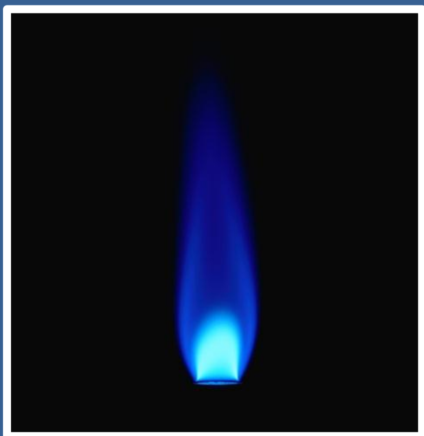
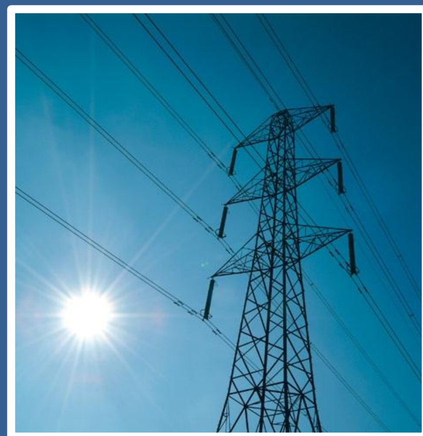
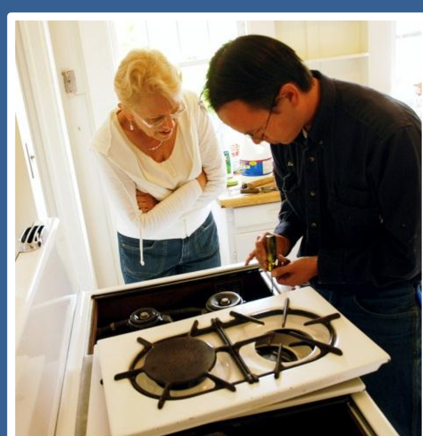
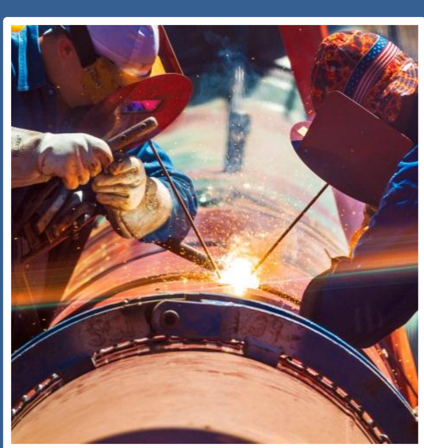
# 2014 CALIFORNIA GAS REPORT

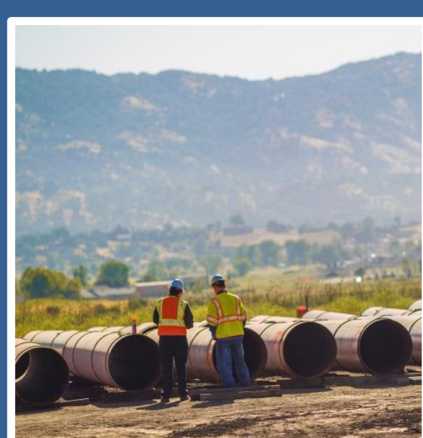


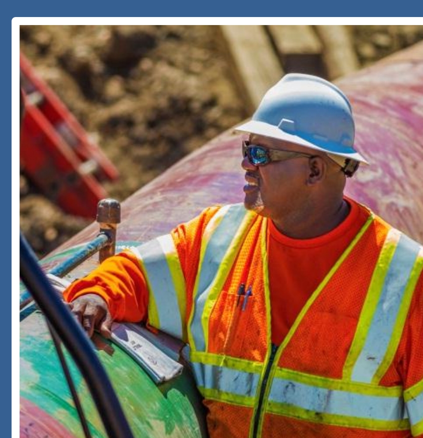


Prepared by the California Gas and Electric Utilities







# 2014 CALIFORNIA GAS REPORT

**PREPARED BY THE CALIFORNIA GAS AND ELECTRIC UTILITIES**


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

# TABLE OF CONTENTS

# LIST OF CHARTS AND TABLES

# 2014 CALIFORNIA GAS REPORT

## FOREWORD

# FOREWORD

The 2014 California Gas Report presents a comprehensive outlook for natural gas requirements and supplies for California through the year 2035. This report is prepared in even-numbered years, followed by a supplemental report in odd-numbered years, in compliance with California Public Utilities Commission Decision (CPUC) D.95-01-039. The projections in the California Gas Report are for long-term planning and do not necessarily reflect the day-to-day operational plans of the utilities.

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

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

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

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

# 2014 CALIFORNIA GAS REPORT

## EXECUTIVE SUMMARY

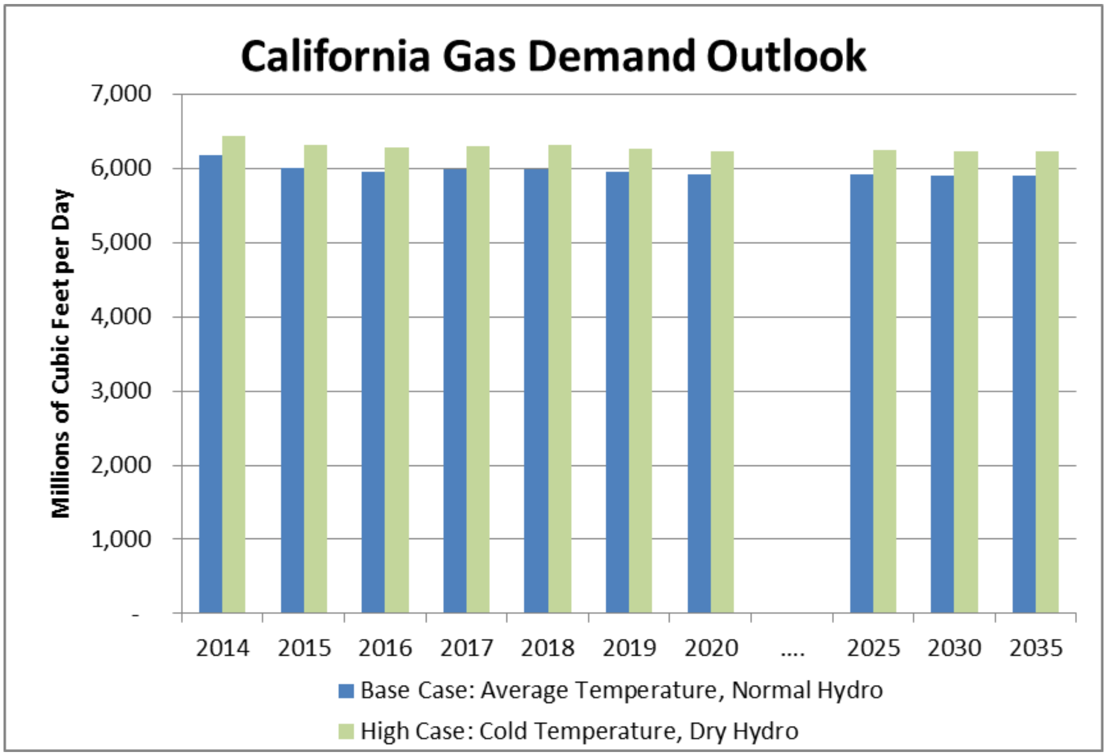
# EXECUTIVE SUMMARY

## DEMAND OUTLOOK

California natural gas demand, including volumes not served by utility systems, is expected to decrease at a modest rate of 0.2 percent per year from 2014 to 2035. The forecast decline is a combination of moderate growth in the Natural Gas Vehicle (NGV) and Enhanced Oil Recovery (EOR) markets and across-the-board declines in all other market segments: residential; commercial; electric generation; and industrial markets.

Residential gas demand is expected to decrease at an annual average rate of 0.2 percent. Demand in the core commercial and core industrial markets are expected to decline at an annual rate of 0.1 percent; whereas demand in the industrial noncore sector is estimated to decline by 0.25 percent annually as California continues its transition from a manufacturing-based to a service-based economy. Aggressive energy efficiency programs are expected to make a significant impact in managing growth in the residential, commercial, and industrial markets.

For the purpose of load following as well as backstopping intermittent renewable resource generation, gas-fired generation will continue to be the technology of choice to meet the ever growing demand for electric power. However, overall gas demand for electric generation is expected to decline at a modest 0.2 percent per year for the next 20 years due to more efficient power plants, statewide efforts to minimize greenhouse gas (GHG) emissions through aggressive programs pursuing demand side reductions, and the acquisition of preferred resources that produce little or no carbon emissions.




The graph above summarizes statewide demand under base case and high case scenarios. The base case refers to the expected gas demand for an average temperature year and normal hydroelectric power (hydro) year, and the high case refers to expected gas demand for a cold-temperature year and dry hydro conditions. Under an average temperature condition and a normal hydro year, gas demand for the state is projected to average 6,173 MMcf/d in 2014 decreasing to 5,910 MMcf/d by 2035, a decline of 0.2% per year.

In 2014, northern California is projected to require an additional 6% of gas supply to meet demand for the high gas-demand scenario; whereas southern California is projected to require an additional 3.5% of supply to meet the demand under the high scenario condition. This spread between the regions is expected; Northern California is colder and tends to rely more heavily on hydroelectric power than southern California. The weather scenario for each year is an independent event and each event has the same likelihood of occurring. The annual demand forecast for the base case and high case should, therefore, not be viewed as a combined event from year to year.

## FOCUS ON EFFICIENCY AND ENVIRONMENTAL QUALITY

California utilities continue to focus on Customer Energy Efficiency (CEE) and other Demand Side Management (DSM) programs in their utility electric and gas resource plans. The 2000-2001 "energy crisis" in California was not limited to electricity. Gas prices at the southern California border reached levels nearly ten times greater than had been experienced in previous years. California utilities are committed to helping their customers make the best possible choices regarding use of this increasingly valuable resource. Gas demand for electric power generation is expected to be moderated by CPUC-mandated goals for electric energy efficiency programs and renewable power. The base case forecasts in this report assume that the state will have 33% of its electric needs met with renewable power by 2020 and beyond.

The state's 2006 Global Warming Solutions Act, also known as Assembly Bill (AB) 32, has set aggressive targets for the state to reduce its overall GHG production. This law creates substantial uncertainty on the amount of natural gas that will be used in the outer years of the forecast. There is a high degree of uncertainty regarding what impact will occur in each sector as a result of the implementation of the measures to meet the GHG reduction goals.

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

## Impact of Renewable Generation and Energy Efficiency Programs on Gas Demand

| | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2025 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| California Energy Requirement Forecast [1] | | | | | | | | | |
| Electricity Demand (GWh) | 257,526 | 258,543 | 258,826 | 259,654 | 260,610 | 262,341 | 264,359 | 273,606 | 290,996 |
| 33% Renewables by 2020 | | | | | | | | | |
| Renewable Electric Generation (GWh/Yr) [2] | 55,883 | 60,241 | 64,707 | 70,107 | 75,577 | 81,326 | 87,238 | 90,290 | 96,029 |
| Increase over 2013 Level (GWh/Yr) [3] | 4,728 | 9,086 | 13,552 | 18,952 | 24,422 | 30,171 | 36,083 | 39,135 | 44,874 |
| Gas Savings over 2013 Level (Bcf/Yr) | 29 | 55 | 82 | 115 | 148 | 183 | 219 | 237 | 272 |
| Electric Energy Efficiency Goals [1] | | | | | | | | | |
| Electricity Savings over 2013 Level (GWh/Yr) | 5,304 | 10,705 | 16,465 | 21,747 | 26,971 | 31,490 | 35,712 | 57,257 | 91,912 |
| Gas Savings over 2013 Level (Bcf/Yr) [4] | 32 | 65 | 100 | 132 | 164 | 191 | 217 | 347 | 558 |
| Energy Efficiency Goal for Natural Gas Programs [1] | | | | | | | | | |
| Gas Savings over 2013 Level (Bcf/Yr) | 5 | 11 | 17 | 23 | 29 | 35 | 41 | 74 | 110 |
| **Total Gas Savings (Bcf/Yr)** [5] | 66 | 131 | 199 | 270 | 341 | 409 | 477 | 659 | 940 |

Note:

(1) Electricity demand forecast and gas and electric efficiency goals sourced from the California Energy Demand 2014-2024 Final Forecast from the California Energy Commission. Mid demand, mid additional achievable energy efficiency scenario. (http://www.energy.ca.gov/2013_energypolicy/documents/index.html#demandforecast) Forecast to 2030 was extended by CEC staff.

(2) Assumes 33% Renewables by 2020.

(3) Increase reflects only impacts of equipment installed after 12/31/2013.

(4) Gas savings are estimated based on the following generic assumptions for California: gas-fired peaking plants are assumed to be the marginal source for 10% of the 8,760 hours in each year (24 * 365), and combined-cycle plants are marginal in another 75% of each year. Each MWh displaced from a peaking plant saves 10 MMBtu (10 Dth, or approx. 10,000 CF) of natural gas. Each MWh displaced from a combined-cycle plant saves 7 MMBtu (7 Dth, or approx. 7000 CF) of natural gas. A conservation program that saves 1 MWh in every hour of a year saves about 55,000 MMBtu of natural gas (8,760 hours * 10% * 10 MMBtu, plus 8,760 hours * 75% * 7 MMBtu). Conservation programs that save MWh primarily during summer peak periods produce greater natural gas savings per MWh. Similar estimates apply to renewable electric generators.

(5) Total gas savings are **annual** savings from equipment installed after 12/31/2013.

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

Electric system operators must balance electrical demand with supply resources on a real time basis. Historically, system operators have relied on "dispatchable" gas-fired, resources that can respond quickly to changes in demand to keep the system in balance. The substantial increase in renewable resources will present an additional challenge to system operators. They must now deal with real time, unanticipated variations in intermittent renewable resources like wind and solar resources. In addition, these resources greatly increase morning and evening ramps, as both wind and solar resources can come online, as well as, offline very quickly.

California is currently on track to meet a 33% Renewable Portfolio Standard by 2020. It is expected that solar and wind generating units will provide the majority of the new, renewable generation. In addition, the Governor has indicated an interest in significantly increasing the amount of smaller (less than 20 megawatts) generation in the state primarily with renewable or efficient technology. Much of the smaller incremental renewable energy is expected to come from solar Photo Voltaic (PV) installations because solar generation costs have declined rapidly in the past few years and solar has siting advantages especially in the urban areas. All this renewable energy will displace a significant amount of the natural gas currently being used to generate electricity in California. However, the intermittent nature of renewable generation is likely to cause the electric system to rely more heavily on natural gas-fired electric generation for providing the ancillary services (load following, ramping, and quick starts) needed to balance the electric system in the short-term until other technologies like battery or compressed air storage can mature.

The direct result of the addition of significant amounts of renewable generation resources to the California generation resource mix is that the gas system is likely to experience increased gas demand volatility for the gas-fired generators required to provide the additional ancillary service needed. In many months of the year the variability of wind is significant and in months that have significant cloud formation, or overcast conditions, the solar PV units may also have increased generation variability. The uncertainty in day-ahead gas demands will likely cause increased gas system inventory fluctuations. The gas system will, therefore, need to be flexible enough to handle such fluctuations with minimal interruption to gas deliveries to other customers. There will undoubtedly be higher daily fluctuations of gas usage in the future; especially on days when clouds materialize that were not forecast. The gas system will need to be able to accommodate such operations.

The challenge of incorporating intermittent resources into the California electric system is being addressed in several ways. Currently, utility planners are anticipating the use of increased cycling, gas-fired plants, pumped hydroelectric facilities, price responsive demand reducing programs, energy storage products, and distributed generation at load centers to handle much of the variability in electricity demand. Recently, the CPUC Storage Mandate Decision (D).13-10-040 was passed. These energy storage products would use the excess renewables energy to charge the battery or system during the time of low energy demand and would provide energy back into the grid during periods of high energy demand. In addition, the California Independent System Operator (CAISO) has instituted a number of operational changes that move the forecasting of wind and solar availability closer to real time, which should reduce forecasting errors significantly. More accurate forecasting will help reduce the need for spinning reserves and other ancillary services. Also, the CAISO has broadened its electrical footprint with the creation of an Energy Imbalance Market (EIM). The EIM will allow both the CAISO and non-CAISO members to optimize resource availability that will allow the CAISO to better manage the integration of intermittent renewable resources. Broadening the interconnection to the regional grid will offset some of the intermittent nature of renewable resources and alleviate some of the operational obstacles to renewable integration. In addition, FERC Order 764, mandated intra-hour scheduling (fifteen minutes instead of on hour) between electric control areas. The shorter scheduling time interval will increase the accuracy of schedules, thus reducing the reliance on ancillary services to maintain electric system balance. Even with all of these operational changes to the electric system, there is still a need to have sufficient quick start resources available, most likely gas-fired resources, to balance the grid, as the State integrates more intermittent renewable resources into the California electric grid to achieve its 33% Renewable Portfolio Standard by 2020.

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

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

### Supply Outlook/Pipeline Capacity

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

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

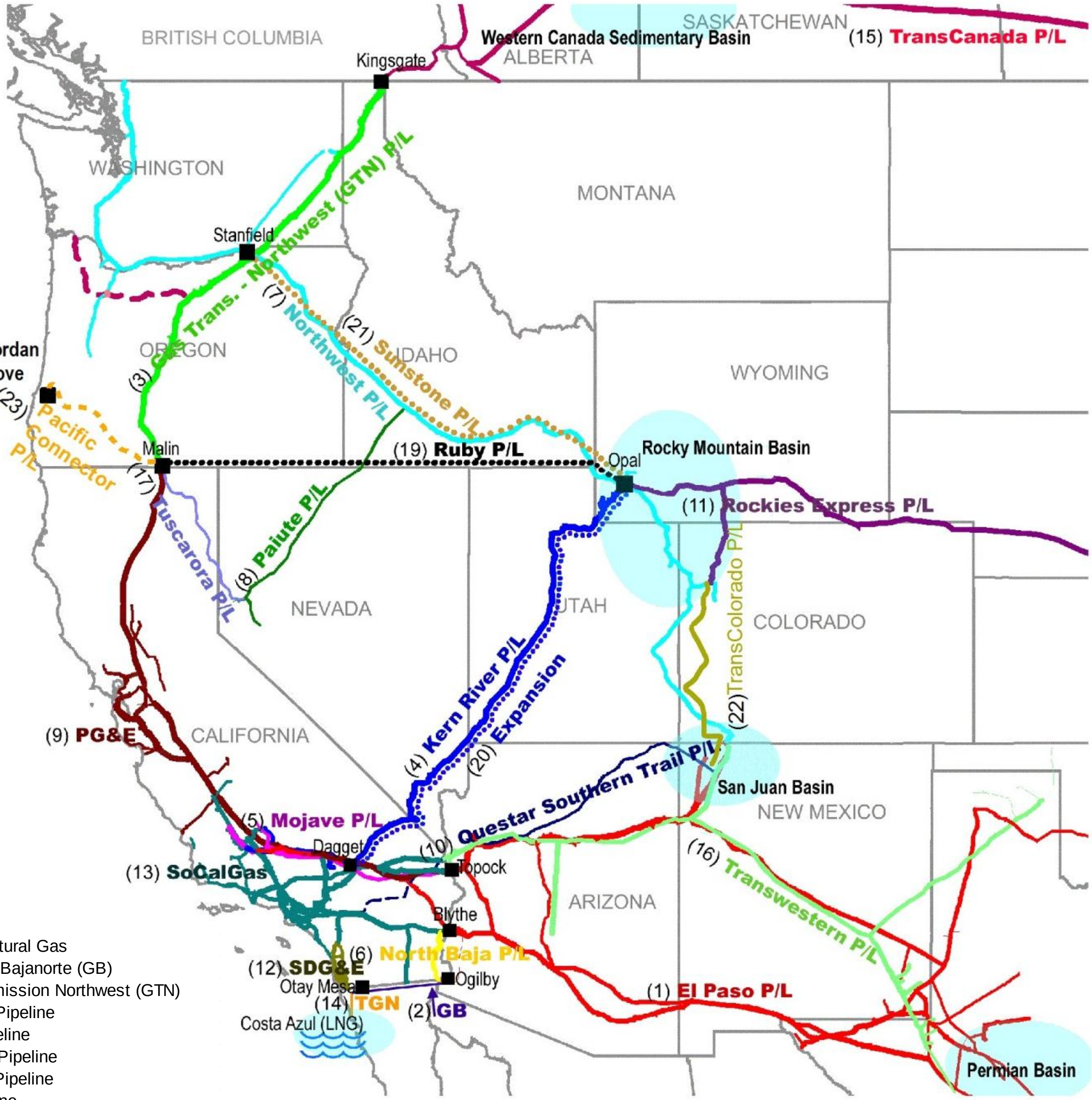
Traditional Southwestern U.S. sources of natural gas, especially from the San Juan Basin, will continue to supply most of Southern California's natural gas demand. This gas is primarily delivered via the El Paso Natural Gas and Transwestern pipelines. The San Juan Basin's gas supplies peaked in 1999 and have been declining at an annual rate of roughly 3%, but at a faster rate in recent years. The Permian Basin's share of supply into Southern California has increased in recent years, although increasing demand in Mexico for natural gas supplies may significantly reduce the volume of Permian Basin supply available to Southern California in the future. In A.13-12-013, SoCalGas and SDG&E have discussed this situation in more detail and have proposed a response to the operational concerns this situation creates for us.

### Storage Capacity

Abundant gas storage capacity is available to help meet the supply needs of northern California. Storage services have been provided to the northern California market by PG&E, Lodi Storage, and Wild Goose Storage. In addition, there have been several storage projects that have recently expanded the capacity available to the market. These projects include Gill

Ranch Storage, which came online in 2010, and Central Valley Storage, which came online in 2012. In addition, Wild Goose had a large expansion that became operational in 2012.

## Western North American Natural Gas Pipelines




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

## Liquefied Natural Gas (LNG)

The abundance of shale gas has changed the paradigm for LNG in the West. Until the latter part of the last decade, LNG was seen as being a potential source of imported gas for California, but that has changed. There are 14 proposed or potential export terminals on the west coast of North America totaling 27 billion cubic feet per day of capacity. Most of these are proposed in British Columbia as shown in the table below. The Costa Azul terminal remains the only import terminal on the west coast; however, it remains unutilized as a source of gas for California. It is uncertain whether all of the proposed and potential export terminals will be built, but their construction and operation could put upward pressure on gas prices in the West.

### Potential and Proposed North American West Coast LNG Terminals
As of May 21, 2014[1]

| Terminal Location | Company or Project Name | Production Capacity (Bcf/d) | Status |
|---|---|---|---|
| Coos Bay, OR, USA | Jordan Cove Energy Project | 0.9 | Proposed Export |
| Astoria, OR, USA | Oregon LNG | 1.3 | Proposed Export |
| Kitimat, BC, Canada | Apache Canada Ltd. | 1.3 | Proposed Export |
| Douglas Island, BC, Canada | BC LNG Export Cooperative | 0.2 | Proposed Export |
| Kitimat, BC, Canada | LNG Canada | 3.2 | Proposed Export |
| Prince Rupert Island, BC, Canada | BG Group | 2.9 | Potential Export |
| Prince Rupert Island, BC, Canada | Pacific Northwest LNG | 2.7 | Potential Export |
| Prince Rupert Island, BC, Canada | ExxonMobil - Imperial | 4.0 | Potential Export |
| Squamish, BC, Canada | Woodfibre LNG Export | 0.3 | Potential Export |
| Kitimat/Prince Rupert, BC, Canada | Triton LNG | 0.3 | Potential Export |
| Prince Rupert Island, BC, Canada | Aurora LNG | 3.1 | Potential Export |
| Kitsault, BC, Canada | Kitsault Energy | 2.7 | Potential Export |
| Stewart, BC, Canada | Canada Stewart Energy Group | 4.1 | Potential Export |
| Baja California, Mexico | Sempra - Energia Costa Azul | 1.5 | Approved Import |

[1] Source: FERC List of Existing, Proposed, and Potential LNG Terminals (http://www.ferc.gov/industries/gas/indus-act/lng.asp, accessed 5/22/2014).

## 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 2014 to 2035 for average-temperature and normal-hydro years and cold temperature and dry hydro years.

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

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

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| **California's Supply Sources** | | | | | |
| *Utility* | | | | | |
| California Sources | 392 | 392 | 392 | 392 | 392 |
| Out-of-State | 4,960 | 4,813 | 4,790 | 4,833 | 4,853 |
| Utility Total | 5,352 | 5,205 | 5,182 | 5,225 | 5,245 |
| *Non-Utility Served Load* (1) | 1,090 | 1,068 | 1,050 | 1,030 | 1,018 |
| **Statewide Supply Sources Total** | **6,442** | **6,273** | **6,232** | **6,255** | **6,263** |
| **California's Requirements** | | | | | |
| *Utility* | | | | | |
| Residential | 1,218 | 1,210 | 1,205 | 1,202 | 1,201 |
| Commercial | 505 | 505 | 505 | 506 | 505 |
| Natural Gas Vehicles | 43 | 46 | 48 | 50 | 52 |
| Industrial | 934 | 930 | 937 | 940 | 942 |
| Electric Generation (2) | 2,026 | 1,881 | 1,853 | 1,890 | 1,906 |
| Enhanced Oil Recovery Steaming | 44 | 52 | 52 | 52 | 52 |
| Wholesale/International+Exchange | 235 | 236 | 237 | 238 | 240 |
| Company Use and Unaccounted-for | 80 | 78 | 78 | 79 | 79 |
| Utility Total | 5,085 | 4,938 | 4,915 | 4,958 | 4,978 |
| *Non-Utility* | | | | | |
| Enhanced Oil Recovery/Industrial | 497 | 502 | 499 | 494 | 496 |
| EOR Cogeneration | 128 | 123 | 120 | 118 | 117 |
| Electric Generation | 466 | 444 | 431 | 418 | 405 |
| Non-Utility Served Load (1) | 1,090 | 1,068 | 1,050 | 1,030 | 1,018 |
| **Statewide Requirements Total** (3) | **6,175** | **6,006** | **5,964** | **5,988** | **5,995** |

Notes:

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

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

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

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

| | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| **California's Supply Sources** | | | | | |
| *Utility* | | | | | |
| California Sources | 394 | 394 | 394 | 394 | 394 |
| Out-of-State | 4,830 | 4,832 | 4,859 | 4,845 | 4,850 |
| Utility Total | 5,224 | 5,226 | 5,253 | 5,239 | 5,244 |
| *Non-Utility Served Load* [(1)] | 999 | 961 | 938 | 938 | 938 |
| **Statewide Supply Sources Total** | **6,223** | **6,187** | **6,191** | **6,177** | **6,182** |
| **California's Requirements** | | | | | |
| *Utility* | | | | | |
| Residential | 1,196 | 1,186 | 1,166 | 1,160 | 1,159 |
| Commercial | 503 | 499 | 488 | 486 | 490 |
| Natural Gas Vehicles | 54 | 56 | 64 | 70 | 75 |
| Industrial | 940 | 931 | 908 | 895 | 888 |
| Electric Generation [(2)] | 1,889 | 1,913 | 1,979 | 1,975 | 1,972 |
| Enhanced Oil Recovery Steaming | 52 | 52 | 52 | 52 | 52 |
| Wholesale/International+Exchange | 241 | 241 | 247 | 253 | 260 |
| Company Use and Unaccounted-for | 79 | 79 | 80 | 79 | 79 |
| Utility Total | 4,955 | 4,957 | 4,983 | 4,970 | 4,974 |
| *Non-Utility* | | | | | |
| Enhanced Oil Recovery/Industrial | 492 | 489 | 475 | 475 | 475 |
| EOR Cogeneration | 117 | 117 | 115 | 115 | 115 |
| Electric Generation | 390 | 355 | 348 | 348 | 348 |
| Non-Utility Served Load [(1)] | 999 | 961 | 938 | 938 | 938 |
| **Statewide Requirements Total** [(3)] | **5,954** | **5,918** | **5,921** | **5,908** | **5,912** |

Notes:

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

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

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

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

| **Utility** | **2014** | **2015** | **2016** | **2017** | **2018** |
|---|---|---|---|---|---|
| *Northern California* | | | | | |
| California Sources (1) | 82 | 82 | 82 | 82 | 82 |
| Out-of-State | 2,468 | 2,409 | 2,389 | 2,446 | 2,473 |
| Northern California Total | 2,550 | 2,491 | 2,471 | 2,528 | 2,555 |
| *Southern California* | | | | | |
| California Sources (2) | 310 | 310 | 310 | 310 | 310 |
| Out-of-State | 2,492 | 2,404 | 2,401 | 2,387 | 2,380 |
| Southern California Total | 2,802 | 2,714 | 2,711 | 2,697 | 2,690 |
| **Utility Total** | 5,352 | 5,205 | 5,182 | 5,225 | 5,245 |
| **Non-Utility Served Load** (3) | 1,090 | 1,068 | 1,050 | 1,030 | 1,018 |
| **Statewide Supply Sources Total** | **6,442** | **6,273** | **6,232** | **6,255** | **6,263** |

| **Utility** | **2019** | **2020** | **2025** | **2030** | **2035** |
|---|---|---|---|---|---|
| *Northern California* | | | | | |
| California Sources (1) | 82 | 82 | 82 | 82 | 82 |
| Out-of-State | 2,464 | 2,494 | 2,508 | 2,511 | 2,512 |
| Northern California Total | 2,546 | 2,576 | 2,590 | 2,593 | 2,594 |
| *Southern California* | | | | | |
| California Sources (2) | 310 | 310 | 310 | 310 | 310 |
| Out-of-State | 2,366 | 2,338 | 2,351 | 2,334 | 2,337 |
| Southern California Total | 2,676 | 2,648 | 2,661 | 2,644 | 2,647 |
| **Utility Total** | 5,222 | 5,224 | 5,251 | 5,237 | 5,242 |
| **Non-Utility Served Load** (3) | 999 | 961 | 938 | 938 | 938 |
| **Statewide Supply Sources Total** | **6,221** | **6,185** | **6,189** | **6,175** | **6,180** |

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

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| **Utility** | | | | | |
| *Northern California* | | | | | |
| Residential | 543 | 545 | 547 | 547 | 549 |
| Commercial - Core | 230 | 232 | 233 | 234 | 234 |
| Natural Gas Vehicles - Core | 7 | 7 | 7 | 8 | 8 |
| Natural Gas Vehicles - Noncore | 1 | 1 | 1 | 1 | 1 |
| Industrial - Noncore | 498 | 492 | 498 | 503 | 507 |
| Wholesale | 0 | 0 | 0 | 0 | 0 |
| SMUD Electric Generation | 122 | 122 | 122 | 122 | 122 |
| Electric Generation (2) | 837 | 780 | 751 | 801 | 821 |
| Exchange (California) | 1 | 1 | 1 | 1 | 1 |
| Company Use and Unaccounted-for | 44 | 43 | 43 | 44 | 44 |
| Northern California Total (3) | 2,283 | 2,224 | 2,203 | 2,261 | 2,287 |
| *Southern California* | | | | | |
| Residential | 676 | 664 | 658 | 655 | 652 |
| Commercial - Core | 226 | 227 | 228 | 230 | 230 |
| Commercial - Noncore | 48 | 46 | 44 | 43 | 41 |
| Natural Gas Vehicles - Core | 35 | 38 | 40 | 42 | 43 |
| Industrial - Core | 60 | 59 | 59 | 59 | 58 |
| Industrial - Noncore | 376 | 379 | 379 | 379 | 377 |
| Wholesale | 234 | 235 | 236 | 237 | 239 |
| SDG&E+Vernon Electric Generation | 204 | 190 | 196 | 194 | 186 |
| Electric Generation (4) | 863 | 789 | 785 | 773 | 777 |
| Enhanced Oil Recovery Steaming | 44 | 52 | 52 | 52 | 52 |
| Company Use and Unaccounted-for | 36 | 35 | 35 | 35 | 35 |
| Southern California Total | 2,802 | 2,714 | 2,711 | 2,697 | 2,690 |
| **Utility Total** | 5,085 | 4,938 | 4,915 | 4,958 | 4,978 |
| **Non-Utility Served Load (5)** | 1,090 | 1,068 | 1,050 | 1,030 | 1,018 |
| **Statewide Gas Requirements Total (6)** | **6,175** | **6,006** | **5,964** | **5,988** | **5,995** |

