# DOCKETED

| | |
|---|---|
| **Docket Number:** | 15-IEPR-09 |
| **Project Title:** | Natural Gas Market Assessment |
| **TN #:** | 215314 |
| **Document Title:** | 2015 Natural Gas Outlook Staff Report |
| **Description:** | *** THIS DOCUMENT WAS ERRONEOUSLY FILED IN 15-IEPR-04; TN 213911 *** - CEC Staff Report on 2015 Natural Gas Outlook |
| **Filer:** | Patty Paul |
| **Organization:** | California Energy Commission |
| **Submitter Role:** | Commission Staff |
| **Submission Date:** | 1/12/2017 3:13:41 PM |
| **Docketed Date:** | 1/12/2017 |

# DOCKETED

| | |
|---|---|
| **Docket Number:** | 15-IEPR-04 |
| **Project Title:** | AB1257 Natural Gas Act Report |
| **TN #:** | 213911 |
| **Document Title:** | 2015 Natural Gas Outlook Staff Report |
| **Description:** | CEC Staff Report on 2015 Natural Gas Outlook |
| **Filer:** | Raquel Kravitz |
| **Organization:** | California Energy Commission |
| **Submitter Role:** | Commission Staff |
| **Submission Date:** | 10/6/2016 9:45:53 AM |
| **Docketed Date:** | 10/6/2016 |

California Energy Commission

**STAFF REPORT**

# 2015 Natural Gas Outlook

**California Energy Commission**

Edmund G. Brown Jr., Governor

**June 2016 | CEC-200-2015-007-SF**

# California Energy Commission

Leon Brathwaite
Anthony Dixon
Jorge Gonzales
Chris Marxen
Peter Puglia
Angela Tanghetti
**Primary Authors**

Chris Marxen
**Project Manager**

Marc Pryor
**Acting Office Manager**
**SUPPLY ANALYSIS OFFICE**

Sylvia Bender
**Deputy Director**
**ENERGY ASSESSMENTS DIVISION**

Robert P. Oglesby
**Executive Director**

# ACKNOWLEDGEMENTS

The authors would like to acknowledge the following individuals for their valuable contributions to this report:

Dr. Kenneth B. Medlock III, Ph.D., Institute for Public Policy, Baker Institute, Rice University, Houston, Texas, for assumption inputs, data, and guidance.

Melissa Jones, Energy Commission staff, for report reviews and edits.

Malachi Weng-Gutierrez, Chris Kavalec, Asish Gautam, and Andrea Gough, Energy Commission staff, for providing inputs on end-use demand.

Catherine Elder of Aspen Environmental Group for report reviews and edits.

# ABSTRACT

California Energy Commission staff produced the *2015 Natural Gas Outlook* report to support the California Energy Commission's *2015 Integrated Energy Policy Report*. California Energy Commission staff, in consultation with industry experts, developed cases depicting future natural gas demand and supply trends under a variety of assumptions. The mid demand case represents a business-as-usual case in which staff based likely outcomes on current trends in natural gas markets, commercial activity, and economic developments. Staff created the high demand/low price and the low demand/high price cases by altering assumptions in ways that led to conditions that would move natural gas demand lower or higher than in the mid demand case. The results from this modeling effort are coordinated with other modeling efforts at the California Energy Commission.

**Keywords**: Natural gas supply, demand, infrastructure, storage, prices, exports, imports, shale, hydraulic fracturing, biomethane, liquefied natural gas

Brathwaite, Leon, Anthony Dixon, Jorge Gonzales, Chris Marxen, Peter Puglia, Angela Tanghetti. 2015. *2015 Natural Gas Outlook Draft Staff Report*. California Energy Commission. CEC-200-2015-007-SD.

# TABLE OF CONTENTS

Page

# LIST OF FIGURES

# LIST OF TABLES

# EXECUTIVE SUMMARY

California Energy Commission staff collects, analyzes, and publishes data on the operation of energy markets, including electricity, natural gas, petroleum, and alternative energy sources. This process is essential to serve the information and policy development needs of the Governor, the Legislature, public agencies, market participants, and the public. This report provides multiple plausible estimates of trends in natural gas prices, supply, demand, and infrastructure. These broad estimates are necessary due to the high complexity of the gas market, numerous options for decision-makers, and deep uncertainties about future conditions. In 2015, staff also published a companion document titled *Assembly Bill 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained From Natural Gas as an Energy Source* that addressed several topics covered in the *2013 Natural Gas Trends, Issues, and Outlook* report, such as natural gas pipeline safety, methane emissions, and the southern system minimum flow issue.

## 2015 Integrated Energy Policy Report Natural Gas Common Cases

Staff examined historical trends in variables known to be major drivers in natural gas markets and then altered these variables by applying assumptions to project plausible future trends. *Plausible changes* are those that could occur with some level of certainty based upon past observances and the directives of current energy policies. Game-changing events and unforeseen technological advances, such as horizontal drilling coupled with hydraulic fracturing, are unpredictable. History shows that these events can have a greater impact on natural gas markets than estimable variables. As such, the results presented here do not estimate with certainty the future of the complex natural gas markets. Staff used a mix of plausible cases that incorporate transparent and vetted assumptions to model how the market may behave in the next 10 years.

For this assessment, staff is using a modification of the Rice World Gas Trade Model, constructed specifically for the North American gas market. Staff refers to this as the *North American Market Gas Trade Model* (*NAMGas model*). Staff developed cases around trends that represent three plausible futures: a business-as-usual or mid demand case, a high demand/low price case, and a low demand/high price case. Each case contains different assumptions about market and regulatory developments. Staff refers to these cases as "common" because they are common to several analyses performed for the *2015 Integrated Energy Policy Report* (*IEPR*) across the California Energy Commission's Energy Assessments Division. The mid demand case represents a future in which the economy, technology improvements, state and federal policy effectiveness, and cost environment proceed as they have done in the past. Staff created the high demand/low price case and low demand/high price case by altering assumptions in ways that would lead to plausible conditions for natural gas demand to move higher or lower than in the mid demand case. Assumptions that vary in each case include economic growth, technology improvements, percentage of renewable generation within the overall electricity generation portfolio, amount of generation in megawatts historically provided by coal, the amount of expected coal-fired generation retirement, cost, and several other assumptions.

