factors include hydroelectric conditions and electric load. The EG demand impact of this price differential is dampened by the end of the forecast period (2040) as more renewables and storage make up the CAISO portfolio.

CAISO Imports Availability

As previously mentioned, the Average Demand EG forecast assumes imports into CAISO are limited to 2023 actuals. Imports into CAISO over the past few years have declined (Figure 7), and thus far the trend has continued in 2024.

FIGURE 7: CAISO HISTORICAL THERMAL GENERATION AND IMPORTED ENERGY



Relative change in EG demand was tested under two additional import assumptions, including a “Low Imports” case in which the limit is 25% less than 2023 levels, and a “High Imports’ case which assumes a 5-year rolling average of historical import levels (2019-2023). Imports in 2023 were 47% lower than this 5-year average. Decreased limits on import availability into CAISO lead to an increase in EG demand, and vice versa for increased limits. However, just like with the NG price scenario, the impact is dampened later in the forecast period as the system portfolio is less reliant on imports. In the near term, the EG demand increases by 7% on average in the “Low Imports” scenario and decreases by 6% under the “High Imports” scenario.

Location of Future Renewables and North-South Transmission Constraints

The uncertainty in the amount and the location of new renewable and storage resources also plays a big role in future EG gas demand. The 2023 PSP indicates renewable generation and storage capacity additions are mostly built in Southern California, except offshore wind. Given the limited electric transmission capability to transfer generation from southern to northern California, the location of the actual California renewable buildout or changes to CAISO's transmission system will impact EG gas throughput.

In PG&E's PLEXOS model, power flows between PG&E and SCE are represented as WECC Path 26.[29] The current rating[30] on this path is 4000 MW (and 3000 MW S-N). The path rating remains at current levels in the Average and High Demand EG forecasts. Historically, exports into SCE have been higher than exports into PG&E. To assess the impact of Path 26 on EG demand, PG&E tested a "No Path26 Constraint" where the restriction on power flows along this path is removed. As the CAISO renewable portfolio grows, and with the majority of new solar located in Southern California, this leads to a reverse dynamic – where SCE is a net exporter into PG&E. Under this scenario, EG demand decreases 82% by 2040 relative to EG demand in 2040 in the Average case, as SCE exports any excess generation to the North. EG demand in this scenario can serve as a bookend reference for long-term resource planning and addressing South-to-North congestion.

Hydro Availability

Variability in hydroelectric generation within and outside of CAISO can lead to significant fluctuations in EG gas demand. In 2017 the average gas demand was 698 MMcf/d and in 2021 it was 964 MMcf/d, a difference of almost 40%. One of the major drivers of this difference is hydroelectric generation. Relative to the 15-year average (2009-2023), the volume of hydroelectric generation in 2017 was 156% and the volume in 2021 was 58%. Although 2023 was an above-average year for hydroelectric generation (123% of the 15-year average), EG

[29] Path 26 provides a transmission connection for exchange of electricity between Northern and Southern California.

[30] WECC Path Rating Catalog: [2022 Path Rating Catalog Public.pdf (wecc.org)]

demand increased relative to 2022 (a lower-than-average hydro generation year). This is due to the impact of resource availability outside of CAISO's Balancing Area (BA) available for imports. CAISO relies on imports from the Pacific Northwest (PNW) with a significant portion of import availability driven by PNW hydro conditions. In contrast to hydro conditions within California, PNW hydro conditions in 2023 were 80% of the 15-year average, resulting in much lower availability for exports to other BAs, thus driving up EG demand within CAISO. Compared to 2022, CAISO net imports were on average 47% lower in 2023.

In the High Demand case, hydro availability is represented by using an average of generation in 2015 and 2021, both historically dry years (Figure 8(a)). This assumption was applied to both CAISO hydroelectric generators, and imports from the northwest (NW), a system that greatly relies on hydropower to meet system demand. Applying "dry year" conditions to hydro availability increases EG demand across the forecast period. This is due to both a reduction in within-CAISO hydroelectric generation and lower import availability in the NW. As stated above, imports into CAISO during 2023 declined significantly compared to previous years, in part due to dry hydro conditions in the NW (Figure 8(b)). This interregional dynamic is a critical driver of EG demand within Northern California and CAISO at large. As part of the uncertainty analysis, the Average Demand case was run with wet hydro conditions to evaluate the impact of greater hydro availability on EG demand. In this case, the assumption for hydro conditions were determined using historical data from 2011 and 2017. The result of this assumption was a 12% decrease in EG demand relative to the Average Demand/Average Hydro case.

FIGURE 8A: HISTORICAL ANNUAL HYDRO GENERATION IN CALIFORNIA

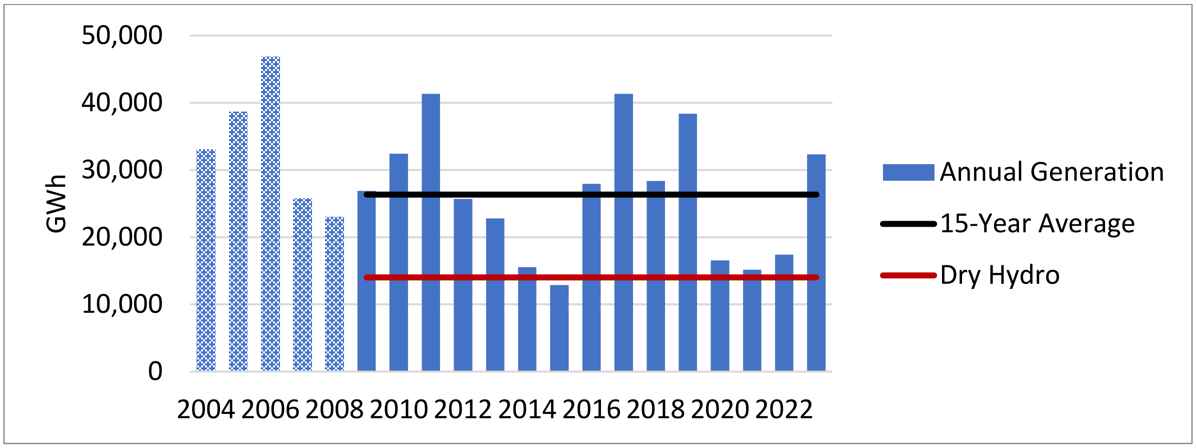
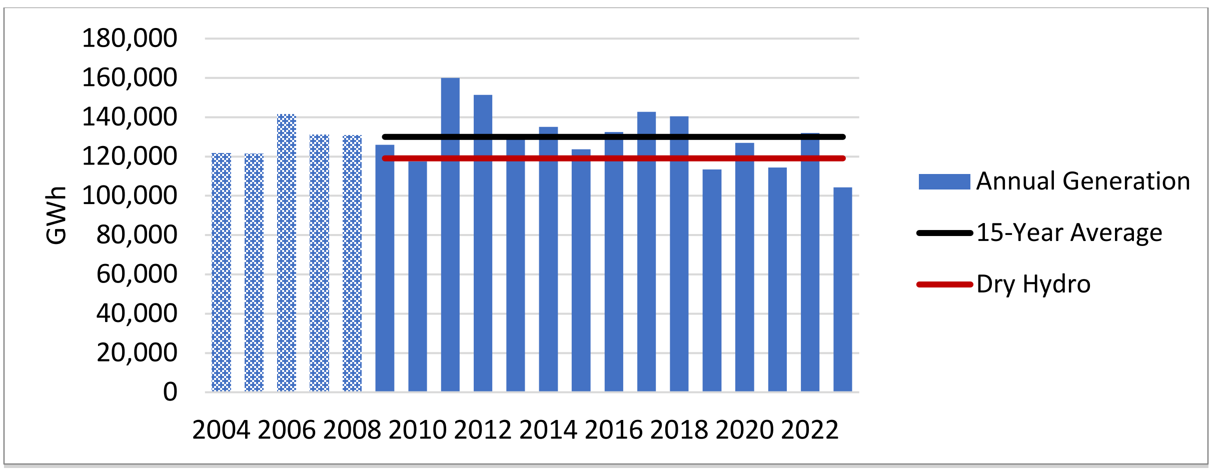


FIGURE 8B: HISTORICAL ANNUAL HYDRO GENERATION IN THE NORTHWEST



PEAK DAY GAS DEMAND FORECASTS

This chapter contains forecasts for daily gas demand on peak winter days under various conditions and an estimate of high gas demand on a summer day. The three winter forecasts (1-in-90 Abnormal Peak Day (APD), 1-in-2-year Cold Winter Day, and 1-in-10-year Peak Winter Day) are developed consistent with the orders in the Long-Term Gas System Planning OIR D.22-07-002. While not required by the decision, PG&E also presents an estimate of high gas demand on a summer day for illustrative purposes. These forecasts incorporate the appropriate weather year and hydroelectric generation conditions as described in the sections below.

The peak forecasts also incorporate the impacts of climate change where appropriate. For example, climate change has a noticeable impact on winter Core and EG demand, as well as summer EG, but a negligible impact on summer Core since there is already no space heating demand at that time. For climate change impacts on Core, PG&E utilized the models from California's Fifth Climate Change Assessment. For EG, PG&E utilized the CEC's 2023 IEPR Planning forecast which incorporates climate change impacts from the "Business as Usual" Shared Socio-Economic Pathway (SSP3-7.0).[31] This is the same pathway used in the Core forecast.

ABNORMAL PEAK DAY DEMAND FORECAST

The APD forecast is a projection of demand under extreme weather conditions. PG&E defines an APD as a 1-in-90-year cold temperate event. The 1-in-90 temperature corresponds to a 28.2° F system-weighted mean temperature across the PG&E system, and under these conditions, PG&E core demand is forecasted to be approximately 3.0 Bcf/d. The PG&E load forecast shown here excludes all noncore and 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.

[31] CEC Adopted 2023 Integrated Energy Policy Report with Errata, February 2024, p. 113. https://efiling.energy.ca.gov/GetDocument.aspx?tn=254463

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.

ABNORMAL PEAK DAY 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'(ISP) 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 an 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 supply basins, which in turn can affect the total supply to the PG&E system and others.

If gas supplies are insufficient to meet core demand, PG&E can curtail noncore customers, including EG customers, to meet core demand.[32] PG&E's tariffs contain Emergency Flow Order noncompliance charges that are designed to cause the noncore market customers to either reduce or cease their use of gas, if required. Since little, if any, alternate fuel burn capability exists

[32] See PG&E's Gas Curtailment Procedure Proposal, Prepared Testimony A.24-05-004.

today, supply curtailment would necessitate those noncore customers to curtail operations. Under supply shortfall conditions—such as an APD—a sizable portion of EG customers could be curtailed, potentially impacting electric system reliability.[33]

The Total Resources to Meet Demands row below is made up of PG&E firm capacities, PG&E storage withdrawals, and ISP withdrawals. The PG&E and ISP withdrawal numbers are subject to change based on the California Geologic Energy Management Division (CalGEM's), previously known as the Division of Oil Gas and Geothermal Resources (DOGGR), implementation of underground gas storage regulations. Firm Flowing Supply changes below reflect the planned retirement of Tionesta Compressor Station as seen in Table 11-5 of PG&E's 2023 General Rate Case.

[33] Ibid.

TABLE 22 – FORECAST OF CORE GAS DEMAND AND SUPPLY ON AN APD, MMcf/d

Line No.		2024-2025	2025-2026	2026-2027
1	Unadjusted APD Core Demand (1)	3,029	3,039	3,048
2	Climate Change Modifier	0	-4	-7
3	APD Core Demand with Climate Change Modifier	3,029	3,035	3,041
4	Independent Storage Provider Withdrawal (2)	2,162	2,162	2,162
5	Firm Flowing Supply (3)	3,030	2,885	2,885
6	Projected Resources to Meet Demands (4)	3,966	4,020	4,074

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 28.2 degrees F system composite temperature, corresponding to a 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 PG&E analysis.

(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. 6) are less than the sum of Independent Storage Provider Withdrawal (Line No. 4) and Firm Flowing Supply (Line No. 5) because PG&E's system cannot simultaneously accommodate all flowing supplies and all storage withdrawals. These values come from Table 3-B of the proposed PG&E Supply Standard application.

WINTER PEAK DAY DEMAND FORECASTS

The tables below provide winter peak day demand projections on PG&E's system for both a 1-in-10-Year Peak Winter Day and a 1-in-2-Year Cold Winter Day.

TABLE 23 – 1-IN-10-YEAR PEAK WINTER DAY DEMAND, MMcf/d

Year	Core Unadjusted for BE	BE Modifier	Climate Change Modifier	Core With BE	Noncore Non-EG	EG, Including SMUD	Total Demand
2024-2025	2,493	-2	0	2,491	509	1,186	4,186
2025-2026	2,501	-8	-2	2,491	512	1,021	4,024
2026-2027	2,509	-16	-5	2,488	516	915	3,919
2027-2028	2,517	-22	-8	2,487	518	974	3,979
2028-2029	2,526	-32	-11	2,483	513	972	3,968
2029-2030	2,534	-49	-14	2,471	508	989	3,968

The Core demand in the 1-in-10-Year Peak Winter 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 BE modifier represents PG&E's 2024 ALF for December. The projection in the AAFS 2 represents the BE, moving from natural gas use to electric use. The climate change modifier utilizes climate models from California's Fifth Climate Change Assessment under the SSP3-7.0 scenario. This modifier is calculated as a change in peak temperature relative to the forecasted 2024-2025 winter values, thus beginning at 0 and increases according to temperature changes in the climate models.

The Noncore, Non-EG forecast is the average daily December demand under 1-in-10 Cold and Dry conditions, modified to account for the historical relationship between Noncore, Non-EG gas demand on a peak winter day and an average winter day. Since the Noncore, Non-EG sector is largely Industrial which is not statistically sensitive to climate impacts, this forecast does not vary by weather scenario and is not affected by climate change.

Last, the EG, including SMUD projection, is in the 90 percentile for the months of December through February under 1-in-10 cold and 1-in-10 dry hydro demand conditions. This forecasted value already embeds the impacts of BE and climate change as described in the sections above.

TABLE 24 – 1-IN-2-YEAR COLD WINTER DAY DEMAND, MMcf/d

Year	Core Unadjusted for BE	BE Modifier	Climate Change Modifier	Core With BE	Noncore Non-EG	EG, Including SMUD	Total Demand
2024-2025	2,200	-2	0	2,198	506	1,001	3,705
2025-2026	2,207	-8	-2	2,197	509	869	3,575
2026-2027	2,214	-16	-5	2,193	512	819	3,524
2027-2028	2,222	-22	-8	2,192	514	831	3,537
2028-2029	2,229	-32	-10	2,187	509	798	3,494
2029-2030	2,237	-49	-13	2,175	505	902	3,582

PG&E's methodology used in the development of the 1-in-2-Year Cold Winter Day table is largely similar to the 1-in-10-Year Peak Winter Day methodology. The main differences are in the temperature and hydroelectric generation conditions. As stated in the title, this table assumes 1-in-2-year, or average, temperature conditions which will result in a warmer high demand day than the 1-in-10-Year. For hydroelectric generation, this table assumes 1-in-2-year, or average, hydroelectric generation conditions which will result in less CAISO electric demand needing to be met by thermal resource generation. BE and climate change are handled similarly to the 1-in-10-Year Winter Peak Day as well.

SUMMER HIGH DAY DEMAND ESTIMATE

This section contains an estimate of what demand on PG&E's gas system could be during a high demand day in the summer. This is not the same as a summer peak demand forecast since the CGR peak forecasts are primarily designed to account for winter conditions, when PG&E's gas system peak actually usually occurs. Although PG&E did adjust the Noncore, Non-EG methodology and EG assumptions that increase summer high day demand estimates relative to the 2022 CGR, future summer peak events could be higher than what is estimated in this section.

A key factor affecting summer peak demand is electric demand and temperature. The 2024 PG&E forecast presented below assumes 1-in-10 cold winter and 1-in-10 dry hydroelectric generation conditions. Since heating is not a factor in summer demand, this essentially assumes a 1-in-2, or average year, electric peak. If the upcoming summers are hotter than average, demand could exceed what is estimated here.

TABLE 25 – SUMMER HIGH DEMAND DAY ESTIMATE, MMcf/d

Year	Core Unadjusted for BE	BE Modifier	Core With BE	Noncore Non-EG	EG, Including SMUD	Total Demand
2024	354	-1	353	634	1,386	2,373
2025	334	-5	329	633	1,195	2,157
2026	336	-9	327	640	1,159	2,126
2027	331	-13	318	646	1,176	2,140
2028	324	-19	305	642	1,169	2,116
2029	316	-28	288	638	1,163	2,089

The Core demands in the Summer High Demand Day Estimate table represent the average August daily summer demand under 1-in-10 cold conditions. When analyzing historical Core demand during a summer high demand day, PG&E determined that using the average day is appropriate for the Core sector. The BE modifier represents PG&E's 2024 ALF for August. Since Core demand during a summer high demand day is not expected to include any space heating, no adjustment for climate change was made.

The Noncore, Non-EG demands utilize the average August daily summer demand, modified to account for the historical relationship between Noncore, Non-EG gas demand on a peak winter day and an average winter day. Since the Noncore, Non-EG sector is largely Industrial which is not statistically sensitive to climate impacts, this forecast does not vary by weather scenario and is not affected by climate change.

Last, the EG including SMUD demand forecast is the 90 percentile for July through September under 1-in-10 cold and 1-in-10 dry hydro demand conditions. This forecasted value already embeds the impacts of BE and climate change as described in the sections above. This value is higher than that produced in the 2022 CGR, primarily driven by the CAISO imports assumption which reduces import availability primarily driven by Pacific Northwest hydro.

POLICIES IMPACTING GAS DEMAND

During the forecast horizon covered by this report, many policies may significantly impact the future trajectory of natural gas demand, including:

- **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.
- **California Air Resources Board (CARB) Scoping Plan and Zero Emissions Appliance Standards** sets economy-wide targets around emissions, including for buildings and transportation. Scoping plan targets inform policy, such as cap-and-trade and the low carbon fuel standard (LCFS) and provide guidance on the most cost-effective strategies to reach net zero emissions.
- **CARB Zero Emissions Appliance Standards,** currently in rulemaking, proposes a statewide ban on the sale of natural gas furnaces and water heaters beginning in the 2027 to 2030 timeframe.
- **Bay Area Air Quality Management District (BAAQMD) Rules 9-4 and 9-6 Amendments** propose an air district-wide ban on the sale of natural gas furnaces and water heaters beginning in the 2027 to 2030 timeframe. PG&E serves on the Implementation Working Group to assist BAAQMD with understanding the effects of the amendments.

- **The CPUC's Long-Term Gas System Planning OIR and Building Decarbonization OIR** look at issues pertaining to long-term gas planning, BE and decarbonization.

GHG Policies

The gas demand forecast used in this analysis includes a Cap-and-Trade GHG allowance price projection.[34] The forecast also incorporates complementary policies that aim to achieve California's GHG emissions reduction goals. In addition, any trends embedded in historical demand patterns due to GHG goals and/or the compliance entities' participation in the Cap-and-Trade market translate to the forecast.

PG&E has a unique responsibility as a combined gas and electric utility serving 5.5 million electric customer accounts and 4.5 million natural gas customer accounts in Northern and Central California. PG&E embraces its foundational role in helping transition the State to a decarbonized and more climate-resilient economy. In June 2022, PG&E issued a Climate Strategy Report establishing the company's commitment to achieving a net zero energy system in 2040—five years ahead of California's carbon neutrality goal established in Executive Order (EO) B-55-18—and to become climate and nature positive by 2050.[35] Given that the utilization of fossil natural gas represents the bulk of PG&E's Scope 3[36] GHG emissions, PG&E believes that the evolution of the gas system plays an important role in meeting our ambitious climate goals. This will involve the utilization of renewable gases (RNG or hydrogen), further enhancements to our methane abatement program, and demand-side reductions through strategies such as BE.

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[34] 2023 CEC Integrated Energy Policy Report mid-case forecast.

[35] PG&E Climate Strategy Report. https://www.pge.com/en/about/corporate-responsibility-and-sustainability/taking-responsibility.html

[36] The U.S. EPA defines Scope 3 emissions as, "Scope 3 emissions are the result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly affects in its value chain. An organization's value chain consists of both its upstream and downstream activities." https://www.epa.gov/climateleadership/scope-3-inventory-guidance

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 requirements:

- Accelerates the RPS to 50 percent by 2026 and 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 completed its development of California's plan for achieving carbon neutrality in its Climate Change Scoping Plan Update in 2022.[37]

RENEWABLE ELECTRIC GENERATION

PG&E expects renewable electric generation to grow due to procurement orders by the CPUC in the IRP Proceeding.[38] 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 throughout the forecast horizon. Offsetting the impact on the EG demand forecast will be both short-term and long-term electric storage.

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[37] CARB Scoping Plan: https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan.
[38] https://www.cpuc.ca.gov/irp/

ENERGY EFFICIENCY PROGRAMS

PG&E engages in many 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.

PG&E's forecast of cumulative natural gas savings is dominated by the residential sector. Most forecasted savings are due to codes and standards, such as federal and state appliance standards and state building codes, with State building codes (Title 24) making up most of these savings.

IMPACT OF SB 350 ON ENERGY EFFICIENCY

SB 350, which was enacted in the fall 2015, requires the CEC, in coordination with the CPUC and the local public utilities, to set EE targets that double the CEC's Additional Achievable Energy Efficiency (AAEE) mid-case forecast, subject to what is cost-effective and feasible.[39] The CEC issued its final report doubling targets in October 2017,[40] and the CPUC incorporated higher levels of EE savings in their EE goals for 2018 and beyond,[41] which was partially due to the adoption of an interim GHG adder in the Integrated Distributed Energy

[39] 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."

[40] 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.

[41] D.17-09-025: Decision Adopting Energy Efficiency Goals for 2018-2030, CPUC, September 28, 2017.

Resources proceeding.[42] 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, Publicly Owned Utilities (POU) programs, and codes and standards.[43]

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. Over 50 local jurisdictions in PG&E's service territory have adopted reach codes.[44] Electrification policies continue to evolve at both the local and state levels. CARB and BAAQMD have introduced policies regarding gas space and water heating appliances. BAAQMD's amendment[45] to Rules 9-4 and 9-6 put in place a point-of-sale ban on gas water heaters beginning in 2027 and gas furnaces in 2029. Similarly, CARB's 2022 State Implementation Plan (SIP) calls for 1) all furnaces and water heaters sold within California to comply with a 0 ng/joule nitrogen oxides (NOx) limit beginning in 2030, and 2) new construction to be zero-emission starting in 2026 for residential buildings and 2029 for commercial buildings. 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.

The CPUC has also removed gas line extension allowances, discounts, and refunds as well as the electric line allowance, discounts, and refunds for dual-fuel buildings as part of the Building Decarbonization OIR (R.19-01-011)[46]. PG&E did not oppose the removal of

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[42] D.17-08-022: Decision Adopting Interim GHG Adder, CPUC, August 24, 2017.
[43] See Figure 2 from the CEC report cited above.
[44] California Energy Codes & Standards, accessed May 21, 2024 https://localenergycodes.com/content/adopted-ordinances
[45] Building Appliances (baaqmd.gov)
[46] D.23-12-037: Decision Eliminating Electric Line Extension Subsidies, CPUC, December 14, 2023.

residential gas line extension allowances but requested that allowances remain for non-residential customers that provide a financial or environmental benefit to ratepayers.

Although gas demand in the Average Year forecast declines, the forecast is not constrained to meet PG&E or California's carbon neutrality goals. The effort to achieve net-zero emissions could come by additional throughput decrease (such as through BE), lower carbon fuel options, or carbon capture technologies. The natural gas supply sources could be a cleaner version in the form of RNG or hydrogen. The next chapter on natural gas supply will elaborate on these potential gas supplies.

As regulations continue to be revised and updated, the cost of providing a safe and reliable natural gas system could continue to rise. State and local GHG goals are expected to drive down natural gas throughput (as household electrification increases). Lower natural gas throughput will likely result in a higher cost-per-therm for customers if the evolution is not well-managed. Fortunately, PG&E has been working on programs and processes to reduce costs on the gas system to help mitigate the cost-per-therm for our customers who remain on the gas system.