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

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

| | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| **Utility** | | | | | |
| *Northern California* | | | | | |
| Residential | 549 | 548 | 547 | 548 | 548 |
| Commercial - Core | 234 | 234 | 234 | 235 | 235 |
| Natural Gas Vehicles - Core | 8 | 9 | 9 | 9 | 10 |
| Natural Gas Vehicles - Noncore | 1 | 1 | 1 | 1 | 1 |
| Industrial - Noncore | 509 | 508 | 508 | 510 | 511 |
| Wholesale | 0 | 0 | 0 | 0 | 0 |
| SMUD Electric Generation | 122 | 122 | 122 | 122 | 122 |
| Electric Generation (2) | 810 | 841 | 855 | 855 | 855 |
| Exchange (California) | 1 | 1 | 1 | 1 | 1 |
| Company Use and Unaccounted-for | 44 | 45 | 45 | 45 | 45 |
| Northern California Total (3) | 2,279 | 2,309 | 2,322 | 2,326 | 2,327 |
| *Southern California* | | | | | |
| Residential | 647 | 638 | 619 | 612 | 611 |
| Commercial - Core | 230 | 228 | 226 | 228 | 231 |
| Commercial - Noncore | 39 | 37 | 28 | 23 | 24 |
| Natural Gas Vehicles - Core | 45 | 46 | 54 | 59 | 64 |
| Industrial - Core | 57 | 55 | 48 | 43 | 41 |
| Industrial - Noncore | 373 | 367 | 351 | 341 | 336 |
| Wholesale | 240 | 240 | 246 | 252 | 259 |
| SDG&E+Vernon Electric Generation | 183 | 180 | 181 | 179 | 178 |
| Electric Generation (4) | 774 | 770 | 821 | 819 | 817 |
| Enhanced Oil Recovery Steaming | 52 | 52 | 52 | 52 | 52 |
| Company Use and Unaccounted-for | 35 | 34 | 35 | 34 | 34 |
| Southern California Total | 2,676 | 2,648 | 2,661 | 2,644 | 2,647 |
| **Utility Total** | 4,955 | 4,957 | 4,983 | 4,970 | 4,974 |
| **Non-Utility Served Load (5)** | 999 | 961 | 938 | 938 | 938 |
| **Statewide Gas Requirements Total (6)** | **5,954** | **5,918** | **5,921** | **5,908** | **5,912** |

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

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| **California's Supply Sources** | | | | | |
| *Utility* | | | | | |
| California Sources | 394 | 394 | 394 | 394 | 394 |
| Out-of-State | 5,198 | 5,091 | 5,073 | 5,114 | 5,145 |
| Utility Total | 5,592 | 5,485 | 5,467 | 5,508 | 5,539 |
| *Non-Utility Served Load* (1) | 1,110 | 1,098 | 1,080 | 1,058 | 1,047 |
| **Statewide Supply Sources Total** | **6,702** | **6,583** | **6,547** | **6,566** | **6,585** |
| **California's Requirements** | | | | | |
| *Utility* | | | | | |
| Residential | 1,329 | 1,320 | 1,316 | 1,314 | 1,313 |
| Commercial | 528 | 529 | 530 | 531 | 530 |
| Natural Gas Vehicles | 43 | 46 | 48 | 50 | 52 |
| Industrial | 935 | 932 | 938 | 942 | 944 |
| Electric Generation (2) | 2,111 | 2,006 | 1,982 | 2,015 | 2,042 |
| Enhanced Oil Recovery Steaming | 44 | 52 | 52 | 52 | 52 |
| Wholesale/International+Exchange | 248 | 249 | 250 | 252 | 253 |
| Company Use and Unaccounted-for | 85 | 83 | 82 | 83 | 84 |
| Utility Total | 5,323 | 5,216 | 5,198 | 5,239 | 5,270 |
| *Non-Utility* | | | | | |
| Enhanced Oil Recovery/Industrial | 497 | 502 | 499 | 494 | 496 |
| EOR Cogeneration | 128 | 123 | 120 | 118 | 117 |
| Electric Generation | 485 | 473 | 461 | 446 | 434 |
| Non-Utility Served Load (1) | 1,110 | 1,098 | 1,080 | 1,058 | 1,047 |
| **Statewide Requirements Total** (3) | **6,433** | **6,314** | **6,278** | **6,297** | **6,316** |

Notes:

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

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

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

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

| | **2019** | **2020** | **2025** | **2030** | **2035** |
|---|---|---|---|---|---|
| **California's Supply Sources** | | | | | |
| *Utility* | | | | | |
| California Sources | 394 | 394 | 394 | 394 | 394 |
| Out-of-State | 5,119 | 5,115 | 5,155 | 5,144 | 5,150 |
| Utility Total | 5,513 | 5,509 | 5,549 | 5,538 | 5,544 |
| *Non-Utility Served Load* (1) | 1,026 | 984 | 963 | 963 | 963 |
| **Statewide Supply Sources Total** | **6,539** | **6,493** | **6,512** | **6,500** | **6,506** |
| **California's Requirements** | | | | | |
| *Utility* | | | | | |
| Residential | 1,308 | 1,298 | 1,277 | 1,271 | 1,272 |
| Commercial | 528 | 525 | 514 | 512 | 516 |
| Natural Gas Vehicles | 54 | 56 | 64 | 70 | 75 |
| Industrial | 941 | 932 | 909 | 895 | 888 |
| Electric Generation (2) | 2,022 | 2,038 | 2,119 | 2,116 | 2,113 |
| Enhanced Oil Recovery Steaming | 52 | 52 | 52 | 52 | 52 |
| Wholesale/International+Exchange | 255 | 255 | 261 | 268 | 275 |
| Company Use and Unaccounted-for | 84 | 84 | 85 | 85 | 85 |
| Utility Total | 5,244 | 5,240 | 5,280 | 5,269 | 5,275 |
| *Non-Utility* | | | | | |
| Enhanced Oil Recovery/Industrial | 492 | 489 | 475 | 475 | 475 |
| EOR Cogeneration | 117 | 117 | 117 | 117 | 117 |
| Electric Generation | 417 | 379 | 372 | 372 | 372 |
| Non-Utility Served Load (1) | 1,026 | 984 | 964 | 964 | 964 |
| **Statewide Requirements Total** (3) | **6,270** | **6,224** | **6,244** | **6,233** | **6,239** |

Notes:

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

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

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

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

| Utility | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| *Northern California* | | | | | |
| California Sources (1) | 82 | 82 | 82 | 82 | 82 |
| Out-of-State | 2,609 | 2,514 | 2,495 | 2,557 | 2,584 |
| Northern California Total | 2,691 | 2,596 | 2,577 | 2,639 | 2,666 |
| *Southern California* | | | | | |
| California Sources (2) | 310 | 310 | 310 | 310 | 310 |
| Out-of-State | 2,589 | 2,577 | 2,577 | 2,557 | 2,560 |
| Southern California Total | 2,899 | 2,887 | 2,887 | 2,867 | 2,870 |
| **Utility Total** | 5,590 | 5,483 | 5,465 | 5,506 | 5,537 |
| **Non-Utility Served Load** (3) | 1,110 | 1,098 | 1,080 | 1,058 | 1,047 |
| **Statewide Supply Sources Total** | **6,700** | **6,581** | **6,545** | **6,564** | **6,583** |

| Utility | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| *Northern California* | | | | | |
| California Sources (1) | 82 | 82 | 82 | 82 | 82 |
| Out-of-State | 2,572 | 2,599 | 2,627 | 2,631 | 2,634 |
| Northern California Total | 2,666 | 2,654 | 2,681 | 2,709 | 2,713 |
| *Southern California* | | | | | |
| California Sources (2) | 310 | 310 | 310 | 310 | 310 |
| Out-of-State | 2,547 | 2,515 | 2,529 | 2,512 | 2,516 |
| Southern California Total | 2,857 | 2,825 | 2,839 | 2,822 | 2,826 |
| **Utility Total** | 5,523 | 5,480 | 5,520 | 5,531 | 5,539 |
| **Non-Utility Served Load** (3) | 1,026 | 984 | 963 | 963 | 963 |
| **Statewide Supply Sources Total** | **6,550** | **6,464** | **6,482** | **6,494** | **6,502** |

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

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| **Utility** | | | | | |
| *Northern California* | | | | | |
| Residential | 587 | 590 | 593 | 595 | 597 |
| Commercial - Core | 240 | 242 | 244 | 244 | 245 |
| Natural Gas Vehicles - Core | 7 | 7 | 7 | 8 | 8 |
| Natural Gas Vehicles - Noncore | 1 | 1 | 1 | 1 | 1 |
| Industrial - Noncore | 498 | 492 | 498 | 503 | 507 |
| Wholesale | 0 | 0 | 0 | 0 | 0 |
| SMUD Electric Generation | 122 | 122 | 122 | 122 | 122 |
| Electric Generation [2] | 922 | 828 | 799 | 852 | 872 |
| Exchange (California) | 1 | 1 | 1 | 1 | 1 |
| Company Use and Unaccounted-for | 47 | 46 | 45 | 46 | 47 |
| Northern California Total [3] | 2,424 | 2,329 | 2,310 | 2,372 | 2,399 |
| *Southern California* | | | | | |
| Residential | 742 | 730 | 723 | 719 | 716 |
| Commercial - Core | 239 | 240 | 241 | 242 | 243 |
| Commercial - Noncore | 49 | 47 | 45 | 44 | 42 |
| Natural Gas Vehicles - Core | 35 | 38 | 40 | 42 | 43 |
| Industrial - Core | 61 | 61 | 61 | 60 | 59 |
| Industrial - Noncore | 376 | 379 | 379 | 379 | 377 |
| Wholesale | 247 | 248 | 249 | 251 | 252 |
| SDG&E+Vernon Electric Generation | 204 | 199 | 208 | 204 | 200 |
| Electric Generation [4] | 863 | 857 | 854 | 838 | 848 |
| Enhanced Oil Recovery Steaming | 44 | 52 | 52 | 52 | 52 |
| Company Use and Unaccounted-for | 38 | 37 | 37 | 37 | 37 |
| Southern California Total | 2,899 | 2,887 | 2,887 | 2,867 | 2,870 |
| **Utility Total** | 5,323 | 5,216 | 5,198 | 5,239 | 5,270 |
| **Non-Utility Served Load** [5] | 1,110 | 1,098 | 1,080 | 1,058 | 1,047 |
| **Statewide Gas Requirements Total** [6] | **6,433** | **6,314** | **6,278** | **6,297** | **6,316** |

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

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

| | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| **Utility** | | | | | |
| *Northern California* | | | | | |
| Residential | 598 | 597 | 598 | 599 | 600 |
| Commercial - Core | 245 | 245 | 246 | 246 | 247 |
| Natural Gas Vehicles - Core | 8 | 9 | 9 | 9 | 10 |
| Natural Gas Vehicles - Noncore | 1 | 1 | 1 | 1 | 1 |
| Industrial - Noncore | 509 | 508 | 508 | 510 | 511 |
| Wholesale | 0 | 0 | 0 | 0 | 0 |
| SMUD Electric Generation | 122 | 122 | 122 | 122 | 122 |
| Electric Generation [2] | 856 | 884 | 909 | 909 | 909 |
| Exchange (California) | 1 | 1 | 1 | 1 | 1 |
| Company Use and Unaccounted-for | 47 | 47 | 48 | 48 | 48 |
| Northern California Total [3] | 2,387 | 2,414 | 2,442 | 2,446 | 2,449 |
| *Southern California* | | | | | |
| Residential | 711 | 701 | 680 | 672 | 672 |
| Commercial - Core | 243 | 241 | 239 | 241 | 244 |
| Commercial - Noncore | 41 | 39 | 30 | 24 | 25 |
| Natural Gas Vehicles - Core | 45 | 46 | 54 | 59 | 64 |
| Industrial - Core | 58 | 56 | 49 | 44 | 42 |
| Industrial - Noncore | 373 | 367 | 351 | 341 | 336 |
| Wholesale | 254 | 254 | 260 | 267 | 274 |
| SDG&E+Vernon Electric Generation | 196 | 192 | 193 | 192 | 191 |
| Electric Generation [4] | 848 | 840 | 895 | 893 | 891 |
| Enhanced Oil Recovery Steaming | 52 | 52 | 52 | 52 | 52 |
| Company Use and Unaccounted-for | 37 | 37 | 37 | 37 | 37 |
| Southern California Total | 2,857 | 2,825 | 2,839 | 2,822 | 2,826 |
| **Utility Total** | 5,244 | 5,240 | 5,280 | 5,269 | 5,275 |
| **Non-Utility Served Load [5]** | 1,026 | 984 | 963 | 963 | 963 |
| **Statewide Gas Requirements Total [6]** | **6,270** | **6,224** | **6,243** | **6,231** | **6,237** |

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

## STATEWIDE RECORDED SOURCES AND DISPOSITION

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

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

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

## Recorded 2009 Statewide Sources and Disposition Summary
MMcf/Day

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

*Notes:*

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

| San Diego Gas & Electric Company | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Core | 6 | 45 | 36 | 23 | 14 | 0 | 9 | 133 |
| Noncore Commercial/Industrial | 0.058 | 105 | 85 | 0 | 0 | 0 | 0 | 191 |
| Total | 6 | 150 | 122 | 23 | 14 | 0 | 9 | 324 |

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

# Recorded 2010 Statewide Sources and Disposition Summary
## MMcf/Day

| | California Sources | El Paso | Trans western | GTN | Kern River | Mojave (10) | Other (1) | Total |
|---|---|---|---|---|---|---|---|---|
| **Southern California Gas Company** | | | | | | | | |
| Core + UAF (2) | 181 | 504 | 212 | 30 | 91 | 0 | -10 | 1,008 |
| Noncore Commercial/Industrial | 5 | 154 | 41 | 28 | 130 | 9 | 14 | 420 |
| EG (3) | 10 | 323 | 87 | 58 | 273 | 19 | 29 | 768 |
| EOR | 0 | 14 | 4 | 3 | 12 | 1 | 1 | 30 |
| Wholesale/Resale/International (4) | 7 | 191 | 155 | 30 | 17 | 1 | 12 | 412 |
| **Total** | 203 | 1,186 | 499 | 149 | 524 | 29 | 46 | 2,638 |
| **Pacific Gas and Electric Company (5)** | | | | | | | | |
| Core | 0 | 219 | 136 | 486 | 0 | 0 | 0 | 842 |
| Noncore Industrial/Wholesale/EG (6) | 135 | 358 | 175 | 623 | 46 | 0 | 0 | 1,337 |
| **Total** | 135 | 577 | 311 | 1,110 | 46 | 0 | 0 | 2,179 |
| **Other Northern California** | | | | | | | | |
| Core (7) | 0 | 0 | 0 | 0 | 0 | 0 | 13 | 13 |
| **Non-Utilities Served Load (8,9)** | | | | | | | | |
| Direct Sales/Bypass | 386 | 27 | 0 | 0 | 909 | 19 | 0 | 1,341 |
| **TOTAL SUPPLIER** | 724 | 1,790 | 810 | 1,259 | 1,479 | 48 | 59 | 6,171 |

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

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

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

## Recorded 2011 Statewide Sources and Disposition Summary
## MMcf/Day

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

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

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

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

## Recorded 2012 Statewide Sources and Disposition Summary

**MMcf/Day**

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

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

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

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

## Recorded 2013 Statewide Sources and Disposition Summary

MMcf/Day

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

*Notes:*

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

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

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

## STATEWIDE RECORDED HIGHEST SENDOUT

The table below summarizes the highest sendout days by the state in the summer and winter periods from the last five years. Daily sendout from SoCalGas, PG&E, and from customers not served by these utilities were used to construct the following tables. Please note that PG&E's values for sendout in year 2012 published in previous reports have been corrected.

**Estimated California Highest Summer Sendout (MMcf/d[5])**

| Year | Date | PG&E[1] | SoCal Gas[2] | Utility Total[4] | Non-Utility[3] | State Total |
|---|---|---|---|---|---|---|
| 2009 | 09/02/2009 | 2,592 | 3,235 | 5,827 | 1,369 | 7,196 |
| 2010 | 08/25/2010 | 2,700 | 3,504 | 6,204 | 1,153 | 7,357 |
| 2011 | 04/08/2011 | 2,164 | 3,313 | 5,477 | 1,322 | 6,799 |
| 2012 | 08/13/2012 | 2,685 | 3,483 | 6,168 | 1,633 | 7,801 |
| 2013 | 07/01/2013 | 2,558 | 3,393 | 5,951 | 1,437 | 7,388 |

**Estimated California Highest Winter Sendout (MMcf/d[5])**

| Year | Date | PG&E[1] | SoCal Gas[2] | Utility Total[4] | Non-Utility[3] | State Total |
|---|---|---|---|---|---|---|
| 2009 | 12/08/2009 | 4,157 | 4,505 | 8,662 | 1,327 | 9,989 |
| 2010 | 11/29/2010 | 3,426 | 4,356 | 7,782 | 1,151 | 8,932 |
| 2011 | 12/12/2011 | 2,842 | 4,152 | 6,994 | 1,501 | 8,495 |
| 2012 | 12/19/2012 | 3,628 | 4,294 | 7,922 | 1,501 | 9,423 |
| 2013 | 12/09/2013 | 4,850 | 4,881 | 9,731 | 1,426 | 11,157 |

Notes:
(1) PG&E Piperanger.
(2) SoCalGas Envoy.
(3) Source: DOGGR, Monthly Oil and Gas Production and Injection Report, Lipmann Monthly Pipeline Reports. Nonutility Demand equals Kern/Mojave and California monthly average total flows less PG&E and SoCal Gas peak day supply from Kern/Mojave and California Production. Provided by the CEC.
(4) PG&E and SoCalGas sendouts are reported for the day on which the Utility Total sendout is maximum for the respective season each year. Winter season months are Jan, Feb, Mar, Nov and Dec; while Summer season months are Apr, May, Jun, Jul, Aug, Sep, and Oct.
(5) For 2009-2010, PG&E and SoCalGas data were originally in energy units (MDth) and were converted to volumetric units (MMcf) by 1.0150 Dth/Mcf for PG&E and, 1.0235 Dth/Mcf for SoCalGas. For 2011-2013, PG&E's data were reported in volumetric units; SoCalGas' data were converted from energy units using 1.0209, 1.0210, and 1.0266 Dth/Mcf, respectively.

# 2014 CALIFORNIA GAS REPORT

## NORTHERN CALIFORNIA

# INTRODUCTION

Pacific Gas and Electric Company provides natural gas procurement, transportation, and storage services to 4.2 million residential customers and over 225,000 businesses in northern and central California. In addition to serving residential, commercial, and industrial markets, PG&E provides gas transportation and storage services to a variety of gas-fired electric generation plants in its service area. Other wholesale distribution systems, which receive gas transportation service from PG&E, serve a small portion of the gas customers in the region. PG&E's customers are located in 37 counties from south of Bakersfield to north of Redding, with high concentrations in the San Francisco Bay Area and the Sacramento and San Joaquin valleys. In addition, some customers also utilize the PG&E system to meet their gas needs in southern California.

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

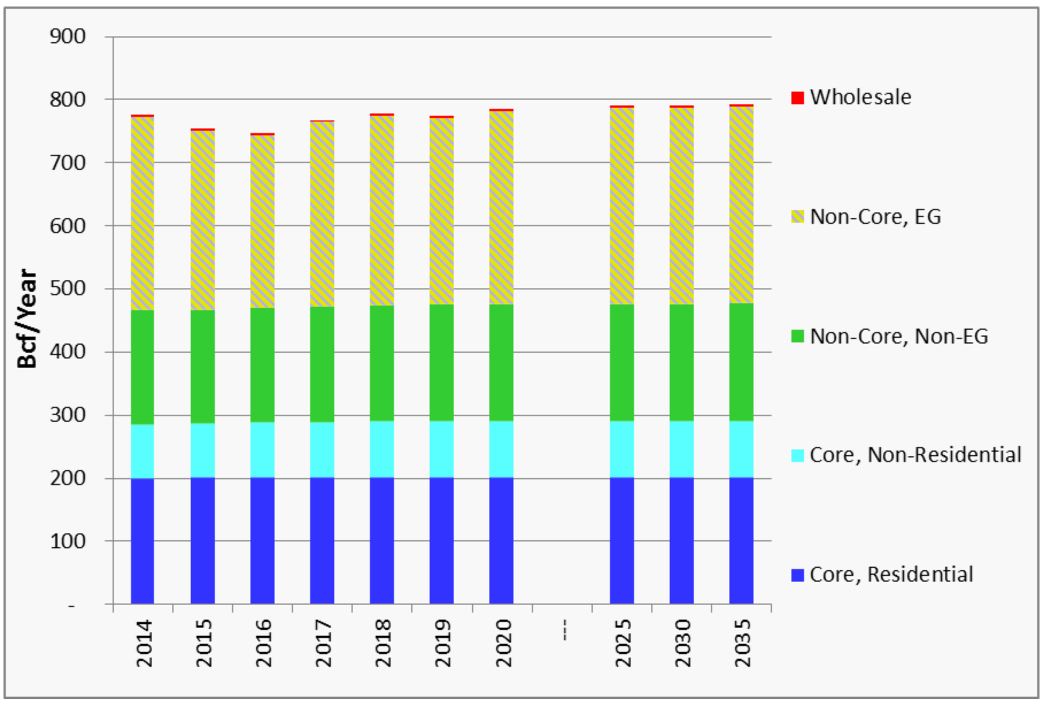
The forecast in this report covers the years 2014 through 2035. However, as a matter of convenience, the tabular data at the end of the section show only the years 2014 through 2020, and the years 2025, 2030, and 2035.

# GAS DEMAND

## OVERVIEW

PG&E's *2014 California Gas Report (CGR)* average-year demand forecast projects total on-system demand to grow at annual average rate of 0.1 percent between 2014 and 2035. This is due to the combination of a 0.1 percent annual growth in the core market and an annual growth of 0.1 percent in the noncore market. By comparison, the 2012 CGR estimated an annual average decline rate of 0.2 percent per year, based on a 0.1 percent annual decline in the core market and a 0.3 percent annual decline in the noncore market.

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




The projected rate of growth of the core market has increased from the *2012 California Gas Report* primarily due to an improving economy, though, this growth is slowed due to increasing emphasis on energy efficiency, and the incorporation of climate change where a warmer climate is assumed in the forecast horizon, thereby reducing winter gas demand in the core market.

The forecast rate of growth of the noncore market has increased due to a decrease in assumed renewable energy generation additions in northern California after several years of rapid growth, a decrease in assumed net retirements of gas-fired power plants in northern California because some have already retired, and decreases in the assumed cost of greenhouse gas allowances and the rate of growth of those costs. In this CGR, total gas demand by electric generators and cogenerators in northern California for average hydrological conditions is estimated to increase at a rate of about 0.5 percent per year from 2015 through 2035 (the forecast for 2014 includes actual demand for the first quarter, which was affected by drought conditions in California). This total gas demand excludes gas delivered by nonutility pipelines to electric generators and cogenerators in PG&E's service area, such as deliveries by the Kern/Mojave pipelines to the La Paloma and Sunrise plants in central California. In addition, increasing quantities of renewable energy generation are expected to increase the need for load following and ancillary services such as regulation. These ancillary services are likely to be provided by gas-fired power plants, thus, affecting gas demand to some extent. PG&E's 2014 CGR forecast, however, does not capture this impact.

## FORECAST METHOD

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

## FORECAST SCENARIOS

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

For the high-demand scenario, PG&E relied on a weather vintage approach by considering a year with cold temperatures and dry hydro conditions. Assuming the demographic conditions and infrastructure likely to exist in each forecast year, PG&E forecasts total gas demand with the weather conditions set to match the conditions that have an approximately 1-in-10 likelihood of occurrence. PG&E used the weather conditions from November 1988 through October 1989, as the winter of 1988-1989 was colder than normal, and this time period was dry in both northern California and the Pacific Northwest.

### Temperature Assumptions

Because space heating accounts for a high percentage of use, gas requirements for PG&E's residential and commercial customers are sensitive to prevailing temperature conditions. In previous CGRs, PG&E's average-year demand forecast assumed that temperatures in the forecast period would be equivalent to the average of observed temperatures during the past twenty years. PG&E is now building into its forecast an assumption of climate change. The climate change scenario is developed from work done at the

National Center for Atmospheric Research (Boulder, Colorado), downscaled to the PG&E service area. Although the near-term temperatures of this scenario differ little from long-term averages, the years beyond 2015 begin to show the effects of a warming climate. For example, in 2020, total December/January heating degree days are only 2 percent below the 20-year average. By 2035, however, the impact is more significant, with the difference at 7 percent.

Of course, actual temperatures in the forecast period will be higher or lower than those assumed in the climate-change scenario and gas use will vary accordingly. PG&E's high-demand forecast assumes that winter temperatures in the forecast horizon will be the same as those that prevailed during November 1988-October 1989.

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

### Hydro Conditions

In contrast to temperature deviations, annual water runoff for hydroelectric plants has varied by 50% above and below the long-term annual average. The impact of dry conditions was demonstrated during the drought and electricity crisis in 2001 (October 2000 through September 2001). For the 2014 CGR's high-demand scenario, as noted above, PG&E used the 1988-1989 conditions.

### Gas Price and Rate Assumptions

Inputs for gas prices and rate assumptions are very important for forecasting gas demand; this is especially true for market sectors that are particularly price sensitive, such as industrial or electric generation. PG&E utilized the gas commodity price forecast described in detail in the Southern California section on page 87. PG&E currently has two rate cases outstanding that will significantly affect gas transmission and distribution rates, the 2014 General Rate Case and the 2015 Gas Transmission and Storage Rate Case. Because of the uncertainty in the outcome of these cases, PG&E has elected to hold transmission and distribution rates constant at their 2014 levels.

## MARKET SECTORS

### Residential

Households in the PG&E service area are forecast to grow 0.8 percent annually from 2015 to 2035. However, gas use per household has been dropping in recent years due to improvements in appliance and building-shell efficiencies. This decline accelerated sharply in 2001 when gas prices spiked, causing temperature-adjusted residential gas demand to plunge by more than 8 percent. After recovering somewhat in 2002 and 2003, temperature-adjusted gas use per household reverted to its long-term trend and, despite slight upticks in 2009 and 2011 due to cold winters, has fallen on average 2 percent per year since 2004. Total residential demand is expected to remain flat despite household growth due to continuing upgrades in appliance and building efficiencies, as well as warming temperatures.

**Commercial**

The number of commercial customers in the PG&E service area is projected to grow on average by 0.5 percent per year from 2015 to 2035. The 2000-2001 noncore-to-core migration wave has caused this class to be less temperature sensitive than it had previously been, and has also tended to stunt overall growth in both customer base and gas use per customer. Gas use per commercial customer is projected to decline slightly over the forecast horizon due to continuing energy efficiency efforts as well as warmer temperatures. Over the next 20 years commercial sales are expected to grow at 0.1 percent per year.

**Industrial**

Gas requirements for PG&E's industrial sector are affected by the level and type of industrial activity in the service area and changes in industrial processes. Gas demand from this sector plummeted by close to 20 percent in 2001 due to a combination of increasing gas prices, noncore-to-core migration, and a manufacturing sector mired in a severe downturn. After a slight recovery in 2002, demand from this sector fell another 6 percent in 2003 but has seen slow growth in the recent past due to very low natural gas prices and increased capacity at local refineries, though these effects have been tempered by the continuing structural change in California's manufacturing sector. PG&E observed historically high demand from the industrial sector in 2012 and 2013 due in part to refinery demand. While the industrial sector has the potential for high year-to-year variability, over the long term, industrial gas consumption is expected to grow slowly at 0.2 percent annually over the next 20 years.

**Electric Generation**

This sector includes cogeneration and power plants. Forecasts for this sector are subject to greater uncertainty due to the retirement of existing power plants with once-through cooling; the timing, location, and type of new generation, particularly renewable-energy facilities; construction of new electric transmission lines; and the impact of greenhouse gas policies and regulations on both generation and load. Because of these uncertainties, the forecast is held constant at 2025 levels for 2030 and 2035.

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

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

PG&E's forecast for 2014-2035 uses the mid-case electricity demand forecast from the California Energy Commission's 2013 *Integrated Energy Policy Report*. The forecast assumes that renewable energy generation will provide 25% of the state's retail sales by 2016 and 33% by 2020. PG&E assumed that gas-fired plants that employ once-through cooling will retire by the compliance date set by the State Water Resources Control Board (with some exceptions where the plant owner has proposed a different date), generally replaced by new gas-fired plants with comparable capacities.

### SMUD Electric Generation

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

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

## GREENHOUSE GAS LEGISLATION/AB32

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

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

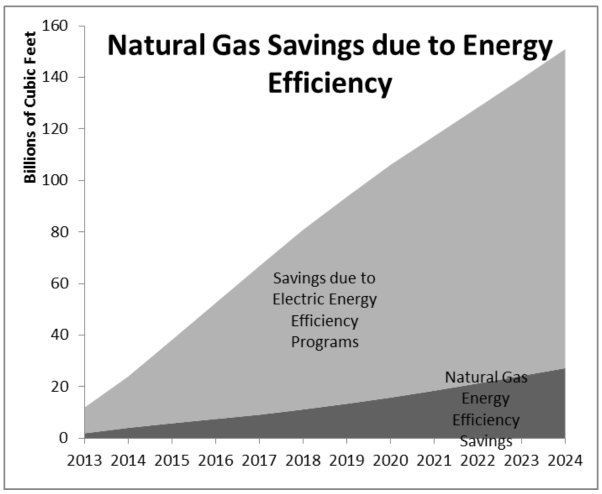
## RENEWABLE ELECTRIC GENERATION

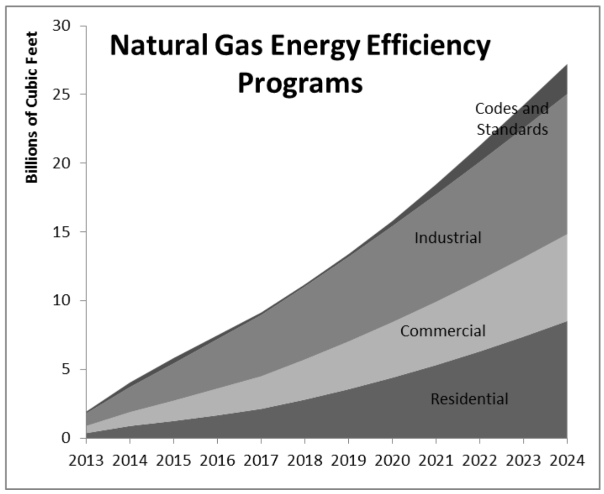
PG&E expects the  growth of renewable electric generation will result in higher daily and hourly deviations between forecast and actual generation from natural gas-fueled electric resources. In addition, the intermittent nature of some renewable generation (e.g., wind or solar power) is likely to cause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

## ENERGY EFFICIENCY PROGRAMS

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

Forecast of cumulative natural gas savings due to energy efficiency is provided in the figures below. Savings for these efforts are based on the report *2013 California Energy Efficiency Potential and Goals Study*, which was conducted by Navigant Consulting and published February 14, 2014.




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

Details of PG&E's 2013-14 Energy Efficiency Portfolio can be found in CPUC Decision 12-11-015.

# GAS SUPPLY, CAPACITY, AND STORAGE

## OVERVIEW

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

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

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

## GAS SUPPLY

### California-Sourced Gas

Northern California-sourced gas supplies come primarily from gas fields in the Sacramento Valley. In 2013, PG&E's customers obtained on average 57 MMcf/day of California-sourced gas.

### U.S. Southwest Gas

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

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

### Canadian Gas

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

### Rocky Mountain Gas

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

### Storage

In addition to storage services offered by PG&E, there are four other storage providers in northern California—Wild Goose Storage, Inc., Gill Ranch Storage, LLC; Central Valley Gas Storage, LLC; and Lodi Gas Storage, LLC. As of 2013, these facilities had total working gas capacity of roughly 240 billion cubic feet and peak withdrawal capacity of 4.8 billion cubic feet per day.

## INTERSTATE PIPELINE CAPACITY

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

### U.S. Southwest and Rocky Mountains

PG&E's Baja Path (Line 300) is connected to U.S. Southwest and Rocky Mountain pipeline systems (Transwestern, El Paso, Southern Trails, and Kern River) at and west of Topock, Arizona. The Baja Path has a firm capacity of 1,010 MMcf/day.

### Canada and Rocky Mountains

PG&E's Redwood Path (Lines 400/401) is connected to Gas Transmission Northwest and Ruby at Malin, Oregon. The Redwood Path has a firm capacity of 2,038 MMcf/day.