Staff held public workshops on February 26, 2015, and May 21, 2015, to present the key assumptions used to build the cases and the preliminary modeling results. Staff presented the preliminary results of the modeling efforts undertaken as part of the IEPR process at a workshop on September 21, 2015. Based on comments and feedback received at the workshop, staff made several refinements to the models and results. As a result, the charts and tables contained in this report may vary from those presented at the September workshop. A summary of the changes can be found in Chapter 1.

## Modeling Results

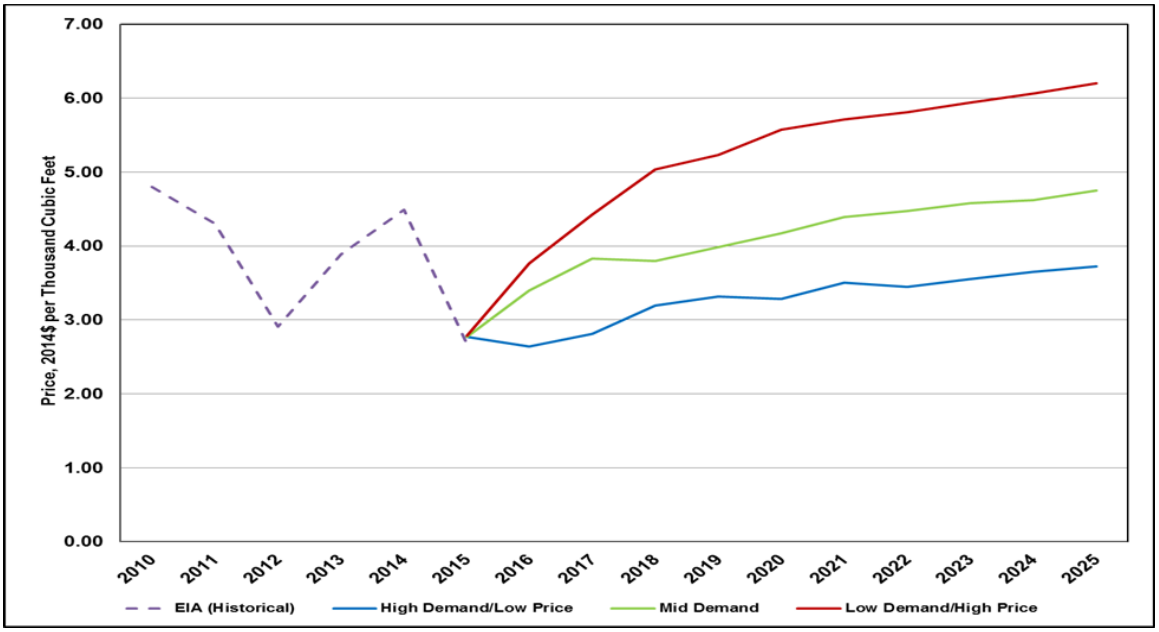
### Natural Gas Prices

The natural gas prices projected by staff's NAMGas model for this outlook are estimates that use annual inputs to produce annual average prices. **Figure 1** shows projected natural gas prices from 2015 to 2025. All prices are for natural gas traded at Henry Hub, which is the North American benchmark pricing point near Erath, Louisiana, and is the trading location used to price the New York Mercantile Exchange natural gas futures contracts. These prices reflect the estimated cost of producing natural gas, processing it for injection into the pipeline system, and transporting it to that hub. The NAMGas model used in this analysis produces annual average estimates of supply, demand, and price; these annual averages do not account for temperature-driven or other fluctuations that can occur in the natural gas market daily or seasonally.

To transition from short-term market forces seen in daily trading to longer-term outcomes modeled in the NAMGas model, October Bidweek values blended with model estimates were used. Bidweek values are the average price of natural gas during the last three to five business days at the end of each month. This is when the bulk of natural gas is bought and sold for use in the following month. This process smoothed the transition from short-term drivers to longer-term outcomes and provided a basis in actual prices seen in the market. The Bidweek forward prices were combined with both the low demand and mid demand cases.

In the high demand/low price case, the NAMGas model high price values were combined with the blended mid demand case values from 2015–2019 to produce a reasonable slope to approach the fundamentally higher price level for the high demand/low price case. The low demand/high price case uses NAMGas model results exclusively. Staff produced all values from 2020 forward within the NAMGas model.

**Figure 1: IEPR Common Cases for Henry Hub Pricing Point**




Source: Energy Commission, Supply Analysis Office

Henry Hub prices exhibit average annual growth rates between 2.0 and 5.5 percent per year from 2015 to 2025 for the three cases. By 2025, prices in the high demand/low price case reach $3.72 (2014$) per thousand cubic feet, and prices in the low demand/high price case reach $6.20 (2014$) per thousand cubic feet. From 2015 to 2025, the gas market reflects traders' expectations of slowly rising gas prices combined with fundamental market forces driving prices upward at an average rate of roughly 4 percent per year. In the United States, natural gas demand is rising slowly, while excess production is diminishing, leading staff to expect prices to rebound from the 2015 low.

### California Natural Gas Supply

The three common cases estimate that by 2025 California will import about 98 percent of its natural gas. California's natural gas enters the state at the northern hub of Malin, Oregon, and the cluster of southern hubs located near Topock, Arizona. Gas entering at Malin comes from a combination of gas from Canada and the Rocky Mountains, while gas entering at the southern end of the state can come from the Rocky Mountains via the Kern River pipeline or from the San Juan basin, in the four corners region of the southwestern United States, via the pipelines entering at either Topock or Ehrenberg. Staff expects California to continue to import gas from the Canadian, Rocky Mountain, and San Juan basins, with varying amounts coming into the state from each source depending on the price and availability of gas. Staff expects California to receive gas imports through the Malin Hub (47 percent), the Southwest (36 percent) and the Rocky Mountains and Kern River (15 percent).The in-state portion of California's gas supplies will come from the small, but long-standing production basins mostly located in the Sacramento and San Joaquin Valleys (2 percent).