California's natural gas system is expected to go through unprecedented changes over the next few decades. As it evolves, regulatory bodies and the utilities must work together to support Californians' access to clean, reliable, and affordable energy.

GAS DEMAND TRENDS AND STRATEGY

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 could put upward pressure on gas transportation rates if this transition is not well managed.

In addition, the transition from fossil fuels (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 increases for the remaining gas customers.

To minimize the rate impacts on gas customers, PG&E is following a comprehensive approach while keeping safety as its top priority: (1) reduce carbon footprint, (2) reduce cost, (3) identify alternative revenue sources and (4) leverage innovative financial mechanisms.

- To reduce the carbon footprint of the gas system PG&E is actively planning to green the gas supply, leveraging electrification, converting facilities from using higher GHG emitting fuel sources, and conducting methane abatement.

- To reduce costs, PG&E is pursuing opportunities to systematically retire infrastructure and reduce capital and operating expenses through PG&E's Gas Investments for the Future (GIF) program (formally Integrated Investment Planning). Since 2018 the GIF program has been aggressively pursuing cost effective electrification through non pipeline alternatives to planned gas investment work, reaching agreements with approximately 45% of those customers.

- 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 and exploring new opportunities to support RNG adoption across new industries. This involves increasing load on the natural gas system in areas that would replace less favorable hydrocarbon (e.g., in the industrial, large commercial, marine, rail and transportation sectors) and seeking opportunities to utilize the gas system to store hydrogen 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 will 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 CARB approval of the Advanced Clean Truck (ACT) Regulation. This regulation requires increasing percentages of all new medium- and heavy-duty truck sales in California to be zero-emission vehicles (ZEV).[47] 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 manufacturers 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.

In addition, companies such as Amazon have internal goals for decarbonizing fleets. Chevron has announced that they are building compressed natural gas (CNG) fueling stations, including about 15 in Northern California, and truck engine producer Cummins has announced a new 15-liter NGV truck engine (Next Generation X15N). When powered by RNG, the X15N could have up to a 97% reduction in CO2 and 80% reduction in GHG emissions. While adoption of such NGV technology is determined by market response, and the carbon status of this fuel

[47] ZEVs are defined as either battery electric or hydrogen fuel cell vehicles.

choice may change over time based on actions taken at CARB, this is a potential path to higher NGV adoption in the near to intermediate term than is reflected in the forecast numbers.

Rail

Another high horsepower sector for increasing clean fuel throughput via our pipeline system is rail transportation. Based on a study by CARB from 2016, annual statewide locomotive diesel fuel consumption totals about 260 million gallons. Union Pacific Railroad (UP) and BNSF Railway Company combined interstate and intrastate locomotives account for 93 percent of this fuel usage, California's passenger locomotives are 6%, and the remaining 1 percent is from military-industrial locomotives[48]CNG and LNG as fuel sources have been considered by the rail industry, but thus far have been mostly limited to pilot studies. It is PG&E's understanding that 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 inadequately 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 the cost and complexity of the fuel transition[49].

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[50]. In 2017, CARB petitioned the U.S. EPA to consider adopting a

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[48] CARB. (2016). *Technology Assessment: Freight Locomotives.* Sacramento: California Air Resource Board.

[49] *Ibid*

[50] 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)

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.[51]

Technological advancements are occurring in the rail industry. In January 2024 OptiFuel Systems announced its near-term, low-risk, affordable Total-Zero™ RNG-Electric Line Haul Locomotive will have ZERO Well-to-Wheel (WTW) NOx and PM criteria emissions and Negative Carbon Intensity (CI) while simultaneously improving fuel cost and operating range by 25%. In 2026, OptiFuel plans to start a 2-year, 1-million-mile test program with ten pre-production 5600 hp RNG line haul locomotives and five 10,000 DGE RNG tenders operating around the US.

Marine

Another potential growth area for gas throughput is the marine transportation sector which is increasingly looking at reducing its sulfur oxides (SOx) and GHG emissions. This is orchestrated by the International Maritime Organization (IMO) which regulates global shipping emissions under Annex VI.[52] The IMO updated Annex VI on January 1, 2020, to target reductions in NOx and SOx. To reduce SOx, the sulfur 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 sulfur limit is only a stop on the way to a global 0.10 percent sulfur limit, which currently exists in several Emissions Control Areas (ECA)[53] around the globe. Moving to 0.10% would necessitate using road-grade diesel fuel as bunker fuel, increasing fuel cost. Refining companies would need to further invest in hydrodesulfurization, which is costly to build and operate.

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[51] https://www2.arb.ca.gov/sites/default/files/2020-07/final_locomotive_petition_and_cover_letter_4_3_17.pdf

[52] http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx

[53] http://www.imo.org/en/OurWork/Environment/SpecialAreasUnderMARPOL/Pages/Default.aspx

NORTHERN CALIFORNIA

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.[54]

LNG is widely recognized as the best path forward to reduce SOx and GHG for marine purposes but has not seen much domestic growth in the previous decade. The updated IMO Annex VI is changing that, spurring investments in bunkering equipment[55] and vessels[56]. LNG also allows for decarbonizing of the shipping industry as the fuel can be made from RNG and, eventually, hydrogen.

California marine fuel markets can be divided into ocean and coastal areas. 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 compliance.[57] 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.[58]

The 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.[59]

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[54] https://www.maersk.com/news/articles/2019/06/26/towards-a-zero-carbon-future
[55] https://sea-lng.org/why-lng/bunkering/; https://www.ship-technology.com/news/west-coasts-lng-bunker-abs/
[56] https://www.cma-cgm.com/news/2749/world-premiere-launching-of-the-world-s-largest-lng-powered-containership-and-future-cma-cgm-group-flagship
[57] https://www.wartsila.com/twentyfour7/energy/taking-dual-fuel-marine-engines-to-the-next-level
[58] 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
[59] https://www.mckinsey.com/industries/oil-and-gas/our-insights/imo-2020-and-the-outlook-for-marine-fuels#

Small on-demand liquefaction terminals can bunker vessels at berth and have already been installed in Europe[60] successfully. They can be connected directly to the natural gas grid producing fuel on-demand.

LNG 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[61] 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.

The U.S. began exporting LNG in 2016 on a larger scale than in the past. 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.[62] 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.

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[60] https://ec.europa.eu/energy/intelligent/projects/sites/iee-projects/files/projects/documents/magalog_lng_supply_chain.pdf

[61] U.S. Energy Information Administration (US EIA) U.S. Liquefied Natural Gas Imports https://www.eia.gov/dnav/ng/hist/n9103us2m.htm

[62] U.S. EIA https://www.eia.gov/naturalgas/U.S.liquefactioncapacity.xlsx

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Two greenfield projects on North America's West Coast are in British Columbia. The larger project is LNG Canada located in Kitimat.[63]

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 liquefy and re-export up to 1.7 billion cubic feet per day (Bcf/d) of U.S. produced natural gas.[64] This facility will have a nameplate capacity of 3.25 million metric tons (mmt) per annum of liquefication capacity. Construction of the project is underway with an online date of 2024.[65]

The ECA LNG export project, which would be the second on North America's West Coast, is positioned to source gas from 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.[66] 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.

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 2023.[67] The U.S. natural gas exports to Mexico have grown in recent

[63] LNG Canada https://www.lngcanada.ca/media-kit/

[64] https://ecalng.com/

[65] 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

[66] OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning.

[67] 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.

years from 0.9 Bcf/d in 2010 to 6.4 Bcf/d in 2023,[68] and pipeline exports are projected to reach 8.4 Bcf/d by 2035.[69]

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.

[68] EIA, U.S. Natural Gas Pipeline Exports to Mexico: https://www.eia.gov/dnav/ng/ng_move_poe2_dcu_NUS-NMX_a.htm.

[69] EIA, Annual Energy Outlook 2023 – Table 60. Natural Gas Imports and Exports Case: AEO2022 Reference case: https://www.eia.gov/outlooks/aeo/data/browser/#/?id=76-AEO2023&cases=ref2023&sourcekey=0

GAS SUPPLY, CAPACITY, AND STORAGE

This section provides information about the current gas supply, natural gas pipeline capacity, and gas storage facilities providing supply and capacity to the PG&E Service Area. This section also includes details of the policies and regulations affecting these topics.

The Gas Supply section includes information about current and anticipated developments regarding RNG, as well as gas supply from sources throughout North America. The Gas Pipeline Capacity section includes information about "upstream" interstate pipelines and intrastate pipelines. The Gas Storage section gives an overview of PG&E's gas storage capacity and facilities. The Policies section looks at a range of current policy and regulatory developments, describing their impacts on PG&E's gas supply, including potential integration challenges for alternative fuel types, such as hydrogen.

Competition for natural 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.

GAS SUPPLY

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 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 CNG fueling stations;
- Actively working with RNG developers to interconnect their projects through the biomethane program;
- Advancing a woody biomass pilot project under CPUC Decision (D.) 22-02-025 with the June 30, 2023, filing of PG&E Application (A.) 23-06-023, which is still under CPUC review;
- Planning for implementation of biomethane (also referred to as 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.

While there is significant potential for renewable gas (RG) to replace some portion of the natural gas supply, the current investments and incentives for RG end-use principally favor the transportation sector.

PG&E has several RNG projects in various phases. Four projects are already connected and flowing renewable gas -into the PG&E system. Four additional projects are in development and should be online by the end of 2024. Once all the eight projects are online PG&E expects to have a total of 2 billion cubic feet (BCF) of RNG flowing into PG&E's pipeline system by year-end for the year 2024, since starting sourcing RNG for the system at the end of 2021. One of the projects is a result of the SB 1383 Dairy Pilot Program, highlighted below, and the other seven are identified in the Biomethane Project Incentive Reservation Queue located on the CPUC website[70].

Existing interconnections continue to increase volumes annually as each project develops upstream sources. 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.

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[70] https://www.cpuc.ca.gov/industries-and-topics/natural-gas/renewable-gas

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The RNG supply from California Gas Production interconnections is not reserved for PG&E to procure as it is treated as any other natural gas being injected into our system and subject to the same market forces. The RNG can be procured directly from the production facility without being injected into the system, by non-core customers on the system, and/or be shipped off-system. Therefore, this supply may not be available for PG&E to meet core biomethane procurement targets mandated by the State of California.

The following table shows a high-level estimate of the RNG delivered to Core Customers on PG&E's system.

TABLE 26: PG&E RENEWABLE NATURAL GAS DELIVERIES, MMcf/d

	2021	**Approx. % of Core (2021)**	**2022**	**Approx. % of Core (2022)**	**2023**	**Approx. % of Core (2023)**
Total Core Gas Deliveries (MMcf/d)	704		715		745	
Renewable Gas Standard (RGS)	0	--	0	--	0	--
NGV usage (MMcf/d)	3.2	0.005%	4.4	0.006%	5.3	0.007%
Physical	0		0		0	
Estimated book and claim	3.2		4.4		5.3	

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 April 2024, J.G. Weststeyn Dairy project is working with the CPUC to determine if the project can remain active and meet the compliance requirements within the SB 1383 Dairy Pilot Program.

FIGURE 9 – PG&E SERVICE AREA: RNG PILOT PROJECT LOCATIONS

Future RNG Supply In The PG&E Service Area

Biomethane projects capture methane emissions from various organic sources that act as a direct replacement for fossil natural gas which helps California reduce GHG emissions. By reducing greenhouse gases, improving waste management, and preserving soil quality, biomethane projects play a key role in the development of a local circular economy where waste is converted into a resource.

PG&E has been developing a program to work with developers in a collaborative and deliberate method to interconnect biomethane gas to PG&E's pipeline system. This program is compliant with CPUC-approved gas rules and implements CPUC's directives to encourage renewable gas usage and production.

Biomethane source development is increasing in volume and diversity. As projects continue to move forward, production rates will continue to increase. PG&E's observation shows that once a project is interconnected, volumes continue to grow on an annual basis due to expansion as well as efficiency. In 2024, PG&E anticipates landfill and food waste feedstock types to be added to the existing biomethane gas source portfolio. In the coming years, additional feedstock types such as wastewater treatment plants, agricultural waste, ethanol waste, and woody biomass are projected to interconnect with PG&E's system. Biomethane production will also involve gasification in addition to anaerobic digestion and may be delivered through gathering line systems or virtual pipeline hubs.

PG&E's focus is to build the gas network of tomorrow that supports overall decarbonization efforts. By utilizing our existing infrastructure, we are in a unique position to support the energy transition in California, taking advantage of every opportunity to promote gas energy, establish new uses and increase the share of renewable gas in gas consumption.

Interconnecting Biomethane Supply

To encourage the effective development of RNG, PG&E has a Biomethane Interconnection page created online.[71] This information is a high-level- overview of our biomethane program and provides information on how to have a Screening Study completed at no cost for potential projects. Suppliers are encouraged to contact PG&E to discuss opportunities to bring on RNG supplies.

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)[72], with Energy Information Administration (EIA) figures showing a new record for proven natural gas reserves in 2022 at 691 trillion cubic feet (Tcf).[73] Natural gas resource development has improved over the past two decades as horizontal drilling and hydraulic fracturing have matured. Furthermore, advancements in drilling know-how and improved efficiencies have improved resource development, typically at lower costs. The U.S. produced almost 103 Bcf/d on average in 2023.[74] 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.[75] The resources that contribute to these production regions include both shale gas resources and

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[71] Available at: https://www.pge.com/en/about/doing-business-with-pge/interconnections/biomethane-interconnection.html

[72] 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.

[73] U.S. Energy Information Administration U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2022

[74] U.S. Energy Information Administration Natural Gas Dry Production (eia.gov)

[75] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

associated gas from oil production.[76] 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 (Haynesville and Appalachia) continues 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 2023, PG&E's customers obtained on average 20 MMcf/d of California sourced gas. PG&E anticipates that California sourced gas may increase from this level. The primary driver for this growth is RNG production.

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-

[76] 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)

Oregon border or 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 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, Tuscarora 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.

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. Tionesta compressor station is scheduled for retirement in 2025, at which point the Redwood Path firm capacity will decrease to 1915 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, looking 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 eliminating or streamlining projects. Electrifying these customers and decommissioning these local pipelines could 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 spending and predict long-term gas needs more accurately.

GAS STORAGE

In Northern California, PG&E operates key natural gas storage facilities at McDonald Island and Los Medanos, while also holding a 25% ownership in Gill Ranch Storage. Combined, these fields contribute to a total working gas inventory of 55 Bcf, with 12 Bcf reserved for firm services such as Core and Pipeline Balancing. Supplementing these operations are several independently-owned storage providers (ISPs) including Wild Goose Storage, Lodi Gas Storage, Central Valley Gas Storage, and the remaining 75% of Gill Ranch Gas Storage. Collectively, ISPs and PG&E-owned gas storage offer approximately 185 BCF of working gas capacity within Northern California. These facilities play a pivotal role in meeting the region's peak seasonal and daily natural gas demands.

Within the past ten years, Northern California's natural gas storage facilities have experienced legislative and 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, CalGEM, previously known as 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.[77] Packers seal off

[77] https://www.conservation.ca.gov/index/Documents/CALGEM-SR-1%20Web%20Copy.pdf

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.[78]

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 its plans to sell 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. On July 18, 2023, PG&E, Pleasant Creek Gas Storage Holdings, LLC, and eCORP Natural Gas Storage Holdings, LLC filed a section 851 joint application with the CPUC for approval of the sale. The sale is currently pending regulatory approval anticipated to close in 2024.

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 PG&E's 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.

In PG&E's 2023 GRC application, filed at the CPUC on June 30, 2021, PG&E proposed updates to the NGSS in response to evolving CalGEM regulations. These updates included an updated Peak Day Supply Standard and a proposal to retain the Los Medanos storage facility

[78] Workpaper Table 7-37. Pacific Gas and Electric Company 2023 General Rate Case Workpapers.

while still decommissioning or selling the Pleasant Creek storage facility. The proposal to retain Los Medanos was approved by the CPUC in D.23-11-069. The CPUC's 2023 GRC decision also directed PG&E to submit applications to update its curtailment procedures and its Peak Day Supply Standard.[79]

POLICIES AND REGULATIONS IMPACTING FUTURE GAS SUPPLY, CAPACITY, AND STORAGE

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, enabling the gas system to transport hydrogen, supplying hard-to-electrify industries, and planning to utilize the gas system as a long-term energy storage mechanism.

This section also 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.

The 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.

Gas System Planning OIR R.20-01-007

The CPUC has an in-progress Rulemaking - OIR 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

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[79] PG&E filed the curtailment application on May 14, 2024, in Application 25-05-004. PG&E currently anticipates filing its application to update the Peak Day Supply Standard at the end of July 2024.

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 Phase 3.

GHG Reporting and Cap-and-Trade Obligations

In March 2024, PG&E Gas Operations reported to the U.S. Environmental Protection Agency (EPA) GHG emissions per 40 Code of Federal Regulations Part 98 in four primary categories: GHG emissions in the reporting year 2023 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 the complete combustion of the annual volumes of natural gas provided to end users on PG&E distribution system (consuming more less than 460 MMcf in calendar year 2023); vented and fugitive emissions from the seven compressor stations and natural gas distribution system; and GHG emissions from transmission pipeline blowdowns.

In April 2024, PG&E reported to CARB GHG emissions of approximately 43.2 million mtCO2e (metric tons carbon dioxide (CO_2) equivalent) in these primary categories for reporting year 2023: 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 complete combustion of the annual volumes of natural gas provided to end users on PG&E distribution system; and vented and fugitive emissions from seven compressor stations, one underground gas storage facility, and natural gas distribution system.

Covered GHG emissions from all seven compressor stations and PG&E as a natural gas supplier are subject to the CARB Cap-and-Trade Program. In November of 2023, CARB issued that PG&E's compliance obligations as a natural gas supplier for the reporting year 2022 was at approximately 18.4 million mtCO2e. CARB will issue PG&E's 2023 final compliance obligations as a natural gas supplier in October of 2024.

In June 2023, PG&E filed the 2022 Annual Natural Gas Leakage Abatement Report and reported 1.49 billion standard cubic feet (Bcf) 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 2024. This plan addresses the 26 best practices outlined in the Leak Abatement OIR decision (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 an annual Super Emitter survey of the entire system and a three-year cycle for compliance surveys. In addition, PG&E reduced the Super Emitter threshold from 10 scfh (standard cubic feet per hour) to 7 scfh in 2023 and reduced further to 6 scfh in 2024; extended blowdown reduction strategies to a 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.

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 CPUC and, voluntarily, also reports—and obtains third-party verification for—a more comprehensive corporate GHG 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.

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 (SRGIT) 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

In November 2019, the CPUC issued a Ruling to establish Phase 4 of the proceeding that will address injection standards for renewable H_2 into gas pipelines and the implementation of SB 1440 (RNG procurement).

On February 24, 2022, the CPUC approved D.22-02-025 implementing SB 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.

In April 2022, the Joint Utilities hosted public workshops to discuss the Standard Biomethane Procurement Methodology as well as the Renewable Gas Procurement Plan (RGPP). 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 hydrogen projects to further understand the capabilities of H_2 blending and inform a statewide injection standard.

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.[80]

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[80] https://www.cpuc.ca.gov/industries-and-topics/natural-gas/renewable-gas

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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, twelve projects have received a total of approximately $43.6 million of funding under the incentive program, leaving approximately $36.4 million remaining in the program.

RESEARCH AND DEVELOPMENT

PG&E's R&D roadmap[81] further outlines PG&E's goals for incorporating RNG, Hydrogen, and carbon capture into our clean fuels and decarbonization pathways.

RNG

Even though PG&E is maturing processes to get RNG interconnected into our system, R&D work is still needed to advance technologies to incorporate additional feedstock into the RNG fuel mix. Areas that are being piloted include continued work to evaluate woody biomass conversion given the big potential of not only utilizing woody biomass as feedstock for RNG, but also hydrogen. In addition, this will help provide a pathway for dealing with waste from vegetation management programs in our service territory.

Additional research is being done in (a) methanation technologies to create green methane from captured carbon and (b) exploring methanation as a power-to-gas energy storage pathway.

Finally, R&D is being done to upgrade our standardized biomethane interconnection skid.

Hydrogen

Hydrogen is seen as a potential game changer in decarbonizing the gas supply and sectors that will be difficult to electrify. To achieve the goals set forth outlined in SB 100, discussed

[81] Renewable Natural Gas, Hydrogen & Carbon Capture Roadmaps (pge.com)

below, California will need to incorporate hydrogen into the portfolio of green fuels for various sectors.

Given the momentum, California, through the Governor's Office of Business and Economic Development, created ARCHES (the Alliance for Renewable Clean Hydrogen Energy Systems) to help lead the development of a single application for the DOE Hydrogen Hub RFP (Request for Proposals) for hydrogen infrastructure investment. In October 2023, the DOE selected California as a National Hydrogen Hub, enabling the state to receive up to $1.2 billion in federal funding to accelerate the development and deployment of clean, renewable hydrogen. By winning one of the Hubs, California is in a position to help lead the nation in the development of the hydrogen infrastructure and economy as a necessary piece of achieving PG&E's climate goals.

Additionally, the California IOUs are working together on an action plan for incorporating hydrogeninto the pipelines through pilot and demonstration projects to help inform an eventual hydrogen injection standard. A hydrogen blending application was filed with the CPUC in early March 2024 describing these blending projects that, once completed, will help inform a statewide hydrogen blending standard.

Hydrogen Storage *(Conventional and New Technology)*

One of the many applications for hydrogen 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 hydrogen as fuel for electric generation to back up intermittent renewable generation. Hydrogen has significant 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, especially in the winter season. Battery storage technology currently cannot provide the scale needed to back up seasonal intermittency.

Carbon Management

Finally, there is no scenario where PG&E will be able to meet our 2040 climate goals without some form of carbon management. We are exploring avenues to evaluate carbon capture technologies, trying to understand how we might be able to utilize our pipeline network to transport captured carbon, and evaluation different means to utilize that captured carbon to help benefit the climate.

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 required for this demand will need to come from cleaner sources of fuel such as RNG and hydrogen. Additionally, LNG infrastructure developed by third parties would need to be developed at the appropriate scale to meet marine demand for LNG.

2024 CALIFORNIA GAS REPORT

NORTHERN CALIFORNIA – TABULAR DATA

NORTHERN CALIFORNIA – TABULAR DATA

TABLE 27 – ANNUAL GAS SUPPLY AND REQUIREMENTS RECORDED YEARS 2019-2023, MMcf/d

LINE		2019	2020	2021	2022	2023
GAS SUPPLY TAKEN						
	CALIFORNIA SOURCE GAS					
1	Core Purchases	0	0	0	0	0
2	Customer Gas Transport & Exchange	62	63	60	43	54
3	Total California Source Gas	62	63	60	43	54
	OUT-OF-STATE GAS					
	Core Net Purchases					
6	Rocky Mountain Gas	170	158	158	156	170
7	U.S. Southwest Gas	58	41	29	38	34
8	Canadian Gas	286	379	410	391	398
	Customer Gas Transport					
10	Rocky Mountain Gas	486	416	329	190	276
11	U.S. Southwest Gas	599	505	539	468	570
12	Canadian Gas	888	927	933	1,023	1,089
13	Total Out-of-State Gas	2,487	2,425	2,397	2,266	2,536
14	STORAGE WITHDRAWAL(2)	350	252	344	357	258
15	Total Gas Supply Taken	2,898	2,740	2,801	2,666	2,848
GAS SENDOUT						
	CORE					
19	Residential	503	495	488	489	510
20	Commercial	226	196	209	218	227
21	NGV	7	7	7	8	8
22	Total Throughput-Core	736	698	704	715	745
	NONCORE					
24	Industrial	534	467	453	442	457
25	Electric Generation (1)	865	895	964	891	943
26	NGV	4	3	4	4	4
27	Total Throughput-Noncore	1,403	1,365	1,421	1,337	1,403
28	WHOLESALE	9	8	8	9	9
29	Total Throughput	2,148	2,072	2,133	2,061	2,157
30	OFF-SYSTEM DELIVERIES	224	241	284	253	181
31	CALIFORNIA EXCHANGE GAS	38	37	38	20	33
32	STORAGE INJECTION (2)	441	343	292	283	434
33	SHRINKAGE Company Use / Unaccounted for	47	47	55	49	44
34	Total Gas Send Out	2,898	2,740	2,801	2,666	2,848
	TRANSPORTATION & EXCHANGE					
38	CORE — ALL END USES	138	115	111	111	115
39	NONCORE — INDUSTRIAL	534	467	453	442	457
40	ELECTRIC GENERATION	865	895	964	891	943
41	SUBTOTAL/RETAIL	1,538	1,477	1,529	1,445	1,515
43	WHOLESALE/INTERNATIONAL	9	8	8	9	9
45	TOTAL TRANSPORTATION AND EXCHANGE	1,547	1,485	1,537	1,453	1,523
	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.