## GAS SUPPLIES AND INFRASTRUCTURE PROJECTS

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

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

**LNG Imports/Exports**

U.S. imports of liquefied natural gas (LNG) have been declining since 2008. Continued success in developing low-cost domestic shale gas supplies has largely eliminated the need for LNG imports and positioned the United States as a net exporter of LNG Exports of LNG from the contiguous U.S. are projected to start in 2016.

There are numerous proposed projects to export LNG to world markets. Many of the projects are "brownfield", using existing U.S. import terminals to export LNG, but some are "greenfield". The "greenfield" LNG export projects targeting the Asian gas market are mostly in the U.S. West Coast and western Canada. More than 30 Bcf/day of LNG project applications are in line for approval by the U.S. federal government.

The U.S. Department of Energy (DOE) evaluates the impact of LNG projects proposing to export LNG to countries without a Free Trade Agreement (FTA) with the U.S. and grants approval only if the project is deemed in the "public interest." As of May 2014, the DOE had approved seven non-FTA LNG export applications with a total export capacity of 9.3 Bcf/day.

The U.S. Federal Energy Regulatory Commission (FERC), on the other hand, is focused on evaluating the environmental impacts of proposed LNG projects, and is responsible for authorizing the siting and construction of LNG facilities. FERC has approved for construction 5.3 Bcf/day of LNG export capacity. Of approved projects, only the Sabine Pass Liquefaction, LLC, is currently under construction.

The DOE granted authorization to the Jordan Cove project in Oregon with non-FTA LNG export capacity of 0.8 Bcf/day on March 24, 2014. It could soon approve the Oregon LNG project with 1.25 Bcf/day export capacity. However, much more work lies ahead to resolve complex issues of commercial contracts, FERC and local approvals, financing, and new pipelines, before plans can succeed.

The LNG export projects in Oregon, the first on the U.S. West Coast are positioned to source gas from Canada and the U.S. Rockies; thus, they could directly compete for gas supplies available to northern California.

**Rocky Mountains**

In July 2011, El Paso Natural Gas Corp (since purchased by Kinder Morgan, Inc.) completed the 1.5 Bcf/day Ruby Pipeline project, which connects the Rocky Mountain supply basin at Opal with Malin, Oregon. This project provides a source of supply that competes at Malin with supply from the Western Canadian Sedimentary Basin in Canada.

### North American Supply Development

The most promising development in the North American gas supply picture in the past several years has been the rapid development of various shale gas resources through horizontal drilling combined with hydraulic fracturing. While the initial developments were concentrated in the U.S. midcontinent, the large Marcellus and Utica plays in the eastern U.S. have been ramping up, resulting in record U.S. gas production in 2013. While some of the traditional supply basins have shown modest declines in production, the Marcellus and Utica plays have grown from roughly 10 percent of U.S. production in 2012 to 20 percent in 2014, with further strong growth expected in the next few years. Most industry forecasts now expect supply can increase to meet the most aggressive demand scenario in the future.

## GAS STORAGE

Northern California is served by several gas storage facilities in addition to the long-standing PG&E fields at McDonald Island, Pleasant Creek, and Los Medanos. Other storage providers include Gill Ranch Storage, LLC (the 20 Bcf facility was co-developed with PG&E, which owns 25% of the capacity), Wild Goose Storage, Inc., Lodi Gas Storage, LLC, and Central Valley Storage, LLC. Of note are the recent addition of 11 Bcf of working gas capacity at Central Valley Storage and the recent series of expansions at Wild Goose Storage that increased its working gas capacity from 29 Bcf to 75 Bcf.

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

# REGULATORY ENVIRONMENT

## STATE REGULATORY MATTERS

### Gas Quality

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

PG&E has historically used the heating value of gas as an indicator of gas interchangeability (the ability to substitute gas of one chemical composition for gas of another different chemical composition). However, based on recent testing, the Wobbe Number is a better indicator of gas quality. The Wobbe Number reflects not only the heating value but the specific gravity of the gas as well. Specific gravity is an indicator of the relative proportion of heavier versus lighter hydrocarbons. In its testing, PG&E tentatively concluded that it could accept gas supplies with a Wobbe Number as high as 1,385.

### Pipeline Safety

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

PG&E filed with the CPUC its Pipeline Safety Enhancement Plan (PSEP) in August 2011 and a PSEP Update in October 2013. That filing presented the first phase of a comprehensive plan to strength-test or replace all natural gas transmission lines currently in service that have not previously been strength-tested.

In December 2013, PG&E filed its 2015 Gas Transmission and Storage (GT&S) Rate Case, which proposes increased funding for 2015 through 2017 to continue the implementation of best-practice safety improvements using an investment plan based on risk mitigation. This filing proposes a substantial increase in revenue requirement from currently authorized 2014 levels that were adopted in the 2011 GT&S Rate Case and the PSEP proceeding.

### Core Gas Aggregation Program

As of early 2014, Core Transport Agents (CTAs) serve approximately 19 percent of PG&E's core gas demand. PG&E recently began implementing the CTA Settlement Agreement, part of the Gas Accord V Settlement Agreement. The CTA Settlement Agreement modifies the practice by which PG&E offers a share of its pipeline and storage capacity holdings to CTAs to serve core customers. Implementation has resulted in numerous revisions to PG&E's Gas Schedule G-CT (Core Gas Aggregation Service) and to PG&E's CTA Service Agreement.

## FEDERAL REGULATORY MATTERS

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

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

Ruby Pipeline filed an application with the Federal Energy Regulatory Commission (FERC) on January 27, 2009, authorizing the construction and operation of the Ruby Pipeline Project. On April 5, 2010, the FERC approved the application. Construction began on July 31, 2010, and the pipeline was placed in service on July 28, 2011. Ruby is capable of transporting approximately 1.5 Bcf/day to bring Rocky Mountain natural gas supplies the Northwest, and to California.

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

El Paso filed a rate case application in the Federal Energy Regulatory Commission (FERC) Docket No. RP10 -1398, for revised rates and terms and conditions effective April 1, 2011. At issue in the rate case are commitments made in a 1996 Settlement, which established rate protections for certain El Paso shippers, and which remain in effect. FERC is conducting a supplemental proceeding to determine the appropriate level of costs reflected in protected contracts, and to adjust proposed rates accordingly.

**Kern River Gas Transmission (Kern River)**

On February 15, 1992, Kern River went into service, providing Rocky Mountain supplies to the San Joaquin Valley near Bakersfield, Calif. Major expansions occurred in 2002 and 2003, and 2010. Kern River currently has a design capacity of approximately 2.17 billion cubic feet per day.

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

Transwestern and its customers agreed to a rate pre-settlement on September 21, 2011 in FERC Docket No. RP11-2576. Pursuant to Article VI of the FERC-approved settlement, Transwestern is required to file a Natural Gas Act (NGA) Section 4 general rate case on October 1, 2014.

**Gas Transmission Northwest, L.L.C.**

Gas Transmission Northwest and its customers agreed to rate settlement, effective January 1, 2012, covering a 4 year period. The FERC-approved settlement requires GTN to file a Section 4 general rate case for new rates effective January 1, 2016.

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

FERC sought comments in April 2010 as to how to more effectively integrate renewable generation resources into the electric grid. While providing numerous comments from an electric perspective, PG&E also emphasized that electric system planners need to work closely with gas system planners to confirm that gas systems are sized appropriately and offer the necessary services to allow gas-fired electric generation projects to respond to sudden changes in renewable project output. FERC has not taken any specific action in response to the comments.

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

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

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

PG&E is actively participating in the NAESB process to create a consensus proposal. PG&E's position is that gas-electric coordination may be viewed on a regional basis due to the numerous differences in infrastructure and electric markets across the country. PG&E believes that a high degree of coordination already exists in California between gas system operators and the (electric) California Independent System Operator.

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

## OTHER REGULATORY MATTERS

### Hydraulic Fracturing

Hydraulic fracturing is not a new technology (see www.fracfocus.org). It is the combination of hydraulic fracturing with horizontal drilling that has unlocked vast shale gas resources across North America. Given the rapid growth in shale drilling and the number of "fracked" wells, federal, state, and local governments are focusing on better understanding the water and air quality impacts.

In 2009, the US Congress requested that the Environmental Protection Agency (EPA) conduct a study on the relationship between hydraulic fracturing and drinking water, which the EPA expects to complete by 2016. In April 2012, the EPA issued its first federal regulation for natural gas wells that are hydraulically fractured to reduce volatile organic compounds and methane emissions. Also in 2012, the Department of Energy, the Department of the Interior (DOI), and the EPA announced that they will jointly develop a multi-agency program to study the key challenges associated with unconventional oil and gas production. The program takes into consideration the recommendations of the Secretary of Energy Advisory Board Subcommittee 2011 report on shale gas production.[2] The outcomes of these studies will support policy decisions at both the federal and state levels. Since 2012, the Bureau of Land Management, within the DOI, has been developing rules to strengthening existing well-integrity standards, requiring measures for management of wastewater and chemical disclosure for hydraulic fracturing wells on federal lands. In February 2014, the EPA released final rules restricting the use of diesel fuels in the hydraulic fracturing process; however, the effects on production will be minimal as "diesel fuels appeared in fewer than two percent of the wells" according to a 2012 report by FRACFocus.

In November 2013, California passed Senate Bill 4 to strengthen California's hydraulic fracturing regulations by requiring permits, notifications, disclosures and impact studies. California regulators, environmentalists, and the gas and oil industry are continuing the discussion to modify the bill.

### Gas Exports

The record rise of natural gas production in the United States over the last five years reverses the U.S. position in the international gas trade.

With low domestic natural gas prices compared to world markets, the United States is positioned to become a net exporter of natural gas by 2020. Mexico is projected to be a major importer of U.S. gas. The U.S. natural gas exports to Mexico have grown in recent years from 1.0 Bcf/day in 2008 to approximately 2.0 Bcf/day in 2013. They are projected to reach 5.0 Bcf/day by 2030, due to declining gas production and increasing gas demand for power generation and industrial use in Mexico. Several gas pipeline capacity-expansion projects on both sides of the U.S.-Mexico border are under way to help meet Mexico's growing demand for U.S. gas. These projects are projected to be in service by 2015. When completed, they will significantly increase the total U.S.-to-Mexico pipeline-export capacity. As noted earlier, the U.S. is expected to become a net exporter of LNG beginning in 2016. While project developers

[2] http://www.shalegas.energy.gov/resources/111811_final_report.pdf.

seek to arbitrage North American gas prices and international oil-linked prices, the U.S. federal government is assessing the impact of more than 30 Bcf/day of proposed LNG export projects. The U.S. DOE has approved 9.3 Bcf/day of non-FTA LNG exports, and FERC has authorized the construction of 5.3 Bcf/day of LNG export capacity. Only one of approved projects, Sabine Pass Liquefaction, LLC, is currently under construction in the U.S.

The U.S. LNG exports are projected to grow to 4-6 Bcf/day by 2020. Two of the LNG export projects, the Jordan Cove LNG recently approved by DOE and the Oregon LNG expected to be approved, are on the U.S. West Coast.

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

In 2014, PG&E Gas Operations reported to the EPA GHG emissions in accordance with 40 CFR Part 98 in three primary categories: GHG emissions in 2013 resulting from combustion at seven compressor stations where the annual emissions exceed 25,000 metric tons of $CO_2$ equivalent; the GHG emissions resulting from combustion of all customers except customers consuming more than 460 MMcf; and certain vented and fugitive emissions from the seven compressor stations and the distribution system.

In 2014, PG&E Gas Operations reported to the California Air Resources Board (CARB) GHG emissions in the amount of 40.5 million metric tons of $CO_2$ equivalent in three primary categories: GHG emissions resulting from combustion at seven compressor stations and one underground gas storage station where the annual emissions exceed 25,000 metric tons of $CO_2$ equivalent; the GHG emissions resulting from combustion of delivered gas to all customers; and vented and fugitive emissions from seven compressor stations, one underground gas storage station and the distribution system.

In 2014, PG&E expects that a total of seven compressor stations and one underground gas storage station will emit more than 25,000 metric tons of $CO_2$ equivalent and, so, is included in CARB's cap-and-trade program. The scope of CARB's cap-and-trade program expands in 2015 to include natural gas suppliers, who will have a compliance obligation for GHG emissions associated with the natural gas use of their small customers (i.e., those customers who are not covered directly under CARB's cap-and-trade program). In 2012, CARB determined that PG&E's GHG emissions as a natural gas supplier were approximately 18.9 million metric tons of $CO_2$ equivalent.

# ABNORMAL PEAK DAY DEMAND AND SUPPLY

## APD DEMAND FORECAST

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

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

## APD SUPPLY REQUIREMENT FORECAST

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

PG&E's Core Gas Supply Department is responsible for procuring adequate flowing supplies to serve approximately 81 percent of PG&E's core gas usage. Core aggregators provide procurement services for the balance of PG&E's core customers and have the same obligation as PG&E Core Gas Supply to make and pay for all necessary arrangements to deliver gas to PG&E to match the use of their customers.

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

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

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

**Forecast of Core Gas Demand and Supply on an APD**
**MMcf/day**

| | 2014-15 | 2015-16 | 2016-17 |
|---|---|---|---|
| **APD Core Demand**(1) | 3,168 | 3,228 | 3,234 |
| **Firm Storage Withdrawal**(2) | 1,071 | 1,071 | 1,071 |
| **Required Flowing Supply**(3) | 2,097 | 2,157 | 2,163 |
| **Total APD Resources** | 3,168 | 3,228 | 3,234 |

**Notes:**

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

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

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

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

**Winter Peak Day Demand**
**(MMcf/day)**

| Year | Core(1) | Noncore Non-EG(2) | EG, including SMUD(3) | Total Demand |
|---|---|---|---|---|
| **2014** | 2,587 | 476 | 1,085 | 4,148 |
| **2015** | 2,636 | 484 | 982 | 4,102 |
| **2016** | 2,640 | 489 | 990 | 4,119 |
| **2017** | 2,649 | 493 | 1,052 | 4,194 |
| **2018** | 2,641 | 497 | 1,070 | 4,208 |
| **2019** | 2,634 | 498 | 1,076 | 4,208 |

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

**Summer Peak Day Demand**
**(MMcf/day)**

| Year | Core(4) | Noncore Non-EG(4) | EG, including SMUD(5) | Total Demand |
|---|---|---|---|---|
| **2014** | 419 | 619 | 1,293 | 2,331 |
| **2015** | 421 | 627 | 1,183 | 2,231 |
| **2016** | 423 | 633 | 1,173 | 2,229 |
| **2017** | 425 | 639 | 1,245 | 2,309 |
| **2018** | 426 | 644 | 1,245 | 2,315 |
| **2019** | 427 | 647 | 1,191 | 2,265 |

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

# 2014 CALIFORNIA GAS REPORT

## NORTHERN CALIFORNIA
## TABULAR DATA

**ANNUAL GAS SUPPLY AND REQUIREMENTS**
**RECORDED YEARS 2009-2013**
**MMCF/DAY**

| LINE | | 2009 | 2010 | 2011 | 2012 | 2013 | LINE |
|---|---|---|---|---|---|---|---|
| | **GAS SUPPLY TAKEN** | | | | | | |
| | CALIFORNIA SOURCE GAS | | | | | | |
| 1 | Core Purchases | 0 | 0 | 0 | 0 | 0 | 1 |
| 2 | Customer Gas Transport & Exchange | 135 | 135 | 120 | 84 | 57 | 2 |
| 3 | Total California Source Gas | 135 | 135 | 120 | 84 | 57 | 3 |
| | OUT-OF-STATE GAS | | | | | | |
| | Core Net Purchases | | | | | | |
| 6 | Rocky Mountain Gas | 1 | 0 | 2 | 203 | 223 | 6 |
| 7 | U.S. Southwest Gas | 356 | 352 | 293 | 255 | 207 | 7 |
| 8 | Canadian Gas | 502 | 486 | 536 | 353 | 330 | 8 |
| | Customer Gas Transport | | | | | | |
| 10 | Rocky Mountain Gas | 65 | 94 | 125 | 846 | 774 | 10 |
| 11 | U.S. Southwest Gas | 564 | 535 | 428 | 190 | 180 | 11 |
| 12 | Canadian Gas | 623 | 623 | 674 | 483 | 432 | 12 |
| 13 | Total Out-of-State Gas | 2,111 | 2,091 | 2,057 | 2,330 | 2,146 | 13 |
| 14 | STORAGE WITHDRAWAL (2) | 290 | 256 | 310 | 259 | 395 | 14 |
| 15 | Total Gas Supply Taken | 2,535 | 2,483 | 2,487 | 2,673 | 2,598 | 15 |
| | **GAS SENDOUT** | | | | | | |
| | CORE | | | | | | |
| 19 | Residential | 541 | 547 | 553 | 537 | 538 | 19 |
| 20 | Commercial | 237 | 217 | 220 | 229 | 229 | 20 |
| 21 | NGV | 5 | 5 | 5 | 6 | 6 | 21 |
| 22 | Total Throughput-Core | 783 | 769 | 779 | 771 | 774 | 22 |
| | NONCORE | | | | | | |
| 24 | Industrial | 477 | 461 | 480 | 518 | 519 | 24 |
| 25 | Electric Generation (1) | 861 | 853 | 795 | 939 | 987 | 25 |
| 26 | NGV | 1 | 1 | 1 | 1 | 1 | 26 |
| 27 | Total Throughput-Noncore | 1,339 | 1,315 | 1,276 | 1,458 | 1,507 | 27 |
| 28 | WHOLESALE | 10 | 10 | 10 | 10 | 10 | 28 |
| 29 | Total Throughput | 2,132 | 2,094 | 2,064 | 2,240 | 2,292 | 29 |
| 30 | CALIFORNIA EXCHANGE GAS | 2 | 2 | 2 | 2 | 2 | 30 |
| 31 | STORAGE INJECTION (2) | 329 | 312 | 363 | 344 | 267 | 31 |
| 32 | SHRINKAGE Company Use / Unaccounted for | 51 | 35 | 43 | 46 | 37 | 32 |
| 33 | Total Gas Send Out (3) | 2,514 | 2,442 | 2,487 | 2,632 | 2,598 | 33 |
| | TRANSPORTATION & EXCHANGE | | | | | | |
| 37 | CORE — ALL END USES | 69 | 87 | 101 | 130 | 152 | 37 |
| 38 | NONCORE — INDUSTRIAL | 477 | 461 | 480 | 518 | 519 | 38 |
| 39 | ELECTRIC GENERATION | 861 | 853 | 795 | 939 | 987 | 39 |
| 40 | SUBTOTAL/RETAIL | 1,407 | 1,402 | 1,376 | 1,587 | 1,658 | 40 |
| 42 | WHOLESALE/INTERNATIONAL | 10 | 10 | 10 | 9 | 10 | 42 |
| 44 | TOTAL TRANSPORTATION AND EXCHANGE | 1,417 | 1,412 | 1,385 | 1,596 | 1,668 | 44 |
| | CURTAILMENT/ALTERNATIVE FUEL BURNS | | | | | | |
| 47 | Residential, Commercial, Industrial | 0 | 0 | 0 | 0 | 0 | 47 |
| 48 | Utility Electric Generation | 0 | 0 | 0 | 0 | 0 | 48 |
| 49 | TOTAL CURTAILMENT | 0 | 0 | 0 | 0 | 0 | 49 |

**NOTES:**

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

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

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

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

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY

## AVERAGE DEMAND YEAR

| LINE | | 2014 | 2015 | 2016 | 2017 | 2018 | LINE |
|---|---|---|---|---|---|---|---|
| | **FIRM CAPACITY AVAILABLE** | | | | | | |
| 1 | **California Source Gas** | 82 | 82 | 82 | 82 | 82 | 1 |
| | **Out of State Gas** | | | | | | |
| 2 | Baja Path(1) | 1,010 | 1,010 | 1,010 | 1,010 | 1,010 | 2 |
| 3 | Redwood Path(2) | 2,038 | 2,038 | 2,038 | 2,038 | 2,038 | 3 |
| 3.a | SW Gas Corp. from Paiute Pipeline Comp. | 41 | 41 | 41 | 41 | 41 | 3.a |
| 4 | **Supplemental(3)** | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | **Total Supplies Available** | 3,171 | 3,171 | 3,171 | 3,171 | 3,171 | 5 |
| | **GAS SUPPLY TAKEN** | | | | | | |
| 6 | **California Source Gas** | 82 | 82 | 82 | 82 | 82 | 6 |
| 7 | **Out of State Gas (via existing facilities)** | 2,480 | 2,421 | 2,400 | 2,458 | 2,484 | 7 |
| 8 | **Supplemental** | 0 | 0 | 0 | 0 | 0 | 8 |
| 9 | **Total Supply Taken** | 2,562 | 2,503 | 2,482 | 2,540 | 2,566 | 9 |
| 10 | **Net Underground Storage Withdrawal** | 0 | 0 | 0 | 0 | 0 | 10 |
| 11 | **Total Throughput** | 2,562 | 2,503 | 2,482 | 2,540 | 2,566 | 11 |
| | **REQUIREMENTS FORECAST BY END USE** | | | | | | |
| | **Core** | | | | | | |
| 12 | Residential(4) | 543 | 545 | 547 | 547 | 549 | 12 |
| 13 | Commercial | 230 | 232 | 233 | 234 | 234 | 13 |
| 14 | NGV | 7 | 7 | 7 | 8 | 8 | 14 |
| 15 | **Total Core** | 780 | 784 | 787 | 789 | 791 | 15 |
| | **Noncore** | | | | | | |
| 16 | Industrial | 498 | 492 | 498 | 503 | 507 | 16 |
| 17 | SMUD Electric Generation(5) | 122 | 122 | 122 | 122 | 122 | 17 |
| 18 | PG&E Electric Generation(6) | 837 | 780 | 751 | 801 | 821 | 18 |
| 19 | NGV | 1 | 1 | 1 | 1 | 1 | 19 |
| 20 | Wholesale | 10 | 10 | 10 | 10 | 10 | 20 |
| 21 | California Exchange Gas | 1 | 1 | 1 | 1 | 1 | 21 |
| 22 | **Total Noncore** | 1,469 | 1,406 | 1,383 | 1,438 | 1,462 | 22 |
| 23 | **Off-System Deliveries(7)** | 269 | 269 | 269 | 269 | 269 | 23 |
| | **Shrinkage** | | | | | | |
| 24 | Company use and Unaccounted for | 44 | 43 | 43 | 44 | 45 | 24 |
| 25 | **TOTAL END USE** | 2,562 | 2,503 | 2,482 | 2,540 | 2,566 | 25 |
| | **TRANSPORTATION & EXCHANGE** | | | | | | |
| 26 | CORE — ALL END USES | 171 | 170 | 168 | 169 | 169 | 26 |
| 27 | NONCORE — COMMERCIAL/INDUSTRIAL | 498 | 492 | 498 | 503 | 507 | 27 |
| 28 | ELECTRIC GENERATION | 959 | 902 | 873 | 923 | 943 | 28 |
| 29 | SUBTOTAL/RETAIL | 1,628 | 1,564 | 1,540 | 1,595 | 1,620 | 29 |
| 30 | WHOLESALE/INTERNATIONAL | 10 | 10 | 10 | 10 | 10 | 30 |
| 31 | TOTAL TRANSPORTATION AND EXCHANGE | 1,638 | 1,574 | 1,549 | 1,605 | 1,629 | 31 |
| 32 | System Curtailment | 0 | 0 | 0 | 0 | 0 | 32 |

NOTES:

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

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

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

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

(5) Forecast by SMUD.

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

(7) Deliveries to southern California.

**ANNUAL GAS SUPPLY FORECAST**
**MMCF/DAY**

## AVERAGE DEMAND YEAR

| LINE | | 2019 | 2020 | 2025 | 2030 | 2035 | LINE |
|---|---|---|---|---|---|---|---|
| | **FIRM CAPACITY AVAILABLE** | | | | | | |
| 1 | **California Source Gas** | 82 | 82 | 82 | 82 | 82 | 1 |
| | **Out of State Gas** | | | | | | |
| 2 | Baja Path[(1)] | 1,010 | 1,010 | 1,010 | 1,010 | 1,010 | 2 |
| 3 | Redwood Path[(2)] | 2,038 | 2,038 | 2,038 | 2,038 | 2,038 | 3 |
| 3.a | SW Gas Corp. from Paiute Pipeline Comp. | 41 | 41 | 41 | 41 | 41 | 3.a |
| 4 | **Supplemental[(3)]** | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | **Total Supplies Available** | 3,171 | 3,171 | 3,171 | 3,171 | 3,171 | 5 |
| | **GAS SUPPLY TAKEN** | | | | | | |
| 6 | **California Source Gas** | 82 | 82 | 82 | 82 | 82 | 6 |
| 7 | **Out of State Gas (via existing facilities)** | 2,476 | 2,506 | 2,519 | 2,523 | 2,524 | 7 |
| 8 | **Supplemental** | 0 | 0 | 0 | 0 | 0 | 8 |
| 9 | **Total Supply Taken** | 2,558 | 2,588 | 2,601 | 2,605 | 2,606 | 9 |
| 10 | **Net Underground Storage Withdrawal** | 0 | 0 | 0 | 0 | 1 | 10 |
| 11 | **Total Throughput** | 2,558 | 2,588 | 2,601 | 2,605 | 2,607 | 11 |
| | **REQUIREMENTS FORECAST BY END USE** | | | | | | |
| | **Core** | | | | | | |
| 12 | Residential[(4)] | 549 | 548 | 547 | 548 | 548 | 12 |
| 13 | Commercial | 234 | 234 | 234 | 235 | 235 | 13 |
| 14 | NGV | 8 | 9 | 9 | 9 | 10 | 14 |
| 15 | **Total Core** | 791 | 790 | 790 | 792 | 793 | 15 |
| | **Noncore** | | | | | | |
| 16 | Industrial | 509 | 508 | 508 | 510 | 511 | 16 |
| 17 | SMUD Electric Generation[(5)] | 122 | 122 | 122 | 122 | 122 | 17 |
| 18 | PG&E Electric Generation[(6)] | 810 | 841 | 855 | 855 | 855 | 18 |
| 19 | NGV | 1 | 1 | 1 | 1 | 1 | 19 |
| 20 | Wholesale | 10 | 10 | 10 | 10 | 10 | 20 |
| 21 | California Exchange Gas | 1 | 1 | 1 | 1 | 1 | 21 |
| 22 | **Total Noncore** | 1,453 | 1,483 | 1,497 | 1,499 | 1,499 | 22 |
| 23 | **Off-System Deliveries[(7)]** | 269 | 269 | 269 | 269 | 269 | 23 |
| | **Shrinkage** | | | | | | |
| 24 | Company use and Unaccounted for | 45 | 45 | 45 | 45 | 45 | 24 |
| 25 | **TOTAL END USE** | 2,558 | 2,588 | 2,601 | 2,605 | 2,606 | 25 |
| | **TRANSPORTATION & EXCHANGE** | | | | | | |
| 26 | CORE — ALL END USES | 169 | 169 | 170 | 171 | 172 | 26 |
| 27 | NONCORE — COMMERCIAL/INDUSTRIAL | 509 | 508 | 508 | 510 | 511 | 27 |
| 28 | ELECTRIC GENERATION | 932 | 963 | 977 | 977 | 977 | 28 |
| 29 | SUBTOTAL/RETAIL | 1,611 | 1,641 | 1,656 | 1,658 | 1,660 | 29 |
| 30 | WHOLESALE/INTERNATIONAL | 10 | 10 | 10 | 10 | 10 | 30 |
| 31 | TOTAL TRANSPORTATION AND EXCHANGE | 1,620 | 1,651 | 1,665 | 1,668 | 1,669 | 31 |
| 32 | System Curtailment | 0 | 0 | 0 | 0 | 0 | 32 |

NOTES:

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

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

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

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

(5) Forecast by SMUD.

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

(7) Deliveries to southern California.

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY

## HIGH DEMAND YEAR

| LINE | | 2014 | 2015 | 2016 | 2017 | 2018 | LINE |
|---|---|---|---|---|---|---|---|
| | **FIRM CAPACITY AVAILABLE** | | | | | | |
| 1 | **California Source Gas** | 82 | 82 | 82 | 82 | 82 | 1 |
| | **Out of State Gas** | | | | | | |
| 2 | Baja Path (1) | 1,010 | 1,010 | 1,010 | 1,010 | 1,010 | 2 |
| 3 | Redwood Path (2) | 2,038 | 2,038 | 2,038 | 2,038 | 2,038 | 3 |
| 3.a | SW Gas Corp. from Paiute Pipeline Comp. | 41 | 41 | 41 | 41 | 41 | 3.a |
| 4 | **Supplemental (3)** | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | **Total Supplies Available** | 3,171 | 3,171 | 3,171 | 3,171 | 3,171 | 5 |
| | **GAS SUPPLY TAKEN** | | | | | | |
| 6 | **California Source Gas** | 82 | 82 | 82 | 82 | 82 | 6 |
| 7 | **Out of State Gas (via existing facilities)** | 2,621 | 2,526 | 2,507 | 2,568 | 2,596 | 7 |
| 8 | **Supplemental** | 0 | 0 | 0 | 0 | 0 | 8 |
| 9 | **Total Supply Taken** | 2,703 | 2,608 | 2,589 | 2,650 | 2,678 | 9 |
| 10 | **Net Underground Storage Withdrawal** | 0 | 0 | 0 | 0 | 0 | 10 |
| 11 | **Total Throughput** | 2,703 | 2,608 | 2,589 | 2,650 | 2,678 | 11 |
| | **REQUIREMENTS FORECAST BY END USE** | | | | | | |
| | **Core** | | | | | | |
| 12 | Residential (4) | 587 | 590 | 593 | 595 | 597 | 12 |
| 13 | Commercial | 240 | 242 | 244 | 244 | 245 | 13 |
| 14 | NGV | 7 | 7 | 7 | 8 | 8 | 14 |
| 15 | **Total Core** | 833 | 840 | 844 | 847 | 849 | 15 |
| | **Noncore** | | | | | | |
| 16 | Industrial | 498 | 492 | 498 | 503 | 507 | 16 |
| 17 | SMUD Electric Generation (5) | 122 | 122 | 122 | 122 | 122 | 17 |
| 18 | PG&E Electric Generation (6) | 922 | 828 | 799 | 852 | 872 | 18 |
| 19 | NGV | 1 | 1 | 1 | 1 | 1 | 19 |
| 20 | Wholesale | 10 | 10 | 10 | 10 | 10 | 20 |
| 21 | California Exchange Gas | 1 | 1 | 1 | 1 | 1 | 21 |
| 22 | **Total Noncore** | 1,554 | 1,453 | 1,431 | 1,488 | 1,513 | 22 |
| 23 | **Off-System Deliveries (7)** | 269 | 269 | 269 | 269 | 269 | 23 |
| | **Shrinkage** | | | | | | |
| 24 | Company use and Unaccounted for | 47 | 46 | 45 | 47 | 47 | 24 |
| 25 | **TOTAL END USE** | 2,703 | 2,608 | 2,589 | 2,650 | 2,678 | 25 |
| | **TRANSPORTATION & EXCHANGE** | | | | | | |
| 26 | CORE — ALL END USES | 175 | 179 | 180 | 180 | 181 | 26 |
| 27 | NONCORE — COMMERCIAL/INDUSTRIAL | 498 | 492 | 498 | 503 | 507 | 27 |
| 28 | ELECTRIC GENERATION | 1,044 | 950 | 921 | 974 | 994 | 28 |
| 29 | SUBTOTAL/RETAIL | 1,718 | 1,621 | 1,600 | 1,657 | 1,682 | 29 |
| 30 | WHOLESALE/INTERNATIONAL | 10 | 10 | 10 | 10 | 10 | 30 |
| 31 | TOTAL TRANSPORTATION AND EXCHANGE | 1,727 | 1,630 | 1,609 | 1,666 | 1,691 | 31 |
| 32 | System Curtailment | 0 | 0 | 0 | 0 | 0 | 32 |

NOTES:

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

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

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

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

(5) Forecast by SMUD.

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

(7) Deliveries to southern California.