**California Natural Gas Demand**

Staff produced the forecast of California end-use natural gas demand using the Energy Commission's end-use demand models that also produce the end-use electricity forecast. The end-use forecast models encompass agriculture, commercial, industrial, residential, transportation (light-duty vehicles, buses, medium- and heavy-duty trucks), communication, and utilities along three utility planning areas (Pacific Gas and Electric Company, Southern California Gas Company, and San Diego Gas & Electric Company).

The new forecasts begin at a higher point in 2015, as actual natural gas demand in California was higher in 2015 than estimated in the *California Energy Demand 2014–2024* mid demand case and grow at a higher rate in all three cases from 2012–2025. Staff attributes this to an expected steep increase in forecasted prices that did not materialize. The implementation of renewable generation and the penetration of energy efficiency are suppressing natural gas demand in the state. Staff estimates that by 2025, end-use demand in the mid demand case to be around 2 percent higher compared to the *California Energy Demand 2014–2024* mid demand case. Natural gas for transportation sees a large percentage increase over the forecast period, but this amount is small compared to overall natural gas demand in California.

These end-use forecasts do not include natural gas for electric generation and are used as inputs into the North American Market Gas Trade model. Staff produced the natural gas for electric generation portion of the forecast by modeling the electricity dispatch in the western United States using the PLEXOS production cost-modeling platform.

The decline in natural gas demand becomes more apparent in the electric generation sector, where California's Renewables Portfolio Standard has the greatest impact. While overall demand declines at an annual rate of 1 percent, the decline observed in the electric generation sector is roughly 3.0 percent per year. In the mid demand case, demand in electric generation sector declines to 2.0 billion cubic feet per day, from 3.2 billion cubic feet per day in 2015. **Table 1** shows natural gas demand by sector in California.

**Table 1: Actual and Forecasted Natural Gas Demand for All Sectors in California (Million Cubic Feet per Day)**

| | 2013* | 2015 | 2020 | 2025 | % Change 2015-2025 |
|---|---|---|---|---|---|
| **High Demand/Low Price Case** | | | | | |
| Residential | 1,314 | 1,333 | 1,380 | 1,398 | 5% |
| Commercial | 576 | 557 | 546 | 530 | -5% |
| Industrial | 1,592 | 1,570 | 1,619 | 1,664 | 6% |
| Transportation | 22 | 110 | 251 | 615 | 459% |
| Power Generation | 2,821 | 3,202 | 2,478 | 2,552 | -20% |
| State Total | 6,325 | 6,772 | 6,274 | 6,759 | 0% |
| | | | | | |
| **Mid Demand Case** | | | | | |
| Residential | 1,314 | 1,320 | 1,352 | 1,374 | 4% |
| Commercial | 576 | 555 | 530 | 503 | -9% |
| Industrial | 1,592 | 1,569 | 1,558 | 1,545 | -2% |
| Transportation | 22 | 30 | 67 | 164 | 447% |
| Power Generation | 2,821 | 3,181 | 2,203 | 2,001 | -37% |
| State Total | 6,325 | 6,655 | 5,710 | 5,587 | -16% |
| | | | | | |
| **Low Demand/High Price Case** | | | | | |
| Residential | 1,314 | 1,320 | 1,307 | 1,307 | -1% |
| Commercial | 576 | 554 | 518 | 486 | -12% |
| Industrial | 1,592 | 1,567 | 1,524 | 1,505 | -4% |
| Transportation | 22 | 29 | 60 | 147 | 407% |
| Power Generation | 2,821 | 3,085 | 2,002 | 1,444 | -53% |
| State Total | 6,325 | 6,555 | 5,412 | 4,889 | -25% |

* 2013 values are actual values.

Source: Energy Commission, Supply Analysis Office, Demand Analysis Office

## Natural Gas Infrastructure

In 2015, 90 percent of California's natural gas supply came from outside the state, and staff expects this to increase to 98 percent by 2025. The primary production areas for imported natural gas are the Southwest, the Rocky Mountains, and Canada.

Several interstate pipelines deliver the natural gas to the California border, and from there, intrastate pipelines take the natural gas to the citygate and the local distribution pipelines or to storage facilities for later use. California has 14 operating natural gas storage facilities, all of which are depleted oil or gas production fields. The total current working gas capacity of these facilities is 349.3 billion cubic feet, with a maximum daily delivery of 8.56 billion cubic feet when the fields are full. These storage facilities, however, cannot all deliver at the maximum rate at any one time. In addition, some operate for supplier price arbitrage and others for utility reliability.

### North American Export and Import Issues

Demand for natural gas in Mexico's power generation sector is growing. Mexico's national energy ministry expects annual growth in this sector to exceed 5 percent over the next 10 years. At least six United States pipeline operators have proposed building pipelines to export natural gas to Mexico. The vast quantities of reserves now available in the United States natural gas resource base, in part, motivate pipeline expansions. The exporting of natural gas to Mexico could affect the availability of natural gas delivered to California.

U.S. operators are also seeking licenses to export liquefied natural gas from 22 proposed liquefaction facilities. Operators of these facilities have petitioned the U.S. Department of Energy; eight have received approval, and two facilities are under construction. On October 1, 2015, Sabine Pass, in Cameron, Louisiana, started receiving natural gas and expects to start exporting liquefied natural gas in 2016. The Jordan Cove LNG terminal in Coos Bay, Oregon, received the final Federal Energy Regulatory Commission's (FERC) environmental impact statement on June 22, 2015; however, FERC voted not to issue a notice to proceed for the project on March 11, 2016.