TABLE 28 – ANNUAL GAS SUPPLY FORECAST 2024-2028
AVERAGE DEMAND YEAR, MMcf/d

LINE			2024	2025	2026	2027	2028
FIRM CAPACITY AVAILABLE							
1	California Source Gas		22	22	22	22	22
	Out of State Gas						
2	Baja Path [(1)]		935	935	935	935	935
3	Redwood Path [(2)]		2,060	1,963	1,915	1,915	1,915
3.a	SW Gas Corp. from Great Basin Gas Transmission Company		41	41	41	41	41
4	Supplemental [(3)]		0	0	0	0	0
5	Total Supplies Available		3,058	2,961	2,913	2,913	2,913
GAS SUPPLY TAKEN							
6	California Source Gas		22	22	22	22	22
7	Out of State Gas (via existing facilities)		2,398	2,326	2,283	2,218	2,160
8	Supplemental		0	0	0	0	0
9	Total Supply Taken		2,420	2,348	2,305	2,240	2,182
10	Net Underground Storage Withdrawal		0	0	0	0	0
11	Total Throughput		2,420	2,348	2,305	2,240	2,182
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential [(4)]		493	465	462	451	439
13	Commercial		216	213	211	209	206
14	NGV		8	8	8	9	9
15	Total Core		716	686	682	669	654
	Noncore						
16	Industrial		468	471	475	480	478
17	SMUD Electric Generation [(5)]		96	89	88	74	74
18	PG&E Electric Generation [(6)]		740	696	653	611	570
19	NGV		4	4	4	4	5
20	Wholesale		9	9	9	9	9
21	California Exchange Gas		33	33	33	33	33
22	Total Noncore		1,349	1,301	1,263	1,212	1,168
23	Off-System Deliveries [(7)]		310	320	320	320	320
	Shrinkage						
24	Company use and Unaccounted for		44	40	40	39	39
25	TOTAL END USE		2,420	2,348	2,305	2,240	2,182
	TRANSPORTATION & EXCHANGE						
26	CORE	ALL END USES	110	106	105	104	101
27	NONCORE	COMMERCIAL/INDUSTRIAL	504	508	512	518	515
28		ELECTRIC GENERATION	836	785	741	685	644
29		SUBTOTAL/RETAIL	1,449	1,398	1,359	1,307	1,261
30		WHOLESALE/INTERNATIONAL	9	9	9	9	9
31		TOTAL TRANSPORTATION AND EXCHANGE	1,458	1,407	1,368	1,315	1,270
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.

NORTHERN CALIFORNIA – TABULAR DATA

TABLE 29 – ANNUAL GAS SUPPLY FORECAST 2029-2040

AVERAGE DEMAND YEAR, MMcf/d

LINE		2029	2030	2031	2035	2040
	FIRM CAPACITY AVAILABLE					
1	California Source Gas	22	22	22	22	22
	Out of State Gas					
2	Baja Path [1]	935	935	935	935	935
3	Redwood Path [2]	1,915	1,915	1,915	1,915	1,915
3.a	SW Gas Corp. from Great Basin Gas Transmission Company	41	41	41	41	41
4	Supplemental [3]	0	0	0	0	0
5	Total Supplies Available	2,913	2,913	2,913	2,913	2,913
	GAS SUPPLY TAKEN					
6	California Source Gas	22	22	22	22	22
7	Out of State Gas (via existing facilities)	2,090	2,113	1,779	1,442	1,277
8	Supplemental	0	0	0	0	0
9	Total Supply Taken	2,112	2,135	1,801	1,464	1,299
10	Net Underground Storage Withdrawal	0	0	0	0	0
11	Total Throughput	2,112	2,135	1,801	1,464	1,299
	REQUIREMENTS FORECAST BY END USE					
	Core					
12	Residential [4]	420	399	377	275	149
13	Commercial	203	198	193	168	135
14	NGV	10	10	11	12	14
15	Total Core	633	608	581	455	298
	Noncore					
16	Industrial	473	469	465	451	432
17	SMUD Electric Generation [5]	74	74	74	74	74
18	PG&E Electric Generation [6]	527	578	596	400	410
19	NGV	5	5	5	6	7
20	Wholesale	9	9	9	9	8
21	California Exchange Gas	33	33	33	33	33
22	Total Noncore	1,121	1,168	1,182	973	964
23	Off-System Deliveries [7]	320	320	0	0	0
	Shrinkage					
24	Company use and Unaccounted for	39	40	39	36	36
25	TOTAL END USE	2,112	2,135	1,801	1,464	1,299
	TRANSPORTATION & EXCHANGE					
26	CORE — ALL END USES	99	95	92	74	53
27	NONCORE — COMMERCIAL/INDUSTRIAL	511	507	504	490	472
28	ELECTRIC GENERATION	601	652	670	474	484
29	SUBTOTAL/RETAIL	1,211	1,254	1,265	1,039	1,009
30	WHOLESALE/INTERNATIONAL	9	9	9	9	8
31	TOTAL TRANSPORTATION AND EXCHANGE	1,219	1,263	1,274	1,047	1,018
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 Rubypipeline.

(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 30 – ANNUAL GAS SUPPLY FORECAST 2024-2028

HIGH DEMAND YEAR, MMcf/d

LINE			2024	2025	2026	2027	2028
FIRM CAPACITY AVAILABLE							
1	**California Source Gas**		22	22	22	22	22
	Out of State Gas						
2	Baja Path [(1)]		935	935	935	935	935
3	Redwood Path [(2)]		2,060	1,963	1,915	1,915	1,915
3.a	SW Gas Corp. from Great Basin Gas Transmission Company		41	41	41	41	41
4	**Supplemental** [(3)]		0	0	0	0	0
5	**Total Supplies Available**		3,058	2,961	2,913	2,913	2,913
GAS SUPPLY TAKEN							
6	**California Source Gas**		22	22	22	22	22
7	**Out of State Gas (via existing facilities)**		2,622	2,532	2,471	2,389	2,313
8	**Supplemental**		0	0	0	0	0
9	**Total Supply Taken**		2,644	2,554	2,493	2,411	2,335
10	**Net Underground Storage Withdrawal**		0	0	0	0	0
11	**Total Throughput**		2,644	2,554	2,493	2,411	2,335
REQUIREMENTS FORECAST BY END USE							
	Core						
12	Residential [(4)]		531	503	501	490	477
13	Commercial		225	222	220	218	215
14	NGV		8	8	8	9	9
15	**Total Core**		763	733	729	717	702
	Noncore						
16	Industrial		469	472	477	482	479
17	SMUD Electric Generation [(5)]		96	89	88	74	74
18	PG&E Electric Generation [(6)]		914	852	792	731	673
19	NGV		4	4	4	4	5
20	Wholesale		10	10	10	9	9
21	California Exchange Gas		33	33	33	33	33
22	**Total Noncore**		1,525	1,459	1,403	1,334	1,272
23	**Off-System Deliveries** [(7)]		310	320	320	320	320
	Shrinkage						
24	Company use and Unaccounted for		46	42	41	40	40
25	**TOTAL END USE**		2,644	2,554	2,493	2,411	2,335
	TRANSPORTATION & EXCHANGE						
26	CORE	ALL END USES	115	112	111	110	107
27	NONCORE	COMMERCIAL/INDUSTRIAL	506	509	514	519	516
28		ELECTRIC GENERATION	1,010	941	880	805	747
29		SUBTOTAL/RETAIL	1,631	1,562	1,504	1,434	1,371
30		WHOLESALE/INTERNATIONAL	10	10	10	9	9
31		TOTAL TRANSPORTATION AND EXCHANGE	1,641	1,571	1,514	1,444	1,380
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 31 – ANNUAL GAS SUPPLY FORECAST 2024-2028

HIGH DEMAND YEAR, MMcf/d

LINE			2029	2030	2031	2035	2040	LINE
FIRM CAPACITY AVAILABLE								
1	**California Source Gas**		22	22	22	22	22	1
	Out of State Gas							
2	Baja Path [(1)]		935	935	935	935	935	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.		41	41	41	41	41	3.a
4	**Supplemental [(3)]**		0	0	0	0	0	4
5	**Total Supplies Available**		2,913	2,913	2,913	2,913	2,913	5
GAS SUPPLY TAKEN								
6	**California Source Gas**		22	22	22	22	22	6
7	**Out of State Gas (via existing facilities)**		2,225	2,285	1,976	1,628	1,501	7
8	**Supplemental**		0	0	0	0	0	8
9	**Total Supply Taken**		2,247	2,307	1,998	1,650	1,523	9
10	**Net Underground Storage Withdrawal**		0	0	0	0	0	10
11	**Total Throughput**		2,247	2,307	1,998	1,650	1,523	11
REQUIREMENTS FORECAST BY END USE								
	Core							
12	Residential [(4)]		459	438	415	313	186	12
13	Commercial		211	207	202	176	144	13
14	NGV		10	10	11	12	14	14
15	**Total Core**		680	655	628	502	344	15
	Noncore							
16	Industrial		475	470	467	452	433	16
17	SMUD Electric Generation [(5)]		74	74	74	74	74	17
18	PG&E Electric Generation [(6)]		611	699	742	536	586	18
19	NGV		5	5	5	6	7	19
20	Wholesale		9	9	9	9	9	20
21	California Exchange Gas		33	33	33	33	33	21
22	**Total Noncore**		1,207	1,291	1,330	1,110	1,142	22
23	**Off-System Deliveries [(7)]**		320	320	0	0	0	23
	Shrinkage							
24	Company use and Unaccounted for		40	41	40	37	38	24
25	**TOTAL END USE**		2,247	2,307	1,998	1,650	1,523	25
	TRANSPORTATION & EXCHANGE							
26	CORE	ALL END USES	105	101	98	80	59	26
27	NONCORE	COMMERCIAL/INDUSTRIAL	512	508	505	491	473	27
28		ELECTRIC GENERATION	685	773	816	610	660	28
29		SUBTOTAL/RETAIL	1,302	1,383	1,419	1,182	1,192	29
30		WHOLESALE/INTERNATIONAL	9	9	9	9	9	30
31		TOTAL TRANSPORTATION AND EXCHANGE	1,311	1,392	1,428	1,191	1,201	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.

2024 CALIFORNIA GAS REPORT

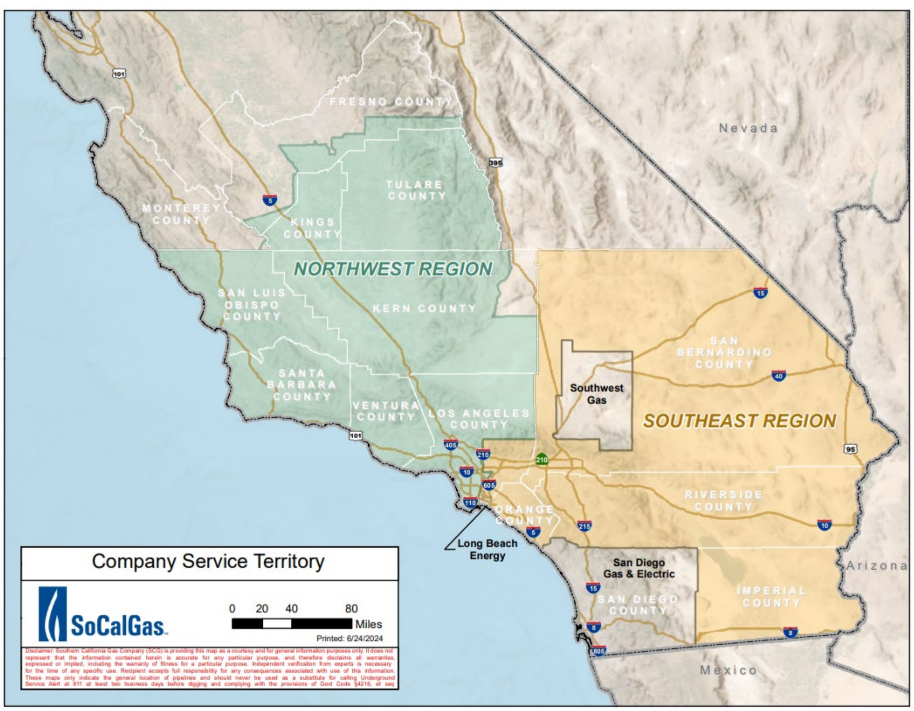
SOUTHERN CALIFORNIA GAS COMPANY

INTRODUCTION

SoCalGas is the principal distributor of natural gas in Southern California and provides retail and wholesale customers with transportation, exchange, storage services and 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 5.950 million meters in 2023.

SoCalGas' vast system extends from the Colorado River on the eastern end to the Pacific Ocean on the western end and extends as far North as Tulare County and reaches the U.S./Mexico Border in the South (excluding San Diego County).

FIGURE 10: SOCALGAS SERVICE TERRITORY MAP



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, Southwest Gas (SWG), the City of Long Beach Utilities 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 17-year demand and forecast period, from 2024 through 2040; only the consecutive years 2024 through 2031, and the point years of 2035 and 2040 are shown in the tabular data in the next sections. All forecasts are inherently subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

The Southern California section of the 2024 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.

ECONOMICS AND DEMOGRAPHICS

The gas demand projections are in part determined by short-term and long-term economic outlook for the SoCalGas service territory. Both gross metro product and employment have surpassed their pre-COVID-19 levels; however, both are expected to grow at slower rates than the pre-pandemic time period. Risks to the region's economic outlook include elevated interest rates in the short-term as the Federal Reserve continues to address inflation and weak population growth triggered by high housing costs and slowing levels of international migration.

GAS DEMAND (REQUIREMENTS)

OVERVIEW

SoCalGas projects total gas demand to decline at an annual rate of 0.7% percent from 2024 to 2040. By comparison, the total gas demand had been projected to decline at an annual rate of 1.5% in the 2022 CGR over the same time period. The forecasted deaccelerated decline in throughput demand is being driven by reduced energy efficiency and updated fuel substitution assumptions.[82] Factors that contribute to the overall downward trend are standards created by Title 20 and 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 0.2 percent or from 111 Bcf in 2024 to 108 Bcf by 2040. However, the NGV market is expected to grow 3.4 percent per year 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[83] and the affordability of RNG compared to traditional fuels such as gasoline and diesel.[84] The noncore, non-EG-markets are expected to decline 0.3 percent from 164 Bcf in 2024 to 157 Bcf by 2040. That decline is being driven by established 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 225 Bcf in 2024 to 173 Bcf in 2040, a decrease of 1.6 percent per year.

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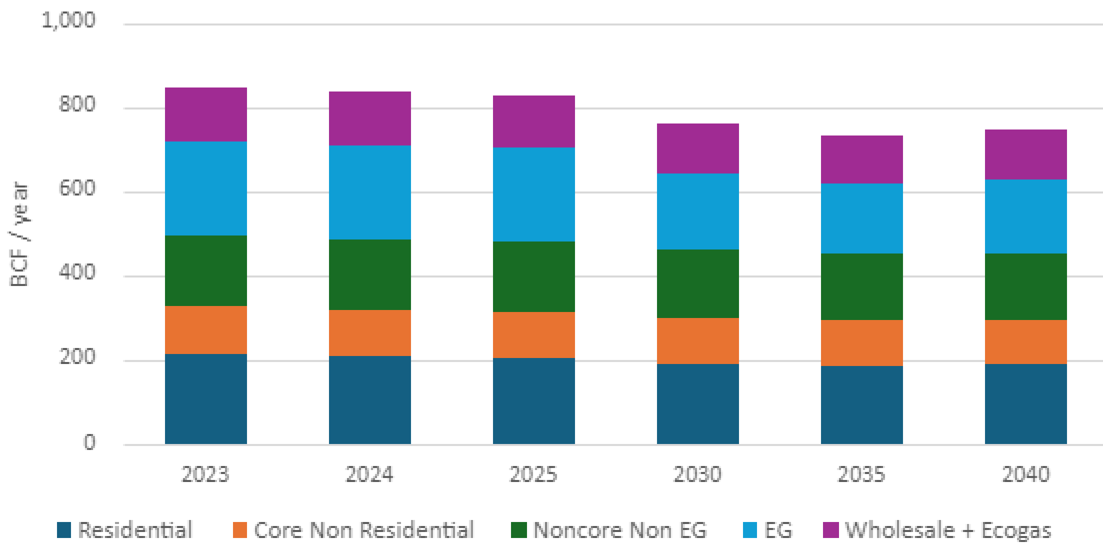
[82] For the 2024 California Gas Report, SoCalGas incorporated the California Energy Commission's (CEC) Additional Achievable Fuel Substitution (AAFS) Scenario 3 Programmatic

[83] These include for example battery electric vehicles (BEV), natural gas vehicles, hydrogen fuel cell electric, and hybrid vehicles.

[84] https://www.cummins.com/news/2022/05/04/natural-gas-engines-vs-diesel-engines [85] Decision D.21-06-035.

The chart shows the composition of SoCalGas' throughput for the recorded year 2023 (with weather-sensitive market segments adjusted to average year HDD assumptions) and forecasts for the 2024 to 2040 forecast period.

FIGURE 11 – COMPOSITION OF SOCALGAS REQUIREMENTS AVERAGE TEMPERATURE AND NORMAL HYDRO YEAR



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 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 2024 CGR, SoCalGas and SDG&E have included a climate-change warming trend that gradually reduces HDDs over the forecast period. First, average temperature year values were computed as the simple average of annual HDDs for the calendar years 2004 through 2023: 1,242 HDD's for SoCalGas and 1,172 HDDs for SDG&E. Corresponding 1-in-35 cold year HDDs were 1,470 for SoCalGas and 1,429 for SDG&E. For the forecast period, projected annual HDDs were reduced each year by 7 HDDs for SoCalGas and 6 HDDs for SDG&E. For SoCalGas, projected average year and cold year HDDs both drop by 7 HDD annually: from 1,235 and 1,463 in year 2023, to 1,123 and 1,351 in year 2040. For SDG&E, projected average year and cold year HDDs drop by 6 HDD annually: from 1,166 and 1,423 in year 2024, to 1,070 and 1,327 in year 2040. 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 HDDs for years 1985-2004, then 1986-2005, 1987-2005 and ending with the average HDDs for years 2004-2023.

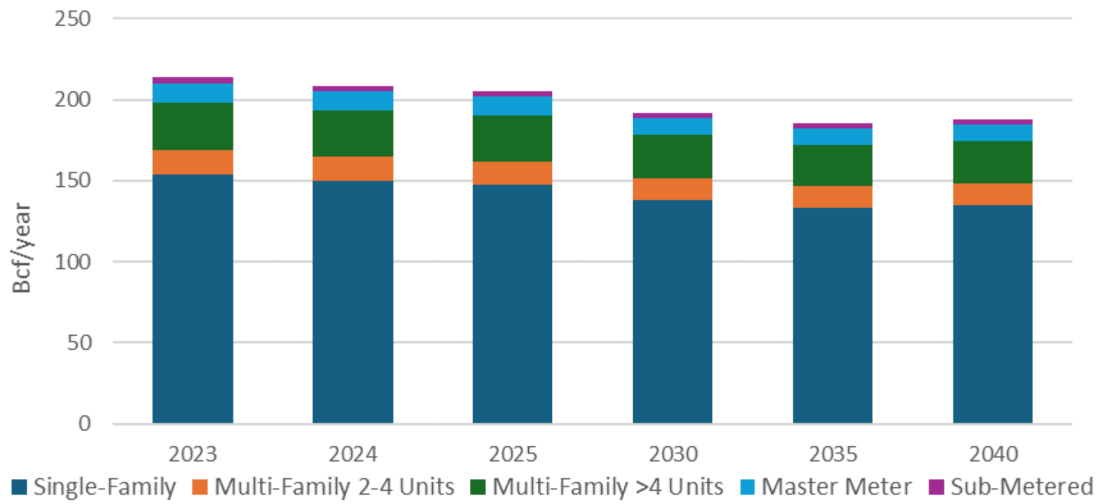
Hydro Conditions

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

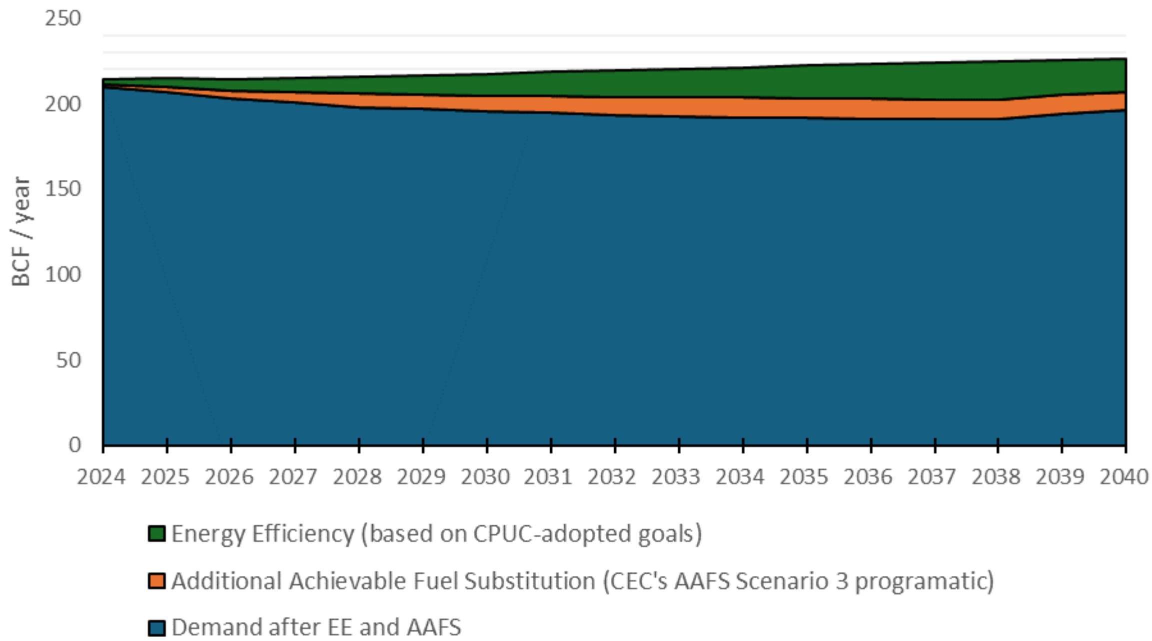
Residential

FIGURE 12: COMPOSITION OF SOCALGAS RESIDENTIAL DEMAND FORECAST



Residential gas demand is forecasted to decline from 209 Bcf in 2024 to 188 Bcf by 2040 at an average annual rate of 0.6%. The decline is due to declining use per meter, primarily driven by aggressive energy efficiency goals, anticipated fuel substitution, and tightening Title 24 Codes and Standards. The demand reduction created by the policies described offset the load created by the new meter growth forecasted over the planning period.

FIGURE 13: RESIDENTIAL IMPACTS OF EE AND AAFS



By 2040, energy efficiency removes 8.7% of total residential demand, while assumed additional achievable fuel substitution accounts for 4.8% of total residential demand reduction. For the purposes of the 2024 California Gas Report (CGR), SoCalGas used the CEC's adopted AAFS Programmatic 3 Scenario from the 2023 Integrated Energy Policy Report (IEPR) forecast based on availability in order to timely submit the 2024 CGR by July 1, 2024, as well as suitability for gas system planning purposes. Subsequent to this selection, the CEC adopted an additional AAFS scenario (Gradual Transition) that is between their earlier AAFS 2 and 3 scenarios. Based on initial comparison of the AAFS 3 Programmatic and Gradual Transition forecasts, relatively little difference in the early part of the forecast (through 2030) is apparent. In future CGRs, SoCalGas expects to have additional information and regulatory clarity surrounding likely fuel substitution to assist in capacity planning.