ANNUAL GAS SUPPLY FORECAST
MMCF/DAY

## HIGH DEMAND YEAR

| LINE | | | 2019 | 2020 | 2025 | 2030 | 2035 | LINE |
|---|---|---|---|---|---|---|---|---|
| **FIRM CAPACITY AVAILABLE** | | | | | | | | |
| 1 | **California Source Gas** | | 82 | 82 | 82 | 82 | 82 | 1 |
| | **Out of State Gas** | | | | | | | |
| 2 | Baja Path[(1)] | | 1,010 | 1,010 | 1,010 | 1,010 | 1,010 | 2 |
| 3 | Redwood Path[(2)] | | 2,038 | 2,038 | 2,038 | 2,038 | 2,038 | 3 |
| 3.a | SW Gas Corp. from Paiute Pipeline Comp. | | 41 | 41 | 41 | 41 | 41 | 3.a |
| 4 | **Supplemental[(3)]** | | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | **Total Supplies Available** | | 3,171 | 3,171 | 3,171 | 3,171 | 3,171 | 5 |
| **GAS SUPPLY TAKEN** | | | | | | | | |
| 6 | **California Source Gas** | | 82 | 82 | 82 | 82 | 82 | 6 |
| 7 | **Out of State Gas (via existing facilities)** | | 2,584 | 2,611 | 2,638 | 2,643 | 2,646 | 7 |
| 8 | **Supplemental** | | 0 | 0 | 0 | 0 | 0 | 8 |
| 9 | **Total Supply Taken** | | 2,666 | 2,693 | 2,720 | 2,725 | 2,728 | 9 |
| 10 | **Net Underground Storage Withdrawal** | | 0 | 0 | 0 | 0 | 0 | 10 |
| 11 | **Total Throughput** | | 2,666 | 2,693 | 2,720 | 2,725 | 2,728 | 11 |
| **REQUIREMENTS FORECAST BY END USE** | | | | | | | | |
| | **Core** | | | | | | | |
| 12 | Residential[(4)] | | 598 | 597 | 598 | 599 | 600 | 12 |
| 13 | Commercial | | 245 | 245 | 246 | 246 | 247 | 13 |
| 14 | NGV | | 8 | 9 | 9 | 9 | 10 | 14 |
| 15 | **Total Core** | | 851 | 851 | 852 | 855 | 857 | 15 |
| | **Noncore** | | | | | | | |
| 16 | Industrial | | 509 | 508 | 508 | 510 | 511 | 16 |
| 17 | SMUD Electric Generation[(5)] | | 122 | 122 | 122 | 122 | 122 | 17 |
| 18 | PG&E Electric Generation[(6)] | | 856 | 884 | 909 | 909 | 909 | 18 |
| 19 | NGV | | 1 | 1 | 1 | 1 | 1 | 19 |
| 20 | Wholesale | | 10 | 10 | 10 | 10 | 10 | 20 |
| 21 | California Exchange Gas | | 1 | 1 | 1 | 1 | 1 | 21 |
| 22 | **Total Noncore** | | 1,499 | 1,526 | 1,551 | 1,553 | 1,554 | 22 |
| 23 | **Off-System Deliveries[(7)]** | | 269 | 269 | 269 | 269 | 269 | 23 |
| | **Shrinkage** | | | | | | | |
| 24 | Company use and Unaccounted for | | 47 | 47 | 48 | 48 | 48 | 24 |
| 25 | **TOTAL END USE** | | 2,666 | 2,693 | 2,720 | 2,725 | 2,728 | 25 |
| | **TRANSPORTATION & EXCHANGE** | | | | | | | |
| 26 | CORE | ALL END USES | 180 | 180 | 179 | 179 | 180 | 26 |
| 27 | NONCORE | COMMERCIAL/INDUSTRIAL | 509 | 508 | 508 | 510 | 511 | 27 |
| 28 | | ELECTRIC GENERATION | 978 | 1,006 | 1,031 | 1,031 | 1,031 | 28 |
| 29 | | SUBTOTAL/RETAIL | 1,667 | 1,694 | 1,719 | 1,720 | 1,723 | 29 |
| 30 | | WHOLESALE/INTERNATIONAL | 10 | 10 | 10 | 10 | 10 | 30 |
| 31 | | TOTAL TRANSPORTATION AND EXCHANGE | 1,677 | 1,703 | 1,729 | 1,730 | 1,732 | 31 |
| 32 | System Curtailment | | 0 | 0 | 0 | 0 | 0 | 33 |

NOTES:

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

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

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

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

(5) Forecast by SMUD.

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

(7) Deliveries to southern California.

# 2014 CALIFORNIA GAS REPORT

## SOUTHERN CALIFORNIA GAS COMPANY

# INTRODUCTION

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

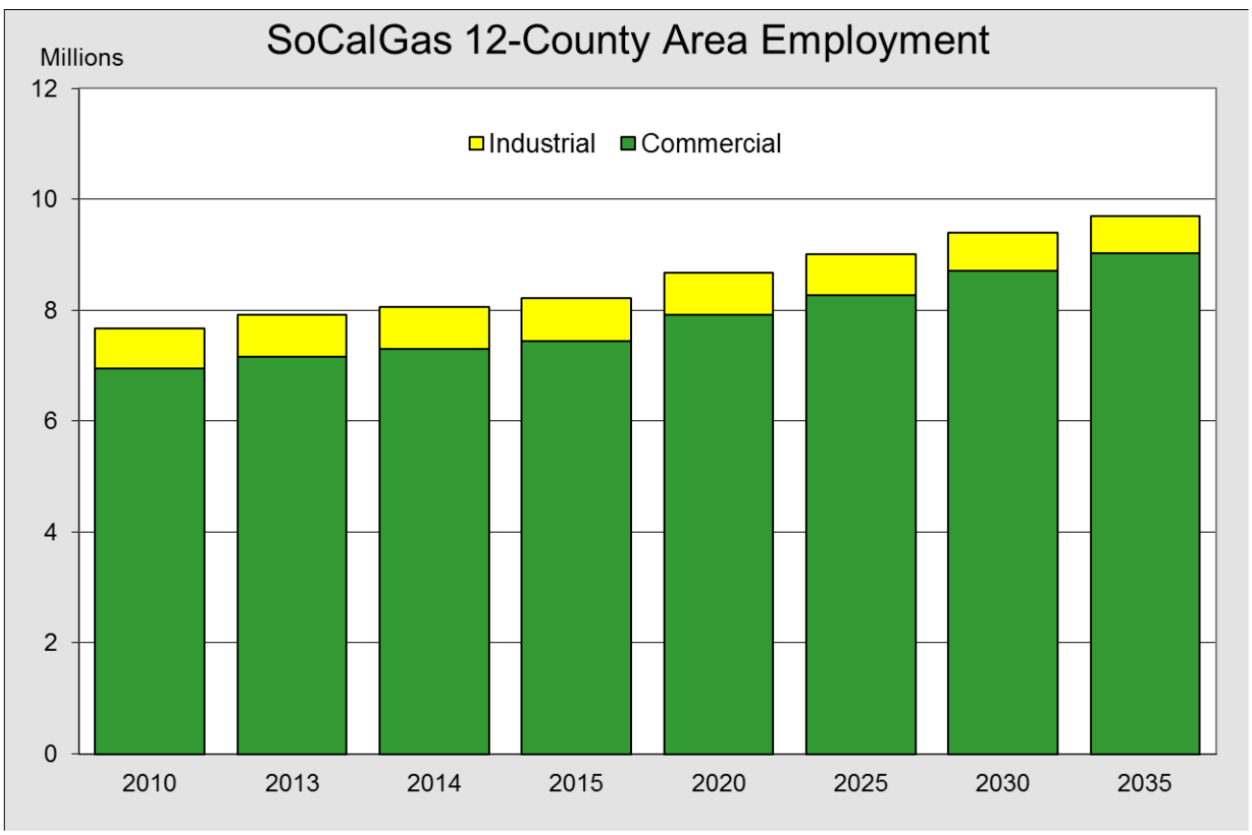
This report covers a 22-year demand and forecast period, from 2014 through 2035; only the consecutive years 2014 through 2020 and the point years 2025, 2030, and 2035 are shown in the tabular data in the next sections. These single point forecasts are subject to uncertainty, but represent best estimates for the future, based upon the most current information available.

The Southern California section of the *2014 California Gas Report* (CGR) begins with a discussion of the economic conditions and regulatory issues facing the utilities, followed by a discussion of the factors affecting natural gas demand in various market sectors. The outlook on natural gas supply availability, which continues to be favorable, is also presented. The natural gas price forecast methodology used to develop the gas demand forecast is discussed followed by a review of the peak day demand forecast. Summary tables and figures underlying the forecast are also provided.

# THE SOUTHERN CALIFORNIA ENVIRONMENT

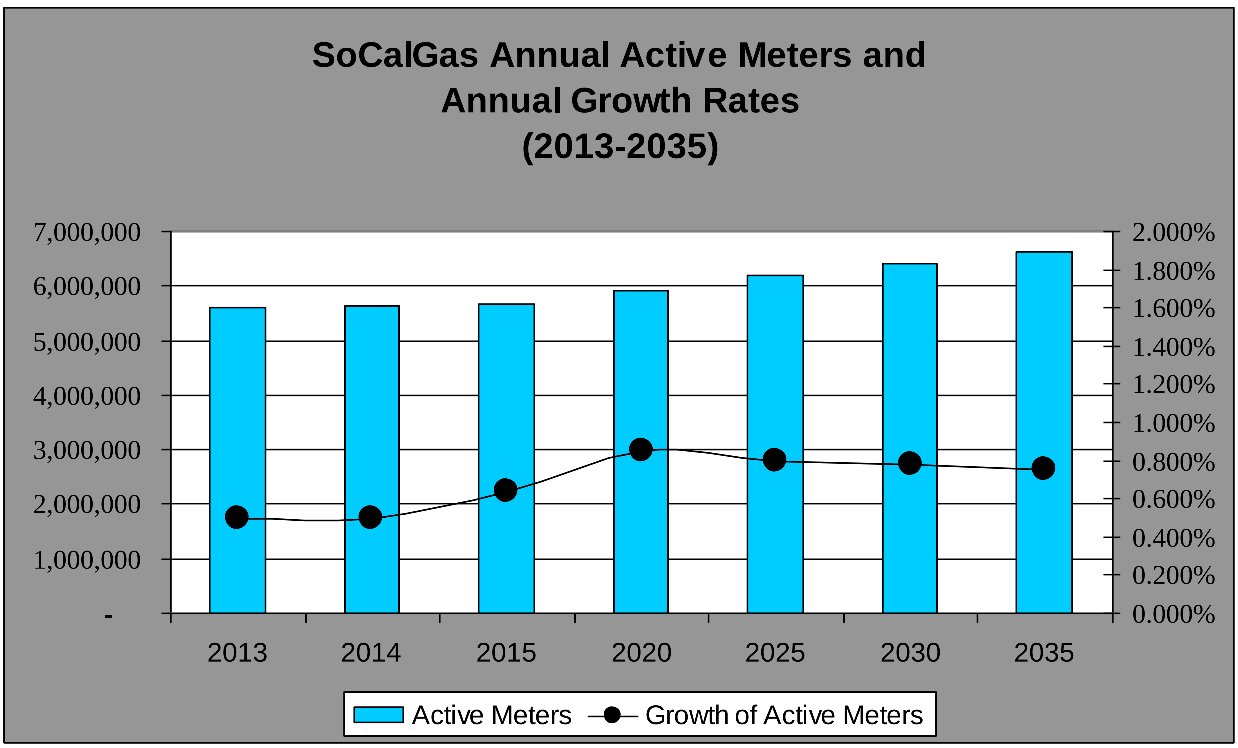
## ECONOMICS AND DEMOGRAPHICS

The gas demand projections are in large part determined by the long-term economic outlook for the SoCalGas service territory. As of mid-2014, southern California's economy is gradually recovering from a severe multi-year slump. After peaking in 2007, SoCalGas' service area employment dropped until 2010 and has been growing gradually since then. Overall area jobs are expected to average 1.4% annual growth from 2013 through 2020. Local industrial employment (manufacturing and mining) is expected to grow a more modest 0.6% per year from 2013 to 2020. Commercial jobs should grow by 1.5% per year during the same period. Construction employment should make a strong comeback--albeit from a low current level, averaging 6% annual growth from 2013 through 2020. Other job sectors with expected strong growth in the same period include professional and business services (growing 2.7% per year) and wholesale trade (1.9% per year).



In the longer term, SoCalGas' service area employment will likely see slower growth, as the area population's average age gradually increases--part of a national demographic trend of aging and retiring "baby boomers". From 2013 through 2035, total area job growth should average 0.9% per year. Area industrial jobs are forecasted to shrink an average of 0.3% per year through 2035; we expect the industrial share of total employment to fall from 9.1% in 2013 to 7.1% by 2035. Commercial jobs are expected to grow an average of 1.0% annually from 2013 through 2035.

SoCalGas' service area suffered a serious housing slump in 2007, when the last recession began. As a result, new gas meter hookups dropped drastically from a peak year of nearly 85,000 in 2006 to a low of under 19,000 in 2011. Since 2011, home building and meter hookups have increased modestly, with SoCalGas adding almost 27,000 new meters in 2013. In coming years, new housing and meter growth should continue to recover. SoCalGas expects its active meters to grow an average of 0.8% annually from 2013 through 2035.



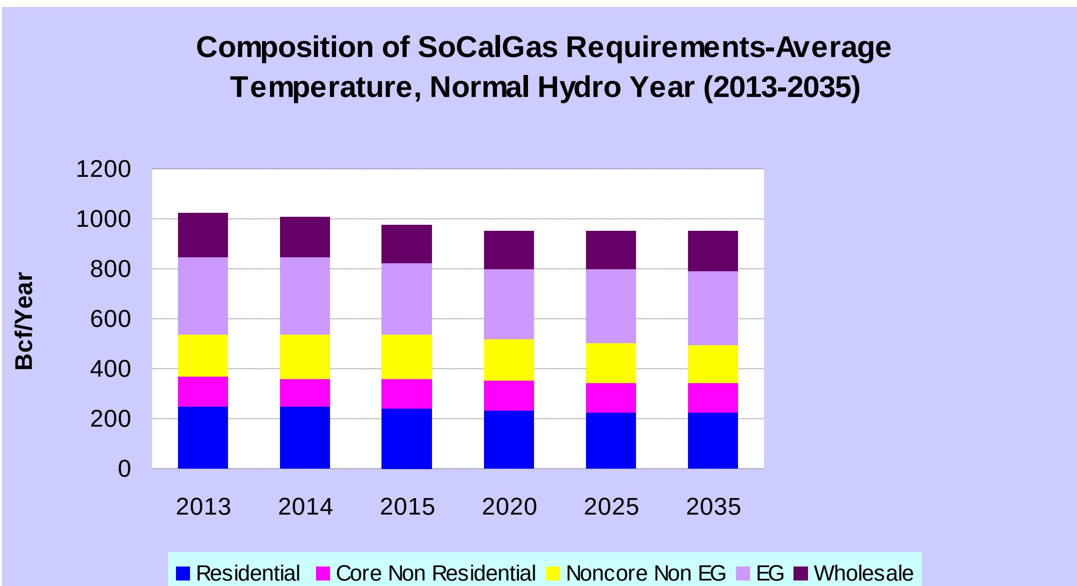

Since 2011, SoCalGas' service area housing market has been in a slow recovery period. Inactive meters in homes vacant due to foreclosures have been gradually re-activating as those homes are re-occupied. SoCalGas' active meter annual growth rate hit a low of 0.24% in 2009. It has since recovered modestly to 0.5% in 2013 and is expected to remain at about 0.5% in 2014. In the longer term, SoCalGas expects its active meters to increase by an annual average of just over 0.8% from the period 2013 through 2035.

# GAS DEMAND (REQUIREMENTS)

## OVERVIEW

SoCalGas projects total gas demand to decline at an annual rate of 0.33% from 2013 to 2035. The decline in throughput demand is due to modest economic growth, CPUC-mandated energy efficiency (EE) standards and programs, renewable electricity goals, the decline in commercial and industrial demand, and conservation savings linked to Advanced Metering Infrastructure (AMI). By comparison, the 2012 CGR projected an annual decline in gas demand at a rate of 0.13% from 2012 to 2030. The difference between the two forecasts is caused primarily by a higher gas rates outlook, and modest meter and employment growth in the 2014 report.

The following chart shows the composition of SoCalGas' throughput for the recorded year 2013 (with weather-sensitive market segments adjusted to average year heating degree day assumptions) and for the 2014 to 2035 forecast period.




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

From 2014 to 2035, residential demand is expected to decline from 247 Bcf to 223 Bcf. The decline is due to declining use per meter offsetting new meter growth. The core, non-residential markets are expected to grow from 118 Bcf in 2014 to 122 Bcf by 2035. The change reflects an annual growth rate of 0.15% over the forecast period. The noncore, non-EG markets are expected to decline from 169 Bcf in 2013 to 150 Bcf by 2035. The annual rate of decline is approximately 0.5% due to very aggressive energy efficiency goals and associated programs. On the other hand, utility gas demand for EOR steaming operations, which had declined since the FERC-regulated Kern/Mojave interstate pipeline began offering direct service to California customers in 1992, has shown some growth in recent years because of continuing high oil prices and is expected to show further growth in the early years of the forecast period. EOR demand is forecast to level off in 2016 and remain relatively flat through 2035 as gains are offset by the depletion of older oil fields. Total electric generation load, including cogeneration and non-cogeneration EG for a normal hydro year, is expected to decline from 311 Bcf in 2014 to 298 Bcf in 2035, a decrease of 0.12% per year.

## Market Sensitivity

### Temperature

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

In our 2014 CGR, average year and cold year HDD totals are 1,385 and 1,677 respectively, on a calendar year basis for SoCalGas. For SDG&E, these values are 1,342 and 1,654 HDDs, respectively. The average year values were computed as the simple average of annual HDD's for the years 1994 through 2013.

### Hydro Condition

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

## MARKET SECTORS

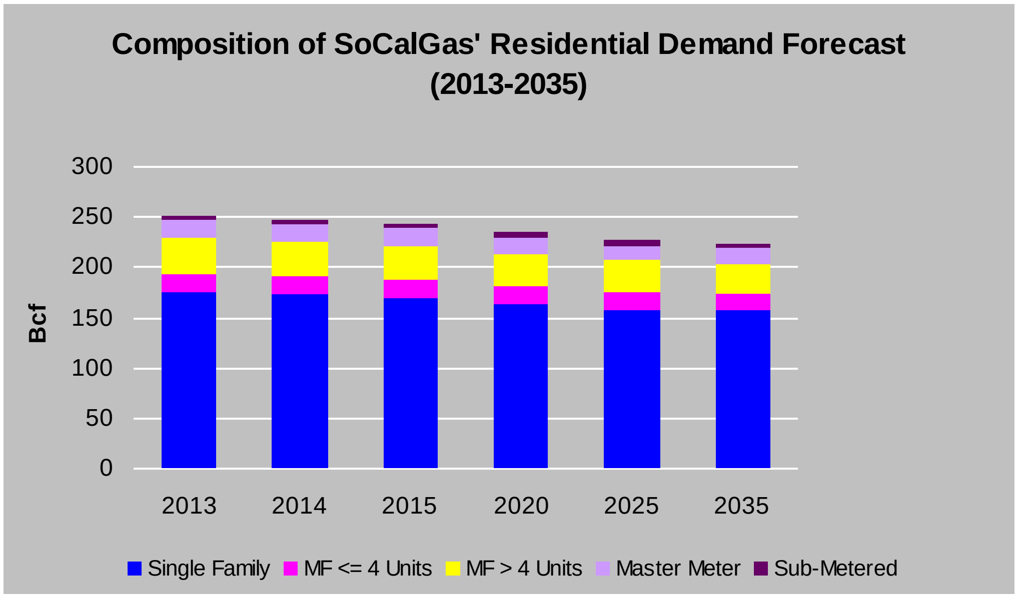
### Residential

Residential demand adjusted for temperature totaled 251 Bcf in 2013 which is 8 Bcf higher than 2012 weather adjusted deliveries. The residential load is expected to decline by 0.5% per year from 251 Bcf in 2013 to 223 Bcf in 2035. The decrease in gas demand results from a combination of continued decline in the residential use per meter, increases in the marginal gas rates, the impact of savings from SoCalGas' Advanced Meter Infrastructure (AMI) project deployment which began in 2013 and CPUC authorized energy efficiency program savings in this market.

The total residential customer count for SoCalGas consists of five residential segment types: single family, small and large multi-family customers, master meter and sub-metered customers. The active meters for all residential customer classes were 5.4 million at the end of 2013. This amount reflects a 29,308 active meter increase between 2012 at year end and 2013 at year end. The overall observed 2012-2013 residential meter growth was 0.55%. Just six years before, the observed meter growth had been 53,326 new meters between 2006 and 2007, which amounts to an annual growth rate of 1.03%. The decrease in active meter growth reflects the overall state of the Southern California economy.

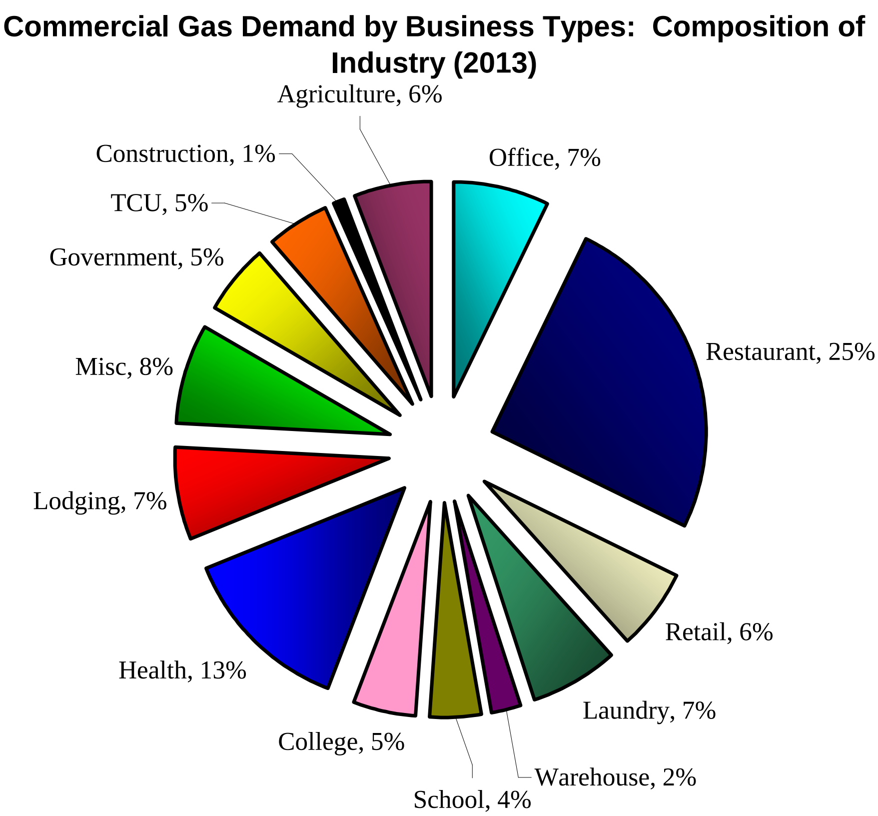
The 2014 CGR shows that in 2013, single family and multi family average annual use per meter was 493 therms and 323 therms, respectively. Over the forecast period, the demand per customer is expected to decline at an annual rate of 1.3%. The decline in use per meter for residential customers is explained by conservation and the energy savings resulting from tightened building and appliance standards and energy efficiency programs and demand reductions anticipated as a result of the deployment of AMI in the Southern California area. With AMI, customers will have more timely information available about their daily and hourly gas use and thereby are expected to use gas more efficiently. Mass deployment of SoCalGas' AMI modules began in 2013 and is expected to be completed by 2017. The deployment of SoCalGas' AMI will not only provide operating efficiencies but will also generate long term conservation benefits.

In summary, the projected residential natural gas demand will be influenced primarily by residential meter growth, moderated by the forecasted declining use per customer, and the gradual conversion of some sub-meter and master meter customers to individual meter use. The residential load trend over the forecast period is illustrated in the graph below.



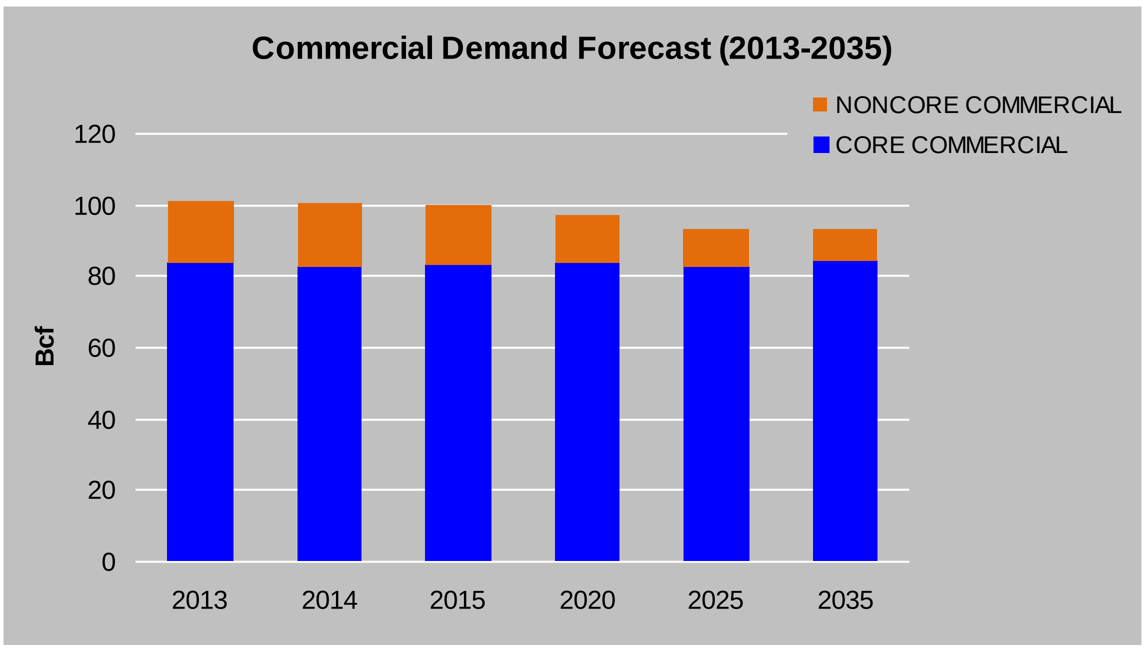

## Commercial

The commercial market consists of 14 business types identified by the customer's North American Industry Classification System (NAICS) codes. The restaurant business dominates this market with 25% of the usage in 2013. The health industry is next largest with a share of 13% of the overall market based on 2013 natural gas consumption.



The core commercial market demand is expected to remain relatively flat over the forecast period. On a temperature-adjusted basis, the core commercial market demand in 2013 totaled 83 Bcf. By the year 2035, the load is anticipated to be approximately 84 Bcf. The average annual rate of growth from 2013 to 2035 is forecasted at 0.04% percent. The slow growth in gas usage is mainly the result of the impact of CPUC-authorized energy efficiency programs in this market.

Noncore commercial demand in 2013 was 17.7 Bcf. From 2014 through 2035, this market is expected to decline approximately 3.3% annually to 8.6 Bcf. Aggressive CPUC-authorized energy efficiency programs targeted at this market along with high costs of compliance with environmental regulations are expected to decrease demand in this market.



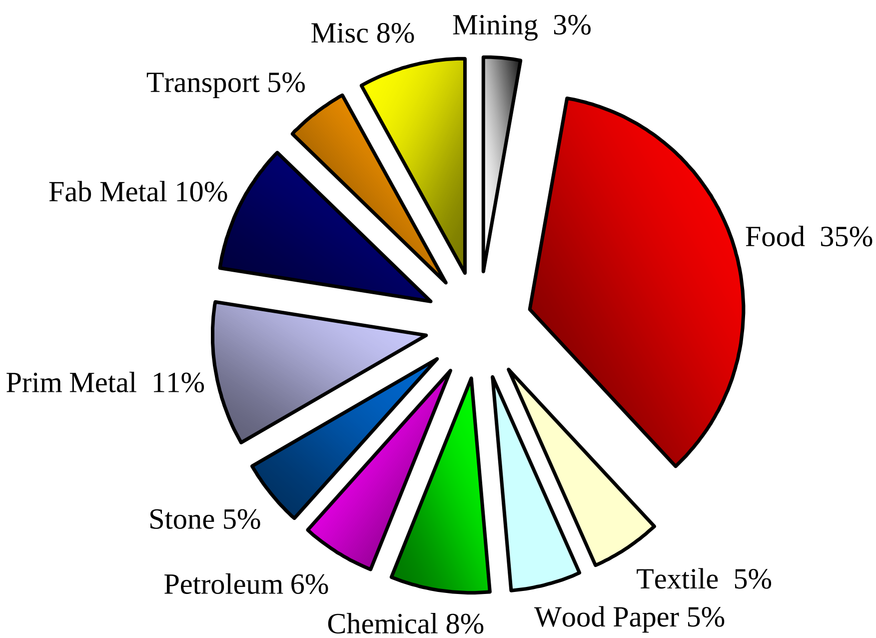

## Industrial

*Non-Refinery Industrial Demand*

In 2013, temperature-adjusted core industrial demand was 22.9 Bcf, which is higher than the 2012 deliveries by 0.8 Bcf. Core industrial market demand is projected to decrease by 1.9% per year from 22.9 Bcf in 2013 to 15.0 Bcf in 2035. This decrease in gas demand results from a combination of factors: minor increases in marginal gas rates, the municipalization of the City of Vernon, and CPUC authorized energy efficiency programs.

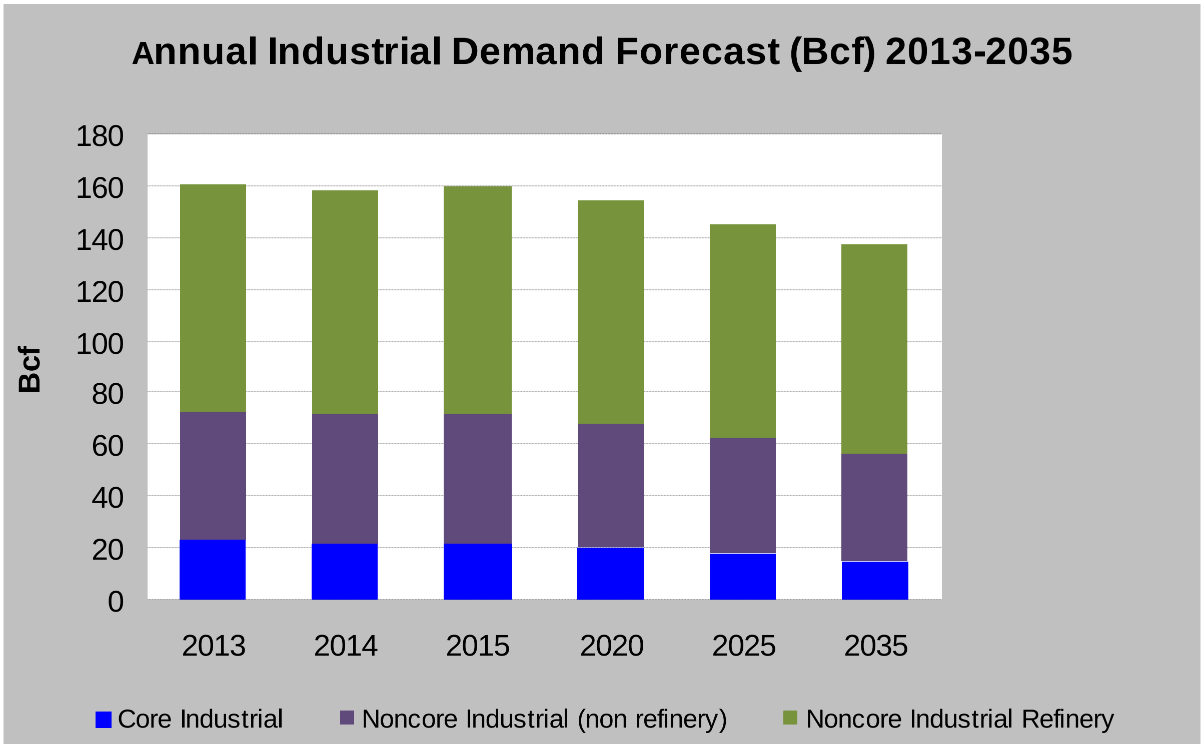
The 2013 industrial gas demand served by SoCalGas is shown below. Food processing, with 35% of the total share, dominates this market.