### Well-Stimulation Technology Issues

The development of natural gas from shale formations has expanded the resource base and boosted U.S. natural gas production. However, the production from this resource type requires the use of well-stimulation technologies. Horizontal drilling combined with the technique known as *hydraulic fracturing*, or more simply known as *fracking*, is the most commonly used well-stimulation technology. Oil and gas operators have used some form of fracking technique in the United States since 1947 on more than 1 million wells. In the last 20 years, use of the technique has accelerated and raised several environmental concerns. These concerns include greenhouse gas emissions, surface disturbances, water use and disposal of wastewater, increased seismic activity, groundwater contamination, and socioeconomic impacts.

State and federal decision-makers and regulators have developed regulatory frameworks to guide oil and natural gas activities within their jurisdictions. In California, efforts are continuing to develop the regulatory framework for well stimulation technologies. In 2013, the state Legislature passed, and the Governor signed, Senate Bill 4 (Pavley, Chapter 313, Statutes of 2013). The California Department of Conservation adopted permanent Well Stimulation Treatment Regulations on July 1, 2015.

**California Pipeline Safety Issues**

The explosion of a Pacific Gas and Electric Company high-pressure transmission pipeline in a residential neighborhood in San Bruno on September 9, 2010—killing 8 people, injuring 58, and destroying or damaging more than 100 homes—changed how citizens, energy regulators, and other public officials view natural gas pipeline safety. Lapses in pipeline safety led to that explosion. A natural gas system that does not protect the health and safety of Californians, by definition, does not satisfy the requirements of the California Public Utilities Code and cannot meet California's future need for natural gas. Staff discusses issues pertaining to pipeline safety, such as the California Legislature's response, the utilities work and the California Public Utility Commission's work towards insuring a safer natural gas system in detail in the companion report, *Assembly Bill 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained from Natural Gas as an Energy Source*.

## Key Findings

This report provides a comprehensive view of natural gas usage in California and the United States; the following are key findings of the report:

- In the three common cases, the United States' pricing point (Henry Hub) will likely exhibit annual growth rates between 2.0 and 5.5 percent per year from 2015 to 2025.
- The negative price differential between Henry Hub and Malin, California's main northern receiving hub will persist. This difference reflects the fundamentally lower cost of gas production both in the Rocky Mountain and Canadian regions.
- The positive price differential between Henry Hub and Topock, California's main southern receiving hub persists throughout the outlook horizon. The positive price differential reflects relatively higher costs of resources produced in the San Juan basin and the added cost of transporting gas to the California border.
- California currently imports about 90 percent of its natural gas demand, and imports are expected to be about 98 percent in 2025. Staff expects California to receive gas imports through the Malin Hub (47 percent), the Southwest (36 percent) and the Rocky Mountains and Kern River (15 percent).
- Natural gas demand for power generation in California is expected to decline by about 37 percent over the forecast period in the mid demand case, due to the implementation of renewable generation and energy efficiency.
- Annual *per capita* demand for natural gas varies in response to annual temperatures and business conditions, but it has been generally declining since the late 1990s. Staff expects this trend to continue as population grows faster than total natural gas demand.

# CHAPTER 1: Introduction

Natural gas has been an important part of California's fuel mix for well over 150 years. Initially manufactured and used primarily for lighting, California now uses natural gas for heating, cooking, transportation fuel, industrial uses, and power generation.

As the state grows its renewable energy portfolio, the way people use natural gas is changing. The use of natural gas-fired generation to smooth the intermittent nature of wind and solar energy has highlighted the need to ensure that there is adequate supply for the power generation sector. Because of efforts to reduce air pollution, natural gas may provide new options in the fuel mix for the industrial and transportation sectors. Finally, the development of zero-net-energy buildings may present new opportunities for natural gas use in the residential sector. This report presents the results of the analysis of natural gas supply, demand, prices, and infrastructure issues in California and North America for the 2015 *Integrated Energy Policy Report* (*IEPR*). Energy Commission staff produced three cases based upon plausible and transparent assumptions to give planners and decision makers information about the future supply, demand, and price of natural gas. In 2015, staff also published a companion document titled *Assembly Bill 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained from Natural Gas as an Energy Source*. Staff addressed several topics covered in the *2013 Natural Gas Trends, Issues, and Outlook* report, such as natural gas pipeline safety, methane emissions, and the southern system minimum flow issue, in the *Assembly Bill 1257 Natural Gas Act Report*.

As part of the overall IEPR process, staff has accepted input from stakeholders through workshops and written comments. This feedback has been invaluable to improving the overall forecast. On September 21, 2015, staff presented preliminary natural gas outlook results. Following that workshop, comments from stakeholders provided the impetus to make several refinements. The net result of these changes reduced the overall price trajectory of the national natural gas market, lowering the expected mid demand price in 2025 from about $5.50 per thousand cubic feet (Mcf) to about $4.75 per (Mcf). In addition, small changes in nationwide natural gas demand also resulted. The key changes are as follows:

- The retirement of coal-fired generation across the United States as a result of the new Part 111(d) rules put forward by the U.S. EPA were adjusted to be consistent with the *Final Regulatory Impact Report* released in July 2015.
- All states with renewable portfolio goals were estimated to meet those goals on time.
- To transition from short-term market forces seen in daily trading to longer-term outcomes modeled in the North American Market Gas Trade Model, October Bidweek values were averaged with model estimates to develop prices for the 2015 to 2019 years of the forecast. Post processing adjustments were made to address minor modeling issues affecting the amount of natural gas imported from Canada.

- Adjustments to national residential, commercial, and industrial natural gas demand were made to align them more closely with the growth rates expected by the U.S. Energy Information Administration (EIA).