Commercial

The core commercial market demand is expected to decline over the forecast period. On a temperature adjusted basis, the 2024 core commercial market demand totaled 75.5 Bcf. By the year 2040, the load is anticipated to drop to approximately 62.2 Bcf. The average annual rate of decline from 2024-2040 is forecasted to be 1.2 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 2024, the noncore commercial temperature adjusted usage was 18.1 Bcf. From 2024 through 2040, demand in this market is expected to rise slightly to about 18.3 Bcf in 2040. The noncore commercial market will be expected to increase at an average annual rate of 0.06 percent per year. Key factors of the trend are increasing commercial employment, commercial customers that move from core to noncore, and the estimated fuel substitution.

FIGURE 14 – COMMERCIAL GAS DEMAND BY BUSINESS TYPE, 2023

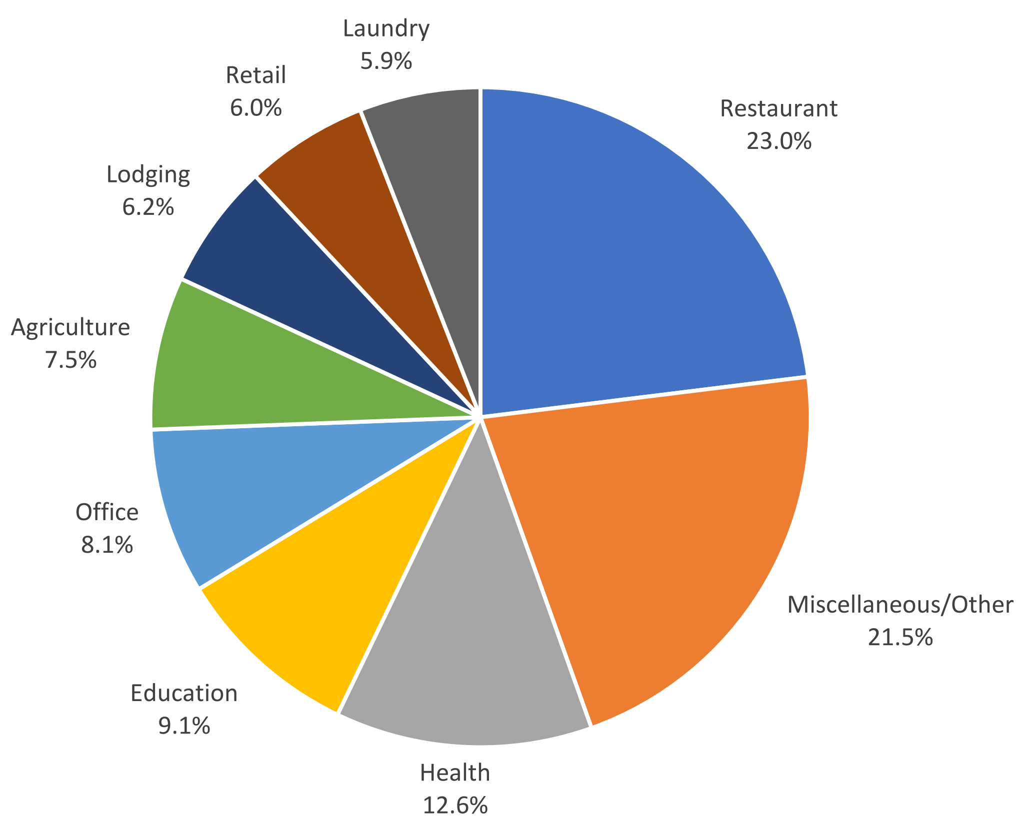
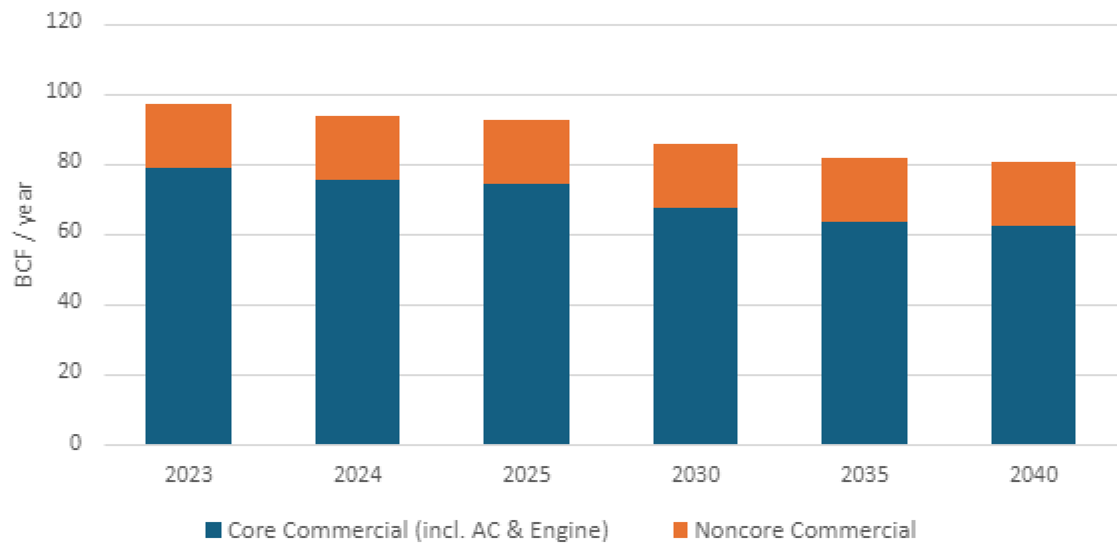


FIGURE 15 – ANNUAL COMMERCIAL DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN



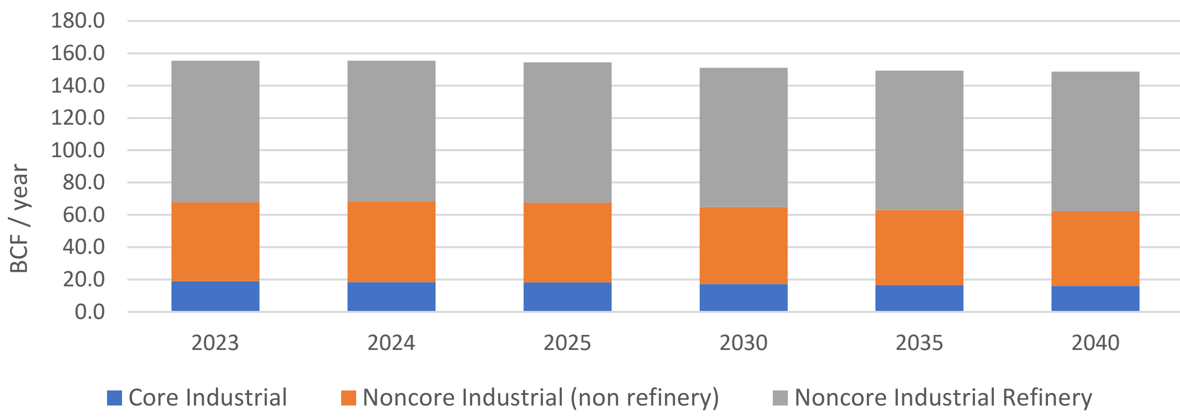
The commercial market consists of nine business types identified by the customers' North American Industry Classification System codes. It represents includes both core and noncore usage. The restaurant business dominates this market with 23 percent of commercial usage in 2023, followed by miscellaneous with a 21.5 percent share. The miscellaneous sector includes, but is not limited to, the warehouse sector, government, TCU, construction and other.

Industrial

Non-Refinery Industrial Demand

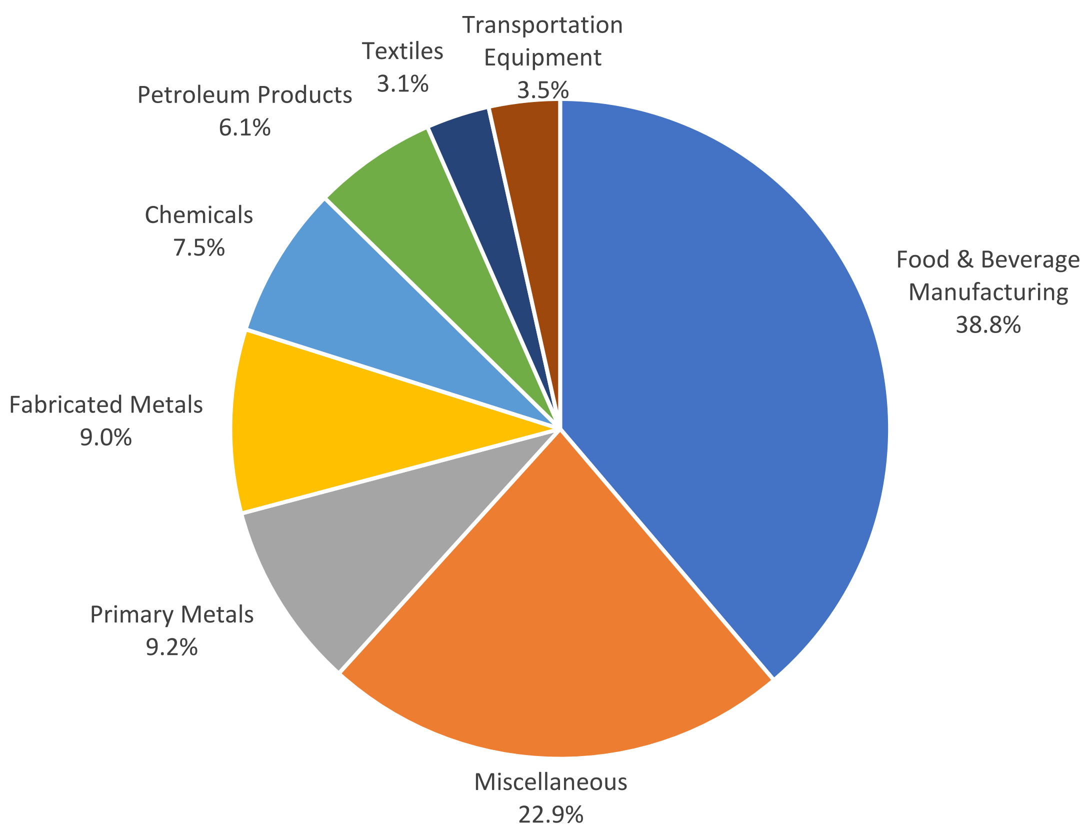
In 2024, temperature-adjusted core industrial demand was 18.5 Bcf. Core industrial market demand is projected to drop by 0.9 percent per year from 18.5 Bcf in 2024 to 16 Bcf in 2040. This decrease results from a combination of factors: a decrease in core industrial customer counts, an increase in gas rates, the impact of climate change, and the savings from authorized energy efficiency programs in the core industrial sector.

FIGURE 16– ANNUAL INDUSTRIAL DEMAND FORECAST



The 2023 non--refinery industrial gas demand served by SoCalGas is shown below. Food and beverage manufacturing, with 38.8 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 17 - INDUSTRIAL COMMERCIAL GAS DEMAND BY BUSINESS TYPE, 2023



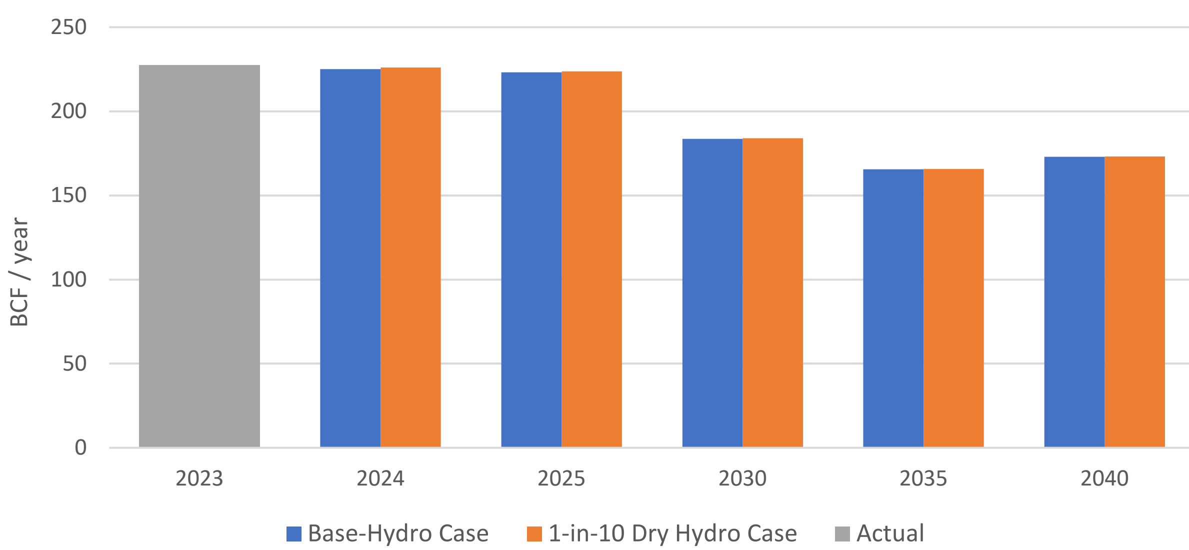
Gas demand for the retail noncore industrial (non-refinery) market is expected to decline at an annual rate of 0.5 percent from 49.8 Bcf in 2024 to 46.1 Bcf by 2040. The reduced demand is primarily due to the CPUC-authorized energy efficiency programs, decreasing industrial employment, and the departure 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 decrease slightly in the forecast period, from 87.1 Bcf in 2024 to 86.5 Bcf in 2040.

ELECTRIC GENERATION

FIGURE 18 – TOTAL ELECTRIC GENERATION



The EG sector includes all commercial/industrial cogeneration, enhanced oil recovery (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 on Southern California gas demand from 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) 2023 Integrated Energy Policy Report (IEPR) 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 4,520 MW of local gas-fired power plants and a 2,240 MW nuclear plant in northern California will retire by the end of 2030.

The gas-driven EG forecast uses a power market simulation for the period of 2024-2040. 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 most of the CPUC adopted 2023 Preferred System Plan, which also assumes compliance with the Mid-Term Reliability (MTR).[85] Also assumed in the forecast is compliance with the GHG planning target of 25 million metric tons (MMT) by year 2040. 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.

[85] Decision D.21-06-035.

The EG demand forecast for the State of California, used in the simulation, is sourced from the CEC's California Energy Demand Forecast, 2023 – 2040, adopted January 2024. 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 3 Programmatic was selected as the energy demand forecast. PG&E provided its own version of AAFS for its region.

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 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 24.2 Bcf in 2024 and is expected to modestly decrease to 23.5 Bcf by the year 2040, or at an average rate of change of 0.2 percent per year.

Refinery-Related Cogeneration

Refinery cogeneration units are installed primarily to generate electricity for internal use. This market is forecasted to be stable at 21.6 Bcf over the 2024 - 2040 forecast period.

Enhanced Oil Recovery (EOR)-Related Cogeneration

In 2024, recorded gas deliveries to the EOR -related cogeneration were 0.35 Bcf. EOR Cogeneration demand is forecasted to increase, reaching 1.9 Bcf by 2040. The forecasted demand remains volatile and uncertain due to factors such as renewable energy goals, fuel substitutions, and shifts in customer demand related to California's energy transition.

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 179 Bcf in 2024 to 126 Bcf in 2040. The main factors for the decline are an aggressive energy storage resource addition, a significant renewable resource addition, and the retirement of older gas-fired plants.

Wholesale

SoCalGas provides wholesale transportation service to SDG&E, the City of Long Beach Utilities 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 39.1 Bcf in 2024 to 44.6 Bcf in 2040. The change reflects a 0.8 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 0.82 percent per year from 86.7 Bcf in 2024 to 73.6 Bcf in 2040. 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 Utilities Department. Long Beach's gas use is expected to decrease slightly, from 8.4 Bcf in 2024 to 7.7 Bcf by 2040. Additional information regarding the City of Long Beach Utilities Department's gas demand is provided in the City of Long Beach Utilities Department section of this report.

Southwest Gas Corporation

SoCalGas used the forecast prepared by Southwest Gas for this report. In 2024, SoCalGas is expected to deliver 10.8 Bcf to Southwest Gas and the total load is expected to rise to 12.0 Bcf by 2040. 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 is expected to decline from 8.24 Bcf in 2024 to 7.84 Bcf by 2040. . 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 11.7 Bcf in 2024 to 17.0 Bcf by 2040. Refer to Ecogas or IENova, Ecogas' parent company, for more information.

Enhanced Oil Recovery (EOR) - Steam

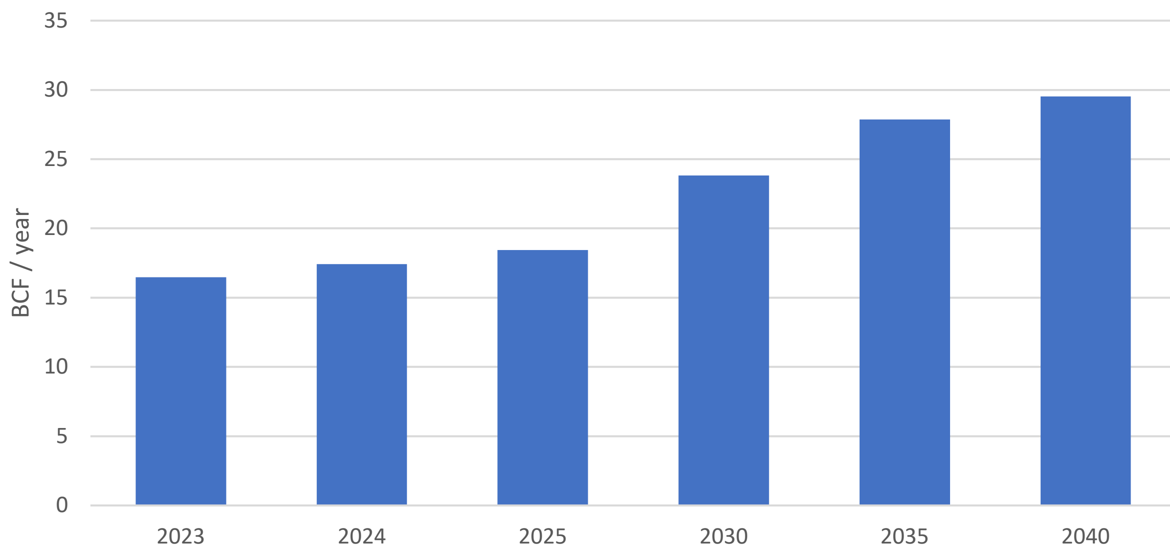
In 2024, recorded gas deliveries to the EOR market were 8.9 Bcf. EOR demand is forecasted to decrease to 5.7 Bcf by 2040. The forecasted demand for EOR remains volatile and extremely uncertain due to factors such as renewable energy goals, fuel substitutions, and shifts in customer demand related to California's energy transition.

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 and state regulations require adoption. 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 2023, there were 358 CNG fueling stations operating in the service territory. The NGV market is expected to grow from 17.4 Bcf in 2024 and reach 29.5 Bcf by 2040, or the equivalent of a 3.4 percent growth per year, on average.

FIGURE 19 – NGV DEMAND FORECAST



ENERGY EFFICIENCY PROGRAMS

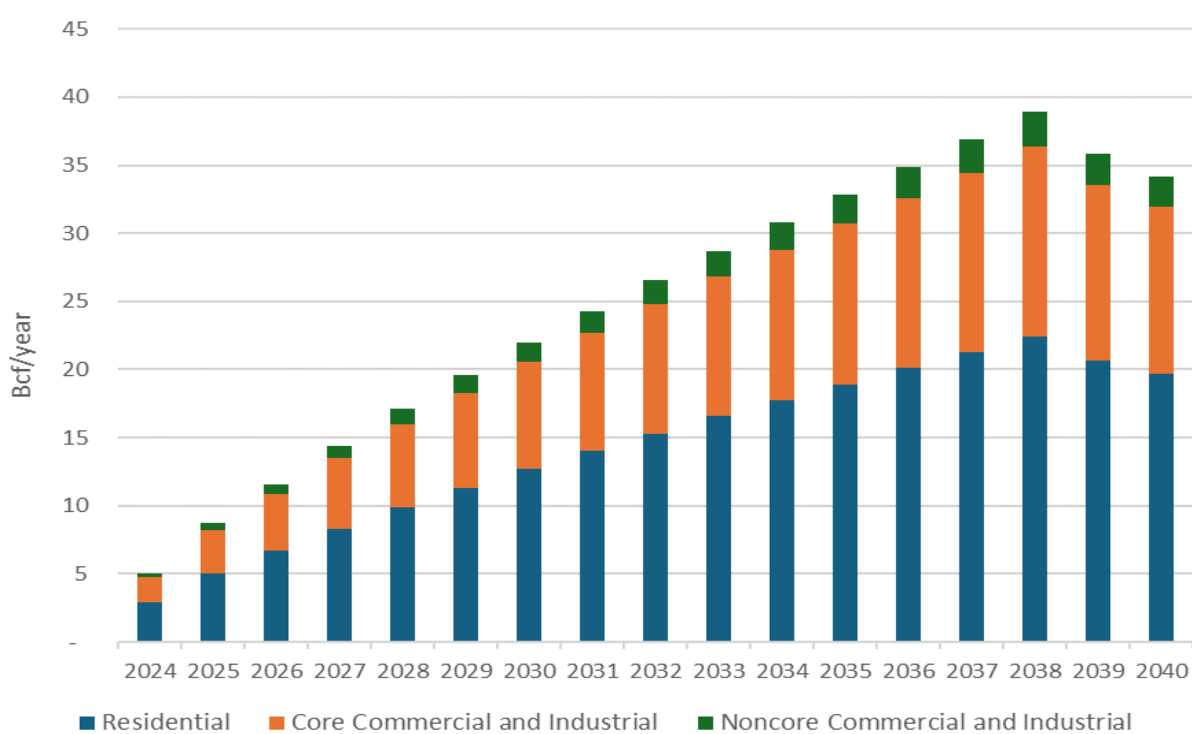
SoCalGas engages in several energy efficiency (EE) and conservation programs designed to help customers identify and implement ways to benefit environmentally and financially from energy efficiency investments. Programs administered by SoCalGas include services that help customers evaluate their energy 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 Programmatic Scenario 3 (included in the CEC's 2023 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 2040.

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 2024 program year. Savings estimates from SoCalGas' 2024 EE programs are grouped by the classifications identified in the 2024 CGR (residential, commercial, industrial, and industrial refinery).

Forecasted savings for the 2024-2040 period are based on the 2023 EE forecast scaled to the goals approved in the recent EE proceeding goals decision, D.23-08-005, which set EE goals through 2035. Forecasted savings beyond 2035 are held constant based on 2035 forecasted values. Cumulative savings reflect the lifecycle EE program achievements from forecasted program savings starting in 2024 and does not include lifecycle savings from prior program years. SoCalGas currently uses a 15-years lifecycle for cumulative savings calculations.

FIGURE 20 – COMBINED PORTFOLIO OF EE PROGRAMS/CODES AND STANDARDS SAVINGS



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 2019 through 2023 receipts from gas supply sources can be found in the Sources and Disposition tables in the Executive Summary.

CALIFORNIA GAS

Scheduled gas supply available to SoCalGas and SDG&E from California sources averaged 84 MMcf/d in 2023.

SOUTHWESTERN U.S. GAS

Traditional Southwestern U.S. sources of natural gas continues 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 2019-2023. This increase positioned the Permian Basin as a preferred gas supply source of economical gas.

Mexican demand for Southwestern U.S. natural gas along with East of California demand continue to steadily increase and compete for southwestern natural gas supplies. This increasing demand will likely continue to compete with Southern California for southwest natural gas supplies.

ROCKY MOUNTAIN GAS

Rocky Mountain natural gas supplies continues to supplement Southwestern U.S. gas sources for Southern California. Natural gas supply from the Rockies is delivered to Southern California primarily on the Kern River Gas Transmission Company's pipeline, although Rockies' gas can also be accessible through pipelines interconnected to the San Juan Basin. Pipelines that supply other markets connect to the Rocky Mountain region, which allows Rockies natural gas supply to be redirected to higher value markets as conditions change. Over the past couple of years, there has been increasing demand for Rockies supplies locally, across the Western Region, and from Eastern demand which has elevated competition for these supplies to Southern California.