**Non-Refinery Industrial Gas Demand by Business Types**
**Composition of Industrial Activity (2013)**




Overall, the retail noncore industrial (non-refinery) gas demand has shown persistent signs of weakness since 2006 due to competitive economic pressure to relocate out-of-state or to exit the line of business altogether. After 2007, the economic downturn has led to further reductions in gas demand from this market segment with industrial demand dropping annually by 5% in 2007, 13.5% in 2008, and 14.3% in 2009. Since 2009, this market has recovered somewhat with annual growth of 10% in 2010 and 5% in 2011. Additional data suggest that the recovery peaked in 2011 at 50.4. Gas consumption in 2012 and 2013 was 49.8 and 49.6 Bcf, respectively.

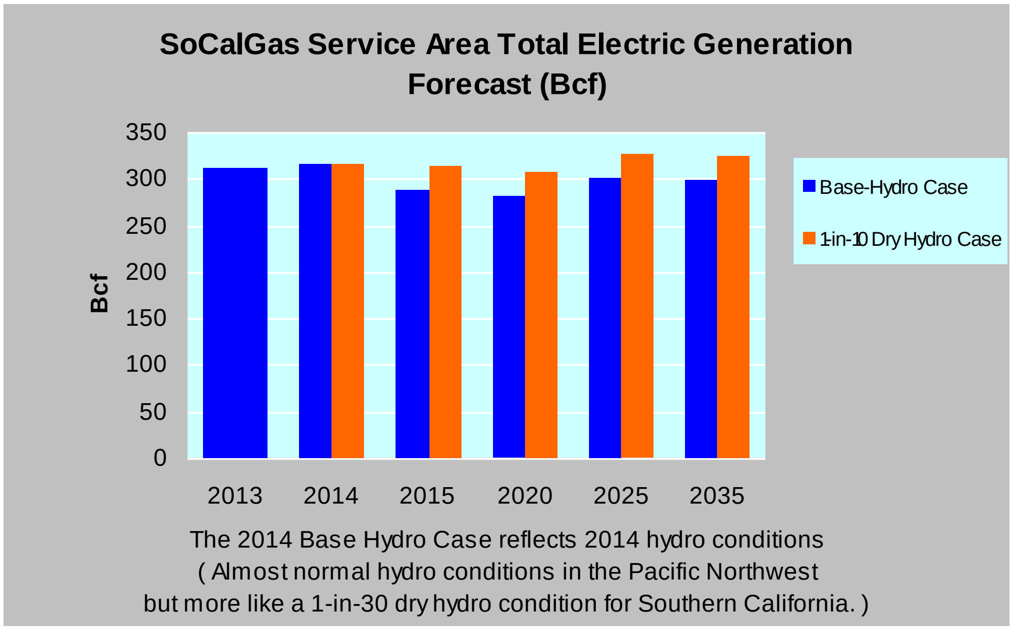
Gas demand for the retail noncore industrial market as a whole is expected to decline at a rate of 0.9% from 49.6 Bcf in 2013 to under 41.5 Bcf by 2035. The reduced demand is primarily due to the departure of customers within the City of Vernon to wholesale service by the City of Vernon, the CPUC-authorized energy efficiency programs designed to reduce gas demand and the expected implementation of regulations to aggressively reduce $CO_2$ emissions by effectively increasing the gas commodity price for many large industrial customers.




*Refinery Industrial Demand*

Refinery industrial demand is comprised of gas consumption by petroleum refining customers, hydrogen producers and petroleum refined product transporters. Gas demand in 2011 was 84.5 Bcf and posted gains in 2012 and 2013 to 85.1 and 87.8 Bcf, respectively. Refinery industrial gas demand is forecast to decline about 0.4% per year over the 2014-2035 forecast period, from 87.0 Bcf in 2014 to 81 Bcf in 2035. The decrease over the forecast period is primarily due to the estimated savings from CPUC-authorized energy efficiency programs. Also, the implementation of regulations to aggressively reduce $CO_2$ emissions effectively increases the commodity prices for both natural gas and butane for large industrial customers; the expected price advantage of natural gas versus butane over the forecast period only lessens the decline in gas consumption that would occur from energy efficiency impacts alone at refineries.

## Electric Generation




This sector includes the following markets: all commercial/industrial cogeneration; EOR-related cogeneration; and, non-cogeneration electric generation. It should be noted that the forecast of electric generation (EG) load is subject to a higher degree of uncertainty than the other sectors. This uncertainty is due to the ambiguity inherent in the underlying key assumptions. The assumptions include, but are not limited to, the following: the continued operation of existing generation facilities and the potential shutdown of units from the state's new once-through-cooling (OTC) regulation; the timing and location of new gas-fired generation facilities in the rest of California and the western United States; the regulatory and market decisions that impact the operation of existing cogeneration facilities; the location, timing and construction of new renewable resources; the continued electric transmission line upgrades throughout the system; the Cap and Trade greenhouse gas (GHG) program; and the timing and construction of new energy storage resources. The forecast uses a power market simulation for the period of 2014 to 2025. The simulation reflects the anticipated dispatch of all EG resources in the SoCalGas service territory using a base electricity demand scenario under both average and low hydroelectric availability market conditions. The base case assumes that 33% of the state's energy needs are met with renewable power by 2020, and additional renewable power is added after 2020 to maintain the 33% level. The base case also assumes the IOUs will meet D.13-10-040, or the energy storage procurement framework and design program. However, there is substantial uncertainty as to how this will be implemented, and its impact on gas throughput is unknown.

Due to the large uncertainty in the timing and type of generating plants that could be added after 2025, the EG forecast is held constant at 2025 levels for 2030 and 2035. During that time period, there is the potential for the development and construction of new, non-gas fired resources. These new generation resources may be in sufficient quantity to create downward pressure on the demand for natural gas after 2025; however, increased electrification in other sectors, such as transportation, could create counteracting upward pressure on electricity demand and associated gas demand.

For electricity demand within California, SoCalGas relies on the California Energy Commission's (CEC) California Energy Demand 2014- 2024 Final Forecast, dated December 2013. SoCalGas selected the Mid Energy Demand scenario with Mid Additional Achievable Energy Efficiency (AAEE) scenario. SoCalGas relies on Ventyx's electric demand forecast for the remainder of the Western Electricity Coordinating Council (WECC) area.

### *Industrial/Commercial/Cogeneration <20MW*

The commercial/industrial cogeneration market segment is generally comprised of customers with generating capacity of less than 20 megawatts (MW) of electric power. Most of the cogeneration units in this segment are installed primarily to generate electricity for internal customer consumption rather than for the sale of power to electric utilities. Customers in this market segment install their own electric generation equipment for both economic reasons (gas-powered systems produce electricity cheaper than purchasing it from a local electric utility) and reliability reasons (lower purchased power prices are realized only for interruptible service). In 2008, recorded gas deliveries to this market were 18.7 Bcf. By 2011, the small cogeneration load totaled 20.9 Bcf, which represents an 11.8% increase over the 2008 level. Consumption continued to increase in 2012 and 2013 to 23.1 and 24.5 Bcf, respectively. Overall, small cogeneration demand is projected to decline modestly from 21.9 Bcf in 2014 to 19.7 Bcf by the year 2035. From 2014 through 2035, small cogeneration load is anticipated to decline at an annual average rate of 0.50%. A key factor in stimulating this gas decline is the expected implementation of regulations to aggressively reduce $CO_2$ emissions which will effectively increase the gas commodity price for many of the larger small cogeneration customers

### *Industrial/Commercial Cogeneration >20 MW*

For commercial/industrial cogeneration customers greater than 20 MW, gas demand is forecast to remain constant at 51 Bcf from 2014 through 2025. Although there is uncertainty in this sector with respect to contract renewals, this forecast assumes that the existing facilities will continue to be cost–effective and thus will continue to operate at historical levels. Changes to this assumption in the future could have a significant impact on the forecast.

### *Refinery-Related Cogeneration*

Refinery cogeneration units are installed primarily to generate electricity for internal use. This cogeneration segment consumed 20.7 Bcf in 2012 and rose to 22.6 Bcf in 2013. This market is forecast to decline modestly at just over 0.61% per year, from 22.2 Bcf in 2014 to 21.7 Bcf in 2035. The slight decline is mainly due to higher gas costs stemming from California's GHG carbon fees.

### *Enhanced Oil Recovery-Related Cogeneration*

In 2013, recorded gas deliveries to the EOR-related cogeneration market were 8.5 Bcf, a 9% increase from 2012. This increase in load was due to changes in operations for some of the existing EOR-related cogeneration customers. EOR-related cogeneration demand is forecast to remain at 8.5 Bcf throughout the forecast period.

### *Non-Cogeneration Electric Generation*

For the non-cogeneration EG market, two gas demand forecast scenarios were developed underlying: (i) a base hydro condition and (ii) a 1-in-10 dry hydro condition. For the base case, gas demand is forecasted to decrease from 211 Bcf in 2014 to 197 Bcf in 2025. It is important to note that in the base case scenario, the first year of the forecast, 2014, is a dry hydro year. Consequently, the forecasted non-cogeneration EG demand for 2014 is higher than it would be under normal hydro conditions. The forecast for the remaining years, 2015-2025, is based on normal hydro conditions. Demand is forecasted to slightly increase from 183 Bcf in 2015 to 197 Bcf in 2025. This small gain is mostly due to new gas-fired resources beyond 2020. Due to the large uncertainty in the timing and type of generating plants that could be added after 2025, SoCalGas holds the EG forecast constant at the 2025 level for 2030 and 2035.

SoCalGas' forecast includes the addition of approximately 1,950 MW of new gas-fired combined cycle and peaking generating resources in its service area by 2025. However, the forecast also assumes 6,900 MW of older plants are retired as a result of the state's once-through-cooling regulation. Throughout the entire forecast period, SoCalGas assumes that market participants will construct additional generation resources to meet a minimum planning reserve margin of 15%.

Starting in 2014, the forecast ramps up renewable electricity generation to meet 33% of the state's total electric energy consumption by 2020. The forecast estimates renewable-sourced energy generation in 2020 by taking 33% of CEC's forecasted electricity sales load. The forecast shows that close to 80% of the incremental renewable power needed to meet the state's 33% target will be physically located in Southern California.

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

As mentioned above, to account for dry climate conditions, a dry hydro sensitivity gas demand forecast was also created. This dry hydro forecast indicates that, under 1-in-10 dry hydro conditions, gas demand for SoCalGas increases by 25 Bcf, on average, each year over the forecast period.

## Enhanced Oil Recovery – Steam

Recorded deliveries to the EOR steaming market in 2013 were 12.8 Bcf, an increase of approximately 15% from 2012. SoCalGas' EOR steaming demand is expected to increase to 15.9 Bcf in 2014, a 24% increase, and to 18.5 Bcf in 2015, a 16% increase, as current EOR customers expand their operations and new customers come on-line. Demand is forecast to level off at 18.5 Bcf from 2016 through the end of the forecast period. These figures include gas delivered to PG&E's EOR customers through inter-utility exchange. In 2013, less than 0.01 Bcf of gas was delivered to PG&E through such arrangements. No change in demand is expected in that market. The EOR-related cogeneration demand is discussed in the Electric Generation section.

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

## Wholesale and International

SoCalGas provides wholesale transportation service to SDG&E, the City of Long Beach Gas and Oil Department (Long Beach), Southwest Gas Corporation (SWG), the City of Vernon (Vernon) and Ecogas Mexico, L. de R.L. de C.V. The wholesale load is expected to decrease from 172 Bcf in 2013 to 160 Bcf in 2035.

### *San Diego Gas & Electric*

Under average year temperature and normal hydro conditions, SDG&E gas demand is expected to decrease at an average rate of 0.7% per year from 137 Bcf in 2013 to 119 Bcf in 2035. Additional information regarding SDG&E's gas demand is provided in the SDG&E section of this report.

### *City of Long Beach*

The wholesale load forecast is based on forecast information provided by the City of Long Beach Municipal Gas & Oil Department. Long Beach's gas use is expected to remain fairly constant, increasing from 9.0 Bcf in 2014 to 9.6 Bcf by 2035. Long Beach's locally supplied deliveries are expected to decline from 0.4 Bcf in 2014 to 0.1 Bcf by 2035. SoCalGas' transportation to Long Beach is expected to increase gradually from 8.6 Bcf in 2014 to 9.5 Bcf by 2035. Refer to the City of Long Beach Municipal Gas & Oil Department for more information.

*Southwest Gas*

The demand forecast for Southwest Gas is based on a long-term demand forecast prepared by Southwest Gas. In 2014, SoCalGas expects to serve approximately 6.4 Bcf directly, with another 2.9 Bcf being served by PG&E under exchange arrangements with SoCalGas. The total load is expected to grow from 9.3 Bcf in 2014 to approximately 12.6 Bcf in 2035.

*City of Vernon*

The City of Vernon initiated municipal gas service to its electric power plant within the city's jurisdiction in June, 2005. Since 2005, there has also been a gradual increase of Commercial/Industrial gas demand as customers within the city boundaries have left the SoCalGas retail system and interconnected with Vernon's municipal gas system. The forecasted throughput starts at 10.5 Bcf in 2014 and increases to 11 Bcf by 2021, after which the demand remains relatively flat through 2035. Vernon's commercial and industrial load is based on recorded historical usage for commercial and industrial customers already served by Vernon plus the customers that are expected to request retail service from Vernon. The throughput forecast for Vernon's municipal EG customers is based on a power market simulation.

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

SoCalGas used the forecast prepared by Ecogas for this report. Ecogas' use is expected to gradually increase from approximately 7.3 Bcf/year in 2014 to 7.9 Bcf/year by 2035.

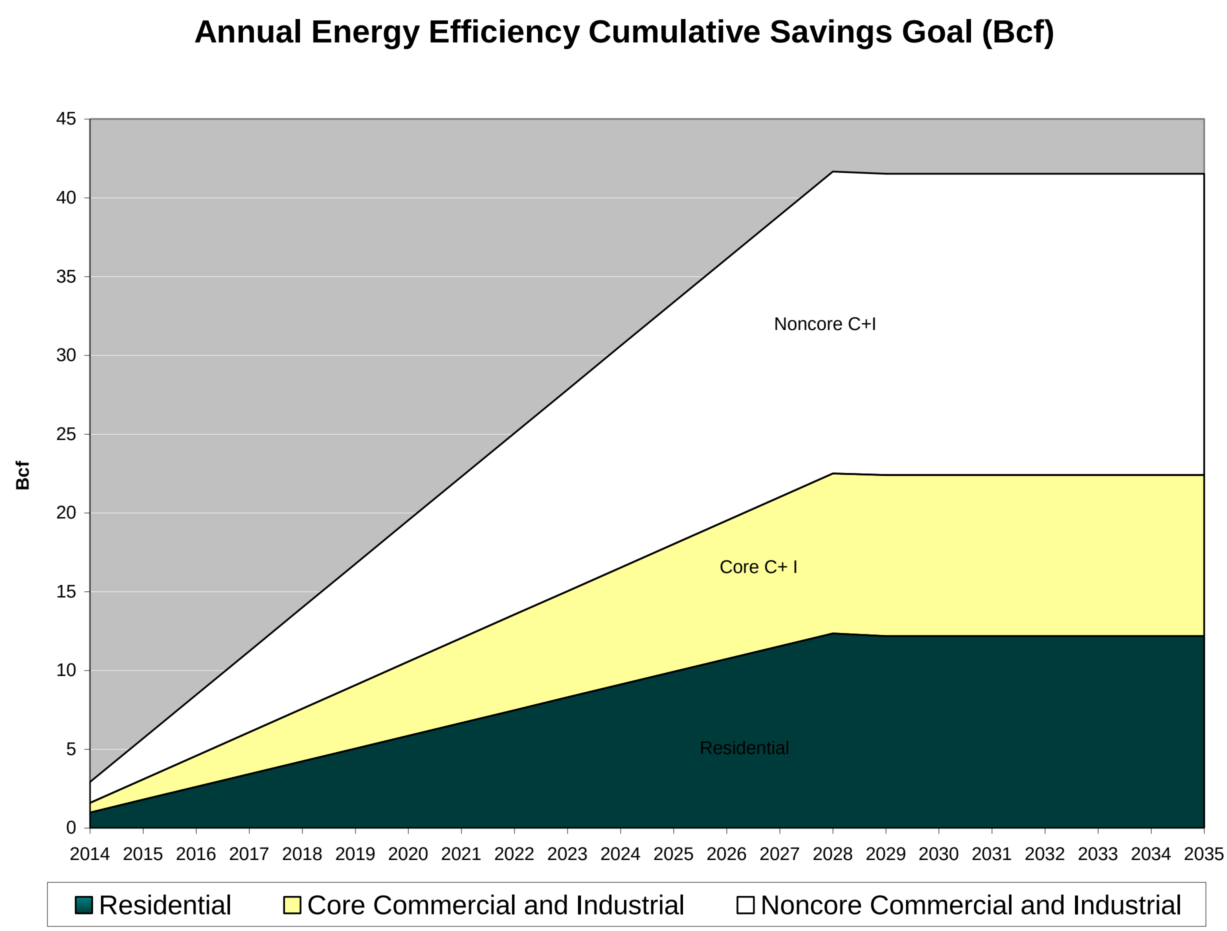
### Natural Gas Vehicles (NGV)

The NGV market is expected to continue to grow due to government (federal, state and local) incentives and regulations related to the purchase and operation of alternate fuel vehicles, growing numbers of natural gas engines and vehicles, and the increasing cost differential between petroleum (gasoline and diesel) and natural gas. At the end of 2013, there were 289 compressed natural gas (CNG) fueling stations delivering 11.4 Bcf of natural gas during the year. The NGV market is expected to grow substantially from 11.4 Bcf in 2013 to 23.3 Bcf in 2035, a growth rate of just over 3.3% per year.

## ENERGY EFFICIENCY PROGRAMS

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

The cumulative net Energy Efficiency load impact forecast for selected years is shown in the graph below. The net load impact includes all Energy Efficiency programs that SoCalGas has forecasted to be occurring through year 2035. The 2014 goals for these programs are based on the levels authorized by the CPUC in D.12-05-015. Values for 2015 are based on the proposed program goals currently pending before the Commission in R.13-11-005. For 2015 and beyond, savings goals are based upon the 2013 California Energy Efficiency Potential and Goals Study final report dated February 14, 2014 and performed by Navigant Consulting, Inc. on behalf of the commission. Energy Efficiency goals for the 2025-2035 period are held constant at the 2024 level.




Savings reported are for measures installed under SoCalGas' Energy Efficiency programs. Credit is only taken for measures that are installed as a result of SoCalGas' Energy Efficiency programs, and only for the estimated lives of the measures installed. Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. This means, for example, that a measure installed in 2014 with a lifetime of 10 years is only included in the forecast through 2023.[3] Naturally occurring conservation that is not attributable to SoCalGas' Energy Efficiency activities is not included in the Energy Efficiency forecast.

[3] The assumed average measure life is 15 years.

Details of SoCalGas' Energy Efficiency program portfolio are contained in D.12-05-015 and D.12-15-015. The Energy Efficiency portfolio for program year 2015 and forward is currently being considered in R.13-11-005.

# GAS SUPPLY, CAPACITY, AND STORAGE

## GAS SUPPLY SOURCES

Southern California Gas Company and San Diego Gas & Electric Company receive gas supplies from several sedimentary basins in the Western United States and Canada including supply basins located in New Mexico (San Juan Basin), West Texas (Permian Basin), the Rocky Mountains, Western Canada, and local California supplies. Recorded 2009 through 2013 receipts from gas supply sources can be found in the Sources and Disposition tables in the Executive Summary.

## CALIFORNIA GAS

Gas supply available to SoCalGas from California sources averaged 153 MMcf/day in 2013.

## SOUTHWESTERN U.S. GAS

Traditional Southwestern U.S. sources of natural gas, especially from the San Juan Basin, will continue to supply most of Southern California's natural gas demand. This gas is primarily delivered via the El Paso Natural Gas and Transwestern pipelines. The San Juan Basin's gas supplies peaked in 1999 and have been declining at an annual rate of roughly 3%, but at a faster rate in recent years. The Permian Basin's share of supply into Southern California has increased in recent years, although increasing demand in Mexico for natural gas supplies may significantly reduce the volume of Permian Basin supply available to Southern California in the future. In A.13-12-013, SoCalGas and SDG&E have discussed this situation in more detail and have proposed a response to the operational concerns this situation creates for California.

## ROCKY MOUNTAIN GAS

Rocky Mountain supply supplements traditional Southwestern U.S. gas sources for Southern California. This gas is delivered to Southern California primarily on the Kern River Gas Transmission Company's pipeline, although there is also access to Rockies gas through pipelines interconnected to the San Juan Basin. Production from the Rocky Mountain region in 2013 has doubled since 2000 due to the successful applications of new technology to drill for coal-bed methane gas. In recent years, Rocky Mountain gas has increasingly flowed to Midwestern and Pacific Northwest markets.

## CANADIAN GAS

SoCalGas anticipates that the role of Canadian gas in meeting Southern California's demand during the forecast period will not change significantly. Eventually, LNG exports to Asia may move Canadian gas away from California. Increased gas deliveries to California from the Rockies and Permian Basin are expected to replace these supplies.

## BIOGAS

Biogas is a mixture of methane and carbon dioxide produced by the bacterial degradation of organic matter. Biogas is a byproduct produced from processes including, but not limited to, anaerobic digestion, anaerobic decomposition, and thermo-chemical decomposition under sub-stoichiometric conditions. These processes are applied to biodegradable biomass materials, such as livestock manure, wastewater sewage, food waste, and green waste. When biogas is conditioned/upgraded to pipeline quality specifications, commonly referred to as "biomethane," it can be interconnected to a gas utility's pipeline and nominated for a specific end-use customer.[4] Biomethane may also be consumed onsite for a variety of uses, including elected power generation from internal combustion engines, fuel cells, and turbines, or as a fuel source for natural gas vehicles. Currently, there are instances where biogas is being vented naturally or flared to the atmosphere. Venting and flaring wastes this valuable renewable resource and fails to support the state in achieving its emission reduction targets set forth by Assembly Bill ("AB") 32 and the Renewables Portfolio Standard ("RPS") goals, as processed renewable natural gas injected into a common carrier natural gas pipeline system can ultimately count toward satisfying AB 32 and RPS goals.

In February 2013, the CPUC issued an Order Instituting Rulemaking ("Rulemaking") to adopt standards and requirements, open access rules, and related enforcement provisions, pursuant to Assembly Bill 1900 (Gatto), which tasked state agencies to address any constituents of concern specifically found in biomethane, and to identify impediments to interconnecting to utility pipelines.[5] CARB released their report on May 15, 2013 which identifies 17 constituents of concern found in biomethane and provides direction on monitoring, testing, reporting and recordkeeping procedures for utilities and biomethane suppliers. The first phase of the Rulemaking - the identification of constituents of concern – resulted in the utilities filing revised tariff rules governing gas quality specifications in February 2014. The second phase of the Rulemaking began in April 2014 to determine "who should bear the costs of complying with the CPUC-adopted testing, monitoring, reporting, and recordkeeping requirements."

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

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

## INTERSTATE PIPELINE CAPACITY

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

**Upstream Capacity to Southern California**

| Pipeline | Upstream Capacity (MMcf/d)(1) |
|---|---|
| El Paso at Blythe | 1,210 |
| El Paso at Topock | 540 |
| Transwestern at Needles | 1,150 |
| PG&E at Kern River | 650(1) |
| Southern Trails at Needles | 80 |
| Kern/Mojave at Wheeler Ridge | 885 |
| Kern at Kramer Junction | 750 |
| Occidental at Wheeler Ridge | 150 |
| California Production | 310 |
| TGN at Otay Mesa | 400 |
| North Baja at Blythe | 600 |
| Total Potential Supplies | 6,725 |

(1) Estimate of physical capacity.

## FIRM RECEIPT CAPACITY

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

**SoCalGas/SDG&E Current Firm Receipt Capacity**

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

(1) Pipelines

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

(2) Transmission Zone Contract Limitations:

Southern Zone:

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

Northern Zone:

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

Wheeler Ridge Zone:

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

## STORAGE

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

Of SoCalGas' total 137.1 Bcf of storage capacity, 83 Bcf is allocated to our core residential, small industrial and commercial customers. About 4.2 Bcf of space is used for system balancing. The remaining capacity is available to other customers.

# REGULATORY ENVIRONMENT

## State Regulatory Matters

### TRIENNIAL COST ALLOCATION PROCEEDING (TCAP)

SoCalGas and SDG&E filed their TCAP, A.11-11-002 in November 2011. The application updated throughput forecasts, cost allocation, and rates by customer class for 2013 through 2015, in addition to addressing issues related to the prior settlement agreements adopted in SoCalGas and SDG&E's previous cost allocation proceeding. A February 2012 Ruling has subsequently bifurcated the TCAP into two phases; Phase I addresses the Pipeline Safety Enhancement Plans (PSEP) originally filed by SoCalGas and SDG&E in Commission Rulemaking R.11-02-019. SoCalGas and SDG&E's PSEP seeks funding for safety enhancement projects for the years 2012 through 2015.

Phase 2 of the TCAP addresses cost allocation including all issues raised by SoCalGas and SDG&E in their original TCAP application (A.11-11-002) to allocate the cost of service to various customer classes to recover the cost of service from the respective rate base. In addition, Phase 2 includes the costs of the PSEP addressed in Phase 1. A proposed decision was issued in April 2014 addressing both Phase 1 and 2 of the TCAP. A final decision is anticipated in 2014.

### PIPELINE SAFETY

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

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

The Utilities' Pipeline Safety Enhancement Plan was transferred for consideration from the Pipeline Safety Rulemaking to the Utilities' Triennial Cost Allocation Proceeding. A final decision was issued in May 2014 which adopts the overall plan and a process to recover the associated costs subject to reasonableness reviews.

## SOUTHERN GAS SYSTEM RELIABILITY PROJECT

On December 20, 2013, SoCalGas and SDG&E filed an application proposing enhancements to the reliability of its Southern System. The proposal requests authority to collect $628.6 million in customer rates to construct a North-to-South Pipeline from SoCalGas' Adelanto compressor station near Victorville down to the Moreno pressure limiting station in Moreno Valley. The pipeline will be a new source of up to 800 million cubic feet of gas per day to the Southern System and would provide an additional 300 million cubic feet of backbone capacity per day in the northern part of the SoCalGas system. Together, these enhancements will increase reliability to Southern System customers and to the generators supporting the electric grid.

The North-South Project consists of three major components:

| | |
|---|---|
| Adelanto – Moreno Pipeline | $331.8M |
| Adelanto Compressor Station | $110.7M |
| Moreno-Whitewater Pipeline | $186.1M |
| Total | $628.6M |

A Commission decision is expected in 2015. The expected in-service date for the North-South Project, subject to environmental permitting, is late 2018.

## FEDERAL REGULATORY MATTERS

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

### El Paso

El Paso's rates have been the subject of extensive litigation at FERC in recent years. El Paso filed its third general rate case in five years in September 2010. The 2010 rate case proceeded to a hearing on all issues in 2011, and we are still awaiting a final decision on these matters in 2014.

During 2012-13, El Paso filed applications to abandon certain compression facilities used to transport San Juan Basin gas supplies to interconnects with the SoCalGas and PG&E systems. The FERC approved one application to abandon compression facilities and El Paso withdrew the other application

Also during 2012-13, El Paso filed several applications to build new or expand on existing interconnections at the U.S.-Mexican border to transport natural gas supplies into Mexico. The FERC has approved most of these applications.

### Kern River

A final ruling was issued in 2013 in Kern River's 2004 general rate case. The ruling denied many rehearing requests to revisit the issues litigated in this case and accepted a series of orders retaining Kern River's original 1992 levelized rate design, resulting in reduced rates for eligible shippers which extend for periods up to 15 years.

### Transwestern

Under the terms of its 2011 rate case settlement, Transwestern agreed to retain its existing tariff rates. Under the settlement, the fuel rate for San Juan Basin gas supplies delivered to California will decrease annually from 2012-2014. The earliest that Transwestern may file for a change in rates is October 1, 2014.

### Gas Transmission Northwest (GTN)

In December 2011 FERC approved a rate case settlement between GTN and its customers. Under the settlement, transportation rates for Canadian gas supplies delivered to California are reduced for the four-year term of 2012-2015.

### Coordination Between Gas and Electric Markets

In February 2012, FERC opened a proceeding to receive comments concerning potential revisions to coordinate scheduling protocols and emergency response measures between gas and electricity markets. Discussions are underway in 2014 to consider changing the start of the nationwide gas day to better accommodate load nominations between gas and electric energy markets. The nationwide gas day is currently set at 9 am Central Time.

# GREENHOUSE GAS ISSUES

## National Policy

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

## Restriction on New Conventional Coal Generation

In March 2012, EPA proposed the first Clean Air Act standards for carbon pollution. The proposed standards apply only to new facilities and can be met by a range of power generation facilities burning fossil fuels, including natural gas or coal with technologies to reduce carbon emissions. Since carbon sequestration technology is not yet proven, in the near term, new generation will likely be dependent upon natural gas. Therefore, as California's electricity demand increases, California, as well as the rest of the country, will likely become more dependent upon new natural gas generation to meet the electricity demand that cannot be met through renewable resources.

## Motor Vehicle Emissions Reductions

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

## California Policy

California is in the process of implementing a broad portfolio of policies and regulations aimed at reducing greenhouse gas (GHG) emissions. This process is a collaborative effort underway at the CPUC, the CEC, and CARB. CARB however is statutorily empowered with developing and implementing the final regulations on GHG regulatory framework and compliance. Approved policies include both programmatic measures and market-based mechanisms to reduce GHG emissions.

## Global Warming Solutions Act of 2006

California enacted the Global Warming Solutions Act, also known as AB 32, to help avoid potential climate change-related damage to the economy, public health and the environment. The legislation requires the state to reduce GHG emissions to 1990 levels by 2020 and directs CARB to develop policies and programs to achieve this goal. CARB adopted its final Scoping Plan in 2009, which includes new and existing emissions reduction measures including a low-carbon fuel standard, energy efficiency and conservation measures, RPS for electricity generation and a market-based emissions cap-and-trade program.

## Low Carbon Fuel Standard

On January 18, 2007, former Governor Schwarzenegger signed an Executive Order establishing the low carbon fuel standard (LCFS). LCFS requires a 10 percent carbon intensity reduction by 2020 in the transportation sector. It is recognized that 40 percent of California's GHG emissions are attributable to the transportation sector and 96 percent of the state's transportation needs require petroleum-based fuels. The LCFS requires fuel providers to ensure that the mix of fuel they sell into the California market meets, on average, a declining standard for GHG emissions measured in $CO_2$ equivalent gram per unit of fuel energy sold. As stated above, the transition to cleaner fuels will increase the demand for both natural gas and natural gas-generated electricity in order to meet the needs of a cleaner state transportation fleet, which will increasingly utilize electricity and natural gas in the future. Further, the CPUC has recently authorized the utilities to sell LCFS credits generated both by their use of low-carbon fuel vehicles and those generated by public refueling stations. The revenue generated by the sale of these credits will be returned to the customers who generated the credits, further enhancing the value of low-carbon fuels.

## Cap and Trade Program

The AB 32 Cap and Trade Program was approved by the Office of Administrative Law in December 2011. The Regulation became effective January 1, 2012. The GHG emissions cap drops by about 2% per year in the initial period and then by about 3% a year through 2020. The 2020 cap is about 15% below 2012 levels. Approximately 85% of the GHG emissions in California are covered under the cap. Industrial sources, the electricity sector, and natural gas suppliers start out with free allocations of emissions allowances. The remainder of the allowances will be sold at auctions, which are being held on a quarterly basis beginning in November 2012.

The first compliance period began January 1, 2013 for electricity, including imports, and large industrial facilities with $CO_2$ emissions equal to or greater than 25,000 metric tons per year. The second compliance period is 2015-2017 and adds distributors of transportation fuels, natural gas, and other fuels. The third compliance period, which includes all covered sectors, is 2018-2020. Currently, several of SoCalGas' and one of SDG&E's compressor stations have a compliance obligation under the Cap and Trade Program. SoCalGas and SDG&E have begun purchasing emissions allowances to cover their GHG emissions related to the compressor stations.

In 2015, SoCalGas' and SDG&E's small and medium-sized customers (fewer than 25,000 tons $CO_2$/yr or 4.7 million therms/yr) will be part of the AB 32 Cap and Trade Program. CARB allocated free allowances to Electric utilities to help offset the cost of AB 32 programs for customers. CARB will allocate allowances to gas utilities on behalf of their customers beginning in 2015. The allocation decreases in conjunction with the overall GHG cap. A portion of these free allowances must be consigned to auction, with the majority of the revenues generated from these sales returned to ratepayers

The CPUC is currently considering rules that would govern how the natural gas utilities would procure the necessary compliance instruments, the cost recovery and rate design mechanisms, and the method for returning consignment revenues to ratepayers.