Decision makers can use this information to help determine near- and long-term procurement needs and perform contingency planning. Staff believes the following are the most important findings of the *2015 Natural Gas Outlook* report:

- In all three common cases, the United States' pricing point (Henry Hub) will exhibit annual growth rates between 2.0 and 5.5 percent per year from 2015 to 2025.
- The negative price differential between Henry Hub and Malin, California's main northern receiving hub will persist. This difference reflects the fundamentally lower cost of gas production both in the Rocky Mountain and Canadian regions.
- The positive price differential between Henry Hub and Topock, California's main southern receiving hub persists throughout the outlook horizon. This positive price differential reflects relatively higher costs of resources produced in the San Juan basin and the added cost of transporting gas to the California border. The differential remains positive throughout the 10-year horizon.
- California imports about 90 percent of its natural gas demand, and imports are expected to rise to about 98 percent in 2025. Staff expects California to receive gas imports through the Malin Hub (47 percent), the Southwest (36 percent) and the Rocky Mountains and Kern River (15 percent).
- Natural gas demand for power generation in California is expected to decline by about 37 percent over the forecast period in the mid demand case, due to the implementation of renewable generation and energy efficiency.
- Annual *per capita* demand for natural gas varies in response to annual temperatures and business conditions, but it has been generally declining since the late 1990s. Staff expects this trend to continue as population grows faster than total natural gas demand.

## Scope and Organization of Report

Chapter 2 presents the assumptions used to construct the three natural gas market common cases and model results. Staff presents results of the three IEPR common cases, high demand/low price, mid demand, and low demand/high price for natural gas price, supply, and natural gas price uncertainty.

Chapter 3 presents the end-use natural gas demand. Results for statewide and the three investor-owned utility planning areas are compared in three cases: high demand/low price, mid demand, and low demand/high price.

Chapter 4 provides an estimate of natural gas demand in the power generation sector.

Chapter 5 focuses on natural gas resource and infrastructure, including pipeline additions, pipeline safety, storage, and North American import and export issues.

Appendix A contains the glossary.

# CHAPTER 2: 2015 Integrated Energy Policy Report Common Cases

## Modeling Approach

In the *2015 IEPR*, Energy Commission staff used the Market Builder platform[1] to construct a natural gas market model. In this platform, staff developed the North American Market Gas-Trade model (NAMGas), a general equilibrium resource model that simulates an interconnected network of economic agents[2] seeking economic utility maximization. Building a model in the Market Builder platform requires defining a physical, geographic network or a topology for the natural gas market. Within the network, staff must define all natural gas demand centers, including large gas consumers such as power plants. Further, staff must locate all interconnecting interstate and intrastate pipelines, all import and export terminals, and all supply sources of natural gas.

Input assumptions for the network include the estimated demand for natural gas at all demand centers, each of which include five demand sectors. The model also includes:

- Price elasticities of demand for natural gas.
- Capacities and transportation costs along each route (or corridor) from supply to demand load.
- Size of the natural gas supply resources.
- Technological innovation rate.
- Cost over time to develop and extract natural gas resources.
- Investment criteria for the endogenous construction[3] of new pipeline capacity.

For the NAMGas model, staff must specify time-points (periods) for the forecasting horizon of the model, which extends, in annual increments, from 2012 to 2050. The period allows the model to account for capital investment decisions. However, results presented in this report cover the 10-year period from 2015 to 2025.

Further, staff considered the potential impact of relevant energy policy, such as the Renewables Portfolio Standard (RPS). In the *2015 IEPR*, California and all other Western Electricity

1 Platform owned by Deloitte LLP Market Point Services.

2 *Economic agents* are actors or decision makers in the marketplace.

3 Endogenous construction refers to pipeline additions that the model itself produces to deal with supply and economic issues within the model. These additional pipelines are not physical pipelines.

Coordinating Council (WECC) states construct generation portfolios that meet their individual RPS. In California, staff included, in all three cases, the requirement of 33 percent renewable generation by 2020. The PLEXOS production cost model provided the inputs for natural gas demand in the power generation sector in all WECC states. In addition, the penetration of energy efficiency, another variable affecting the outcomes of the model, varies among the cases. The low demand/high price case assumes the highest penetration and the high demand/low price case, the lowest. High penetration tends to lower natural gas demand, and low penetration achieves the reverse.

The version of the NAMGas model now used by the Energy Commission requires annual starting (reference) demands and prices[4] an econometric model provides these values. Staff refers to this as the "reference model." The reference model consists of regression equations for each of the five demand sectors represented in the NAMGas model. The independent variables used in the regression equations for each end-use sector appear below:

- Residential reference demand = recent historical demand for natural gas, population, natural gas price, income, heating oil price, and cold weather
- Commercial reference demand = recent historical demand for natural gas, income, natural gas price, population, heating oil price, and cold weather
- Industrial reference demand = recent historical demand for natural gas, natural gas price, coal price, industrial production, and cold weather
- Power generation reference demand = total electricity generation, weather, natural gas price, fuel oil price, renewable electricity generation, and coal price
- Transportation reference demand = recent historical transportation demand for natural gas, income, natural gas price, and population

Performing a regression analysis[5] using historical data for the variables by end-use sector yields the coefficient estimates needed to calculate the reference demand quantities. These starting (reference) values extend through all the years of the forecasting horizon and through the geographic demand centers specified in the model. In addition to reference values generated by the regression analysis, the Natural Gas Unit uses California end-use demand data from the Energy Assessments Division's Demand Analysis Office. Staff also receives the WECC power generation demand from the Energy Assessments Division's Procurement and Modeling Unit and obtains natural gas demand in the transportation sector from the Energy Assessments Division's Transportation Fuels Unit.

---

4 This use of the term "reference" does not mean "reference case" but indicates that the reference demands and prices are the starting input values.

5 *Regression analysis* is a statistical process for estimating the relationships among variables.