CANADIAN GAS

Canadian natural gas provides a small share of Southern California natural gas supplies due to the limited available capacity to transport the gas to Southern California.

RENEWABLE NATURAL GAS (RNG)

With the advent of SB 1440 and the evolution of energy transition at both the national and state levels, physical RNG (biomethane) is earmarked to be part of the supply portfolio for the core gas customers of the four gas IOUs in California.[86] RNG is methane produced from one of several processes known in the industry as: (1) Anaerobic Digestion (aka. AD), (2) Landfill gas, (3) Gasification (also pyrolysis) and 4) Dairy (including other animal waste such as swine).[87] To the extent SB 1440 if fully implemented, the amount of RNG in SoCal Gas' core supply

[86] See description SB 1440 in the regulatory section of this report.

[87] RNG produced from AD is typically derived from organic waste streams such as municipal organic waste (i.e., food scraps and lawn clippings) and wastewater treatment. Non-combustion gasification and pyrolysis pathways typically process woody biomass (i.e. forest debris and certain agricultural waste). Dairy/swine is produced from dairy/swine manure.

portfolio would be 37.86 Bcf/year by 2030.[88] The RNG supply would also be generated from in-state facilities and would thus reduce the out-of-state supplies by the same amount.

Reports estimating RNG supply potential published by Livermore Laboratory Foundation,[89] the CEC,[90] E3 and the University of California Irvine,[91] and ICF,[92] illustrate the potential for significant amount of feedstock available within California for the production of biogas and RNG, were mentioned in the 2022 CGR and are still applicable. For reference, the results from these studies are repeated here. It is estimated 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 (Syngas). Studies that sum both AD and gasification estimates provide an estimate between 148 and 387 Bcf of annual RNG potential within California.[93] 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

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88 SB 1440 mandates that 12.2% of its own share of 2020 annual bundled core customer natural gas demand by 2030.

89 "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.

90 "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.

91 "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.

92 "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.

93 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.

California or approximately 150 percent of the commercial demand, or approximately 45 percent of industrial demand.[94]

[94] https://www.eia.gov/dnav/ng/NG_CONS_SUM_DCU_SCA_A.htm[95] 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:

Looking outside California, the opportunity to produce biogas and RNG expands significantly. According to Department of Energy estimates, the U.S. could produce up to 10 trillion cubic feet of RNG annually by 2030 which is equivalent to five times California's projected natural gas consumption.[95] A more recent study by ICF estimated a nation-wide technical resource potential over 13 trillion cubic feet of RNG potential from AD and gasification, including the conversion of non-biogenic Municipal Solid Waste.[96]

The following table shows a high-level estimate of the RNG delivered to core customers on SoCalGas and SDG&E's system. In the time period shown (2021–2023), it is estimated that all RNG is utilized by Natural Gas Vehicles end uses (NGVs).

[95] 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.

[96] Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, ICF, p. 13.[97] 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)

TABLE 32 – SOCALGAS AND SDG&E RENEWABLE NATURAL GAS DELIVERIES, MMcf/d

	2021	Approx. % of Core (2021)	2022	Approx. % of Core (2022)	2023	Approx. % of Core (2023)
Total Core Gas Deliveries [1]	1,057		1,027		1,088	
RGS - RNG [2]	0	0.0%	0	0.0%	0	0.0%
NGVs - Estimated RNG [3 4]	45	4.3%	51	5.0%	55	5.1%
Physical [5 6]	6	0.5%	10	1.0%	12	1.1%
Estimated book and claim [7]	39	3.7%	41	4.0%	44	4.0%

Notes:

1) Taken from Tables 34 and 48, SoCalGas and SDG&E Annual Gas Supply and Sendout, Deliveries by End-Use
2) Refers to Renewable Natural Gas procured under SB 1440 (Renewable Gas Standard)
3) SoCalGas Data taken from Table 34, SoCalGas Annual Gas Supply and Sendout Table, Deliveries by End-Use: Core, NGVs. SDG&E data provided by SDG&E.
4) Table assumes: ~98% of NGVs utilize RNG in 2021, ~96% utilize RNG in 2022, and ~97% of NGVs utilize RNG in 2023.
This assumption based on Alternative Fuels Volume data from California Air Resources Board (annual volume of Biomethane and Fossil Natural Gas):
https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/dashboard/Fig2_2023.xlsx
5) Annual RNG delivered from all points of receipt to SoCalGas and SDG&E.
6) Taken from SoCalGas & SDG&E Biomethane Annual Report Biomethane Phase 1 (2021, 2022, and 2023).
7) Book-and-Claim estimates were calculated by the difference between total NGV supply and interconnected RNG. It should be noted that actual numbers may differ.

FIRM RECEIPT CAPACITY

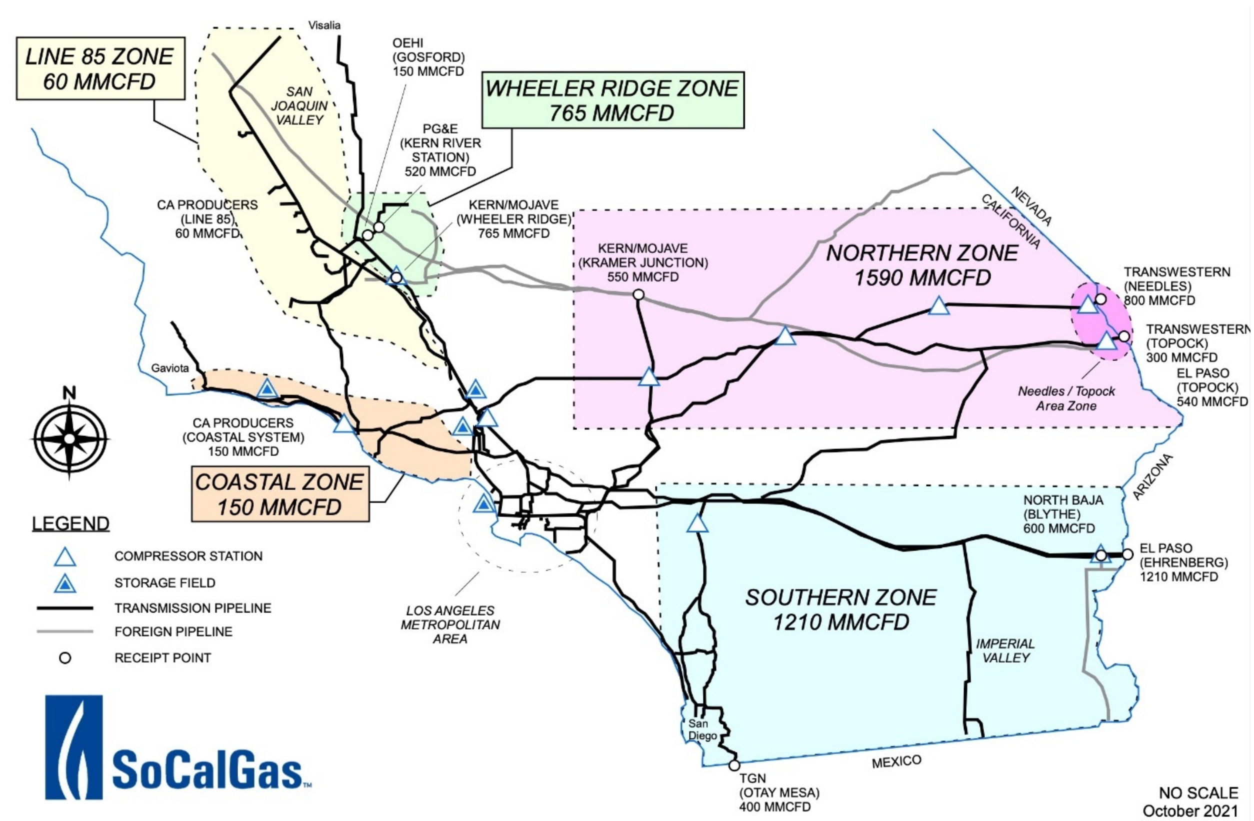
California utilities and end users benefit from access to supply basins and enhanced gas and pipeline competition. Interstate, international, and intrastate pipelines serving Southern and central California include the El Paso Natural Gas, Mojave, Transwestern, Kern River, TGN, North Baja, and PG&E pipelines. 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 firm receipt capacity of 1,590 MMcf/d.

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 21 – 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.[97] 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.[98] 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 located 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 authorized storage working inventory capacity of 119.5 Bcf.[99] Of SoCalGas' total 119.5 Bcf of storage capacity, 82.5 Bcf is allocated to our core residential, small industrial and commercial customers. About 10 Bcf of inventory capacity is used for system balancing. The remaining capacity is available to other customers.

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[97] 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)

[98] *Id.,* Conclusion 2.5 at pp 506.

[99] SoCalGas 2024 General Rate Case (GRC) Filing, A.22-05-015, Exhibit SCG-10-R, p. LTB SH-3. D.23-08-050 the increased the working gas at Aliso Canyon to 68.6 Bcf. Aliso Canyon historically has a design working capacity of 86 Bcf.[100] GO 177 section IV(A)(1): Two thresholds are the following: the project cost exceeds $75 million; or, (1) project is located within 1,000 feet of a "sensitive receptor" (including housing, educational institutions or health care facilities) and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for an increase in levels of (a) a toxic air contaminant or (b) a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant.

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 provide safe and reliable energy and natural gas storage services.

More recently, PHMSA issued their Final Rule for Underground Storage regulations, Code of Federal 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 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

In May 2022, SoCalGas filed its 2024 General Rate Case seeking to revise its authorized revenue requirements for 2024-2027 to recover the reasonable costs of gas operations, facilities, infrastructure, and other functions necessary to provide utility services to customers. Based on a July 2023 update, SoCalGas requests a $4.434 billion revenue requirement for 2024, which, if approved, would be an increase of $894 million over its authorized 2023 revenue requirement, or a 25.3% increase. For 2025-2027, SoCalGas's revenue requirement requested increases range between 5.5-7.6%. Intervenor and rebuttal testimony were served in March 2023 and May 2023, respectively. Evidentiary hearings were held in June and update testimony was served in July 2023. Briefs were filed in August and September 2023. In October 2023, settlements were filed resolving certain key issues among some of the parties. Comments on the settlements were filed in November and December 2023. A proposed decision is expected in the third quarter of 2024.

Aliso Canyon Order Instituting Investigation (OII)

On February 9, 2017, the CPUC opened the Aliso Canyon proceeding, Investigation I.17-02-002, as directed by SB 380 (Pavley, 2016, to determine the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility (Aliso Canyon) while maintaining reliability and just and reasonable rates. Aliso Canyon is the largest of SoCalGas' four gas storage facilities serving Southern California.

In Phase 1, the Commission undertook a comprehensive effort to develop the appropriate analyses and scenarios to evaluate the impact of reducing or eliminating the use of Aliso Canyon, culminating in adoption of a Scenarios Framework in January 2019. In Phase 2, the Commission oversaw the performance of the modeling outlined in the Scenarios Framework, which resulted in issuance of an economic modeling report in November 2020 and the production cost modeling for minimum local generation scenarios, the hydraulic modeling for 1-in-10-year and 1-in-35-

year design scenarios, and the feasibility assessment in March 2021. Phase 3 was initiated in December 2019 with the purpose of engaging an expert consultant to develop portfolios that could be implemented to entirely replace Aliso Canyon. A third-party consultant issued a report in December 2021 that modeled the costs and benefits of adding new resources and infrastructure that could be implemented to replace Aliso Canyon within two planning horizons 2027 and 2045. The consultant modeled five potential alternatives - Gas Transmission Expansion Portfolio, Gas Demand Reduction Portfolio, Electric Generator Additions Portfolio, Electric Transmission Additions Portfolio, and Hybrid Portfolio.

In September 2022, the CPUC Energy Division issued a Staff Proposal discussing the current need for Aliso Canyon to support reasonable rates, reliability, and energy security, and offered a Staff Proposal on a potential path forward. The Staff Proposal includes possible alternative portfolios and recommends that the Commission's Energy Division conduct a biennial analysis of whether sufficient gas is expected to be available to reliably supply demand in Southern California and whether demand has declined by the proposed specified amounts. Commission Staff propose to conduct this analysis jointly with the CEC and in consultation with the CAISO, CalGEM, and LADWP. The resulting report would recommend a new storage level and, if gas system developments are not on track to meet the previously set storage level targets, would assess how far off track they are, propose changes to slow down the adopted storage level trajectory, and propose the amount of gas demand reduction or electric generation supply increase necessary to meet the new trajectory. The Commission would then determine whether to adopt these recommendations and direct any actions necessary to accomplish the new trajectory through a resolution of the Commission. The proceeding remains open, with a CPUC decision expected before the end of 2024.

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. In August 2023, the CPUC issued a decision increasing the interim maximum range of Aliso Canyon storage capacity from 41.16 Bcf to 68.6 Bcf, which will remain in effect until updated due to new facts and circumstances or the completion of Phase 2 and Phase 3 in the OII.

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 directs the CEC 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.

In Phase III of R.19-01-011, the CPUC considering changing the rules regarding allowances, refunds, and discounts paid to builders to help facilitate the connection of buildings to the gas distribution system. The CPUC issued a decision that eliminated gas line extension allowances for applications that SoCalGas and SDG&E would receive on or after July 1, 2023. The change in policy results in the customer who is seeking the gas line extension being responsible for the costs, rather than cost recovery through SoCalGas and SDG&E GRCs. The elimination of line extension allowances will reduce the ratepayer contribution to gas New Business Construction activities but not necessarily result in a decrease in new customer count. In December 2023, the

CPUC issued a final decision eliminating electric line extension subsidies for mixed-fuel new construction projects. Specifically, the decision eliminates electric line extension subsidies for all building projects that use gas and/or propane in addition to electricity, effective July 1, 2024. The new rules also require all mixed-fuel new construction projects use actual cost billing of an electric line extension rather than estimated cost billing effective January 1, 2025. The final decision also adopts the same exemption criteria set by the Commission for gas line extension projects.

Long-term Gas Reliability and Planning Proceeding (R.20-01-007)

The CPUC initiated an Order Instituting Rulemaking (OIR) to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning (Long-term Gas Reliability and Planning Proceeding) (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 consists of the following three activities:

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. Decision (D.)22-07-002, which was adopted in July 2022, included no changes to design standards, and adopted a citation program for failure to meet minimum design standards and new reporting requirements for the California Gas Report starting in 2024.

Track 2 addresses long-term natural gas policy and planning with focus towards gas infrastructure. In December 2022, D.22-12-021 adopted General Order (GO) 177 relating to gas infrastructure. The GO requires regulated gas corporations to file an application for a certificate of public convenience and necessity (CPCN) prior to commencing construction on any gas infrastructure that meets either a monetary or an emissions threshold.[100] The GO outlines CPCN application information and notification requirements and specific types of exempt projects for which CPCN applications are not required. Furthermore, D.22-12-021 and GO 177 require gas corporations to annually file a Report of Planned Gas Investments (gas reports), starting March 1, 2023.[101] Subsequently, D.23-12-003 was issued requiring gas utilities to provide information when filing an application that requests approval for or the collection of revenue requirements of any and all new transmission infrastructure projects and to notify the Commission of planned deration on transmission pipelines.

Phase 3 was initiated in February 2024, with the issuance of a ruling proposing a draft scope for Phase 3 and included a joint agency staff Gas Transition White Paper (White Paper) that reflects contributions by CPUC, CEC, and CARB and frames long-term considerations potentially in scope for the proceeding. The draft Phase 3 scope proposes four tracks that includes the following: Track 1: Gas Transition Scenario Analysis; Track 2: Long-Term Gas Transition Planning Approaches; Track 3: Opportunities for Interim Action; and Track 4: Reducing Gas System Costs, Avoiding Stranded Assets and Maintaining Reliability, Safety, and Gas Commodity Cost Containment as well as Related Revenue Requirement and Ratemaking Implications. The purpose of the White Paper is to frame issues and questions of relevance to the Gas Planning OIR to achieve California's climate goals while mitigating potential negative

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100 GO 177 section IV(A)(1): Two thresholds are the following: the project cost exceeds $75 million; or, (1) project is located within 1,000 feet of a "sensitive receptor" (including housing, educational institutions or health care facilities) and (2) operation of the completed project by the gas corporation requires a permit from the relevant local air quality district for an increase in levels of (a) a toxic air contaminant or (b) a criteria air pollutant, if the area is listed as a serious, severe, or extreme non-attainment area for that pollutant.

101 D.22-12-021, OP. 7 at 101.

impacts to California's residents, businesses, and workforce.[102] A final Phase 3 scope is expected to be issued soon.

Angeles Link Application

On February 17, 2022, SoCalGas filed A.22-02-007 requesting authorization to establish the Angeles Link Memorandum Account (ALMA) for the purposes of recording the incremental costs necessary to develop a new clean renewable hydrogen energy transport system called Angeles Link (Project). The objective of Angeles Link is to develop a non-discriminatory pipeline system that is dedicated to public use to transport clean renewable hydrogen[103] from regional third-party production and storage sites to end users in hard-to-electrify industries and heavy-duty transportation sectors in Central and Southern California, including the Los Angeles Basin. In December 2022, the Commission approved the ALMA to record the costs of performing Phase One feasibility studies for up to an initial cap of $26 million[104], [105]. SoCalGas is not authorized to recover in rates any Project costs at this time – rather, SoCalGas is ordered to file a separate application for cost recovery. The CPUC also directed SoCalGas to join the State in its application for federal funding through the Infrastructure Investment and Jobs Act (IIJA). Finally, the decision adopts an application process for SoCalGas to request Commission authority to record costs for Phase Two activities (e.g. front-end engineering and design), if SoCalGas chooses to do so. SoCalGas anticipates completing Phase 1 feasibility studies for

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[102] Assigned Commissioner's Ruling Scheduling Phase 3 Prehearing Conference and Providing Joint Agency Staff Gas Transition White Paper and Draft Phase 3 Scope and Schedule for Party Comments - Attachment A, Gas Transition White Paper at 6.[103] Per the Decision (D.22-12-055) at 9, "clean renewable hydrogen" is defined as hydrogen produced with a carbon intensity equal to or less than four kilograms of carbon dioxide-equivalent produced on a lifecycle basis per kilogram and does not use any fossil fuel in its production process.

[103] Per the Decision (D.22-12-055) at 9, "clean renewable hydrogen" is defined as hydrogen produced with a carbon intensity equal to or less than four kilograms of carbon dioxide-equivalent produced on a lifecycle basis per kilogram and does not use any fossil fuel in its production process.

[104] D.22-12-055

[105] SoCalGas is authorized to submit a Tier 2 Advice Letter with the Commission's Energy Division to increase the $26 million cap by up to 15% if SoCalGas can demonstrate that such an increase is needed to complete the Phase One feasibility studies and the additional activities ordered in the decision.

Angeles Link in 2024 and plans to file an application to move forward with Phase 2 at a future date.

2024 Cost Allocation Proceeding

On September 30, 2022, SoCalGas and SDG&E jointly submitted their Cost Allocation Proceeding (CAP) application to revise rates for gas services and to implement gas storage related proposals effective January 1, 2024. The CAP is a periodic regulatory proceeding in which SoCalGas and SDG&E update the distribution of their costs of providing gas service to customer classes and determine the transportation rates charged to customers. The costs being distributed in this CAP include gas transmission, gas distribution, underground storage, and customer-related costs. While this allocation of costs is determined in the CAP, the actual dollar amounts of the costs are presented and determined in separate CPUC proceedings (e.g., general rate case). In the CAP, SoCalGas and SDG&E also forecast how much gas their customers may use (i.e., demand), which is used to distribute costs and establish customers' rates. A Commission decision is expected to be issued in the third quarter of 2024.

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.

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 an 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 an NGA section 4 rate case in early 2024.

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 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 each for projects able to 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[106] 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 eight projects placed o 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). 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

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 diverted organic waste, including certain wood waste, at a level in accordance with its proportionate share of statewide cap-and-trade allowances.

[106] https://www.socalgas.com/sustainability/renewable-gas/biomethane-monetary-incentive-program

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[107] and is referred to as a "Renewable Gas Standard" (RGS) for California.[108] 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 diverted organic waste, including landfill, WWTP, syngas or dairy.[109]

SB 1383

Another significant driver for RNG development in California is SB 1383. Signed into law on September 19, 2016, SB 1383 required the California Air Resources Board to implement a comprehensive strategy to reduce emissions of short-lived climate pollutants (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.

SB 1383 required that beginning in 2022, cities and counties provide organic waste collection services to all residents and businesses and secure access for recycling 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 required to procure prescribed amounts of products from in-state recycled organic material

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[107] SB-32 California Global Warming Solutions Act of 2006.

[108] D.22-02-025, p. 32.

[109] Dairy purchases are limited to 4% of the total utility proportionate share of the target volume.[110] 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.

depending on their population.[110] The short-term targets in SB 1440 were explicitly tailored to help facilitate the implementation of SB 1383.

In addition to supporting RNG production to facilitate the diversion of organic waste from landfill, SB1383 has supported RNG production from 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, CARB, and the California Department of Food and Agriculture (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[111]

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 within one year and review contract opportunities now that D.22-02-025 has implemented SB

[110] 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.

[111] 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.

1440. In August of 2022 SoCalGas filed a Tier 3 Advice Letter to modify the program by removing the residential segment and incorporating procurement for customers to meet their SB 1383 mandates. The Advice Letter was approved in March 2024 and program implementation planning has started.

Fuel Standards

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.

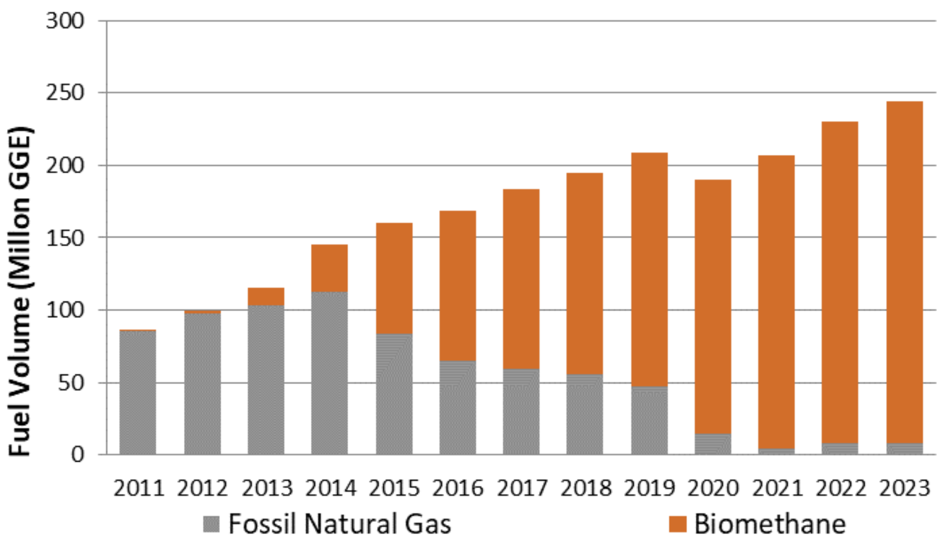
There is a significant amount of RNG used in California NGVs. Recent data from the LCFS Program[112] show that approximately 97 percent of fuel delivered to NGVs in 2023 was RNG. Figure 28 shows how RNG usage in this important program has grown over time. Since 2011, RNG use by NGV's has displaced more than 1,490 million gallons of gasoline and diesel fuel.[113]

In November 2024, CARB has scheduled a public hearing to consider amendments to the LCFS. Over the coming months, CARB staff will continue to analyze and incorporate modifications to the rulemaking proposal including a near term step-down in carbon intensity benchmarks of 7% or greater, as well as refinements to feedstock sustainability provisions, zero-emission vehicle infrastructure eligibility provisions, provisions that would increase support for

[112] classic/fuels/lcfs/dashboard/Fig2_2023.xlsxhttps://ww2.arb.ca.gov/sites/default/files/2022-05/quarterlysummary_043022.xlsx.
[113] *Id.*[114] *Id.*[115] For SDG&E CNG stations, a portion of the credits is returned to CNG customers by reducing the price at the pump.

zero-emission vehicle fueling, and other provisions. The amendments, if approved by CARB, are expected to be in effect in early 2025.