## Programmatic Emission Reduction Measures

The CEC, CPUC and CARB are considering or have approved a variety of non market-based measures to reduce GHG emissions. Some of these programs include: the California Energy

Efficiency Green Building Standards, the Green State Buildings Executive Order, the CPUC's adopted goal of "zero net energy" for all new residential construction by 2020 and a similar goal for commercial buildings by 2030, potential combined heat and power (CHP) and distributed generation portfolio standards or feed-in tariffs, and increasing the electric renewables portfolio standard to 33%. Energy Efficiency and renewables are considered fundamental to GHG emission reduction in the electric sector. As a result, integration of additional renewables will require quick-start peaking capacity for firming and shaping of intermittent power, which in the foreseeable future will be gas-fired combustion turbines.

# GAS PRICE FORECAST

## MARKET CONDITION

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

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

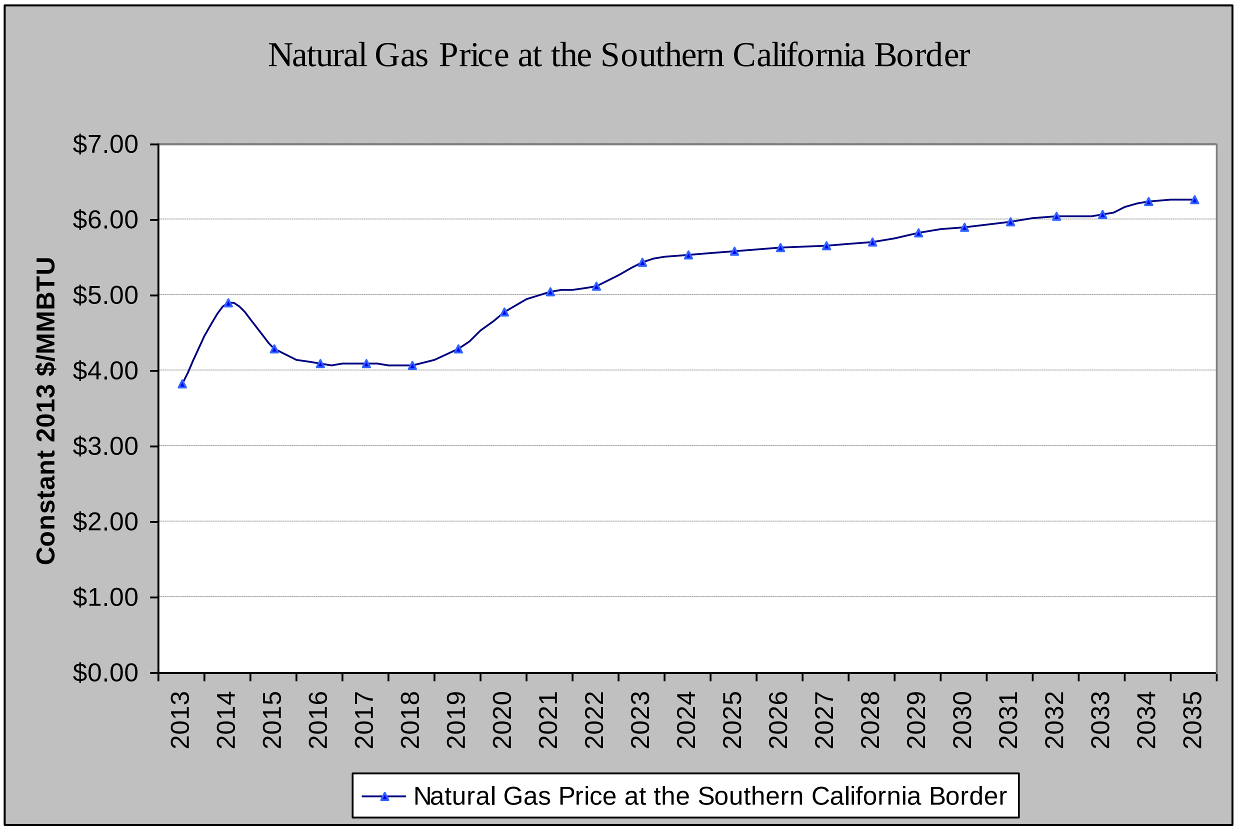
Industry experts now forecast that gas supplies can be expected to be more plentiful and less volatile during the forecast period. Increased shale gas production and increased LNG liquefaction supplies combined with a mild worldwide economic recovery are expected to moderate prices in the medium term. However, increasing demand for clean natural gas for electric power generation, natural gas vehicles fuel, and substitution of gas for coal in electric power production to meet GHG reduction goals will continue to put upward pressure on prices in the longer term.

## DEVELOPMENT OF THE FORECAST

In constant 2013 dollars, natural gas prices are expected to average out at $4.91/MMbtu in 2014 and increase by about 1.2 percent per year through 2035.

Consistent with the prior CGR practices, the 2014 CGR gas price forecast was developed using a combination of market prices and fundamental forecasts. NYMEX futures prices were used for the 2014-2018 period. Fundamental price forecasts were used for 2021 and beyond.

The forecasts for 2019 and 2020 reflect a blending of market and fundamental prices, with declining weights for market prices (and corresponding increasing weights for the fundamental price forecast) over the two-year period. The fundamental gas price forecast represents an average of the forecasts developed by the CEC and independent consultants.




It is important to recognize that the natural gas price forecast is inherently uncertain. SoCalGas and the participants of the *2014 CGR* do not warrant the accuracy of the gas price projection. In no event shall SoCalGas or the participants of the *2014 CGR* be liable for the use of or reliance on this natural gas price forecast.

# PEAK DAY DEMAND AND DELIVERABILITY

Beginning in April 2008, gas supplies to serve both SoCalGas' and SDG&E's retail core gas demand are procured with a combined portfolio. SoCalGas and SDG&E plan and design their systems to provide continuous service to their core customers under an extreme peak day event. The criteria for extreme peak day design is defined as a 1-in-35 likelihood event for each utility's service area. This criteria correlates to a system average temperature of 40.0° Fahrenheit for SoCalGas' service area and 42.6° Fahrenheit for SDG&E's service area.

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

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

| Year | SoCalGas Retail Core Demand(1) | SDG&E Retail Core Demand(2) | Total Demand | Firm Storage Withdrawal(3) | Flowing Supply |
|---|---|---|---|---|---|
| 2014 | 3,101 | 389 | 3,490 | 2,225 | 1,265 |
| 2015 | 3,061 | 388 | 3,449 | 2,225 | 1,224 |
| 2016 | 3,050 | 390 | 3,440 | 2,225 | 1,215 |
| 2017 | 3,035 | 390 | 3,425 | 2,225 | 1,200 |
| 2018 | 3,027 | 391 | 3,419 | 2,225 | 1,194 |
| 2019 | 3,008 | 393 | 3,401 | 2,225 | 1,176 |
| 2020 | 2,979 | 393 | 3,372 | 2,225 | 1,147 |

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

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

**Winter Peak Day Demand**
**(MMcf/Day)**

| Year | Core(1) | Noncore NonEG(2) | Electric Generation(3) | Total Demand(4) |
|---|---|---|---|---|
| 2014 | 3,101 | 999 | 936 | 5,036 |
| 2015 | 3,061 | 993 | 986 | 5,040 |
| 2016 | 3,050 | 996 | 1,031 | 5,077 |
| 2017 | 3,035 | 996 | 1,092 | 5,122 |
| 2018 | 3,027 | 996 | 1,128 | 5,151 |
| 2019 | 3,008 | 995 | 1,048 | 5,051 |
| 2020 | 2,979 | 990 | 1,050 | 5,019 |

Notes:
(1) 1-in-35 peak temperature cold day for SoCalGas' core.
(2) 1-in-10 peak temperature cold day for Hdd-sensitive load. Includes SoCalGas noncore and wholesale non-EG.
(3) UEG/EWG Base Hydro + all other EG.
(4) SoCalGas is only obligated to design its system to maintain service to retail and wholesale core customers during a 1-in-35 winter peak day temperature event .

**Summer High Sendout Day Demand**
**(MMcf/Day)**

| Year | High Demand Month(1) | Core(2) | Noncore NonEG(3) | Electric Generation(4) | Total Demand |
|---|---|---|---|---|---|
| 2014 | Sep | 665 | 650 | 2,012 | 3,327 |
| 2015 | Sep | 662 | 658 | 1,968 | 3,288 |
| 2016 | Jul | 634 | 634 | 1,943 | 3,211 |
| 2017 | Jul | 634 | 633 | 1,808 | 3,074 |
| 2018 | Sep | 663 | 653 | 1,918 | 3,234 |
| 2019 | Sep | 660 | 648 | 1,899 | 3,208 |
| 2020 | Sep | 655 | 641 | 1,910 | 3,206 |

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

# 2014 CALIFORNIA GAS REPORT

## SOUTHERN CALIFORNIA GAS COMPANY
## TABULAR DATA

## SOUTHERN CALIFORNIA GAS COMPANY

### ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY
### RECORDED YEARS 2009 TO 2013

| Line | CAPACITY AVAILABLE | | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|
| 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 | | 216 | 203 | 175 | 148 | 153 |
| | Out-of-State Gas | | | | | | |
| 11 | Other Out-of-State | | 2,397 | 2,445 | 2,452 | 2,728 | 2,514 |
| 12 | Total Out-of-State Gas | | 2,397 | 2,445 | 2,452 | 2,728 | 2,514 |
| 13 | TOTAL SUPPLY TAKEN | | 2,613 | 2,648 | 2,627 | 2,876 | 2,667 |
| 14 | Net Underground Storage Withdrawal | | 8 | (10) | (4) | (42) | 106 |
| 15 | TOTAL THROUGHPUT (1)(2) | | 2,621 | 2,638 | 2,623 | 2,834 | 2,773 |
| | **DELIVERIES BY END-USE** (3) | | | | | | |
| 16 | Core | Residential | 645 | 673 | 696 | 644 | 646 |
| 17 | | Commercial | 210 | 216 | 217 | 216 | 222 |
| 18 | | Industrial | 59 | 61 | 61 | 61 | 62 |
| 19 | | NGV | 26 | 27 | 28 | 29 | 31 |
| 20 | | Subtotal | 940 | 977 | 1,002 | 950 | 961 |
| 21 | Noncore | Commercial | 56 | 59 | 60 | 60 | 60 |
| 22 | | Industrial | 324 | 361 | 363 | 365 | 368 |
| 23 | | EOR Steaming | 35 | 30 | 27 | 29 | 35 |
| 24 | | Electric Generation | 811 | 768 | 726 | 922 | 848 |
| 25 | | Subtotal | 1,226 | 1,218 | 1,176 | 1,376 | 1,311 |
| 26 | Wholesale/International | | 412 | 412 | 407 | 477 | 465 |
| 27 | Co. Use & LUAF | | 43 | 31 | 38 | 31 | 36 |
| 28 | SYSTEM TOTAL-THROUGHPUT (1)(2) | | 2,621 | 2,638 | 2,623 | 2,834 | 2,773 |
| | TRANSPORTATION AND EXCHANGE | | | | | | |
| 29 | Core | All End Uses | 20 | 25 | 29 | 35 | 45 |
| 30 | Noncore | Commercial/Industrial | 380 | 420 | 423 | 425 | 428 |
| 31 | | EOR Steaming | 35 | 30 | 27 | 29 | 35 |
| 32 | | Electric Generation | 811 | 768 | 726 | 922 | 848 |
| 33 | | Subtotal-Retail | 1,246 | 1,243 | 1,205 | 1,411 | 1,356 |
| 34 | Wholesale/International | | 412 | 412 | 407 | 477 | 465 |
| 35 | TOTAL TRANSPORTATION & EXCHANGE | | 1,658 | 1,655 | 1,612 | 1,888 | 1,821 |
| | CURTAILMENT (RETAIL & WHOLESALE) | | | | | | |
| 36 | | Core | | | | | |
| 37 | | Noncore | | | | | |
| 38 | | TOTAL - Curtailment | | | | | |
| 39 | REFUSAL | | | | | | |
| 40 | | Total BTU Factor (Dth/Mcf) | 1.0273 | 1.0235 | 1.0209 | 1.0210 | 1.0266 |

**NOTES:**

| | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|
| (1) Exclude own-source gas supply of procurement by City of Long Beach. | 2 | 2 | 1 | 1 | 2 |

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

TABLE 1-SCG

## SOUTHERN CALIFORNIA GAS COMPANY

## ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
## ESTIMATED YEARS 2014 THRU 2018

## AVERAGE TEMPERATURE YEAR

| LINE | | | 2014 | 2015 | 2016 | 2017 | 2018 | LINE |
|---|---|---|---|---|---|---|---|---|
| | **CAPACITY AVAILABLE** | | | | | | | |
| 1 | California Line 85 Zone (California Producers) | | 160 | 160 | 160 | 160 | 160 | 1 |
| 2 | California Coastal Zone (California Producers) | | 150 | 150 | 150 | 150 | 150 | 2 |
| | Out-of-State Gas | | | | | | | |
| 3 | Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/ | | 765 | 765 | 765 | 765 | 765 | 3 |
| 4 | Southern Zone (EPN,TGN,NBP) 2/ | | 1,210 | 1,210 | 1,210 | 1,210 | 1,210 | 4 |
| 5 | Northern Zone (TW,EPN,QST, KR) 3/ | | 1,590 | 1,590 | 1,590 | 1,590 | 1,590 | 5 |
| 6 | Total Out-of-State Gas | | 3,565 | 3,565 | 3,565 | 3,565 | 3,565 | 6 |
| 7 | TOTAL CAPACITY AVAILABLE | | 3,875 | 3,875 | 3,875 | 3,875 | 3,875 | 7 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 8 | California Source Gas | | 310 | 310 | 310 | 310 | 310 | 8 |
| 9 | Out-of-State | | 2,492 | 2,404 | 2,401 | 2,387 | 2,380 | 9 |
| 10 | TOTAL SUPPLY TAKEN | | 2,802 | 2,714 | 2,711 | 2,697 | 2,690 | 10 |
| 11 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 11 |
| 12 | TOTAL THROUGHPUT 4/ | | 2,802 | 2,714 | 2,711 | 2,697 | 2,690 | 12 |
| | **REQUIREMENTS FORECAST BY END-USE 5/** | | | | | | | |
| 13 | CORE 6/ | Residential | 676 | 664 | 658 | 655 | 652 | 13 |
| 14 | | Commercial | 226 | 227 | 228 | 230 | 230 | 14 |
| 15 | | Industrial | 60 | 59 | 59 | 59 | 58 | 15 |
| 16 | | NGV | 35 | 38 | 40 | 42 | 43 | 16 |
| 17 | | Subtotal-CORE | 997 | 988 | 985 | 985 | 984 | 17 |
| 18 | NONCORE | Commercial | 48 | 46 | 44 | 43 | 41 | 18 |
| 19 | | Industrial | 376 | 379 | 379 | 379 | 377 | 19 |
| 20 | | EOR Steaming | 44 | 52 | 52 | 52 | 52 | 20 |
| 21 | | Electric Generation (EG) | 863 | 789 | 785 | 773 | 777 | 21 |
| 22 | | Subtotal-NONCORE | 1,331 | 1,266 | 1,260 | 1,246 | 1,247 | 22 |
| 23 | WHOLESALE & | Core | 190 | 190 | 191 | 192 | 193 | 23 |
| 24 | INTERNATIONAL | Noncore Excl. EG | 45 | 45 | 45 | 46 | 46 | 24 |
| 25 | | Electric Generation (EG) | 204 | 190 | 196 | 194 | 186 | 25 |
| 26 | | Subtotal-WHOLESALE & INTL. | 438 | 425 | 431 | 432 | 425 | 26 |
| 27 | | Co. Use & LUAF | 36 | 35 | 35 | 35 | 35 | 27 |
| 28 | SYSTEM TOTAL THROUGHPUT 4/ | | 2,802 | 2,714 | 2,711 | 2,697 | 2,690 | 28 |
| | TRANSPORTATION AND EXCHANGE | | | | | | | |
| 29 | CORE | All End Uses | 47 | 47 | 47 | 48 | 48 | 29 |
| 30 | NONCORE | Commercial/Industrial | 424 | 425 | 424 | 421 | 419 | 30 |
| 31 | | EOR Steaming | 44 | 52 | 52 | 52 | 52 | 31 |
| 32 | | Electric Generation (EG) | 863 | 789 | 785 | 773 | 777 | 32 |
| 33 | | Subtotal-RETAIL | 1,378 | 1,313 | 1,307 | 1,294 | 1,295 | 33 |
| | WHOLESALE & | | | | | | | |
| 34 | INTERNATIONAL | All End Uses | 438 | 425 | 431 | 432 | 425 | 34 |
| 35 | TOTAL TRANSPORTATION & EXCHANGE | | 1,816 | 1,738 | 1,739 | 1,725 | 1,720 | 35 |
| | CURTAILMENT (RETAIL & WHOLESALE) | | | | | | | |
| 36 | | Core | 0 | 0 | 0 | 0 | 0 | 36 |
| 37 | | Noncore | 0 | 0 | 0 | 0 | 0 | 37 |
| 38 | | TOTAL - Curtailment | 0 | 0 | 0 | 0 | 0 | 38 |

NOTES:

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| 4/ Excludes own-source gas supply of gas procurement by the City of Long Beach | 1.1 | 0.9 | 0.8 | 0.8 | 0.8 |

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| 6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: | 975 | 966 | 963 | 962 | 960 |

TABLE 2-SCG

## SOUTHERN CALIFORNIA GAS COMPANY

## ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
## ESTIMATED YEARS 2019 THRU 2035

### AVERAGE TEMPERATURE YEAR

| LINE | | | 2019 | 2020 | 2025 | 2030 | 2035 | LINE |
|---|---|---|---|---|---|---|---|---|
| | **CAPACITY AVAILABLE** | | | | | | | |
| 1 | California Line 85 Zone (California Producers) | | 160 | 160 | 160 | 160 | 160 | 1 |
| 2 | California Coastal Zone (California Producers) | | 150 | 150 | 150 | 150 | 150 | 2 |
| | Out-of-State Gas | | | | | | | |
| 3 | Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/ | | 765 | 765 | 765 | 765 | 765 | 3 |
| 4 | Southern Zone (EPN,TGN,NBP) 2/ | | 1,210 | 1,210 | 1,210 | 1,210 | 1,210 | 4 |
| 5 | Northern Zone (TW,EPN,QST, KR) 3/ | | 1,590 | 1,590 | 1,590 | 1,590 | 1,590 | 5 |
| 6 | Total Out-of-State Gas | | 3,565 | 3,565 | 3,565 | 3,565 | 3,565 | 6 |
| 7 | TOTAL CAPACITY AVAILABLE | | 3,875 | 3,875 | 3,875 | 3,875 | 3,875 | 7 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 8 | California Source Gas | | 310 | 310 | 310 | 310 | 310 | 8 |
| 9 | Out-of-State | | 2,366 | 2,338 | 2,351 | 2,334 | 2,337 | 9 |
| 10 | TOTAL SUPPLY TAKEN | | 2,676 | 2,648 | 2,661 | 2,644 | 2,647 | 10 |
| 11 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 11 |
| 12 | TOTAL THROUGHPUT 4/ | | 2,676 | 2,648 | 2,661 | 2,644 | 2,647 | 12 |
| | **REQUIREMENTS FORECAST BY END-USE 5/** | | | | | | | |
| 13 | CORE 6/ | Residential | 647 | 638 | 619 | 612 | 611 | 13 |
| 14 | | Commercial | 230 | 228 | 226 | 228 | 231 | 14 |
| 15 | | Industrial | 57 | 55 | 48 | 43 | 41 | 15 |
| 16 | | NGV | 45 | 46 | 54 | 59 | 64 | 16 |
| 17 | | Subtotal-CORE | 979 | 968 | 947 | 943 | 947 | 17 |
| 18 | NONCORE | Commercial | 39 | 37 | 28 | 23 | 24 | 18 |
| 19 | | Industrial | 373 | 367 | 351 | 341 | 336 | 19 |
| 20 | | EOR Steaming | 52 | 52 | 52 | 52 | 52 | 20 |
| 21 | | Electric Generation (EG) | 774 | 770 | 821 | 819 | 817 | 21 |
| 22 | | Subtotal-NONCORE | 1,239 | 1,226 | 1,252 | 1,235 | 1,228 | 22 |
| 23 | WHOLESALE & | Core | 194 | 194 | 199 | 205 | 211 | 23 |
| 24 | INTERNATIONAL | Noncore Excl. EG | 46 | 46 | 47 | 47 | 48 | 24 |
| 25 | | Electric Generation (EG) | 183 | 180 | 181 | 179 | 178 | 25 |
| 26 | | Subtotal-WHOLESALE & INTL. | 423 | 420 | 427 | 432 | 437 | 26 |
| 27 | | Co. Use & LUAF | 35 | 34 | 35 | 34 | 34 | 27 |
| 28 | SYSTEM TOTAL THROUGHPUT 4/ | | 2,676 | 2,648 | 2,661 | 2,644 | 2,647 | 28 |
| | TRANSPORTATION AND EXCHANGE | | | | | | | |
| 29 | CORE | All End Uses | 48 | 48 | 48 | 49 | 50 | 29 |
| 30 | NONCORE | Commercial/Industrial | 413 | 405 | 379 | 364 | 359 | 30 |
| 31 | | EOR Steaming | 52 | 52 | 52 | 52 | 52 | 31 |
| 32 | | Electric Generation (EG) | 774 | 770 | 821 | 819 | 817 | 32 |
| 33 | | Subtotal-RETAIL | 1,287 | 1,274 | 1,301 | 1,284 | 1,279 | 33 |
| | WHOLESALE & | | | | | | | |
| 34 | INTERNATIONAL | All End Uses | 423 | 420 | 427 | 432 | 437 | 34 |
| 35 | TOTAL TRANSPORTATION & EXCHANGE | | 1,710 | 1,694 | 1,728 | 1,716 | 1,716 | 35 |
| | CURTAILMENT (RETAIL & WHOLESALE) | | | | | | | |
| 36 | | Core | 0 | 0 | 0 | 0 | 0 | 36 |
| 37 | | Noncore | 0 | 0 | 0 | 0 | 0 | 37 |
| 38 | | TOTAL - Curtailment | 0 | 0 | 0 | 0 | 0 | 38 |

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

| | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| 4/ Excludes own-source gas supply of gas procurement by the City of Long Beach | 0.7 | 0.7 | 0.5 | 0.4 | 0.4 |

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

| | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| 6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: | 956 | 944 | 922 | 918 | 921 |

TABLE 3-SCG

## SOUTHERN CALIFORNIA GAS COMPANY

## ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
## ESTIMATED YEARS 2014 THRU 2018

## COLD TEMPERATURE YEAR & DRY HYDRO YEAR

| LINE | | | 2014 | 2015 | 2016 | 2017 | 2018 | LINE |
|---|---|---|---|---|---|---|---|---|
| | **CAPACITY AVAILABLE** | | | | | | | |
| 1 | California Line 85 Zone (California Producers) | | 160 | 160 | 160 | 160 | 160 | 1 |
| 2 | California Coastal Zone (California Producers) | | 150 | 150 | 150 | 150 | 150 | 2 |
| | Out-of-State Gas | | | | | | | |
| 3 | Wheeler Ridge Zone (KR, MP, PG&E, OEHI) 1/ | | 765 | 765 | 765 | 765 | 765 | 3 |
| 4 | Southern Zone (EPN,TGN,NBP) 2/ | | 1,210 | 1,210 | 1,210 | 1,210 | 1,210 | 4 |
| 5 | Northern Zone (TW,EPN,QST, KR) 3/ | | 1,590 | 1,590 | 1,590 | 1,590 | 1,590 | 5 |
| 6 | Total Out-of-State Gas | | 3,565 | 3,565 | 3,565 | 3,565 | 3,565 | 6 |
| 7 | TOTAL CAPACITY AVAILABLE | | 3,875 | 3,875 | 3,875 | 3,875 | 3,875 | 7 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 8 | California Source Gas | | 310 | 160 | 160 | 160 | 160 | 8 |
| 9 | Out-of-State | | 2,589 | 2,727 | 2,727 | 2,707 | 2,710 | 9 |
| 10 | TOTAL SUPPLY TAKEN | | 2,899 | 2,887 | 2,887 | 2,867 | 2,870 | 10 |
| 11 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 11 |
| 12 | TOTAL THROUGHPUT 4/ | | 2,899 | 2,887 | 2,887 | 2,867 | 2,870 | 12 |
| | **REQUIREMENTS FORECAST BY END-USE 5/** | | | | | | | |
| 13 | CORE 6/ | Residential | 742 | 730 | 723 | 719 | 716 | 13 |
| 14 | | Commercial | 239 | 240 | 241 | 242 | 243 | 14 |
| 15 | | Industrial | 61 | 61 | 61 | 60 | 59 | 15 |
| 16 | | NGV | 35 | 38 | 40 | 42 | 43 | 16 |
| 17 | | Subtotal-CORE | 1,078 | 1,068 | 1,064 | 1,063 | 1,062 | 17 |
| 18 | NONCORE | Commercial | 49 | 47 | 45 | 44 | 42 | 18 |
| 19 | | Industrial | 376 | 379 | 379 | 379 | 377 | 19 |
| 20 | | EOR Steaming | 44 | 52 | 52 | 52 | 52 | 20 |
| 21 | | Electric Generation (EG) | 863 | 857 | 854 | 838 | 848 | 21 |
| 22 | | Subtotal-NONCORE | 1,332 | 1,335 | 1,330 | 1,312 | 1,319 | 22 |
| 23 | WHOLESALE & | Core | 203 | 203 | 204 | 205 | 206 | 23 |
| 24 | INTERNATIONAL | Noncore Excl. EG | 45 | 45 | 45 | 46 | 46 | 24 |
| 25 | | Electric Generation (EG) | 204 | 199 | 208 | 204 | 200 | 25 |
| 26 | | Subtotal-WHOLESALE & INTL. | 451 | 447 | 457 | 455 | 452 | 26 |
| 27 | | Co. Use & LUAF | 38 | 37 | 37 | 37 | 37 | 27 |
| 28 | SYSTEM TOTAL THROUGHPUT 4/ | | 2,899 | 2,887 | 2,887 | 2,867 | 2,870 | 28 |
| | TRANSPORTATION AND EXCHANGE | | | | | | | |
| 29 | CORE | All End Uses | 49 | 49 | 50 | 50 | 51 | 29 |
| 30 | NONCORE | Commercial/Industrial | 425 | 427 | 425 | 423 | 420 | 30 |
| 31 | | EOR Steaming | 44 | 52 | 52 | 52 | 52 | 31 |
| 32 | | Electric Generation (EG) | 863 | 857 | 854 | 838 | 848 | 32 |
| 33 | | Subtotal-RETAIL | 1,381 | 1,384 | 1,380 | 1,362 | 1,370 | 33 |
| | WHOLESALE & | | | | | | | |
| 34 | INTERNATIONAL | All End Uses | 451 | 447 | 457 | 455 | 452 | 34 |
| 35 | TOTAL TRANSPORTATION & EXCHANGE | | 1,832 | 1,832 | 1,836 | 1,817 | 1,822 | 35 |
| | CURTAILMENT (RETAIL & WHOLESALE) | | | | | | | |
| 36 | | Core | 0 | 0 | 0 | 0 | 0 | 36 |
| 37 | | Noncore | 0 | 0 | 0 | 0 | 0 | 37 |
| 38 | | TOTAL - Curtailment | 0 | 0 | 0 | 0 | 0 | 38 |

NOTES:

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| 4/ Excludes own-source gas supply of gas procurement by the City of Long Beach | 1.1 | 0.9 | 0.8 | 0.8 | 0.8 |

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| 6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: | 1,056 | 1,046 | 1,041 | 1,040 | 1,039 |

TABLE 4-SCG

## SOUTHERN CALIFORNIA GAS COMPANY

## ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
## ESTIMATED YEARS 2019 THRU 2035

### COLD TEMPERATURE YEAR & DRY HYDRO YEAR

| LINE | | | 2019 | 2020 | 2025 | 2030 | 2035 | LINE |
|---|---|---|---|---|---|---|---|---|
| | **CAPACITY AVAILABLE** | | | | | | | |
| 1 | California Line 85 Zone (California Producers) | | 160 | 160 | 160 | 160 | 160 | 1 |
| 2 | California Coastal Zone (California Producers) | | 150 | 150 | 150 | 150 | 150 | 2 |
| | Out-of-State Gas | | | | | | | |
| 3 | Wheeler Ridge Zone (KR, MP, PG&E, OEHI) [1/] | | 765 | 765 | 765 | 765 | 765 | 3 |
| 4 | Southern Zone (EPN,TGN,NBP) [2/] | | 1,210 | 1,210 | 1,210 | 1,210 | 1,210 | 4 |
| 5 | Northern Zone (TW,EPN,QST, KR) [3/] | | 1,590 | 1,590 | 1,590 | 1,590 | 1,590 | 5 |
| 6 | Total Out-of-State Gas | | 3,565 | 3,565 | 3,565 | 3,565 | 3,565 | 6 |
| 7 | TOTAL CAPACITY AVAILABLE | | 3,875 | 3,875 | 3,875 | 3,875 | 3,875 | 7 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 8 | California Source Gas | | 310 | 310 | 310 | 310 | 310 | 8 |
| 9 | Out-of-State | | 2,547 | 2,515 | 2,529 | 2,512 | 2,516 | 9 |
| 10 | TOTAL SUPPLY TAKEN | | 2,857 | 2,825 | 2,839 | 2,822 | 2,826 | 10 |
| 11 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 11 |
| 12 | TOTAL THROUGHPUT [4/] | | 2,857 | 2,825 | 2,839 | 2,822 | 2,826 | 12 |
| | **REQUIREMENTS FORECAST BY END-USE** [5/] | | | | | | | |
| 13 | CORE [6/] | Residential | 711 | 701 | 680 | 672 | 672 | 13 |
| 14 | | Commercial | 243 | 241 | 239 | 241 | 244 | 14 |
| 15 | | Industrial | 58 | 56 | 49 | 44 | 42 | 15 |
| 16 | | NGV | 45 | 46 | 54 | 59 | 64 | 16 |
| 17 | | Subtotal-CORE | 1,057 | 1,045 | 1,021 | 1,017 | 1,022 | 17 |
| 18 | NONCORE | Commercial | 41 | 39 | 30 | 24 | 25 | 18 |
| 19 | | Industrial | 373 | 367 | 351 | 341 | 336 | 19 |
| 20 | | EOR Steaming | 52 | 52 | 52 | 52 | 52 | 20 |
| 21 | | Electric Generation (EG) | 848 | 840 | 895 | 893 | 891 | 21 |
| 22 | | Subtotal-NONCORE | 1,313 | 1,297 | 1,327 | 1,310 | 1,303 | 22 |
| 23 | WHOLESALE & | Core | 207 | 207 | 213 | 219 | 226 | 23 |
| 24 | INTERNATIONAL | Noncore Excl. EG | 46 | 46 | 47 | 48 | 48 | 24 |
| 25 | | Electric Generation (EG) | 196 | 192 | 193 | 192 | 191 | 25 |
| 26 | | Subtotal-WHOLESALE & INTL. | 449 | 446 | 453 | 458 | 464 | 26 |
| 27 | | Co. Use & LUAF | 37 | 37 | 37 | 37 | 37 | 27 |
| 28 | SYSTEM TOTAL THROUGHPUT [4/] | | 2,857 | 2,825 | 2,839 | 2,822 | 2,826 | 28 |
| | TRANSPORTATION AND EXCHANGE | | | | | | | |
| 29 | CORE | All End Uses | 51 | 50 | 51 | 52 | 53 | 29 |
| 30 | NONCORE | Commercial/Industrial | 414 | 406 | 381 | 365 | 360 | 30 |
| 31 | | EOR Steaming | 52 | 52 | 52 | 52 | 52 | 31 |
| 32 | | Electric Generation (EG) | 848 | 840 | 895 | 893 | 891 | 32 |
| 33 | | Subtotal-RETAIL | 1,364 | 1,348 | 1,378 | 1,361 | 1,356 | 33 |
| | WHOLESALE & | | | | | | | |
| 34 | INTERNATIONAL | All End Uses | 449 | 446 | 453 | 458 | 464 | 34 |
| 35 | TOTAL TRANSPORTATION & EXCHANGE | | 1,813 | 1,794 | 1,831 | 1,820 | 1,820 | 35 |
| | CURTAILMENT (RETAIL & WHOLESALE) | | | | | | | |
| 36 | | Core | 0 | 0 | 0 | 0 | 0 | 36 |
| 37 | | Noncore | 0 | 0 | 0 | 0 | 0 | 37 |
| 38 | | TOTAL - Curtailment | 0 | 0 | 0 | 0 | 0 | 38 |

NOTES:

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

| | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| 4/ Excludes own-source gas supply of gas procurement by the City of Long Beach | 0.7 | 0.7 | 0.5 | 0.5 | 0.5 |

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

| | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| 6/ Core end-use demand exclusive of core aggregation transportation (CAT) in MDth/d: | 1,033 | 1,021 | 997 | 991 | 995 |

# 2014 CALIFORNIA GAS REPORT

## LONG BEACH GAS AND OIL DEPARTMENT

# CITY OF LONG BEACH MUNICIPAL GAS & OIL DEPARTMENT

The annual gas supply and forecast requirements prepared by the Long Beach Gas & Oil Department (Long Beach) are shown on the following tables for the years 2014 through 2035.