With the specified model structure and the input data, the NAMGas model iterates until it finds a solution that obeys basic economic principles for well-behaved markets. Since every unit of natural gas produced from a supply basin shrinks the resource base, the model allows for advances in technology to offset this depletion effect, where necessary. At every iteration, the model seeks to balance supply and demand at the determined price. While the iteration procedure progresses, the NAMGas model:

- Adds pipeline capacity if economic conditions meet or exceed the investment criteria.
- Changes demand in response to price variations and the input price elasticities.
- Changes production in response to price variations, technology assumptions, and supply elasticity.

When the NAMGas model finds a final equilibrium, staff extracts a series of regional annual average natural gas prices, regional natural gas supply and demand, and interregional natural gas flows for the defined network. At this time, the model does not account for operational fluctuations or daily, monthly, and seasonal variations.

# *2015 IEPR* Natural Gas Common Cases

Energy Commission staff created three common cases for the *2015 IEPR* that staff uses across all the forecast models. Assumptions for these cases are in **Table 2**. These cases represent plausible cases of natural gas and electricity markets, and the Natural Gas Unit staff has incorporated elements of the demand forecast, transportation forecast, and electricity production cost forecast to propagate the cases. The three common cases depict trends now seen in the natural gas market. However, the RPS, potential coal retirements, price elasticity, and the cost environment play critical roles in the behavior and outcomes of the model. These assumptions simulate a range of plausible conditions that account for uncertainty in the natural gas market, in the economy, and in policy proposals and requirements.

Staff developed three coal retirement assumptions, one for each case. In the high demand/low price case, coal retirements totaled 61 gigawatts (GW); in the mid demand case, 31 GW; and in the low demand/high price case, 20 GW. Since California uses little coal-fired generation, the state experiences the impact of this assumption through price variations that occur outside the state. Price variations outside California affect natural gas flows to the state, which, in turn, influence price variations within the state.

Elasticities measure the responsiveness of price changes. As prices increase or decrease, the amount supplied or consumed will change. A key feature of NAMGas is the ability, as it iterates, to adjust quantity demanded as prices change. Either the NAMGas model can let the price changes affect the demand for natural gas, or staff can turn off the elasticities, keeping demand at the input levels. In all three cases, staff turned off the elasticities for the power generation sector in California and the WECC to keep those values consistent with those produced by the production cost modeling activity. The natural gas demand for power generation originates from the PLEXOS model where the elasticities are considered. **Table 3** displays the elasticity values used in the *2015 IEPR*.

**Table 2: Assumptions for Common Cases**

| Assumptions | Low Demand/ High Price Case | Mid Demand Case | High Demand/ Low Price Case |
|---|---|---|---|
| GDP Growth Rate | 2.00% | 2.30% | 3.50% |
| Natural Gas Technology Improvement Rate | 1% | 1% | 2.50% |
| CA Meets 2020 RPS Target | On Time | On Time | On Time |
| WECC Meets RPS Target | On Time | On Time | On Time |
| Other States RPS Meet | On Time | On Time | On Time |
| Additional U.S. Coal Generation Converts to Natural Gas Starting in 2016 (GW) | 20 | 31 | 61 |
| Cost Environment[a] | High (P95) | Mid (P50) | Low (P5) |

Source: Energy Commission, Supply Analysis Office

[a] Refers to the assessment of the quantities of recoverable gas resources. By industry convention, the P50 assessments mean there is a 50 percent probability that at least this much gas is recoverable from that play using current technology. To increase the spread of resulting gas prices, additional cases were run assuming higher probability but lower resource amounts (a P95 case) and lower probability but higher resource amounts (a P5 case).

**Table 3: Price Elasticity in NAMGas Model by Sector**

| Sector | Price Elasticity |
|---|---|
| Residential | -0.5297 |
| Commercial | -0.5331 |
| Industrial | -1.2365 |
| Transportation | -0.5331 |
| Power Generation | -0.7963 |

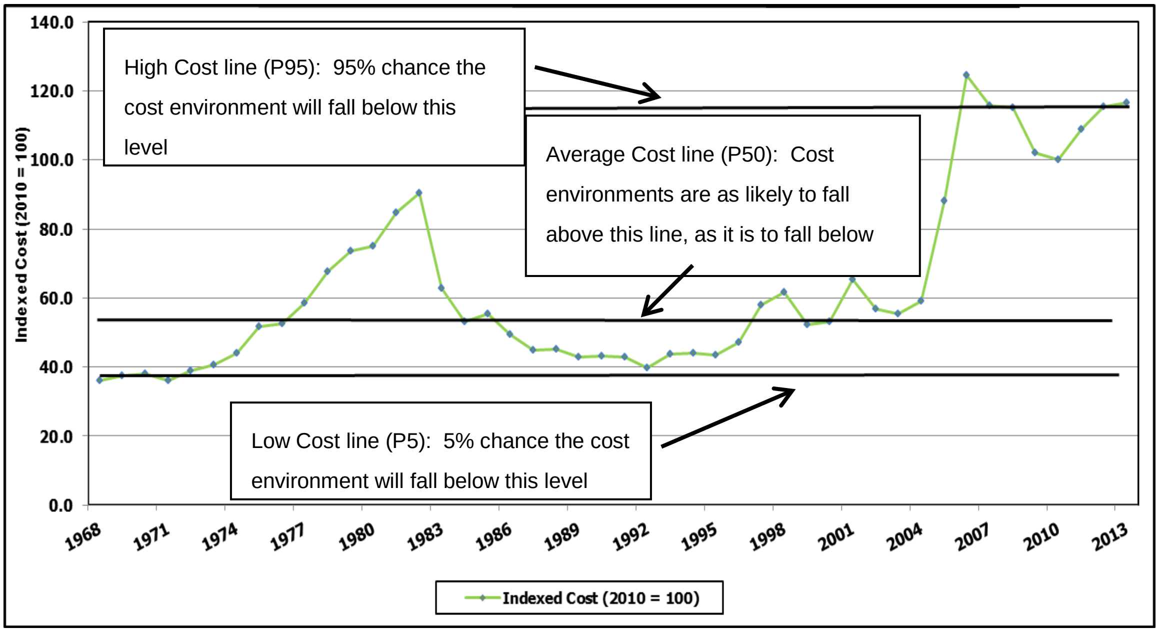
Source: Energy Commission, Supply Analysis Office

Assumptions on the cost of producing natural gas and available reserves differ for each case. Staff placed the high demand/low price case in a low-cost environment, placed the mid demand case in an average-cost environment, and the low demand/high price case in the high-cost environment. **Figure 2** displays the historical indexed combined cost of capital, labor, energy, manufacturing, and service (KLEMS)[6] between 1968 and 2013. These costs determine the cost environment[7] of each unit of natural gas production in each case.