FIGURE 22 - LCFS PROGRAM NGV FUEL VOLUME STATISTICS



RENEWABLE FUEL STANDARD

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, with compliance measured by the number of Renewable Identification Numbers (RINs) generated by producing renewable fuel. In 2023, the EPA announced a final rule establishing volume targets of 30.5 billion RINs for 2023, 32.2 billion RINs for 2024, and 34.4 billion RINs for 2025.

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[114]

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.

RNG Dispensed At SoCalGas CNG Stations

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.[115] 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 this procurement program will result in more value returned to its CNG customers while supporting the development of the RNG market.

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[114] *Id.*[115] For SDG&E CNG stations, a portion of the credits is returned to CNG customers by reducing the price at the pump.

[115] For SDG&E CNG stations, a portion of the credits is returned to CNG customers by reducing the price at the pump.

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, the nation's largest carbon source, 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 Clean Power Plan, freezing carbon pollution standards for existing power plants. In March 2017, President Trump signed an Executive Order directing the EPA Administrator to review the 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, determining that the benefits of its proposed repeal would outweigh the costs. On June 19, 2019, EPA issued the final Affordable Clean Energy (ACE) rule, which focused primarily on coal power plants, and formally repealed the Clean Power Plan.[116] On January 19, 2021, the federal Court of Appeals for the DC Circuit vacated the ACE rule and remanded the case to EPA.

On July 2, 2022, the Supreme Court ruled that the EPA does not have the authority to regulate carbon emissions of power plants. Relying on the "major questions" doctrine, the court

[116] U.S. EPA, News Release: "EPA Finalizes Affordable Clean Energy Rule", June 19, 2019, available at https://www.epa.gov/newsreleases/epa-finalizes-affordable-clean-energy-rule-ensuring-reliable-diversified-energy.

held that explicit congressional authorization is required when an administration acts on issues of broad importance and societal and economic impact.

On April 25, 2024, the Biden administration finalized a suite of rules to reduce carbon emissions generated by power plants. To cut sector GHG output by 75% from 2005 levels, EPA's new rules will require coal and new natural gas power plants to either cut or capture 90% of CO2 emissions by 2032. EPA announced in February 2024 that it would delay the rulemaking process for carbon emissions from existing gas plants, which initially had been included in the agency's 2023 proposed rule. The final rule permits utilities to retrofit existing coal or new gas-fired power plants with equipment to capture and store carbon, a method EPA considers proven and cost-effective and thus deems the "best system of emissions reduction."

On April 25, 2024, EPA published a final rule revising various subparts of the Greenhouse Gas Reporting Program ("GHGRP") to modify upward the Global Warming Potentials for each GHG, expand GHGRP reporting to additional sectors by adding new subparts, and update existing methodologies. Less than two weeks later, on May 6, 2024, EPA addressed reporting of oil and gas sector methane emissions via a related but separate rulemaking under Subpart W of the GHGRP. The Subpart W amendments expand methane emissions reporting requirements for oil and natural gas systems to increase transparency and accountability, improve the accuracy of reporting, ensure reporting is based on empirical data that accurately reflects emissions from applicable facilities, enables and simplifies submission of empirical emissions, and allows new advanced technologies such as satellites for data collection. The amendments also add a new emissions category for Other Large Release Events.

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 California Air Resources Board (CARB) to adopt rules and regulations in an open public process to achieve the "maximum technologically feasible and cost effective GHG emission reductions."[117] AB 32 also

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

required CARB 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 CARB in 2008 and CARB is required to update the plan at least once every five years. The most recent update, as of this writing, was adopted in November 2022. 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 intended result is a policy framework that comprises a broad portfolio of recommended GHG reduction strategies and regulations, including a market-based compliance mechanism, that is cost effective and minimizes administrative burden and GHG emission leakage.

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 CARB 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 CARB 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 November 16, 2022, CARB released the Final 2022 Scoping Plan Update. 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 CARB 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 CARB Chair requesting that CARB 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 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 integrated resources plans, which detail how each required utility will reduce GHGs, deploy clean energy resources and otherwise meet the resources needs of their customers. The electric integrated resource planning (IRP) process is structured to be cyclical, with biennial consideration of individual IRPs filed by each load-serving entity (LSE), then the individual IRPs are aggregated and analyzed by Commission staff in order to construct a Preferred System Plan (PSP) portfolio.[118]

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.[119] 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 CARB, 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 CARB, in consultation with the California Department of Food and Agriculture (CDFA), 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, CARB 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

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[118] Rulemaking (R.) 20-05-003 set forth the timing for LSEs to submit their individual IRPs in October 2025, and anticipates the aggregation of those individual IRPs to conclude near the end of 2026 or early 2027, with consideration of the 2026 PSP and portfolio.

[119] http://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.

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

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 was increased to 60 percent, and the 50 percent target was 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 have begun workshops and modeling for the 2024 SB 100 report and held a land-use planning and an inputs and assumptions workshop in February 2024, and a non-energy impacts workshop in April 2024.

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 mtCO_2e 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.[120] 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 California Climate Credit to all

[120] CPUC D.15-10-032.

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

CARB 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 2024 CGR, the 2023 GHG numbers have not been verified by the independent third party. The 2022 numbers were the most recent verified numbers for the reporting category. As of 2022, SoCalGas reported to CARB *verified* GHG emissions of approximately 43.2mmtCe in three primary categories: (1) combustion emissions at three compressor stations and two storage fields, where annual emissions exceed 10,000 mtCO_2e; (2) vented and fugitive emissions from two compressor stations, one storage field and the natural gas distribution system; and (3) the GHG emissions resulting from combustion of natural gas delivered to all customers.

In 2022, GHG emissions for gas delivered to all customers was 41.5 mmtCO_2e, but 21.1 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, 21.1 mmtCO_2e is the appropriate Cap-and-Trade value. Large, covered customers pay their own Cap-and--Trade bill.

Three 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 CARB's Cap-and-Trade Program). More recently, SoCalGas estimated that its GHG emissions compliance obligation as a natural gas supplier to be approximately 21.4 mtCO_2E for 2023. ARB will issue final 2023 GHG emissions compliance obligations for natural gas suppliers in November 2024.

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. These emissions were reported in the SB 1371 report. Only some intentional emissions are subject to the ARB Cap-and-Trade Program.

Emissions Reduction

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 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 for the foreseeable future will be provided by gas-fired combustion turbines.

Hydrogen

Hydrogen can be utilized as a fuel to generate energy, it can be manufactured from feedstock such as methane, or water and electricity, using scalable, sustainable, and renewable methods. Hydrogen can play an important role in the transition to a clean, low-carbon energy system in California.[121]

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.[122] 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.[123] 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).[124]

Globally, hydrogen is widely seen as a pivotal component of the future clean energy economy. Hydrogen is produced with heat via a reformation process or from electricity using

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[121] http://hydrogencouncil.com
[122] https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm
[123] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB8
[124] https://www.ca.gov/archive/gov39/2018/01/26/governor-brown-takes-action-to-increase-zero-emission-vehicles-fund-new-climate-investments/index.html

electrolysis. [125] 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.

The federal government considers development of a hydrogen economy to be a strategic priority. Among the efforts is the U.S. Department of Energy's (DOE) initiative that seeks to reduce the cost of hydrogen to $1 per kilogram by 2031. Federal government efforts to spur hydrogen development are led in part through the $8 billion DOE Regional Hydrogen Hubs (H2 Hubs) program and the $7 billion that program has reserved for regional H2 Hubs.[126] On October 13, 2023, DOE selected seven H2 Hubs from across the country to enter into award negotiations with the DOE, with the anticipation that each will receive a portion of that $7 billion in federal funding[127]. One of the two largest prospective hub grant selectees was the $1.2 billion envisioned for the California Hydrogen Hub, which is led by the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES). Coordinated under the auspices of the California Governor Gavin Newsom's Office of Business and Economic Development (GO-Biz), ARCHES is California's public-private partnership designed to accelerate renewable hydrogen (H2) projects and the necessary infrastructure to help support a seamless transition to a net-zero carbon economy by 2045. Other key ARCHES priorities are environmental and energy justice, equity, improving quality of life for communities, and developing a robust workforce.

The California Hydrogen Hub seeks to leverage California's clean energy technology leadership to produce hydrogen exclusively from renewable energy and biomass, providing a blueprint for decarbonizing public transportation, heavy duty trucking, and port operations—key emissions drivers in the state and sources of air pollution that are among the hardest to

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[125] 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
[126] Regional Clean Hydrogen Hubs, DOE, available at https://www.energy.gov/oced/regional-clean-hydrogen-hubs-0.
[127] *Id*.

decarbonize.[128] The California Hydrogen Hub will focus considerable attention on cargo handling equipment and drayage to support the eventual conversion of maritime equipment at ports and prepare ports for the potential hydrogen exports.[129] The California Hydrogen Hub aims to reduce carbon emissions by approximately 2 million metric tons per year. As noted by DOE, the California Hydrogen Hub has committed to requiring Project Labor Agreements for all projects connected to the hub, which "will expand opportunities for disadvantaged communities and create an expected 220,000 direct jobs – 130,000 in construction jobs and 90,000 permanent jobs."[130]

On March 13, 2024, DOE announced $750 million for 52 hydrogen projects across 24 states that seek to advance electrolysis technologies and improve manufacturing and recycling capabilities for clean hydrogen systems and components. Directly supporting more than 1,500 new jobs, the projects are intended to support U.S. manufacturing to produce 14 gigawatts of fuel cells per year, as well as 10 gigawatts of electrolyzers per year, which would be sufficient to produce an additional 1.3 million tons of clean hydrogen per year.[131]

ASPIRE 2045

SoCalGas' ASPIRE 2045 Sustainability Strategy (the Sustainability Strategy) is a holistic approach, designed to further integrate sustainability throughout our business. It supports the Company's aspiration to achieve net-zero GHG emissions in company operations and delivery of energy by 2045 and strives to advance California's climate goals, is consistent with the United Nations Sustainable Development Goals, and aligns with SoCalGas' operational and safety

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[128] *See*, DOE Office of Clean Energy Demonstrations, "Regional Clean Hydrogen Hubs Selections for Award Negotiations," available at https://www.energy.gov/oced/regional-clean-hydrogen-hubs-selections-award-negotiations.

[129] *Id*.

[130] Press Release, Biden-Harris Administration Announces $7 Billion For America's First Clean Hydrogen Hubs, Driving Clean Manufacturing and Delivering New Economic Opportunities Nationwide | Department of Energy, October 13, 2024, available at https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving.

[131] DOE, Press Release: "Biden-Harris Administration Announces $750 million to Support America's Growing Hydrogen Industry", March 13, 2024, available at https://www.energy.gov/articles/biden-harris-administration-announces-750-million-support-americas-growing-hydrogen.

imperatives. SoCalGas' sustainability strategy focuses on key areas designed to create strong positive benefits for our customers, employees and the communities we serve.

With a heightened global awareness of the need to accelerate climate actions,[132] thoughtful planning will be critical to achieve enhanced energy security, energy investment plans and actions, and customer benefits. The existing gas infrastructure can play a critical role in delivering cleaner fuels to drive carbon reduction to achieve a cleaner and more resilient energy future. It provides potential solutions for the hard-to-electrify transportation and industrial sectors and supports electric reliability via long duration storage and balancing services to support increasing amounts of intermittent renewable power.

To build a stronger culture around sustainable business practices that supports the company's core values of doing the right thing, championing people, and shaping the future, SoCalGas examined the evolving sustainability landscape to identify and prioritize five focus areas for the company's overarching sustainability strategy. For each focus area, goals were developed with key performance indicators to transparently monitor and share progress as reported in the company's annual Corporate Sustainability Report. The focus areas below provide a framework for integrating sustainability across the business and guide investment decisions.

a. **Accelerating the transition to clean energy** – aim to accelerate the energy transition by increasing the delivery of cleaner fuels such as renewable natural gas; adapting our system for hydrogen; and supporting customer decarbonization.
b. **Protecting the climate and improving air quality in our communities** – aim to help protect California communities with the goal to achieve net zero greenhouse gas emissions by 2045 and help improve local air quality.
c. **Increasing clean energy access and affordability** – aim to increase access to clean and more affordable energy for all energy customers.
d. **Advancing a diverse, equitable, and inclusive culture** – aim to increase diversity, equity, and inclusion in the workplace and in communities we serve to achieve measurable social impact.

[132] Intergovernmental Panel on Climate Change (IPCC), Climate Change 2022 – Mitigation of Climate Change (2022) at 1-4, available at: IPCC_AR6_WGIII_FinalDraft_FullReport.pdf.

e. **Achieving world-class safety** – continually improve employee, contractor, and public safety values and culture by working to develop a best-in-class safety management program.

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 are defined as a 1-in-35 likelihood event for each utility's service area. These criteria correlate to a system average temperature of 40.6 degrees Fahrenheit for SoCalGas' service area and 43.5 degrees Fahrenheit for SDG&E's service area.

TABLE 33 – CORE 1--IN--35 YEAR EXTREME PEAK DAY DEMAND, MMcf/d

Year	SoCalGas Core Demand	SDG&E Core Demand	Other Core Demand	Total Demand	*Estimated AAFS Impact on Core Peak Day Demand*
2024	2,625	302	155	3,082	*-19*
2025	2,600	300	157	3,056	*-39*
2026	2,571	295	158	3,025	*-54*
2027	2,550	293	160	3,003	*-74*
2028	2,528	291	162	2,981	*-95*
2029	2,513	290	163	2,966	*-105*
2030	2,499	289	165	2,952	*-112*

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 3 programmatic.

(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 40.6 degrees Fahrenheit for SoCalGas' service area and 43.5 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".

Demand on an extreme peak day is met through a combination of withdrawals from underground storage facilities and flowing pipeline supplies. Table 31 provides forecasted core extreme peak day demand.

SOUTHERN CALIFORNIA GAS COMPANY

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 actively monitor these trends and expects that each update of the CGR will more clearly define 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. Even as the energy system transitions, we have an obligation to our customers to make sure they have safe and reliable gas service that is supportive of affordability particularly for our most vulnerable communities and taking a more balanced approach on prospective and uncertain projections towards achieving these outcomes better serves the public interest.

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 32 below.

TABLE 34 – WINTER 1-IN-10 YEAR COLD DAY DEMAND, 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)
2024	2,485	289	138	606	1,100	4,618	*-18*
2025	2,461	287	139	603	1,073	4,562	*-36*
2026	2,433	282	141	600	1,033	4,489	*-51*
2027	2,412	280	142	599	1,001	4,435	*-69*
2028	2,391	278	144	596	967	4,377	*-89*
2029	2,377	277	145	595	900	4,295	*-99*
2030	2,364	276	146	593	817	4,197	*-106*

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 and SDG&E noncore Commercial; SoCalGas and SDG&E noncore Commercial is at 1-in-10 peak temperature cold day demand and Refinery is at connected load.
(5) Electric Generation includes UEG/EWG 1-in-10 Dry 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 42.3 degrees Fahrenheit for SoCalGas' service area and 44.9 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 and 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 35 – 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
2024	Sep	589	82	58	570	1,986	3,283
2025	Sep	583	82	59	566	1,949	3,240
2026	Sep	576	80	60	563	1,890	3,169
2027	Sep	573	79	61	562	1,846	3,121
2028	Sep	569	78	63	560	1,829	3,099
2029	Sep	568	78	63	559	1,820	3,088
2030	Sep	567	78	64	557	1,623	2,889

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 2024, when the Electric Generation highest demand is based on 2024 hydro condition.

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SOUTHERN CALIFORNIA GAS COMPANY – TABULAR DATA

TABLE 36 – ANNUAL GAS SUPPLY AND SENDOUT, MMcf/d
RECORDED YEARS 2019 TO 2023

LINE			2019	2020	2021	2022	2023
	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		97	87	86	91	86
	Out-of-State Gas						
11	Other Out-of-State		2,305	2,366	2,377	2,325	2,449
12	Total Out-of-State Gas		2,305	2,366	2,377	2,325	2,449
13	TOTAL SUPPLY TAKEN		2,402	2,453	2,463	2,416	2,535
14	Net Underground Storage Withdrawal		7	(19)	(20)	42	(107)
15	TOTAL THROUGHPUT (1)(2)		2,409	2,435	2,443	2,458	2,428
	DELIVERIES BY END-USE						
16	Core	Residential	645	635	621	583	621
17		Commercial	226	196	211	214	224
18		Industrial	61	53	55	54	53
19		NGV	41	37	40	46	50
20		Subtotal	973	920	927	897	948
21	Noncore	Commercial	58	57	57	57	61
22		Industrial	357	369	376	362	363
23		EOR Steaming	51	51	34	29	26
24		Electric Generation	589	641	654	712	623
25		Subtotal	1,055	1,118	1,121	1,161	1,073
26	Wholesale/International		342	374	372	381	359
27	Co. Use & LUAF		39	23	23	20	48
28	SYSTEM TOTAL-THROUGHPUT (1)(2)		2,409	2,435	2,443	2,458	2,428
	TRANSPORTATION AND EXCHANGE						
29	Core	All End Uses	74	63	64	63	72
30	Noncore	Commercial/Industrial	415	426	433	419	425
31		EOR Steaming	51	51	34	29	26
32		Electric Generation	589	641	654	712	623
33		Subtotal-Retail	1,129	1,181	1,185	1,223	1,145
34	Wholesale/International		342	374	372	381	359
35	TOTAL TRANSPORTATION & EXCHANGE		1,471	1,554	1,557	1,604	1,504
36	CURTAILMENT (3)						
37	REFUSAL						
38		Total BTU Factor (Dth/Mcf)	1.0336	1.0293	1.0322	1.0313	1.0317

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 37 - ANNUAL GAS SUPPLY AND REQUIREMENTS, MMcf/d
ESTIMATED YEARS 2024 THRU 2028
AVERAGE TEMPERATURE YEAR

LINE			2024	2025	2026	2027	2028	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/]		66	66	66	66	66	8
9	Out-of-State		2,241	2,224	2,193	2,153	2,111	9
10	TOTAL SUPPLY TAKEN		2,307	2,290	2,259	2,219	2,177	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [6/]		2,307	2,290	2,259	2,219	2,177	12
	REQUIREMENTS FORECAST BY END-USE [7/]							
13	CORE [8/]	Residential	570	562	552	543	533	13
14		Commercial	206	203	197	194	190	14
15		Industrial	51	50	49	49	48	15
16		NGV	48	50	53	56	59	16
17		Subtotal-CORE	875	866	852	843	831	17
18	NONCORE	Commercial	50	50	50	50	50	18
19		Industrial	375	374	371	370	369	19
20		EOR Steaming	24	24	23	22	22	20
21		Electric Generation (EG)	615	611	602	581	558	21
22		Subtotal-NONCORE	1,065	1,059	1,046	1,023	998	22
23	WHOLESALE &	Core	200	201	199	199	199	23
24	INTERNATIONAL	Noncore Excl. EG	27	27	27	27	27	24
25		Electric Generation (EG)	117	113	112	104	99	25
26		Subtotal-WHOLESALE & INTL.	344	341	338	330	325	26
27		Co. Use & LUAF	25	24	24	24	23	27
28	SYSTEM TOTAL THROUGHPUT [6/]		2,307	2,290	2,259	2,219	2,177	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	70	72	73	74	75	29
30	NONCORE	Commercial/Industrial	425	424	421	420	418	30
31		EOR Steaming	24	24	23	22	22	31
32		Electric Generation (EG)	615	611	602	581	558	32
33		Subtotal-RETAIL	1,135	1,130	1,118	1,097	1,073	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	344	341	338	330	325	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,479	1,472	1,456	1,427	1,398	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 2023 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2024	2025	2026	2027	2028
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.1	1.0	0.9	0.8	0.7

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

	2024	2025	2026	2027	2028
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	830	819	804	793	780

TABLE 38 - ANNUAL GAS SUPPLY AND REQUIREMENTS, MMcf/d
ESTIMATED YEARS 2029 THRU 2040
AVERAGE TEMPERATURE YEAR

LINE			2029	2030	2031	2035	2040	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/]		66	66	66	66	66	8
9	Out-of-State		2,093	2,041	2,000	1,961	1,989	9
10	TOTAL SUPPLY TAKEN		2,159	2,107	2,066	2,027	2,055	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT [6/]		2,159	2,107	2,066	2,027	2,055	12
	REQUIREMENTS FORECAST BY END-USE [7/]							
13	CORE [8/]	Residential	530	525	522	509	514	13
14		Commercial	187	185	183	174	170	14
15		Industrial	48	47	47	46	44	15
16		NGV	62	65	68	76	81	16
17		Subtotal-CORE	828	823	820	804	809	17
18	NONCORE	Commercial	50	50	50	50	50	18
19		Industrial	368	368	367	365	364	19
20		EOR Steaming	21	21	20	18	16	20
21		Electric Generation (EG)	545	503	474	454	473	21
22		Subtotal-NONCORE	985	941	911	887	902	22
23	WHOLESALE &	Core	200	200	200	202	207	23
24	INTERNATIONAL	Noncore Excl. EG	27	27	27	26	26	24
25		Electric Generation (EG)	97	94	86	86	90	25
26		Subtotal-WHOLESALE & INTL.	323	320	313	314	323	26
27		Co. Use & LUAF	23	22	22	22	22	27
28	SYSTEM TOTAL THROUGHPUT [6/]		2,159	2,107	2,066	2,027	2,055	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	77	78	80	83	85	29
30	NONCORE	Commercial/Industrial	418	417	417	415	414	30
31		EOR Steaming	21	21	20	18	16	31
32		Electric Generation (EG)	545	503	474	454	473	32
33		Subtotal-RETAIL	1,061	1,019	991	970	987	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	323	320	313	314	323	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,385	1,340	1,304	1,284	1,310	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 2023 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

Note	2029	2030	2031	2035	2040
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.6	0.6	0.5	0.3	0.2

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

Note	2029	2030	2031	2035	2040
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	775	769	764	744	746

TABLE 39 - ANNUAL GAS SUPPLY AND REQUIREMENTS, MMcf/d
ESTIMATED YEARS 2024 THRU 2028
COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2024	2025	2026	2027	2028	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/		66	66	66	66	66	8
9	Out-of-State		2,310	2,287	2,255	2,216	2,170	9
10	TOTAL SUPPLY TAKEN		2,376	2,353	2,321	2,282	2,236	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,376	2,353	2,321	2,282	2,236	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	612	604	594	585	575	13
14		Commercial	215	211	205	202	198	14
15		Industrial	51	51	50	50	49	15
16		NGV	48	50	53	56	59	16
17		Subtotal-CORE	926	917	902	893	881	17
18	NONCORE	Commercial	50	51	51	51	51	18
19		Industrial	375	374	371	370	369	19
20		EOR Steaming	24	24	23	22	22	20
21		Electric Generation (EG)	617	613	603	583	559	21
22		Subtotal-NONCORE	1,068	1,062	1,048	1,027	999	22
23	WHOLESALE &	Core	210	207	205	205	205	23
24	INTERNATIONAL	Noncore Excl. EG	28	27	27	27	27	24
25		Electric Generation (EG)	119	116	114	106	100	25
26		Subtotal-WHOLESALE & INTL.	357	350	346	338	332	26
27		Co. Use & LUAF	25	25	25	24	24	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,376	2,353	2,321	2,282	2,236	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	72	73	74	75	77	29
30	NONCORE	Commercial/Industrial	426	425	421	421	419	30
31		EOR Steaming	24	24	23	22	22	31
32		Electric Generation (EG)	617	613	603	583	559	32
33		Subtotal-RETAIL	1,139	1,135	1,122	1,102	1,076	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	357	350	346	338	332	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,496	1,484	1,468	1,440	1,408	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 2023 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2024	2025	2026	2027	2028
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	1.1	1.0	0.9	0.8	0.7

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

	2024	2025	2026	2027	2028
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	881	870	855	844	830

TABLE 40 - ANNUAL GAS SUPPLY AND REQUIREMENTS, MMcf/d
ESTIMATED YEARS 2029 THRU 2040
COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2029	2030	2031	2035	2040	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/		66	66	66	66	66	8
9	Out-of-State		2,152	2,101	2,059	2,017	2,044	9
10	TOTAL SUPPLY TAKEN		2,218	2,167	2,125	2,083	2,110	10
11	Net Underground Storage Withdrawal		0	0	0	0	0	11
12	TOTAL THROUGHPUT 6/		2,218	2,167	2,125	2,083	2,110	12
	REQUIREMENTS FORECAST BY END-USE 7/							
13	CORE 8/	Residential	571	567	563	549	553	13
14		Commercial	195	193	191	181	177	14
15		Industrial	49	48	48	46	45	15
16		NGV	62	65	68	76	81	16
17		Subtotal-CORE	878	873	869	852	855	17
18	NONCORE	Commercial	51	51	51	51	51	18
19		Industrial	368	368	367	365	364	19
20		EOR Steaming	21	21	20	18	16	20
21		Electric Generation (EG)	546	504	475	454	473	21
22		Subtotal-NONCORE	986	943	913	888	903	22
23	WHOLESALE &	Core	206	206	206	208	212	23
24	INTERNATIONAL	Noncore Excl. EG	27	27	27	27	27	24
25		Electric Generation (EG)	98	95	87	87	90	25
26		Subtotal-WHOLESALE & INTL.	331	328	320	321	329	26
27		Co. Use & LUAF	24	23	23	22	22	27
28	SYSTEM TOTAL THROUGHPUT 6/		2,218	2,167	2,125	2,083	2,110	28
	TRANSPORTATION AND EXCHANGE							
29	CORE	All End Uses	78	80	81	85	87	29
30	NONCORE	Commercial/Industrial	419	418	418	416	414	30
31		EOR Steaming	21	21	20	18	16	31
32		Electric Generation (EG)	546	504	475	454	473	32
33		Subtotal-RETAIL	1,065	1,023	994	973	990	33
	WHOLESALE &							
34	INTERNATIONAL	All End Uses	331	328	320	321	329	34
35	TOTAL TRANSPORTATION & EXCHANGE		1,395	1,350	1,314	1,294	1,319	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 2023 recorded California Source Gas; production less than capacity due to reservoir performance and economics.