Serving approximately 145,000 customers, Long Beach is the largest California municipal gas utility and the fifth largest municipal gas utility in the United States. Long Beach's service territory includes the cities of Long Beach and Signal Hill, and sections of surrounding communities including Lakewood, Bellflower, Compton, Seal Beach, Paramount, and Los Alamitos. Long Beach's customer load profile is 56 percent residential and 44 percent commercial/industrial.

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

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

# 2014 CALIFORNIA GAS REPORT

## LONG BEACH GAS AND OIL DEPARTMENT
## TABULAR DATA

TABLE 1A-LB

# CITY OF LONG BEACH - GAS & OIL DEPARTMENT

**ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY**
**RECORDED YEARS 2009 THRU 2013**

| LINE | ACTUAL DELIVERIES BY END-USE | | 2009 | 2010 | 2011 | 2012 | 2013 | LINE |
|---|---|---|---|---|---|---|---|---|
| 1 | CORE | Residential | 13.4 | 14.2 | 14.9 | 13.7 | 14.2 | 1 |
| 2 | CORE/NONCORE | Commercial | 5.1 | 5.3 | 5.6 | 5.4 | 5.9 | 2 |
| 3 | CORE/NONCORE | Industrial | 5.1 | 4.4 | 3.6 | 3.4 | 3.4 | 3 |
| 4 | | Subtotal | 23.6 | 23.9 | 24.1 | 22.5 | 23.6 | 4 |
| 5 | NON CORE | Non-EOR Cogeneration | 0.4 | 0.8 | 0.8 | 1.6 | 1.5 | 5 |
| 6 | | EOR Cogen. & Steaming | - | - | - | - | - | 6 |
| 7 | | Electric Utilities | - | - | - | - | - | 7 |
| 8 | | Subtotal | 0.4 | 0.8 | 0.8 | 1.6 | 1.5 | 8 |
| 9 | WHOLESALE | Residential | - | - | - | - | - | 9 |
| 10 | | Com. & Ind., others | - | - | - | - | - | 10 |
| 11 | | Electric Utilities | - | - | - | - | - | 11 |
| 12 | | Subtotal-WHOLESALE | - | - | - | - | - | 12 |
| 13 | | Co. Use & LUAF | 0.5 | 0.4 | 0.6 | 0.2 | 0.2 | 13 |
| 14 | | Subtotal-END USE | 24.5 | 25.1 | 25.5 | 24.4 | 25.4 | 14 |
| 15 | | Storage Injection | - | - | - | - | - | 15 |
| 16 | SYSTEM TOTAL-THROUGHPUT | | 24.5 | 25.1 | 25.5 | 24.4 | 25.4 | 16 |
| | **ACTUAL TRANSPORTATION AND EXCHANGE** | | | | | | | |
| 17 | | Residential | N/A | N/A | N/A | N/A | N/A | 17 |
| 18 | | Commercial/Industrial | 4.2 | 3.5 | 2.7 | 2.7 | 2.5 | 18 |
| 19 | | Non-EOR Cogeneration | 0.3 | 0.8 | 0.8 | 1.6 | 1.5 | 19 |
| 20 | | EOR Cogen. & Steaming | N/A | N/A | N/A | N/A | N/A | 20 |
| 21 | | Electric Utilites | N/A | N/A | N/A | N/A | N/A | 21 |
| 22 | | Subtotal-RETAIL | 4.5 | 4.2 | 3.5 | 4.3 | 3.9 | 22 |
| 23 | WHOLESALE | All End Uses | - | - | - | - | - | 23 |
| 24 | TOTAL TRANSPORTATION & EXCHANGE | | 4.5 | 4.2 | 3.5 | 4.3 | 3.9 | 24 |
| | **ACTUAL CURTAILMENT** | | | | | | | |
| 25 | | Residential | - | - | - | - | - | 25 |
| 26 | | Commercial/Industrial | - | - | - | - | - | 26 |
| 27 | | Non-EOR Cogeneration | - | - | - | - | - | 27 |
| 28 | | EOR Cogen. & Steaming | - | - | - | - | - | 28 |
| 29 | | Electric Utilites | - | - | - | - | - | 29 |
| 30 | | Wholesale | - | - | - | - | - | 30 |
| 31 | | TOTAL- Curtailment | - | - | - | - | - | 31 |
| 32 | REFUSAL | | - | - | - | - | - | 32 |

TABLE 1-LB

# CITY OF LONG BEACH - GAS & OIL DEPARTMENT

**ANNUAL GAS SUPPLY AND SENDOUT - MMCF/DAY**
**RECORDED YEARS 2009 THRU 2013**

| LINE | GAS SUPPLY AVAILABLE | 2009 | 2010 | 2011 | 2012 | 2013 | LINE |
|---|---|---|---|---|---|---|---|
| | California Source Gas | | | | | | |
| 1 | Regular Purchases | - | - | - | - | - | 1 |
| 2 | Received for Exchange/Transport | - | - | - | - | - | 2 |
| 3 | Total California Source Gas | - | - | - | - | - | 3 |
| 4 | Purchases from Other Utilities | - | - | - | - | - | 4 |
| | Out-of-State Gas | | | | | | |
| 5 | Pacific Interstate Companies | - | - | - | - | - | 5 |
| 6 | Additional Core Supplies | - | - | - | - | - | 6 |
| 7 | Incremental Supplies | - | - | - | - | - | 7 |
| 8 | Out-of-State Transport | - | - | - | - | - | 8 |
| 9 | Total Out-of-State Gas | - | - | - | - | - | 9 |
| 10 | Subtotal | - | - | - | - | - | 10 |
| 11 | Underground Storage Withdrawal | - | - | - | - | - | 11 |
| 12 | GAS SUPPLY AVAILABLE | - | - | - | - | - | 12 |
| | **GAS SUPPLY TAKEN** | | | | | | |
| | California Source Gas | | | | | | |
| 13 | Regular Purchases | 2.2 | 1.6 | 1.1 | 1.2 | 1.9 | 13 |
| 14 | Received for Exchange/Transport | 0 | 0 | 0 | 0 | 0 | 14 |
| 15 | Total California Source Gas | 2.2 | 1.6 | 1.1 | 1.2 | 1.9 | 15 |
| 16 | Purchases from Other Utilities | - | - | - | - | - | 16 |
| | Out-of-State Gas | | | | | | |
| 17 | Pacific Interstate Companies | - | - | - | - | - | 17 |
| 18 | Additional Core Supplies | - | - | - | - | - | 18 |
| 19 | Incremental Supplies | 22.3 | 23.5 | 24.3 | 23.2 | 23.5 | 19 |
| 20 | Out-of-State Transport | - | - | - | - | - | 20 |
| 21 | Total Out-of-State Gas | 22.3 | 23.5 | 24.3 | 23.2 | 23.5 | 21 |
| 22 | Subtotal | 24.5 | 25.1 | 25.5 | 24.4 | 25.4 | 22 |
| 23 | Underground Storage Withdrawal | - | - | - | - | - | 23 |
| 24 | TOTAL Gas Supply Taken & Transported | 24.5 | 25.1 | 25.5 | 24.4 | 25.4 | 24 |

TABLE 2-LB

# CITY OF LONG BEACH - GAS & OIL DEPARTMENT

**ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY**
**ESTIMATED YEARS 2014 THRU 2018**

**AVERAGE TEMPERATURE YEAR**

| LINE | CAPACITY AVAILABLE | | 2014 | 2015 | 2016 | 2017 | 2018 | LINE |
|---|---|---|---|---|---|---|---|---|
| 1 | California Source Gas | | | | | | | 1 |
| 2 | Out-of-State Gas | | | | | | | 2 |
| 3 | TOTAL CAPACITY AVAILABLE | | | | | | | 3 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 4 | California Source Gas | | 1.1 | 0.9 | 0.8 | 0.8 | 0.8 | 4 |
| 5 | Out-of-State Gas | | 23.9 | 24.4 | 24.4 | 24.5 | 24.7 | 5 |
| 6 | TOTAL SUPPLY TAKEN | | 25.0 | 25.3 | 25.2 | 25.3 | 25.5 | 6 |
| 7 | Net Underground Storage Withdrawal | | - | - | - | - | - | 7 |
| 8 | TOTAL THROUGHPUT (1) | | 25.0 | 25.3 | 25.2 | 25.3 | 25.5 | 8 |
| | **REQUIREMENTS FORECAST BY END-USE (1)** | | | | | | | |
| 9 | CORE | Residential | 14.7 | 14.7 | 14.8 | 14.9 | 14.9 | 9 |
| 10 | | Commercial | 5.2 | 5.2 | 5.2 | 5.3 | 5.3 | 10 |
| 11 | | NGV | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 11 |
| 12 | | Subtotal-CORE | 20.2 | 20.3 | 20.4 | 20.4 | 20.5 | 12 |
| 13 | NONCORE | Industrial | 3.3 | 3.3 | 3.3 | 3.2 | 3.3 | 13 |
| 14 | | Non-EOR Cogeneration | 1.2 | 1.5 | 1.3 | 1.4 | 1.4 | 14 |
| 15 | | EOR | - | - | - | - | - | 15 |
| 16 | | Utility Electric Generation | - | - | - | - | - | 16 |
| 17 | | NGV | - | - | - | - | - | 17 |
| 18 | | Subtotal-NONCORE | 4.5 | 4.8 | 4.6 | 4.6 | 4.7 | 18 |
| 19 | | Co. Use & LUAF | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 19 |
| 20 | SYSTEM TOTAL THROUGHPUT (1) | | 25.0 | 25.3 | 25.2 | 25.3 | 25.5 | 20 |
| 21 | SYSTEM CURTAILMENT | | - | - | - | - | - | 21 |
| | **TRANSPORTATION** | | | | | | | |
| 22 | CORE | All End Uses | - | - | - | - | - | 22 |
| 23 | NONCORE | Industrial | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 23 |
| 24 | | Non-EOR Cogeneration | 1.2 | 1.5 | 1.3 | 1.3 | 1.4 | 24 |
| 25 | | EOR | - | - | - | - | - | 25 |
| 26 | | Utility Electric Generation | - | - | - | - | - | 26 |
| 27 | | Subtotal NONCORE | 3.7 | 3.9 | 3.8 | 3.8 | 3.9 | 27 |
| 28 | TOTAL TRANSPORTATION | | 3.7 | 3.9 | 3.8 | 3.8 | 3.9 | 28 |

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

TABLE 3-LB

# CITY OF LONG BEACH - GAS & OIL DEPARTMENT

**ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY**
**ESTIMATED YEARS 2019 THRU 2035**

**AVERAGE TEMPERATURE YEAR**

| LINE | CAPACITY AVAILABLE | | 2019 | 2020 | 2025 | 2030 | 2035 | LINE |
|---|---|---|---|---|---|---|---|---|
| 1 | California Source Gas | | | | | | | 1 |
| 2 | Out-of-State Gas | | | | | | | 2 |
| 3 | TOTAL CAPACITY AVAILABLE | | | | | | | 3 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 4 | California Source Gas | | 0.7 | 0.7 | 0.5 | 0.4 | 0.4 | 4 |
| 5 | Out-of-State Gas | | 24.7 | 24.8 | 25.3 | 25.8 | 26.2 | 5 |
| 6 | TOTAL SUPPLY TAKEN | | 25.4 | 25.5 | 25.9 | 26.2 | 26.5 | 6 |
| 7 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 7 |
| 8 | TOTAL THROUGHPUT (1) | | 25.4 | 25.5 | 25.9 | 26.2 | 26.5 | 8 |
| | **REQUIREMENTS FORECAST BY END-USE (1)** | | | | | | | |
| 9 | CORE | Residential | 15.0 | 15.0 | 15.3 | 15.7 | 16.0 | 9 |
| 10 | | Commercial | 5.3 | 5.3 | 5.3 | 5.3 | 5.3 | 10 |
| 11 | | NGV | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 11 |
| 12 | | Subtotal-CORE | 20.6 | 20.6 | 21.0 | 21.3 | 21.6 | 12 |
| 13 | NONCORE | Industrial | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 13 |
| 14 | | Non-EOR Cogeneration | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 14 |
| 15 | | EOR | 0 | 0 | 0 | 0 | 0 | 15 |
| 16 | | Utility Electric Generation | 0 | 0 | 0 | 0 | 0 | 16 |
| 17 | | NGV | 0 | 0 | 0 | 0 | 0 | 17 |
| 18 | | Subtotal-NONCORE | 4.6 | 4.7 | 4.7 | 4.7 | 4.7 | 18 |
| 19 | | Co. Use & LUAF | 0.2 | 0.2 | 0.2 | 0.2 | 0.2 | 19 |
| 20 | SYSTEM TOTAL THROUGHPUT (1) | | 25.4 | 25.5 | 25.9 | 26.2 | 26.5 | 20 |
| 21 | SYSTEM CURTAILMENT | | 0 | 0 | 0 | 0 | 0 | 21 |
| | **TRANSPORTATION** | | | | | | | |
| 22 | CORE | All End Uses | 0 | 0 | 0 | 0 | 0 | 22 |
| 23 | NONCORE | Industrial | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 23 |
| 24 | | Non-EOR Cogeneration | 1.3 | 1.4 | 1.3 | 1.3 | 1.3 | 24 |
| 25 | | EOR | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | | Utility Electric Generation | 0 | 0 | 0 | 0 | 0 | 26 |
| 27 | | Subtotal NONCORE | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 27 |
| 28 | TOTAL TRANSPORTATION | | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 28 |

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

TABLE 6-LB

# CITY OF LONG BEACH - GAS & OIL DEPARTMENT

**ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY**
**ESTIMATED YEARS 2014 THRU 2018**

**1 in 35 TEMPERATURE YEAR**

| LINE | CAPACITY AVAILABLE | | 2014 | 2015 | 2016 | 2017 | 2018 | LINE |
|---|---|---|---|---|---|---|---|---|
| 1 | California Source Gas | | | | | | | 1 |
| 2 | Out-of-State Gas | | | | | | | 2 |
| 3 | TOTAL CAPACITY AVAILABLE | | | | | | | 3 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 4 | California Source Gas | | 1.1 | 0.9 | 0.8 | 0.8 | 0.8 | 4 |
| 5 | Out-of-State Gas | | 25.2 | 25.7 | 25.7 | 25.8 | 26.0 | 5 |
| 6 | TOTAL SUPPLY TAKEN | | 26.3 | 26.6 | 26.6 | 26.6 | 26.8 | 6 |
| 7 | Net Underground Storage Withdrawal | | - | - | - | - | - | 7 |
| 8 | TOTAL THROUGHPUT (1) | | 26.3 | 26.6 | 26.6 | 26.6 | 26.8 | 8 |
| | **REQUIREMENTS FORECAST BY END-USE (1)** | | | | | | | |
| 9 | CORE | Residential | 15.8 | 15.9 | 16.0 | 16.0 | 16.0 | 9 |
| 10 | | Commercial | 5.4 | 5.4 | 5.4 | 5.4 | 5.4 | 10 |
| 11 | | NGV | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 11 |
| 12 | | Subtotal-CORE | 21.5 | 21.6 | 21.7 | 21.7 | 21.8 | 12 |
| 13 | NONCORE | Industrial | 3.3 | 3.3 | 3.3 | 3.2 | 3.3 | 13 |
| 14 | | Non-EOR Cogeneration | 1.2 | 1.5 | 1.3 | 1.4 | 1.4 | 14 |
| 15 | | EOR | - | - | - | - | - | 15 |
| 16 | | Utility Electric Generation | - | - | - | - | - | 16 |
| 17 | | NGV | - | - | - | - | - | 17 |
| 18 | | Subtotal-NONCORE | 4.5 | 4.8 | 4.6 | 4.6 | 4.7 | 18 |
| 19 | | Co. Use & LUAF | 0.2 | 0.3 | 0.2 | 0.3 | 0.3 | 19 |
| 20 | SYSTEM TOTAL THROUGHPUT (1) | | 26.3 | 26.6 | 26.6 | 26.6 | 26.8 | 20 |
| 21 | SYSTEM CURTAILMENT | | - | - | - | - | - | 21 |
| | **TRANSPORTATION** | | | | | | | |
| 22 | CORE | All End Uses | - | - | - | - | - | 22 |
| 23 | NONCORE | Industrial | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 23 |
| 24 | | Non-EOR Cogeneration | 1.2 | 1.5 | 1.3 | 1.3 | 1.4 | 24 |
| 25 | | EOR | - | - | - | - | - | 25 |
| 26 | | Utility Electric Generation | - | - | - | - | - | 26 |
| 27 | | Subtotal NONCORE | 3.7 | 3.9 | 3.8 | 3.8 | 3.9 | 27 |
| 28 | TOTAL TRANSPORTATION | | 3.7 | 3.9 | 3.8 | 3.8 | 3.9 | 28 |

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

TABLE 7-LB

# CITY OF LONG BEACH - GAS & OIL DEPARTMENT

**ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY**
**ESTIMATED YEARS 2019 THRU 2035**

**1 in 35 TEMPERATURE YEAR**

| LINE | CAPACITY AVAILABLE | | 2019 | 2020 | 2025 | 2030 | 2035 | LINE |
|---|---|---|---|---|---|---|---|---|
| 1 | California Source Gas | | | | | | | 1 |
| 2 | Out-of-State Gas | | | | | | | 2 |
| 3 | TOTAL CAPACITY AVAILABLE | | | | | | | 3 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 4 | California Source Gas | | 0.7 | 0.7 | 0.5 | 0.5 | 0.5 | 4 |
| 5 | Out-of-State Gas | | 26.0 | 26.2 | 26.7 | 27.1 | 27.5 | 5 |
| 6 | TOTAL SUPPLY TAKEN | | 26.7 | 26.9 | 27.2 | 27.6 | 27.9 | 6 |
| 7 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 7 |
| 8 | TOTAL THROUGHPUT (1) | | 26.7 | 26.9 | 27.2 | 27.6 | 27.9 | 8 |
| | **REQUIREMENTS FORECAST BY END-USE (1)** | | | | | | | |
| 9 | CORE | Residential | 16.1 | 16.2 | 16.5 | 16.8 | 17.2 | 9 |
| 10 | | Commercial | 5.4 | 5.5 | 5.5 | 5.5 | 5.5 | 10 |
| 11 | | NGV | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 11 |
| 12 | | Subtotal-CORE | 21.9 | 22.0 | 22.3 | 22.7 | 23.0 | 12 |
| 13 | NONCORE | Industrial | 3.3 | 3.3 | 3.3 | 3.3 | 3.3 | 13 |
| 14 | | Non-EOR Cogeneration | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 14 |
| 15 | | EOR | 0 | 0 | 0 | 0 | 0 | 15 |
| 16 | | Utility Electric Generation | 0 | 0 | 0 | 0 | 0 | 16 |
| 17 | | NGV | 0 | 0 | 0 | 0 | 0 | 17 |
| 18 | | Subtotal-NONCORE | 4.6 | 4.7 | 4.7 | 4.7 | 4.7 | 18 |
| 19 | | Co. Use & LUAF | 0.3 | 0.3 | 0.3 | 0.3 | 0.3 | 19 |
| 20 | SYSTEM TOTAL THROUGHPUT (1) | | 26.7 | 26.9 | 27.2 | 27.6 | 27.9 | 20 |
| 21 | SYSTEM CURTAILMENT | | 0 | 0 | 0 | 0 | 0 | 21 |
| | **TRANSPORTATION** | | | | | | | |
| 22 | CORE | All End Uses | 0 | 0 | 0 | 0 | 0 | 22 |
| 23 | NONCORE | Industrial | 2.5 | 2.5 | 2.5 | 2.5 | 2.5 | 23 |
| 24 | | Non-EOR Cogeneration | 1.3 | 1.4 | 1.3 | 1.3 | 1.3 | 24 |
| 25 | | EOR | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | | Utility Electric Generation | 0 | 0 | 0 | 0 | 0 | 26 |
| 27 | | Subtotal NONCORE | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 27 |
| 28 | TOTAL TRANSPORTATION | | 3.8 | 3.8 | 3.8 | 3.8 | 3.8 | 28 |

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

# 2014 CALIFORNIA GAS REPORT

## SAN DIEGO GAS & ELECTRIC COMPANY

# INTRODUCTION

San Diego Gas & Electric Company (SDG&E) is a combined gas and electric distribution utility serving more than three million people in San Diego and the southern portions of Orange County. SDG&E delivered natural gas to 861,573 customers in San Diego County in 2013, including power plants and turbines. Total gas sales and transportation through SDG&E's system for 2013 were approximately 135 billion cubic feet (Bcf), which is an average of over 369 million cubic feet per day (MMcf/day).

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

# GAS DEMAND

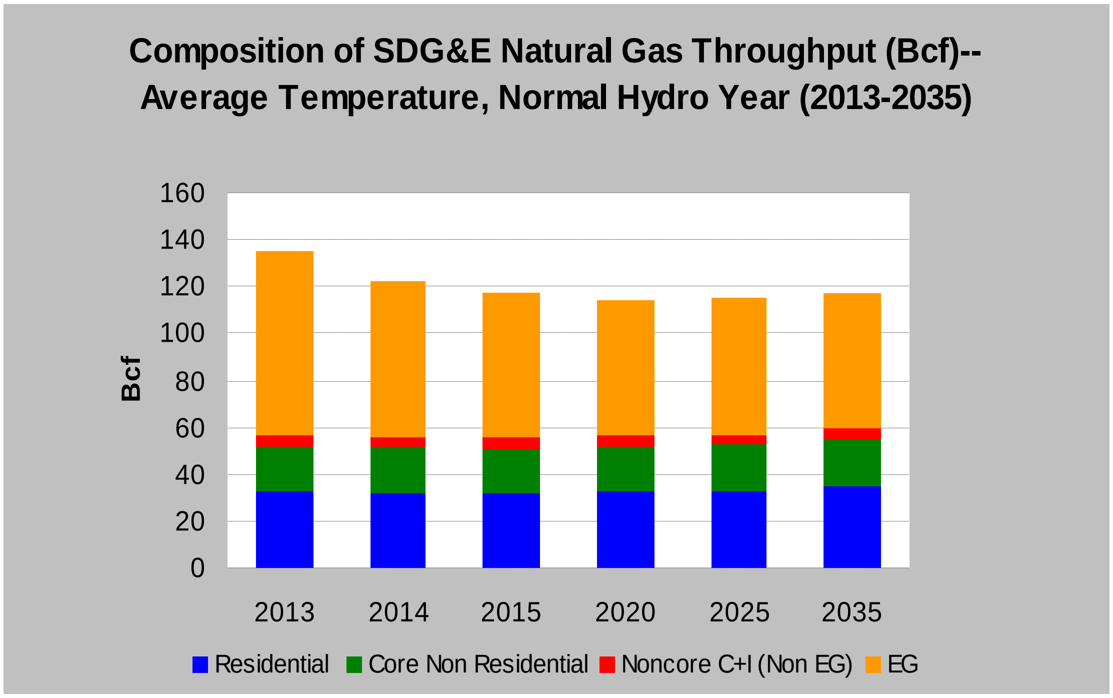
## OVERVIEW

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

This projection of natural gas requirements, excluding electric generation (EG) demand, is derived from models that integrate demographic assumptions, economic growth, energy prices, energy efficiency programs, customer information programs, building and appliance standards, weather and other factors. Non-EG gas demand is projected to remain virtually flat between 2013 and 2035. The total load, including EG, is expected to decline from a total of 135 Bcf in 2013 to 117 Bcf by 2035. Assumptions for SDG&E's gas transportation requirements for EG are included as part of the wholesale market sector description for SoCalGas.

## ECONOMICS AND DEMOGRAPHICS

SDG&E's gas demand forecast is largely determined by the long-term economic outlook for its San Diego County service area. The county's economic trends are expected to generally parallel those of the larger SoCalGas area as discussed above. San Diego County's total employment is forecasted to grow an average of 1.2% annually from 2013 to 2035; the subset of industrial (mining and manufacturing) jobs is projected to remain virtually flat over the same period. From 2013 to 2035, the county's inflation-adjusted Gross Product is expected to average 3.0% annual growth. (Gross Product, the local equivalent of national Gross Domestic Product, is a measure of the total economic output of the area economy.) The number of SDG&E gas meters is expected to increase an average of 1.3% annually from 2013 through 2035.



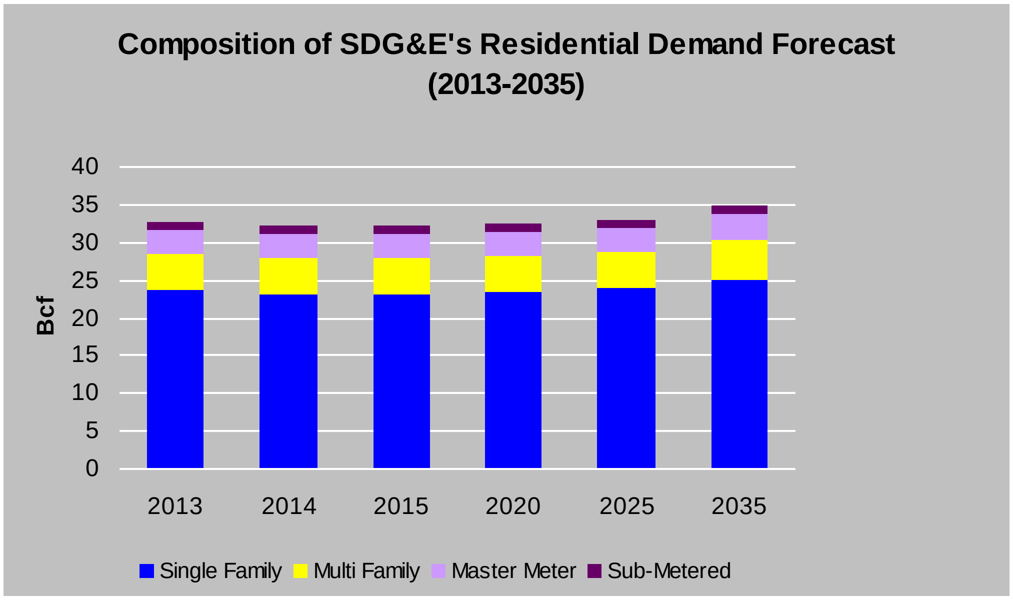

## MARKET SECTORS

### Residential

The total residential customer count for SDG&E consists of four residential segment types. These are single family and multi-family customers, as well as master meter and sub-metered customers. The active meters for all residential customer classes averaged 831,403 in 2013. This total reflects a 5,206 meter increase relative to the 2012 total. The overall observed 2012-2013 residential meter growth was 0.63%.

Residential demand adjusted for average temperature conditions totaled 33 Bcf in 2013. By the year 2035, residential demand is expected to reach 35 Bcf. The change reflects a 0.29% annual compound growth rate.

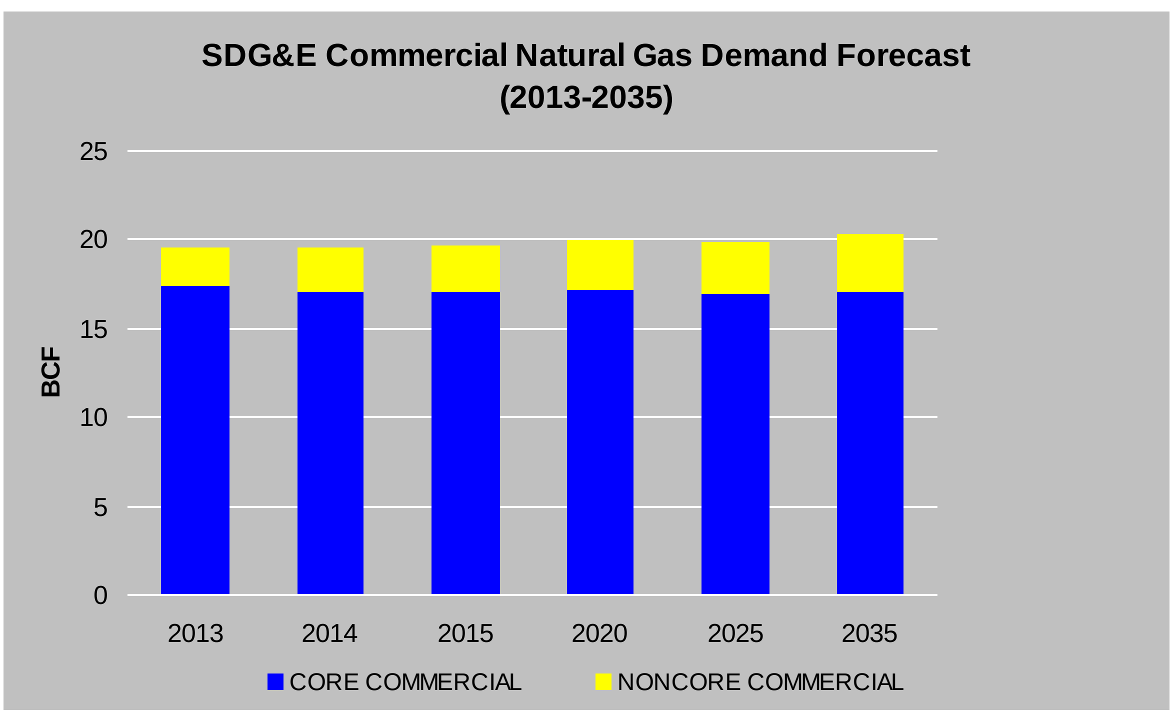
The projected residential natural gas demand will be influenced primarily by residential meter growth moderated by the forecasted declining use per customer due to energy efficiency improvements in the building shell design, appliance efficiency and CPUC-authorized EE programs plus the additional efficiency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




## Commercial

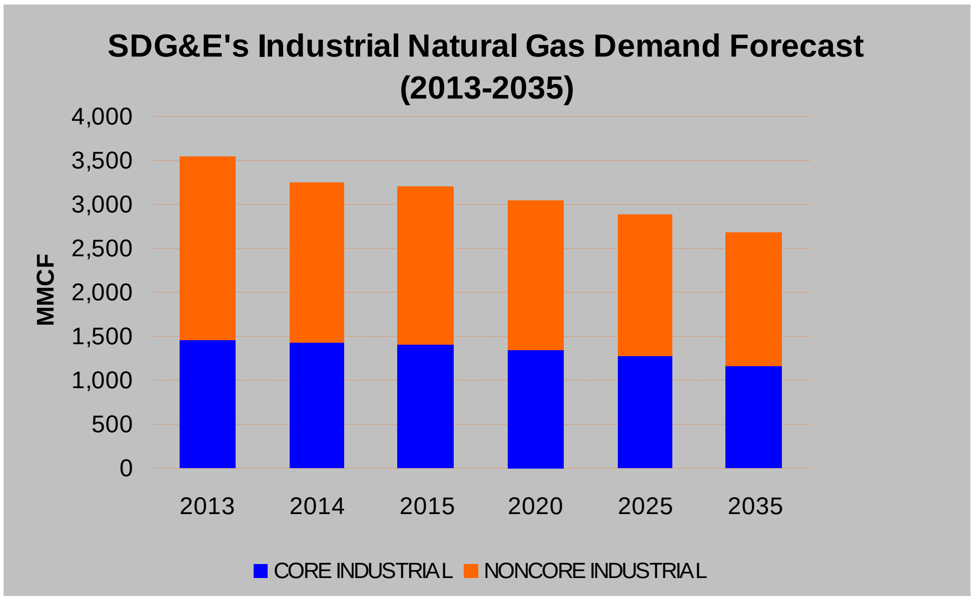
On a temperature-adjusted basis, the core commercial demand in 2013 totaled 17 Bcf. By the year 2035, the SDG&E core commercial load is expected to remain at 17 Bcf.