6 United States Department of Labor KLEMS database. http://www.bls.gov/mfp/mprtech.htm.

7 Staff placed the mid demand case in an averaged sustained cost environment. To construct the high demand/low price and low demand/high price cases, staff used the KLEMS data to place each of these two cases in a high-sustained and low-sustained cost environment, respectively.

**Figure 2: Historical Natural Gas Cost Environments Using KLEMS Data**

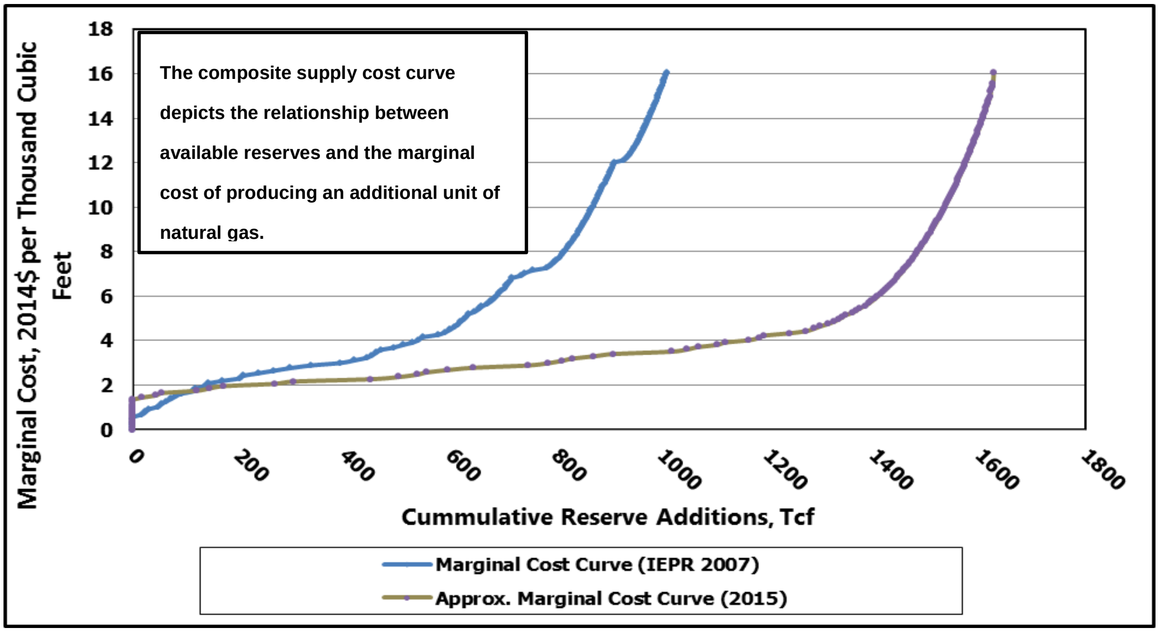



Source: Baker Institute, 2015.

As shown in **Figure 2**, the average cost environment occurs at the P 50 line; for example, 50 percent of all cost environments fall below this line and 50 percent above the line. In addition, the high- and low-cost environments occur at the P 95 and P 5 lines. Ninety-five percent of all cost environments fall below the P 95 line, and, at the other end of the spectrum, 5 percent of all cost environments fall below the P 5 line. The index cost exhibited a sharp escalation after 2003. This resulted from the development of natural gas from shale formations. Each unit of natural gas recovered is costing less, but each well is recovering more natural gas; thus, total costs (unit cost x number of units) are increasing. **Figure 2** reflects the index of total cost, not unit cost.

The supply cost curve, the most important variable of the NAMGas model, catalogs the amount of natural gas available and at what marginal cost. More than 400 supply cost curves, broken up by supply basin and formation depth, compete to satisfy the demand represented in the model. **Figure 3** shows the aggregated (composite) supply cost curve. As depicted in **Figure 3**, cumulative natural gas reserve additions appear on the horizontal (x) axis and the marginal cost, on the vertical (y) axis. An example that best illustrates the relationship is displayed in **Figure 3**; a marginal cost of $4.00 generates 1,150 trillion cubic feet (Tcf) of available natural gas.

**Figure 3: Composite Supply Cost Curve for the *2007* and *2015 IEPR* Common Cases**




Sources: Energy Commission, Supply Analysis Office; National Petroleum Council, Baker Institute, 2015.

The relative flatness observed on the front portion of the composite supply cost curve can limit the effect of changes in other variables. As shown, the curve reflects the vast quantities of natural gas available at lower cost relative to 2007. As such, minimal changes in marginal cost can expand the available natural gas at a rate that may appear disproportionate. If marginal cost changes from $2.00 to $4.00, additional cumulative natural gas reserves available for production expand to 1,150 Tcf from about 300 Tcf. This phenomenon tends to dwarf the effect of other variables because, as the example shows, a doubling of the marginal cost quadruples the reserve additions. The development of shale formations has contributed to this economic behavior.

## Mid Demand Case

The mid demand case can also be referred to as the "business-as-usual case" because the current observable trends in energy policies and market practices are adopted for the duration of the forecasting period. Staff did not assign a probability of occurrence to the assumptions imbedded in the mid demand case. As a result, this should not be considered "the expected case."