	2029	2030	2031	2035	2040
6/ Excludes own-source gas supply of gas procurement by the City of Long Beach	0.6	0.6	0.5	0.3	0.2

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

	2029	2030	2031	2035	2040
8/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d:	825	818	814	792	793

TABLE 41 - ANNUAL GAS REQUIREMENTS, MMcf/d
1-IN-10 COLD TEMPERATURE YEAR & DRY HYDRO YEAR (1)

Year	Core	Noncore	Wholesale & International	Company Use & LUAF	System Total Throughput
2024	908	1,067	355	25	2,355
2025	899	1,061	347	25	2,333
2026	885	1,048	344	24	2,300
2027	876	1,026	336	24	2,262
2028	864	999	330	24	2,216
2029	861	986	328	23	2,198
2030	855	943	325	23	2,147
2031	852	912	318	22	2,105
2035	836	888	319	22	2,064
2040	839	903	327	22	2,091

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.

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2024 CALIFORNIA GAS REPORT

CITY OF LONG BEACH UTILITIES DEPARTMENT

CITY OF LONG BEACH UTILITIES DEPARTMENT

The annual gas supply and forecast requirements prepared by the City of Long Beach Utilities Department (Long Beach) are shown on the following tables for the years 2024 through 2040.

Serving approximately 150,000 customers, Long Beach is the largest California municipal gas utility and the seventh 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's Utility Board, 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 within Long Beach's service territory and 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 Southwest United States. Long Beach, as a wholesale customer, receives intrastate transmission service for this gas from SoCalGas.

2024 CALIFORNIA GAS REPORT

CITY OF LONG BEACH UTILITIES DEPARTMENT – TABULAR DATA

TABLE 42 – CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 1-LB
ANNUAL GAS SUPPLY AND SENDOUT RECORDED YEARS 2019-2023, MMcf/d

LINE	GAS SUPPLY AVAILABLE	2019	2020	2021	2022	2023	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	1.1	0.7	1.3	3.2	1.1	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.1	0.7	1.3	3.2	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	25.2	24.8	24.2	20.2	24.7	19
20	Out-of-State Transport	0.0	0.0	0.0	0.0	0.0	20
21	Total Out-of-State Gas	25.2	24.8	24.2	20.2	24.7	21
22	Subtotal	26.3	25.5	25.5	23.4	25.8	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	26.3	25.5	25.5	23.4	25.8	24

TABLE 43 – CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 1-LB ANNUAL GAS SUPPLY AND SENDOUT RECORDED YEARS 2019-2023, MMcf/d

LINE	ACTUAL DELIVERIES BY END-USE		2019	2020	2021	2022	2023	LINE
1	CORE	Residential	12.9	12.9	12.6	11.9	12.1	1
2	CORE/NONCORE	Commercial	6.1	5.3	5.7	5.8	6.0	2
3	CORE/NONCORE	Industrial	4.7	4.1	4.3	4.2	4.7	3
4		Subtotal	23.8	22.2	22.6	21.9	22.8	4
5	NON CORE	Non-EOR Cogeneration	1.7	2.5	2.3	1.1	2.2	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	1.7	2.5	2.3	1.1	2.2	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	0.8	0.7	0.6	0.4	0.8	13
14		Subtotal-END USE	26.3	25.5	25.4	23.4	25.8	14
15		Storage Injection	0.0	0.0	0.0	0.0	0.0	15
16	SYSTEM TOTAL-THROUGHPUT		26.3	25.5	25.4	23.4	25.8	16
	ACTUAL TRANSPORTATION AND EXCHANGE							
17		Residential	N/A	N/A	N/A	N/A	N/A	17
18		Commercial/Industrial	3.1	2.8	3.1	2.9	3.1	18
19		Non-EOR Cogeneration	1.5	2.5	2.3	1.1	1.9	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	4.7	5.3	5.4	4.0	5.0	22
23	WHOLESALE	All End Uses	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL TRANSPORTATION & EXCHANGE		4.7	5.3	5.4	4.0	5.0	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 44– CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 1A-LB
ANNUAL GAS SUPPLY AND SENDOUT AVERAGE YEAR FORECAST 2024-2040, MMcf/d

LINE	GAS SUPPLY AVAILABLE	2024	2025	2026	2030	2035	2040	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	1.1	1.0	0.9	0.6	0.3	0.2	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.1	1.0	0.9	0.6	0.3	0.2	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	23.9	24.3	24.7	25.0	25.3	25.7	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	23.9	24.3	24.7	25.0	25.3	25.7	21
22	Subtotal	25.0	25.2	25.6	25.6	25.6	25.9	22
23	Underground Storage Withdrawal	0.0	0.0	0.0	0.0	0.0	0.0	23
24	TOTAL Gas Supply Taken & Transported	25.0	25.2	25.6	25.6	25.6	25.9	24

TABLE 45 – CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 2A-LB
ANNUAL GAS SUPPLY AND SENDOUT AVERAGE YEAR FORECAST 2024-2040, MMcf/d

LINE	ACTUAL DELIVERIES BY END-USE		2024	2025	2026	2030	2035	2040	LINE
1	CORE	Residential	12.3	12.4	12.5	12.5	12.5	12.5	1
2	CORE/NONCORE	Commercial	5.5	5.6	5.6	5.6	5.6	5.7	2
3	CORE/NONCORE	Industrial	3.9	3.9	4.0	4.0	4.0	4.1	3
4		Subtotal	21.7	21.9	22.1	22.1	22.1	22.3	4
5	NON CORE	Non-EOR Cogeneration	2.4	2.4	2.6	2.6	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	2.4	2.4	2.6	2.6	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	25.0	25.2	25.6	25.6	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		25.0	25.2	25.6	25.6	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	3.4	3.4	3.5	3.5	3.5	3.7	18
19		Non-EOR Cogeneration	1.8	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	5.1	5.1	5.3	5.3	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		5.1	5.1	5.3	5.3	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 46– CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 3C-LB
ANNUAL GAS SUPPLY AND SENDOUT COLD YEAR FORECAST 2024-2040, MMcf/d

LINE	GAS SUPPLY AVAILABLE	2024	2025	2026	2030	2035	2040	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	1.1	1.0	0.9	0.6	0.3	0.2	13
14	Received for Exchange/Transport	0.0	0.0	0.0	0.0	0.0	0.0	14
15	Total California Source Gas	1.1	1.0	0.9	0.6	0.3	0.2	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	29.6	29.8	29.8	30.2	30.4	30.5	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	29.6	29.8	29.8	30.2	30.4	30.5	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 47– CITY OF LONG BEACH UTILITIES DEPARTMENT: TABLE 4C-LB
ANNUAL GAS SUPPLY AND SENDOUT COLD YEAR FORECAST 2024-2040, MMcf/d

LINE	ACTUAL DELIVERIES BY END-USE		2024	2025	2026	2030	2035	2040	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.

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2024 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY

INTRODUCTION

San Diego Gas & Electric (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 912,608 customers in San Diego County in 2023, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2023 were approximately 97 billion cubic feet (Bcf), which is an average of 260.5 MMcf/d.

GAS DEMAND

SDG&E's gas demand forecast is determined in part by the both the short-term and 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.

SDG&E used the same Energy Efficiency (EE) and Additional Achievable Fuel Substitution (AAFS) as SoCalGas. These assumptions are discussed in the earlier SoCalGas section of the 2024 California Gas Report.

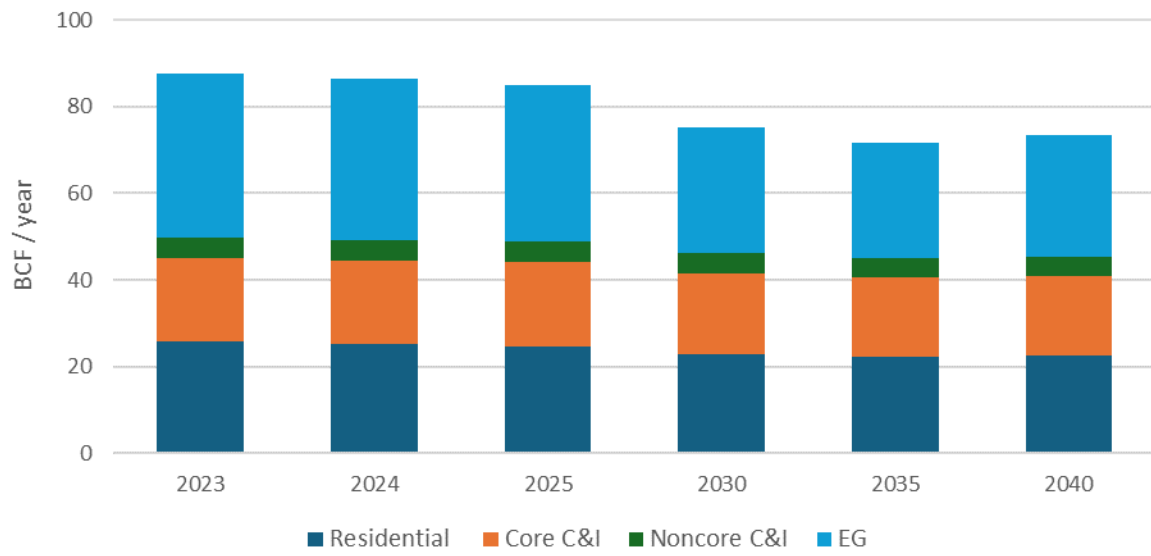
Altogether, SDG&E's gas demand, not inclusive of gas driven EG, is projected to drop slightly from 49.3 Bcf in 2024 to 45.3 Bcf in 2040, which is an average annual rate of decline of 0.5 percent. Including EG, overall demand adjusted for average temperature conditions totaled 86.5 Bcf in 2024 and is expected to drop about 1 percent per year to 73.5 Bcf by 2040.

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 determined in part by the short-term and long-term economic outlook for its San Diego County service area. Like the SoCalGas service territory, both gross metro product and employment have surpassed their pre-COVID-19 levels and are expected to grow at slower rates than before the pandemic. San Diego similarly faces downside risks to its short-term and long-term economic outlook in the form of elevated interest rates in the near-term and weak population growth through the forecast horizon.

FIGURE 23 – SDG&E'S COMPOSITION OF NATURAL GAS THROUGHPUT AVERAGE TEMPERATURE, NORMAL YEAR



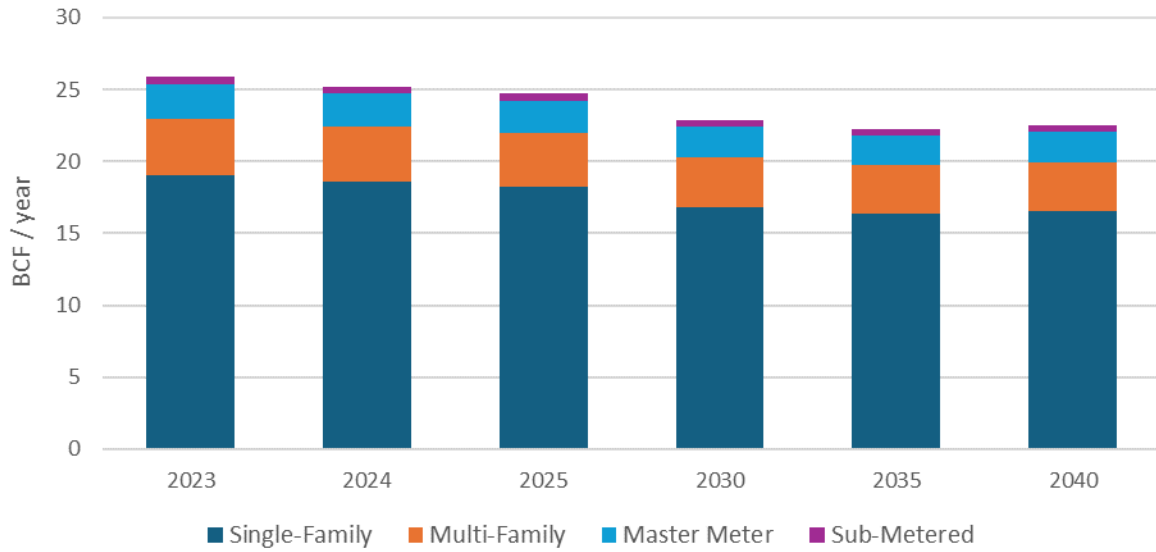
From 2024 through 2040, SDG&E's forecasted gas demand is expected to decline at an average annual rate of 1.0 percent. The decline is being driven by future projected reductions in the EG load, energy efficiency programs (including new requirements on Title 24 building codes and standards) and assumed fuel substitution over the forecast period.

MARKET SECTORS

Residential

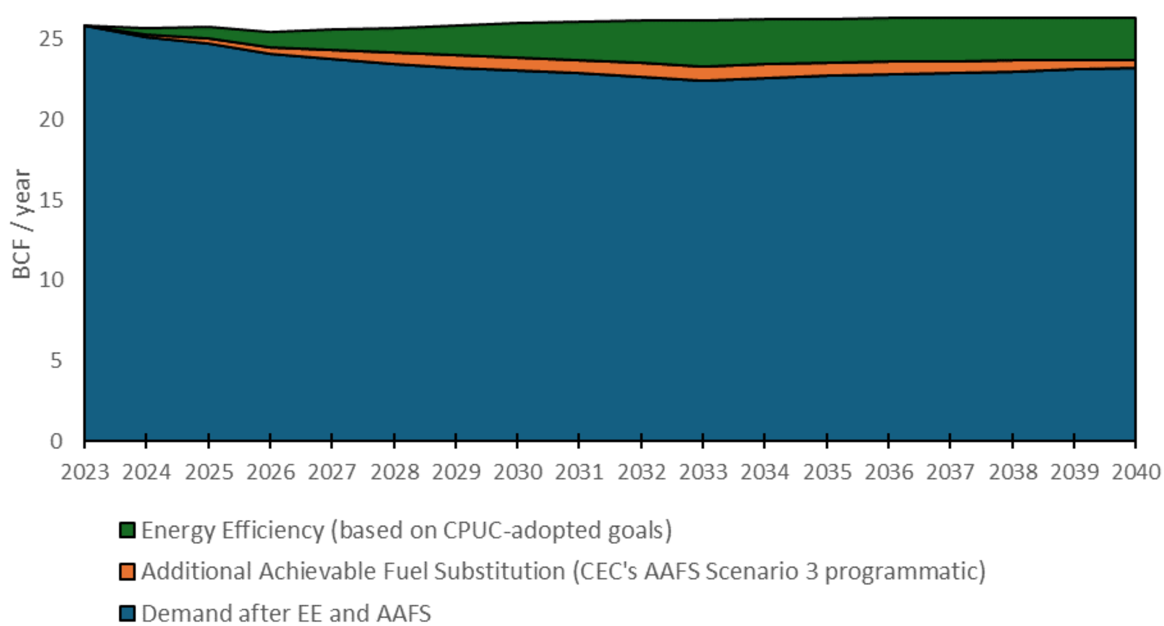
Residential gas demand is forecasted to decline from 25.2 Bcf in 2024 to 22.5 Bcf by 2040 at an average annual rate of 0.7 percent. The decline is due to declining use per meter, primarily driven by aggressive energy efficiency goals, anticipated fuel substitution, and tightening Title 24 Codes and Standards. The demand reduction is created by the policies described above which offset the load created by the new meter growth and efficiencies created by appliance replacements forecasted over the planning period.

FIGURE 24 – COMPOSITION OF SDG&E'S RESIDENTIAL DEMAND FORECAST AVERAGE YEAR WEATHER DESIGN



The effects of both energy efficiency and fuel substitution have an impact on the residential market as shown in Figure 31. The largest impact is reached in year 2040.

FIGURE 25: SDGE EE AND FUEL SUBSTITUTION



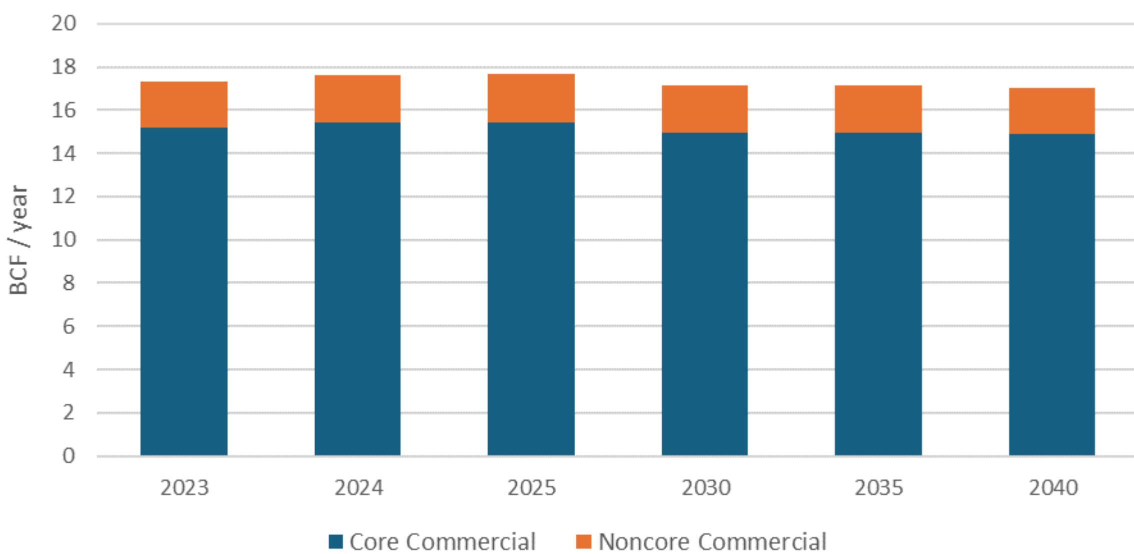
By year 2040, the assumed additional energy efficiency removes 9.8 percent of residential gas demand. Evaluated separately, the assumed additional fuel substitution removes another 2.1 percent of residential gas demand by the year 2040. Similar to SoCalGas, the CEC's 2023 IEPR AAFS Programmatic 3 scenario was used as the fuel substitution assumption for SDG&E. See the SoCalGas section for discussion regarding this assumption selection.

Commercial

On a temperature--adjusted basis, SDG&E's core commercial demand in 2024 totaled 15.4 Bcf. By the year 2040, the core commercial load is forecasted to decline to 14.9 Bcf. The annual average rate of decline of the core commercial market over the forecast horizon is expected to be 0.2 percent.

SDG&E's non-core commercial load in 2024 was 2.22 Bcf. Over the forecast period, gas demand in this market is projected to decline slightly to be about 2.15 BCF by 2040.

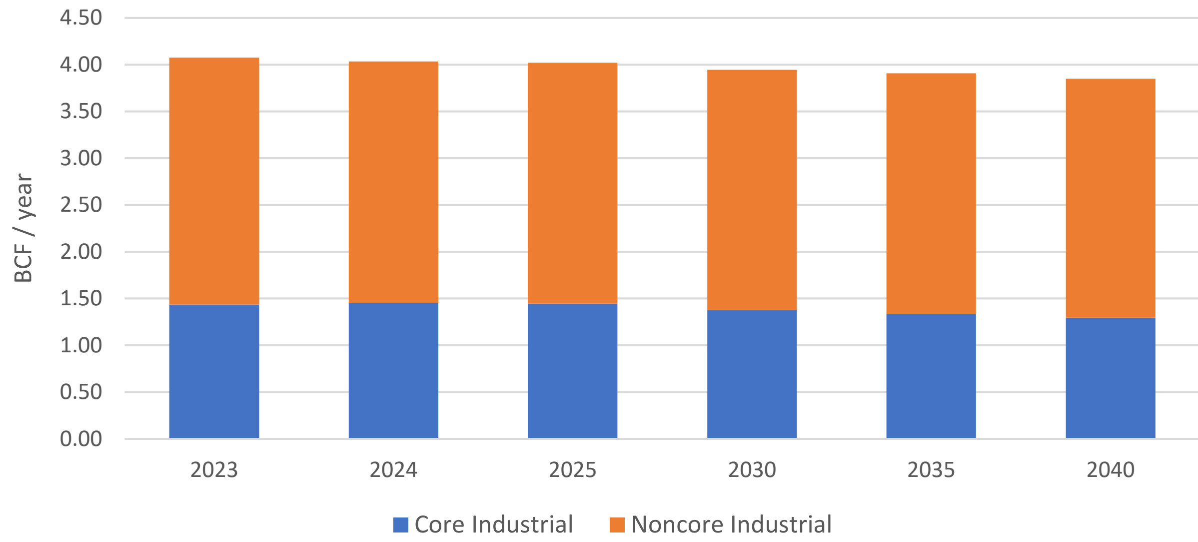
FIGURE 26 –SDG&E COMMERCIAL NATURAL GAS DEMAND FORECAST AVERAGE YEAR WEATHER DESIGN



Industrial

Temperature--adjusted core industrial demand was 1.5 Bcf in 2024 and is expected to decline to 1.3 Bcf by 2040, an average decrease of 0.7 percent per year. This result is due to a combination of factors: a decrease in core industrial customer counts, the impact of climate change, and the impact of savings from CPUC-authorized energy efficiency programs in the core industrial sector.