SDG&E's noncore commercial load in 2013 was 2.2 Bcf. Over the forecast period, gas demand in this market is projected to show moderate growth mostly driven by increased economic activity and employment. Noncore commercial load is projected to grow to 3.3 Bcf by 2035, an average annual increase of 1.9%.



## Industrial

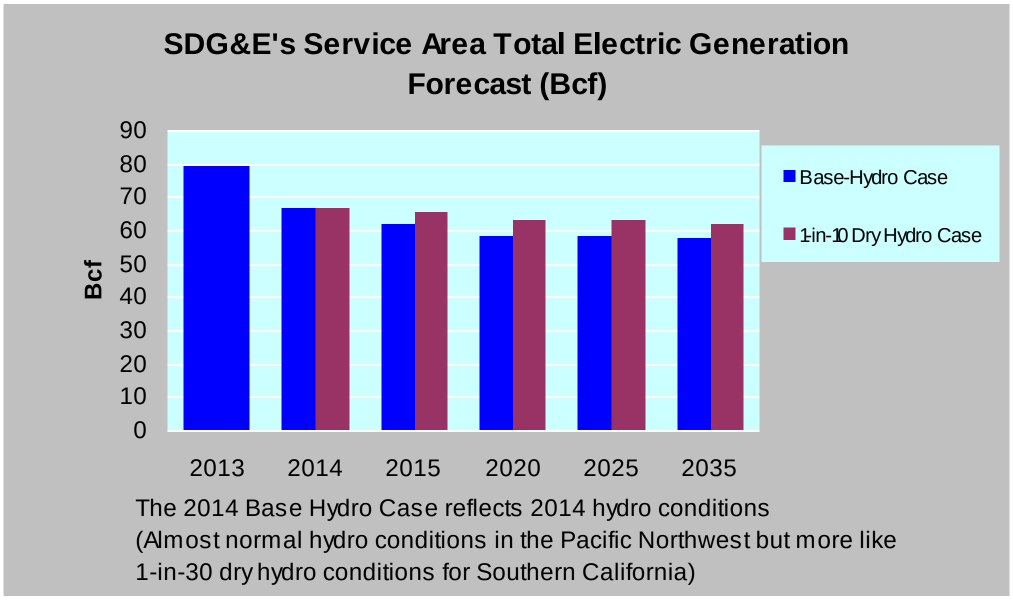
In 2013, temperature-adjusted core industrial demand was 1.4 Bcf. The core industrial market demand is projected to decrease at an average rate of 1% per year from 1.4 Bcf in 2013 to 1.2 Bcf in 2035. This result is due to slightly lower forecasted growth in industrial production and the impact of savings from CPUC-authorized energy-efficiency programs in the industrial sector.




Noncore industrial load in 2013 was 2.2 Bcf and is expected to decline at an average rate of 1.5% per year to 1.6 Bcf by 2035. CPUC-mandated energy efficiency programs more than offset any modest gains from industrial economic growth.

## Electric Generation

Total EG, including cogeneration and non-cogeneration EG, is expected to decrease at an annual average rate of 1.4 percent from 79 Bcf in 2013 to 58 Bcf in 2035. The following graph shows total EG forecasts for a normal hydro year and a 1-in-10 dry hydro year.




*Cogeneration*

Small EG load from self-generation totaled 18.0 Bcf in 2013. By 2035, small EG load is expected to decrease slightly to 17.4 Bcf – declining an average of 0.1% per year, mainly due to the effects of higher costs for mandated carbon emissions reduction.

*Non-Cogeneration Electric Generation*

The forecast of the large EG loads in SDG&E's service area is based on the power market simulation as noted in SoCalGas' electric generation chapter for "Non-Cogeneration EG" demand. This forecast includes approximately 900 MW of new thermal peaking generating resources in its service area by 2020. However, it also assumes that approximately 1,150 MW of the existing plants are retired during the same time period. EG demand is forecasted to decrease from 49 Bcf in 2014 to 41 Bcf in 2025. It is important to note that the first year of the forecast, 2014, is a dry hydro year and the forecast for the remaining years, 2015-2025, is based on normal hydro conditions. Therefore the EG demand for 2014 is higher than it would have been under normal hydro conditions. From 2015 through 2025, EG gas demand is forecast to decrease from 44 Bcf in 2015 to 41 Bcf in 2025. The EG forecast is held constant at 2025 levels for 2030 and 2035 as previously explained.

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

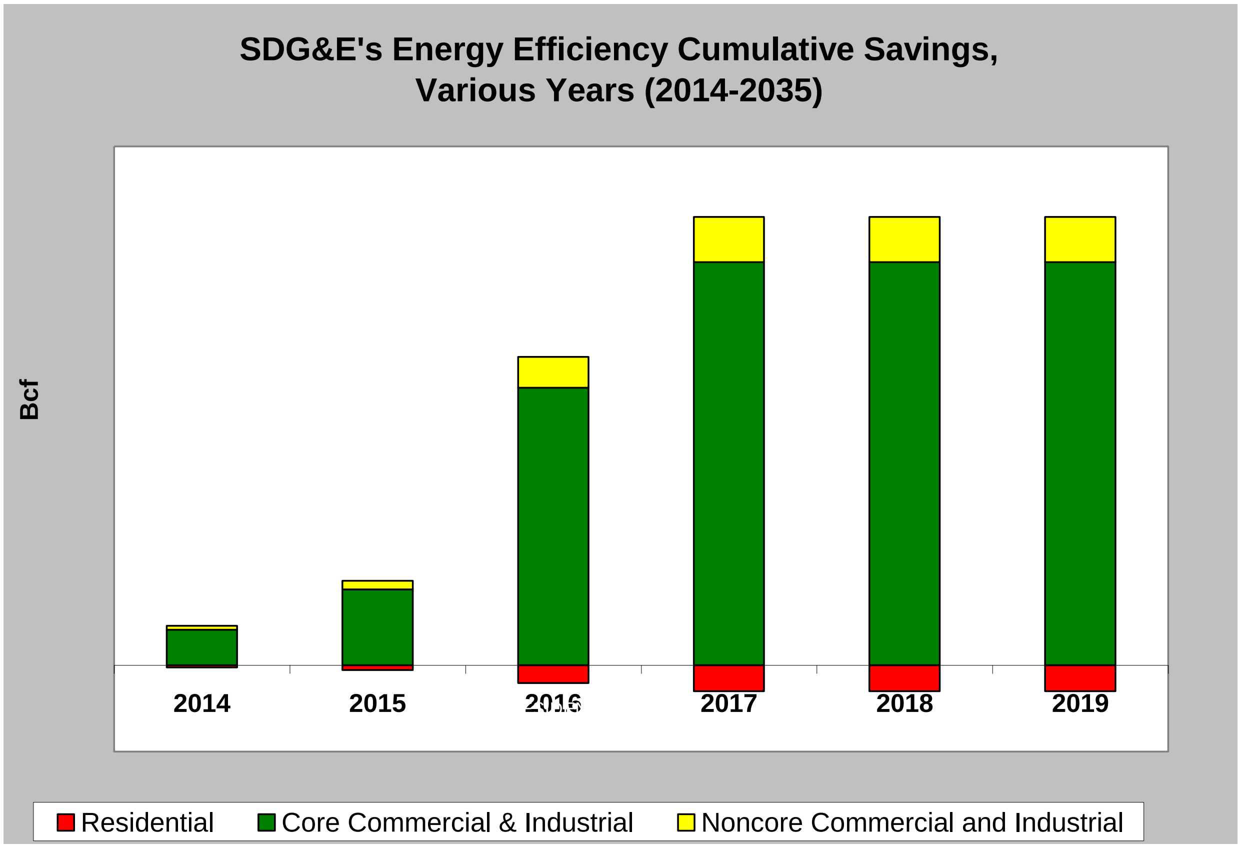
### Natural Gas Vehicles (NGV)

The NGV market is expected to continue to grow due to government (federal, state and local) incentives and regulations related to the purchase and operation of alternate fuel vehicles, growing numbers of natural gas engines and vehicles, and the increasing cost differential between petroleum (gasoline and diesel) and natural gas. At the end of 2013, there were 31 compressed natural gas (CNG) fueling stations delivering about 1.4 Bcf of natural gas during the year. The NGV market is forecast to essentially triple in size to 4.6 Bcf in 2035, a growth rate of nearly 5.6% per year.

## 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 2014 and occurring through the year 2035. Savings and goals for these programs are based on the program goals authorized by the Commission in D.12-05-015 and D.12-15-015.




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.[6] Measures with useful lives less than the forecast planning period fall out of the forecast when their expected life is reached. This means, for example, that a measure installed in 2014 with a lifetime of 10 years is only included in the forecast through 2023.[7] Naturally occurring conservation that is not attributable to SDG&E's Energy Efficiency activities is not included in the Energy Efficiency forecast.

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

[6] The above chart shows that SDG&E's residential integrated gas and electric energy efficiency program leads to gas consumption actually increasing due to the interactive impacts of gas and electric efficiency measures. For example, high efficiency lights generate less heat and thus, lead to more gas heating during winter months.
[7] The assumed average measure life is 10 years.

# GAS SUPPLY

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

# PEAK DAY DEMAND

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

# 2014 CALIFORNIA GAS REPORT

## SAN DIEGO GAS & ELECTRIC COMPANY
## TABULAR DATA

## San Diego Gas & Electric Company
## Annual Gas Supply and Sendout (MMCF/Day)
## Recorded Years 2009-2013

| LINE | | | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|---|
| | **Actual Deliveries by End-Use** | | | | | | |
| 1 | **CORE** | Residential | 82 | 85 | 88 | 83 | 85 |
| 2 | | Commercial | 48 | 48 | 50 | 50 | 52 |
| 3 | | Industrial | 0 | 0 | 0 | 0 | 0 |
| 4 | *Subtotal -* | *CORE* | 130 | 133 | 138 | 134 | 137 |
| 5 | **NONCORE** | Commercial | 0 | 0 | 0 | 0 | 0 |
| 6 | | Industrial | 11 | 12 | 12 | 13 | 12 |
| 7 | | Non-EOR Cogen/EG | 115 | 98 | 69 | 100 | 70 |
| 8 | | Electric Utilities | 64 | 81 | 87 | 134 | 147 |
| 9 | *Subtotal -* | *NONCORE* | 191 | 191 | 169 | 247 | 229 |
| 10 | **WHOLESALE** | All End Uses | 0 | 0 | 0 | 0 | 0 |
| 11 | *Subtotal -* | *Co Use & LUAF* | 3 | 6 | 5 | 4 | 5 |
| 12 | **SYSTEM TOTAL THROUGHPUT** | | 324 | 330 | 312 | 384 | 371 |
| | **Actual Transport & Exchange** | | | | | | |
| 13 | **CORE** | Residential | 0 | 0 | 0 | 0 | 1 |
| 14 | | Commercial | 8 | 10 | 10 | 11 | 12 |
| 15 | **NONCORE** | Industrial | 11 | 12 | 12 | 13 | 12 |
| 16 | | Non-EOR Cogen/EG | 115 | 98 | 69 | 100 | 70 |
| 17 | | Electric Utilities | 64 | 81 | 87 | 134 | 147 |
| 18 | *Subtotal -* | *RETAIL* | 199 | 201 | 179 | 258 | 242 |
| 19 | **WHOLESALE** | All End Uses | 0 | 0 | 0 | 0 | 0 |
| 20 | **TOTAL TRANSPORT & EXCHANGE** | | 199 | 201 | 179 | 258 | 242 |
| | **Storage** | | | | | | |
| 21 | | *Storage Injection* | 0 | 0 | 0 | 0 | 0 |
| 22 | | *Storage Withdrawal* | 0 | 0 | 0 | 0 | 0 |
| | **Actual Curtailment** | | | | | | |
| 23 | | Residential | 0 | 0 | 0 | 0 | 0 |
| 24 | | Com/Indl & Cogen | 0 | 0 | 0 | 0 | 0 |
| 25 | | Electric Generation | 0 | 0 | 0 | 0 | 0 |
| 26 | **TOTAL CURTAILMENT** | | 0 | 0 | 0 | 0 | 0 |
| 27 | **REFUSAL** | | 0 | 0 | 0 | 0 | 0 |
| | ACTUAL DELIVERIES BY END-USE includes sales and transportation volumes | | | | | | |
| | | MMbtu/Mcf: | 1.020 | 1.019 | 1.018 | 1.017 | 1.024 |

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

## SAN DIEGO GAS & ELECTRIC COMPANY

### ANNUAL GAS SUPPLY TAKEN (MMCF/DAY)
### RECORDED YEARS 2009-2013

| LINE | | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| | **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** | 2009 | 2010 | 2011 | 2012 | 2013 |
| | **California Source Gas** | | | | | |
| 11 | Regular Purchases | 0 | 0 | 0 | 0 | 0 |
| 12 | Received for Exchange/Transport | 0 | 0 | 0 | 0 | 0 |
| 13 | **Total California Source Gas** | 0 | 0 | 0 | 0 | 0 |
| 14 | **Purchases from Other Utilities** | 0 | 0 | 0 | 0 | 0 |
| | **Out-of-State Gas** | | | | | |
| 15 | Pacific Interstate Companies | 0 | 0 | 0 | 0 | 0 |
| 16 | Additional Core Supplies | 0 | 0 | 0 | 0 | 0 |
| 17 | Supplemental Supplies-Utility | 125 | 130 | 132 | 126 | 129 |
| 18 | Out-of-State Transport-Others | 199 | 201 | 179 | 258 | 242 |
| 19 | **Total Out-of-State Gas** | 324 | 330 | 312 | 384 | 371 |
| 20 | **TOTAL Gas Supply Taken & Transported** | 324 | 330 | 312 | 384 | 371 |

TABLE 1-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2014 THRU 2018

AVERAGE TEMPERATURE YEAR

| LINE | | | 2014 | 2015 | 2016 | 2017 | 2018 | LINE |
|---|---|---|---|---|---|---|---|---|
| | **CAPACITY AVAILABLE [1/ & 2/]** | | | | | | | |
| 1 | California Source Gas | | 0 | 0 | 0 | 0 | 0 | 1 |
| 2 | Southern Zone of SoCalGas [1/] | | 607 | 607 | 607 | 607 | 607 | 2 |
| 3 | TOTAL CAPACITY AVAILABLE | | 607 | 607 | 607 | 607 | 607 | 3 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 4 | California Source Gas | | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | Southern Zone of SoCalGas | | 341 | 325 | 332 | 330 | 323 | 5 |
| 6 | TOTAL SUPPLY TAKEN | | 341 | 325 | 332 | 330 | 323 | 6 |
| 7 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 7 |
| 8 | TOTAL THROUGHPUT | | 341 | 325 | 332 | 330 | 323 | 8 |
| | **REQUIREMENTS FORECAST BY END-USE [3/]** | | | | | | | |
| 9 | CORE [4/] | Residential | 88 | 87 | 88 | 88 | 88 | 9 |
| 10 | | Commercial | 47 | 47 | 47 | 47 | 47 | 10 |
| 11 | | Industrial | 4 | 4 | 4 | 4 | 4 | 11 |
| 12 | | NGV | 2 | 2 | 2 | 2 | 2 | 12 |
| 13 | | Subtotal-CORE | 141 | 140 | 141 | 141 | 141 | 13 |
| 14 | NONCORE | Commercial | 7 | 7 | 7 | 7 | 8 | 14 |
| 15 | | Industrial | 5 | 5 | 5 | 5 | 5 | 15 |
| 16 | | Electric Generation (EG) | 183 | 169 | 175 | 173 | 165 | 16 |
| 17 | | Subtotal-NONCORE | 195 | 181 | 187 | 185 | 178 | 17 |
| 18 | | Co. Use & LUAF | 5 | 4 | 4 | 4 | 4 | 18 |
| 19 | SYSTEM TOTAL THROUGHPUT | | 341 | 325 | 332 | 330 | 323 | 19 |
| | TRANSPORTATION AND EXCHANGE | | | | | | | |
| 20 | CORE | All End Uses | 11 | 12 | 12 | 12 | 12 | 20 |
| 21 | NONCORE | Commercial/Industrial | 12 | 12 | 12 | 12 | 12 | 21 |
| 22 | | Electric Generation (EG) | 183 | 169 | 175 | 173 | 165 | 22 |
| 23 | TOTAL TRANSPORTATION & EXCHANGE | | 206 | 193 | 199 | 197 | 189 | 23 |
| | CURTAILMENT | | | | | | | |
| 24 | | Core | 0 | 0 | 0 | 0 | 0 | 24 |
| 25 | | Noncore | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | | TOTAL - Curtailment | 0 | 0 | 0 | 0 | 0 | 26 |

NOTES:

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

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

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

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| transportation (CAT) in MDth/d: | 133 | 131 | 132 | 132 | 132 |

TABLE 2-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2019 THRU 2035

AVERAGE TEMPERATURE YEAR

| LINE | | | 2019 | 2020 | 2025 | 2030 | 2035 | LINE |
|---|---|---|---|---|---|---|---|---|
| | **CAPACITY AVAILABLE** 1/ & 2/ | | | | | | | |
| 1 | California Source Gas | | 0 | 0 | 0 | 0 | 0 | 1 |
| 2 | Southern Zone of SoCalGas 1/ | | 607 | 607 | 607 | 607 | 607 | 2 |
| 3 | TOTAL CAPACITY AVAILABLE | | 607 | 607 | 607 | 607 | 607 | 3 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 4 | California Source Gas | | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | Out-of-State | | 321 | 318 | 318 | 322 | 325 | 5 |
| 6 | TOTAL SUPPLY TAKEN | | 321 | 318 | 318 | 322 | 325 | 6 |
| 7 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 7 |
| 8 | TOTAL THROUGHPUT | | 321 | 318 | 318 | 322 | 325 | 8 |
| | **REQUIREMENTS FORECAST BY END-USE** 3/ | | | | | | | |
| 9 | CORE 4/ | Residential | 88 | 88 | 90 | 93 | 95 | 9 |
| 10 | | Commercial | 47 | 47 | 46 | 46 | 46 | 10 |
| 11 | | Industrial | 4 | 4 | 3 | 3 | 3 | 11 |
| 12 | | NGV | 3 | 3 | 3 | 5 | 6 | 12 |
| 13 | | Subtotal-CORE | 142 | 142 | 142 | 147 | 150 | 13 |
| 14 | NONCORE | Commercial | 8 | 8 | 8 | 8 | 9 | 14 |
| 15 | | Industrial | 5 | 5 | 4 | 4 | 4 | 15 |
| 16 | | Electric Generation (EG) | 162 | 159 | 160 | 159 | 158 | 16 |
| 17 | | Subtotal-NONCORE | 175 | 172 | 172 | 171 | 171 | 17 |
| 18 | | Co. Use & LUAF | 4 | 4 | 4 | 4 | 4 | 18 |
| 19 | SYSTEM TOTAL THROUGHPUT | | 321 | 318 | 318 | 322 | 325 | 19 |
| | TRANSPORTATION AND EXCHANGE | | | | | | | |
| 20 | CORE | All End Uses | 12 | 12 | 13 | 15 | 17 | 20 |
| 21 | NONCORE | Commercial/Industrial | 12 | 12 | 12 | 13 | 13 | 21 |
| 22 | | Electric Generation (EG) | 162 | 159 | 160 | 159 | 158 | 22 |
| 23 | TOTAL TRANSPORTATION & EXCHANGE | | 186 | 183 | 185 | 187 | 188 | 23 |
| | CURTAILMENT | | | | | | | |
| 24 | | Core | 0 | 0 | 0 | 0 | 0 | 24 |
| 25 | | Noncore | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | | TOTAL - Curtailment | 0 | 0 | 0 | 0 | 0 | 26 |

NOTES:

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

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

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

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

| | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| transportation (CAT) in MDth/d: | 133 | 133 | 132 | 135 | 136 |

TABLE 3-SDGE

SAN DIEGO GAS & ELECTRIC COMPANY

ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY
ESTIMATED YEARS 2014 THRU 2018

COLD TEMPERATURE YEAR & DRY HYDRO YEAR

| LINE | | | 2014 | 2015 | 2016 | 2017 | 2018 | LINE |
|---|---|---|---|---|---|---|---|---|
| | **CAPACITY AVAILABLE** [1/ & 2/] | | | | | | | |
| 1 | California Source Gas | | 0 | 0 | 0 | 0 | 0 | 1 |
| 2 | Southern Zone of SoCalGas [1/] | | 607 | 607 | 607 | 607 | 607 | 2 |
| 3 | TOTAL CAPACITY AVAILABLE | | 607 | 607 | 607 | 607 | 607 | 3 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 4 | California Source Gas | | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | Out-of-State | | 350 | 344 | 355 | 351 | 348 | 5 |
| 6 | TOTAL SUPPLY TAKEN | | 350 | 344 | 355 | 351 | 348 | 6 |
| 7 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 7 |
| 8 | TOTAL THROUGHPUT | | 350 | 344 | 355 | 351 | 348 | 8 |
| | **REQUIREMENTS FORECAST BY END-USE** [3/] | | | | | | | |
| 9 | CORE [4/] | Residential | 96 | 95 | 96 | 96 | 96 | 9 |
| 10 | | Commercial | 48 | 48 | 49 | 49 | 49 | 10 |
| 11 | | Industrial | 4 | 4 | 4 | 4 | 4 | 11 |
| 12 | | NGV | 2 | 2 | 2 | 2 | 2 | 12 |
| 13 | | Subtotal-CORE | 150 | 149 | 151 | 151 | 151 | 13 |
| 14 | NONCORE | Commercial | 7 | 7 | 7 | 7 | 8 | 14 |
| 15 | | Industrial | 5 | 5 | 5 | 5 | 5 | 15 |
| 16 | | Electric Generation (EG) | 183 | 178 | 187 | 183 | 179 | 16 |
| 17 | | Subtotal-NONCORE | 195 | 190 | 199 | 195 | 192 | 17 |
| 18 | | Co. Use & LUAF | 5 | 5 | 5 | 5 | 5 | 18 |
| 19 | SYSTEM TOTAL THROUGHPUT | | 350 | 344 | 355 | 351 | 348 | 19 |
| | TRANSPORTATION AND EXCHANGE | | | | | | | |
| 20 | CORE | All End Uses | 12 | 12 | 12 | 12 | 13 | 20 |
| 21 | NONCORE | Commercial/Industrial | 12 | 12 | 12 | 12 | 12 | 21 |
| 22 | | Electric Generation (EG) | 183 | 178 | 187 | 183 | 179 | 22 |
| 23 | TOTAL TRANSPORTATION & EXCHANGE | | 207 | 202 | 211 | 207 | 204 | 23 |
| | CURTAILMENT | | | | | | | |
| 24 | | Core | 0 | 0 | 0 | 0 | 0 | 24 |
| 25 | | Noncore | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | | TOTAL - Curtailment | 0 | 0 | 0 | 0 | 0 | 26 |

NOTES:

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

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

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

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

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| CAT in MDth/d | 141 | 140 | 142 | 142 | 141 |

TABLE 4-SDGE

**SAN DIEGO GAS & ELECTRIC COMPANY**

**ANNUAL GAS SUPPLY AND REQUIREMENTS - MMCF/DAY**
**ESTIMATED YEARS 2019 THRU 2035**

**COLD TEMPERATURE YEAR & DRY HYDRO YEAR**

| LINE | | | 2019 | 2020 | 2025 | 2030 | 2035 | LINE |
|---|---|---|---|---|---|---|---|---|
| | **CAPACITY AVAILABLE** [1/ & 2/] | | | | | | | |
| 1 | California Source Gas | | 0 | 0 | 0 | 0 | 0 | 1 |
| 2 | Southern Zone of SoCalGas [1/] | | 607 | 607 | 607 | 607 | 607 | 2 |
| 3 | TOTAL CAPACITY AVAILABLE | | 607 | 607 | 607 | 607 | 607 | 3 |
| | **GAS SUPPLY TAKEN** | | | | | | | |
| 4 | California Source Gas | | 0 | 0 | 0 | 0 | 0 | 4 |
| 5 | Out-of-State | | 345 | 342 | 342 | 345 | 348 | 5 |
| 6 | TOTAL SUPPLY TAKEN | | 345 | 342 | 342 | 345 | 348 | 6 |
| 7 | Net Underground Storage Withdrawal | | 0 | 0 | 0 | 0 | 0 | 7 |
| 8 | TOTAL THROUGHPUT | | 345 | 342 | 342 | 345 | 348 | 8 |
| | **REQUIREMENTS FORECAST BY END-USE** [3/] | | | | | | | |
| 9 | CORE [4/] | Residential | 96 | 96 | 98 | 101 | 103 | 9 |
| 10 | | Commercial | 49 | 49 | 48 | 48 | 48 | 10 |
| 11 | | Industrial | 4 | 4 | 4 | 3 | 3 | 11 |
| 12 | | NGV | 3 | 3 | 3 | 5 | 6 | 12 |
| 13 | | Subtotal-CORE | 152 | 152 | 153 | 157 | 160 | 13 |
| 14 | NONCORE | Commercial | 8 | 8 | 8 | 8 | 9 | 14 |
| 15 | | Industrial | 5 | 5 | 4 | 4 | 4 | 15 |
| 16 | | Electric Generation (EG) | 175 | 172 | 172 | 171 | 170 | 16 |
| 17 | | Subtotal-NONCORE | 188 | 185 | 184 | 183 | 183 | 17 |
| 18 | | Co. Use & LUAF | 5 | 5 | 5 | 5 | 5 | 18 |
| 19 | SYSTEM TOTAL THROUGHPUT | | 345 | 342 | 342 | 345 | 348 | 19 |
| | TRANSPORTATION AND EXCHANGE | | | | | | | |
| 20 | CORE | All End Uses | 13 | 13 | 14 | 15 | 17 | 20 |
| 21 | NONCORE | Commercial/Industrial | 12 | 12 | 12 | 13 | 13 | 21 |
| 22 | | Electric Generation (EG) | 175 | 172 | 172 | 171 | 170 | 22 |
| 23 | TOTAL TRANSPORTATION & EXCHANGE | | 200 | 197 | 198 | 199 | 200 | 23 |
| | CURTAILMENT | | | | | | | |
| 24 | | Core | 0 | 0 | 0 | 0 | 0 | 24 |
| 25 | | Noncore | 0 | 0 | 0 | 0 | 0 | 25 |
| 26 | | TOTAL - Curtailment | 0 | 0 | 0 | 0 | 0 | 26 |

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

| | 2019 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|
| transportation (CAT) in MDth/d: | 142 | 142 | 142 | 145 | 146 |

# 2014 CALIFORNIA GAS REPORT

## GLOSSARY

# GLOSSARY

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

**Average Temperature year**
Long-term average recorded temperature.

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

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

**CEC**
California Energy Commission.

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

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

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

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

**Commercial (PG&E)**
Non-residential gas customers not engaged in electric generation, enhanced oil recovery, or gas resale activities with usage less than 20,800 therms per month.

**Company Use**

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

**Conversion Factor (Natural Gas)**

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

**Conversion Factor (Petroleum Products)**

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

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

**Conversion Factor (LNG)**

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

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

**Core Aggregator**

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

**Core customers (SoCalGas & SDG&E)**

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

**Core Customer (PG&E)**

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

**Core Subscription**

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

**CPUC**

California Public Utilities Commission.

**Cubic Foot of Gas**

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

**Curtailment**

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

**EG**

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

**Energy Service Provider (ESP)**

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

**Enhanced Oil Recovery (EOR)**

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

**Exchange**

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

**Exempt Wholesale Generators (EWG)**

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

**FERC**

Federal Energy Regulatory Commission.

**Futures (Gas)**

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

**Gas Accord**

The Gas Accord is a multi-party settlement agreement, which restructured PG&E's gas transportation and storage services. The settlement was filed with the CPUC in August 1996, approved by the CPUC in August 1997 (D.97-08-055) and implemented by

PG&E in March 1998. In D.03-12-061, the CPUC ordered the Gas Accord structure to continue for 2004 and 2005.

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

**Gas Sendout**

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

**GHG**

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

**Heating Degree Day (HDD)**

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

**Heating Value**

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

**Industrial (SoCalGas & SDG&E)**

Category of gas customers who are engaged in mining and in manufacturing durable goods.

**Industrial (PG&E)**

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

**LDC**

Local electric and/or natural gas distribution company.

**LNG (Liquefied Natural Gas)**

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

**Load Following**

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

**MMBTU**

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

**MCF**

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

**MMCF/DAY**

Million cubic feet of gas per day.

**NGV (Natural Gas Vehicle)**

Vehicle that uses CNG or LNG as its source of fuel for its internal combustion engine.

**Noncore Customers**

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

**Non-Utility Served Load**

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

**Off-System Sales**

Gas sales to customers outside the utility's service area.

**Out-Of-State Gas**

Gas from sources outside the state of California.

**Priority of Service (SoCalGas & SDG&E)**

In the event of a curtailment situation, utilities curtail gas usage to customers based on the following end-use priorities:

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

**Priority of Service (PG&E)**

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

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

**PSIA**

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

**PSEP**

Pipeline Safety Enhancement Plan.

**Purchase from Other Utilities**

Gas purchased from other utilities in California.

**Requirements**

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

**Resale**

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

**Residential**

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

**Short-Term Supplies**

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

**Spot Purchases**

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

**Storage Banking**

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

**Storage Injection**

Volume of natural gas injected into underground storage facilities.

**Storage Withdrawal**

Volume of natural gas taken from underground storage facilities.

**Supplemental Supplies**

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

**System Capacity or Normal System Capacity (Operational Definition)**

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

**System Utilization or Nominal System Capacity (Operational Definition)**

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

**Take-or-Pay**

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

**Tariff**

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

**TCF**

Trillion cubic feet of gas.

**Therm**

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

**Total Gas Supply Available**

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

**Total Gas Supply Taken**

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

**Total Throughput**

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

**Transportation Gas**

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

**UEG**

Utility electric generation.

**Unaccounted-For**

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

**Unbundling**

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

**WACOG**

Weighted average cost of gas.

**Wholesale**

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

**Wobbe**

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

# 2014 CALIFORNIA GAS REPORT

## RESPONDENTS

# RESPONDENTS

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

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

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

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

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

### Working Committee

- Jeff Swanson (Chairperson) – PG&E
- Rose-Marie Payan-SoCalGas/SDG&E
- Sharim Chaudhury- SoCalGas/SDG&E
- Jeff Huang – SoCalGas/SDG&E
- Michelle Clay-Ijomah-SDG&E
- Eric Hsu-PG&E
- David Sanchez- City of Long Beach Gas and Oil
- Robert Kennedy- CEC
- Angela Tanghetti – CEC

### Observers

- Richard Myers– CPUC Energy Division

# RESERVE YOUR SUBSCRIPTION

## 2015 CALIFORNIA GAS REPORT – SUPPLEMENT

**Southern California Gas Company**
2015 CGR Reservation Form
Box 3249, Mail Location GT14D6
Los Angeles, CA 90051-1249

or

Fax: (213) 244-4957
Email: Sharim Chaudhury
IChaudhury@semprautilities.com

- ❑ Send me a 2015 CGR Supplement
- ❑ New subscriber
- ❑ Change of address

Company Name: ______________________________________________

C/O: ______________________________________________

Address: ______________________________________________

City: ____________________ State: ______________ Zip: __________

Phone: ( _____ ) _________________ Fax: ( _____ ) _______________

Also, please visit our website at: www.socalgas.com
www.sdge.com

# RESERVE YOUR SUBSCRIPTION

## 2015 CALIFORNIA GAS REPORT – SUPPLEMENT

**Pacific Gas and Electric Company**
2015 CGR Reservation Form
Attention:  Jeff Swanson
Mail Code B10B
P. O. Box 770000
San Francisco, CA 94177

or

Email:  Jeff Swanson
JKSR@PGE.COM

- ❑ Send me a 2015 CGR Supplement
- ❑ New subscriber
- ❑ Change of address

Company Name: ____________________________________________

C/O: ______________________________________________________

Address: ___________________________________________________

City: __________________    State: _____________    Zip: _________

Phone: ( _____ ) ________________    Fax: ( _____ ) ______________

Digital copies available on our website at:
http://www.pge.com/pipeline/library/regulatory/cgr_index.shtml


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