FIGURE 27 –SDG&E INDUSTRIAL NATURAL GAS DEMAND FORECAST
AVERAGE YEAR WEATHER DESIGN

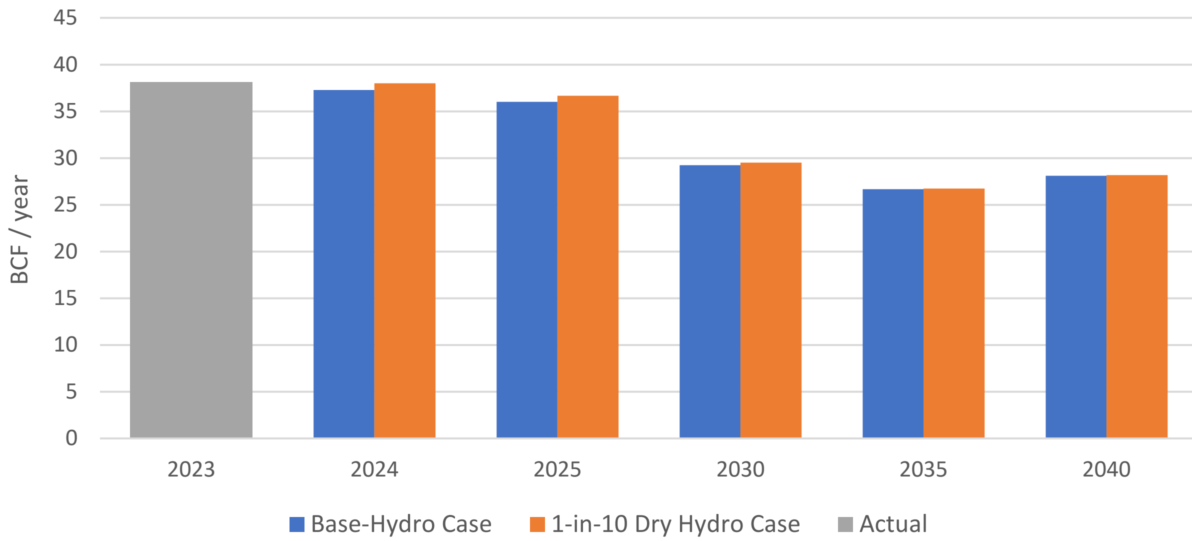


Non-core industrial load in 2024 was 2.59 Bcf and is expected to shrink about 0.1 percent per year to 2.56 Bcf by 2040. The reduced demand is primarily due to the CPUC-authorized energy efficiency programs and decreasing industrial employment.

Electric Generation

Total EG, including cogeneration and non--cogeneration EG, was 37.3 Bcf in 2024. From 2024, EG load is expected to decline an average of 1.7 percent per year to 28.1 Bcf by 2040. The following graph shows total EG forecasts for a normal hydro year and a 1--in--10 dry hydro year.

FIGURE 28 – TOTAL EG GAS DEMAND: BASE HYDRO AND 1-IN-10 DRY HYDRO DESIGN



Small Cogeneration (<20 MW)

Small Electric Generation load from self-generation is expected to decline from 7.2 Bcf in 2024 to 7.0 Bcf by 2040.

Electric Generation Including Large Cogeneration (>20 MW)

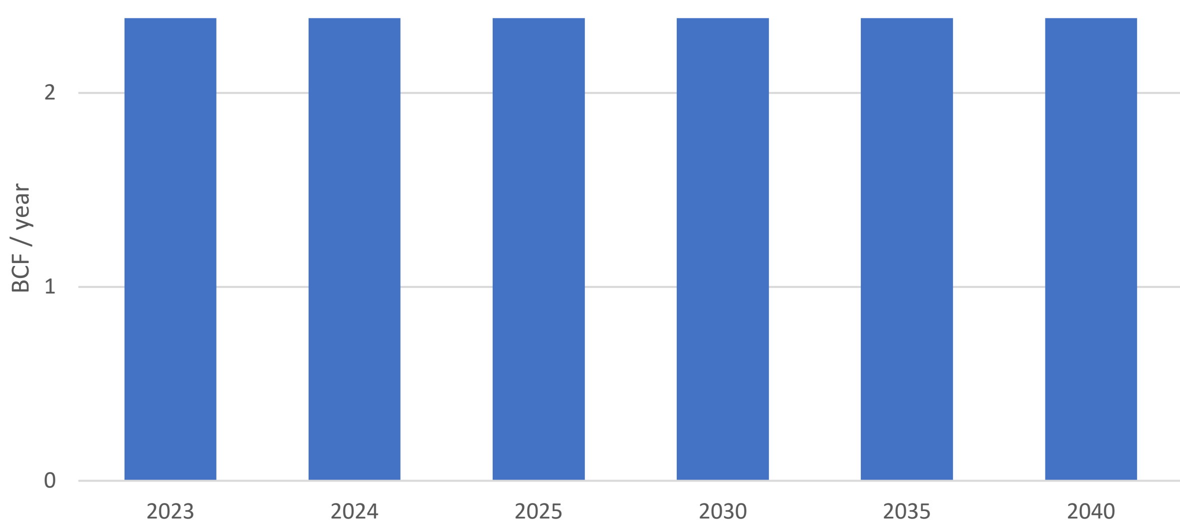
The forecast of large EG loads in SDG&E's service area is based on the power market simulation noted in SoCalGas' EG chapter for "Electric Generation Including All Cogeneration EG demand is forecasted to decrease from 30.0 Bcf in 2024 to 21 Bcf in 2040. This forecast includes no additional thermal generating resources in its service area, and it assumes no retirement during the same time period. It assumes the same 2023 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% 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 2023, SDG&E served 39 compressed natural gas (CNG) fueling stations located throughout the service territory. The SDG&E NGV market is expected to remain stable at 2.4 Bcf per year over the forecast horizon.

FIGURE 29 – ANNUAL NGV DEMAND FORECAST

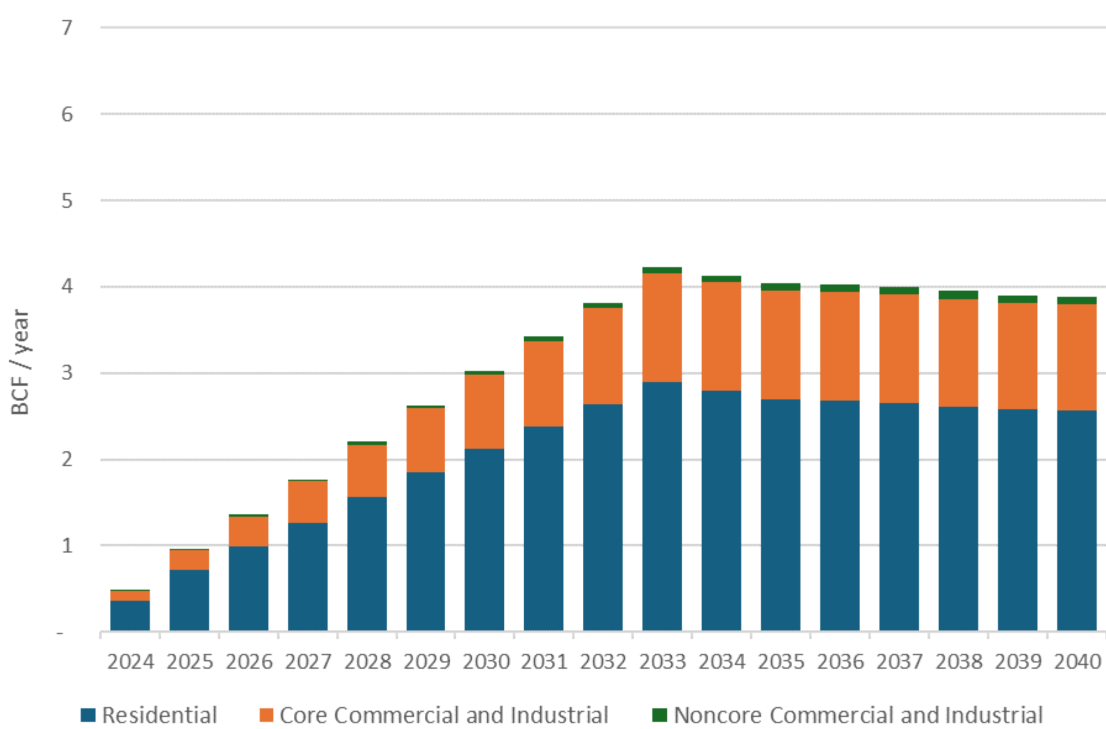


Energy Efficiency Programs

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 2024 and occurring through the year 2040 in addition to the Title 24 Codes and Standards expected over the 2024-2040 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.

FIGURE 30 – SDG&E ANNUAL ENERGY EFFICIENCY CUMULATIVE SAVING GOALS



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.[133] 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.

[133] 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

In May 2022, SDG&E filed its 2024 General Rate Case seeking to revise its authorized revenue requirements for 2024-2027 to recover the reasonable costs of electric and gas operations, facilities, infrastructure, and other functions necessary to provide utility services to customers. Based on a July 2023 update, SDG&E requests a combined $3.007 billion revenue requirement ($659 million gas and $2.348 billion electric), which, if approved, would be an increase of $474 million over authorized 2023 revenue requirement, or a 18.7% increase. For 2025-2027, SDG&E's revenue requirement requests range between 8.2-11.5%. Intervenor and rebuttal testimony were served in March 2023 and May 2023, respectively. Evidentiary hearings were held in June and update testimony was served in July 2023. Briefs were filed in August and September. In October 2023, settlements were filed resolving certain key issues among some of the parties. Comments on the settlements were filed in November and December 2023. A proposed decision is expected in the second quarter of 2024.

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. As discussed in the SoCalGas Peak Day Demand section, SDG&E has observed a decline in recorded core winter peak demand in recent years, which is contributing to a lower forecast in peak demand. SoCalGas will continue to monitor SDG&E core winter peak and provide additional analysis in the 2025 CGR Supplement if material developments occur.

TABLE 48 – SDG&E WINTER PEAK DAY DEMAND, MMcf/d

Year	Core 1-in-35 Extreme Peak Day Demand		1-in-10 Cold Day Demand			
			Core	Noncore C&I	EG	Total
2024	302		289	17	237	543
2025	300		287	17	236	540
2026	295		282	17	233	532
2027	293		280	17	213	511
2028	291		278	17	195	490
2029	290		277	17	204	498
2030	289		276	17	197	491

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 criterion correlates to 43.5 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 3 programmatic.

(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 44.9 degrees Fahrenheit for SDG&E's service area.

(3) 1-in-10 peak day demand for noncore commercial, and average daily December demand for noncore industrial.

(4) Electric Generation includes UEG/EWG 1-in-10 Dry Hydro, large cogeneration, industrial and commercial cogeneration (<20MW).

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2024 CALIFORNIA GAS REPORT

SAN DIEGO GAS & ELECTRIC COMPANY – TABULAR DATA

TABLE 49 - ANNUAL GAS SUPPLY TAKEN, MMcf/d
RECORDED YEARS 2019-2023

LINE		2019	2020	2021	2022	2023
	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	**2019**	**2020**	**2021**	**2022**	**2023**
	California Source Gas					
11	Regular Purchases	-	-	-	-	-
12	Received for Exchange/Transport	-	-	-	-	-
13	**Total California Source Gas**	-	-	-	-	-
14	**Purchases from Other Utilities**	-	-	-	-	-
	OUT-OF-STATE GAS					
15	Pacific Interstate Companies	-	-	-	-	-
16	Additional Core Supplies	-	-	-	-	-
17	Supplemental Supplies-Utility	127	126	126	122	128
18	Out-of-State Transport-Others	103	151	139	152	132
19	**TOTAL OUT-OF-STATE GAS**	230	277	265	274	260
20	**TOTAL GAS SUPPLY TAKEN & TRANSPORTED**	230	277	265	274	260

TABLE 50 - ANNUAL GAS SUPPLY AND SENDOUT, MMcf/d
RECORDED YEARS 2019-2023

LINE			2019	2020	2021	2022	2023
	Actual Deliveries by End-Use						
1	**CORE**	Residential	80	81	78	74	82
2		Commercial	58	50	52	56	58
3		Industrial	-	-	-	-	-
4	*Subtotal -*	*CORE*	138	131	130	130	140
5	**NONCORE**	Commercial	-	-	-	-	-
6		Industrial	13	13	15	19	18
7		Non-EOR Cogen/EG	43	84	77	76	77
8		Electric Utilities	33	41	36	46	25
9	*Subtotal -*	*NONCORE*	89	138	128	141	120
10	**WHOLESALE**	All End Uses	-	-	-	-	-
11	*Subtotal -*	*Co Use & LUAF*	4	8	7	3	1
12	**SYSTEM TOTAL THROUGHPUT**		231	277	265	274	261
	Actual Transport & Exchange						
13	**CORE**	Residential	1	1	0	0	1
14		Commercial	14	12	11	11	12
15	**NONCORE**	Industrial	13	13	15	19	18
16		Non-EOR Cogen/EG	43	84	77	76	77
17		Electric Utilities	33	41	36	46	25
18	*Subtotal -*	*RETAIL*	103	151	139	153	132
19	**WHOLESALE**	All End Uses	-	-	-	-	-
20	**TOTAL TRANSPORT & EXCHANGE**		103	151	139	153	132
	Storage						
21		*Storage Injection*	-	-	-	-	-
22		*Storage Withdrawal*	-	-	-	-	-
	Actual Curtailment						
23		Residential	-	-	-	-	-
24		Com/Indl & Cogen	-	-	-	-	-
25		Electric Generation	-	-	-	-	-
26	**TOTAL CURTAILMENT**		-	-	-	-	-
27	**REFUSAL**		-	-	-	-	-
	ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes						
		MMbtu/Mcf:	1.032	1.025	1.030	1.028	1.025

TABLE 51 - ANNUAL GAS SUPPLY AND REQUIREMENTS, MMcf/d
ESTIMATED YEARS 2024-2028
AVERAGE TEMPERATURE YEARS

LINE			2024	2025	2026	2027	2028	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		238	234	230	220	215	5
6	TOTAL SUPPLY TAKEN		238	234	230	220	215	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		238	234	230	220	215	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	69	68	66	65	64	9
10		Commercial	42	42	41	41	41	10
11		Industrial	4	4	4	4	4	11
12		NGV	7	7	7	7	7	12
13		Subtotal-CORE	121	121	117	116	115	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	7	7	7	7	7	15
16		Electric Generation (EG)	102	99	98	89	86	16
17		Subtotal-NONCORE	115	112	111	102	98	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		238	234	230	220	215	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	11	12	11	11	11	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	102	99	98	89	86	22
23	TOTAL TRANSPORTATION & EXCHANGE		126	123	122	113	110	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 2024 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:

	2024	2025	2026	2027	2028
transportation (CAT) in MDth/d:	113	112	109	108	106

TABLE 52 - ANNUAL GAS SUPPLY AND REQUIREMENTS, MMcf/d
ESTIMATED YEARS 2029 THRU 2040
AVERAGE TEMPERATURE YEARS

LINE			2029	2030	2031	2035	2040	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		212	208	200	198	202	5
6	TOTAL SUPPLY TAKEN		212	208	200	198	202	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		212	208	200	198	202	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	63	63	62	61	61	9
10		Commercial	41	41	41	40	40	10
11		Industrial	4	4	4	4	4	11
12		NGV	7	7	7	7	7	12
13		Subtotal-CORE	114	114	113	111	111	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	7	7	7	7	7	15
16		Electric Generation (EG)	83	80	73	73	77	16
17		Subtotal-NONCORE	96	93	86	85	89	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		212	208	200	198	202	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	11	11	11	11	11	20
21	NONCORE	Commercial/Industrial	13	13	13	12	13	21
22		Electric Generation (EG)	83	80	73	73	77	22
23	TOTAL TRANSPORTATION & EXCHANGE		107	104	97	96	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 value based on weighting winter and non-winter season values: 574 = (595 winter) x (151/365) + (560 non-winter) x (214/365).

2/ For 2024 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:

	2029	2030	2031	2035	2040
transportation (CAT) in MDth/d:	106	105	104	103	103

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TABLE 53 - ANNUAL GAS SUPPLY AND REQUIREMENTS, MMcf/d
ESTIMATED YEARS 2029 THRU-2040
COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2024	2025	2026	2027	2028	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		247	243	238	229	222	5
6	TOTAL SUPPLY TAKEN		247	243	238	229	222	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		247	243	238	229	222	8
	REQUIREMENTS FORECAST BY END-USE 3/							
9	CORE 4/	Residential	73	72	71	70	68	9
10		Commercial	44	44	43	43	42	10
11		Industrial	4	4	4	4	4	11
12		NGV	7	7	7	7	7	12
13		Subtotal-CORE	128	127	124	123	121	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	7	7	7	7	7	15
16		Electric Generation (EG)	104	100	99	91	86	16
17		Subtotal-NONCORE	117	114	112	104	99	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		247	243	238	229	222	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)	104	100	99	91	86	22
23	TOTAL TRANSPORTATION & EXCHANGE		129	126	124	116	111	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 2024 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: 119 118 115 114 112

TABLE 54 - ANNUAL GAS SUPPLY AND REQUIREMENTS, MMcf/d
ESTIMATED YEARS 2029 THRU-2040
COLD TEMPERATURE YEAR (1 IN 35 COLD YEAR EVENT) & DRY HYDRO YEAR

LINE			2029	2030	2031	2035	2040	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		220	216	207	205	209	5
6	TOTAL SUPPLY TAKEN		220	216	207	205	209	6
7	Net Underground Storage Withdrawal		0	0	0	0	0	7
8	TOTAL THROUGHPUT		220	216	207	205	209	8
	REQUIREMENTS FORECAST BY END-USE [3/]							
9	CORE [4/]	Residential	68	67	67	66	66	9
10		Commercial	42	42	42	41	41	10
11		Industrial	4	4	4	4	4	11
12		NGV	7	7	7	7	7	12
13		Subtotal-CORE	121	120	119	117	118	13
14	NONCORE	Commercial	6	6	6	6	6	14
15		Industrial	7	7	7	7	7	15
16		Electric Generation (EG)	84	81	74	73	77	16
17		Subtotal-NONCORE	97	94	86	86	90	17
18		Co. Use & LUAF	2	2	2	2	2	18
19	SYSTEM TOTAL THROUGHPUT		220	216	207	205	209	19
	TRANSPORTATION AND EXCHANGE							
20	CORE	All End Uses	12	12	12	11	11	20
21	NONCORE	Commercial/Industrial	13	13	13	13	13	21
22		Electric Generation (EG)	84	81	74	73	77	22
23	TOTAL TRANSPORTATION & EXCHANGE		109	105	98	97	101	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 2024 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:

	2029	2030	2031	2035	2040
transportation (CAT) in MDth/d:	112	111	110	109	109

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2024 CALIFORNIA GAS REPORT

GLOSSARY

GLOSSARY

AAEE
Additional Achievable Energy Efficiency.

AAFS
Additional Achievable Fuel Substitution.

AB
Assembly Bill.

ACE
Affordable Clean Energy.

ACT
Advanced Clean Truck.

AD
Anaerobic Digestion.

AGA
American Gas Association.

ALF
Annual Load Forecast.

ALMA
Angeles Link Memorandum Account.

ALP
Angeles Link Project.

APD
Abnormal Peak Day.

ARCHES
Alliance for Renewable Clean Hydrogen Energy Systems.

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.

BAAQM
Bay Area Air Quality Management District.

BCF
billion cubic feet.

Bcf/d
billion cubic feet per day.

Bcf/y
billion cubic feet per year.

BE
building electrification.

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.

C&S
Codes and standards.

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.

CAP
Cost Allocation Proceeding.

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.

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 of 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.

CPCN
Certificate of public convenience and necessity.

CPUC
California Public Utilities Commission (see also Commission).

Cubic Foot of Gas
The 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.

DCPP
Diablo Canyon Power Plant.

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.

ECAs
Emissions Control Areas

EE
Energy Efficiency and Conservation and Energy Efficient.

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

EIA(s)
Energy Information Administration.

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 the ability to extract oil by lowering its viscosity. Also used to designate a special category of gas customers.

EPA
Environmental Protection Agency.

ESG
Environmental, Social, Governance.

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 to generate 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 is delivered to gas customers for consumption, including shrinkage.

GHG (Greenhouse Gas)
GHGs are the gases present in the atmosphere that reduce the loss of heat into space and therefore contribute to global temperatures through the greenhouse effect. The most abundant GHGs, in order of relative abundance, are water vapor, CO_2, methane, nitrous oxide, ozone, and CFCs.

GHGRP
Greenhouse Gas Reporting Program.

GIF
Gas Investments for the Future.

GRC
General Rate Case.

GT&S
Gas Transmission and Storage.

GTN
Gas Transmission Northwest LLC.

H_2
Hydrogen.

H2Hub

Hydrogen Hub(s)

HC
Hydrocarbon.

HDD (Heating Degree Day)
An 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-degree F average temperature day, SoCalGas and SDG&E would accumulate 15 HDD, and PG&E would accumulate 10 HDD.

Heating Value
Number of BTUs 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 Pounds per square inch absolute (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.

Hydro
Hydroelectric generation.

ICF
ICF Consulting

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 utilities.

IMO
International Maritime Organization.

IRP
Integrated Resource Plan or Integrated Resource Planning.

ISP(s)
Independent Storage Providers.

LCFS
Low Carbon Fuel Standard(s).

LDC
Local electric and/or natural gas distribution company.

LNG (Liquefied Natural Gas)
Natural gas that has been supercooled 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 ensure that generators are producing neither too little nor too much energy to supply the utilities' customers.

LSE(s)
Load-serving entities.

LUAF
Lost and Unaccounted For.

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.

MMBtu
Million British Thermal Units. One MMbtu is equal to 10 therms or one dekatherm.

MMcf/d
Million cubic feet per day.

mmt
million metric tons.

mmtCO$_2$e
million metric tons of carbon dioxide equivalent.

mtCO$_2$e
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)
A 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.

NW
Northwest.

NO_x
nitrogen oxide.

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

OII
Order Instituting Investigation.

OIR
Order Instituting Rulemaking.

OTC
Once-through cooling.

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

PG&E
Pacific Gas and Electric Company.

PHMSA
Pipeline and Hazardous Materials Safety Administration.

PLEXOS
PLEXOS is a commercial simulation engine and software designed to assist modelers, generators, and market analysts in making informed decisions and conducting analyses across various energy markets. It is capable of modeling and optimizing power systems for electricity,

water, gas, and renewable energy sectors over diverse timescales, from short-term operations to long-term planning.

PNW
Pacific Northwest.

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.

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

PSP
Preferred System Plan.

PM
Particulate matter.

Pub. Util. Code
Public Utilities Code.

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

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 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.

RGPP
Renewable Gas Procurement Plan.

RIN
A Renewable Identification Number (RIN) is a unique 38-character identifier assigned to each gallon of renewable fuel that is produced or imported. Entities that produce or possess RINs, known as obligated parties, are required to register with the Environmental Protection Agency (EPA) and adhere to specific guidelines for recording and reporting RIN information every quarter.

RNG
Renewable Natural Gas.

RNGS
Renewable Gas Standard.

RPS
Renewable Portfolio Standard.

SB
Senate Bill.

scfh
standard cubic feet per hour.

SDG&E
San Diego Gas & Electric Company.

Short-Term Supplies
Gas purchases usually involve 30-day, short-term contracts or spot gas supplies.

SIP
State Implementation Plan.

SLCP
Short-Lived Climate Pollutants.

SMUD
Sacramento Municipal Utility District.

SO_x
sulfur oxide.

SoCalGas
Southern California Gas Company.

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

SRGIT
Standard renewable gas interconnection tariff.

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
The volume of natural gas injected into underground storage facilities.

Storage Withdrawal
The 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.

TGN
Transportadora de Gas Natural (pipeline).

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.

WECC
Western Electricity Coordinating Council.

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

ZEV
zero-emission vehicles.

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RESPONDENTS

RESPONDENTS

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

- Pacific Gas and Electric Company (PG&E)
- San Diego Gas & Electric Company (SDG&E)
- Southern California Gas Company (SoCalGas)

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

- City of Long Beach Utilities Department
- Sacramento Municipal Utilities District
- Southern California Edison Company (SCE)
- 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

SoCalGas/SDG&E*
- Eduardo Martinez (Utility Lead)
- Rose-Marie Payan
- William Guo
- Heng Yang
- Jeff Huang

PG&E
- Kurtis Kolnowski (Utility Lead)
- Anupama Pandey
- Joy Hill
- Todd Peterson
- Andrew Klingler
- Jon Bradshaw

*SoCalGas/SDG&E was the coordinating utility for the 2024 CGR

Observers

CPUC Energy Division
- Jean Spencer
- Khaled Abdelaziz

SCE
- Hongyan Sheng
- Christopher Mehrvarzi

California Energy Commission
- Nicholas Janusch
- Ethan Cooper
- Heidi Javanbakht
- Quentin Gee
- Robert Guliksen

Please visit the SoCalGas/SDG&E or PG&E websites for digital copies of this report and earlier versions including accompanying workpapers. They are in the regulatory sections of the following websites:

https://www.socalgas.com/regulatory/cgr

https://www.sdge.com/rates-and-regulations/regulatory-filing/20381/california-gas-report

http://www.pge.com/pipeline/library/regulatory/cgr_index.shtml

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