In addition to the cost and price environments described above, the mid demand case assumes supply environments that differ from the other two common cases. Energy policies in effect will alter the amount of electricity generated from both coal and renewable fuel sources, which will affect the use of natural gas as an electricity generation source. Coal's share of total electricity generation in the United States was roughly 39 percent in 2013[8] however, in response to

8 EIA *Electric Power Annual Report 2012*, March 2015. http://www.eia.gov/electricity/annual/pdf/epa.pdf.

emission policies and lower natural gas prices; some coal-fired generation will be retired. The mid demand case assumes that coal-fired generation will start to retire in the Lower 48 states in 2016—until a total of 31 GW will be retired by 2025. Staff expects that renewable power will make up some of the generation loss from coal retirement. In the mid demand case, it is assumed that California will meet its RPS mandate of having 33 percent of its load from renewable power sources by 2020. In addition, staff characterized regions outside California with an RPS, or its equivalent within the model, as meeting their RPS targets on time. The projected gross domestic product (GDP) annual growth rate is 2.3 percent.

## High Demand/Low Price Case

This case combines a set of plausible assumptions to capture an environment of less expensive and more abundant natural gas that results in low prices, helping drive demand higher. This case forms the lower band of projected Henry Hub prices. The case assumes a low-cost environment of P5 where costs of materials and labor are lower and there is only about a 5 percent chance that costs will fall below the P5 line based on historical data. An annual technology improvement rate of 1 percent limits the future amount of natural gas development.

The GDP growth rate of 3.5 percent and retirement of 61 GW of coal-fired generation will create greater demand for natural gas. California will meet its RPS mandate of having 33 percent of its load met by renewable power sources by 2020. In addition, staff characterized regions outside California with a renewable portfolio standard or its equivalent within the model as meeting their RPS targets on time.

## Low Demand/High Price Case

This case combines a set of assumptions that produce an environment of high costs for natural gas compared to the other two common cases. This case forms the upper band of projected Henry Hub prices among the three common cases. A high P95 cost environment, which assumes a 95 percent chance that cost will fall below this level based on historical data, causes higher production costs to create pressures to increase the price of natural gas. Staff embedded environmental regulation fees of $0.25/Mcf for all natural gas produced into the cost curves, increasing the production cost of natural gas and contributing to higher gas prices. The simulated supply reductions result in a given quantity of natural gas available at a higher price than for the other two cases.

California and the WECC region will meet RPS targets on time, and other states will experience a 10-year delay; the GDP growth rate is 2 percent; and 20 GW of assumed coal-fired generation capacity will be retired. Combined, these produce an environment of naturally low demand/high prices, combined with higher prices, pushing demand lower.

# Modeling Results

## Natural Gas Price Results

**Figure 4** shows projected natural gas prices from 2015 to 2025. All prices are for natural gas traded at Henry Hub, which is the North American benchmark pricing point near Erath, Louisiana. These prices reflect the estimated cost of producing natural gas, processing it for injection into the pipeline system, and transporting it to that hub. The NAMGas model used in this analysis produces annual average estimates of supply, demand, and price; these estimates do not account for temperature-driven or other fluctuations that can occur in the natural gas market daily or seasonally.

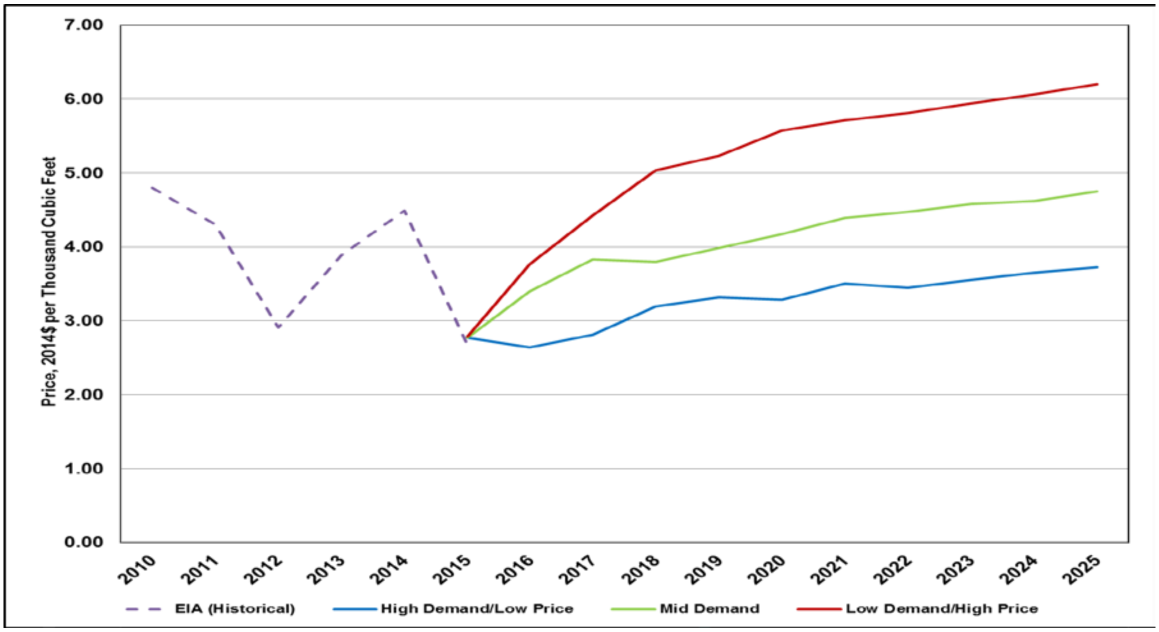
To transition from short-term market forces seen in daily trading to longer-term outcomes modeled in the NAMGas model, October Bidweek values blended with model estimates were used. This process smoothed the transition from short-term drivers to longer-term outcomes and provided a basis in actual prices seen in the market. The Bidweek forward prices were combined with both the low demand and mid demand cases.

In the high demand/low price case, the NAMGas model's high price values were combined with the blended mid demand case values from 2015–2019 to produce a reasonable slope that approaches the fundamentally higher price level for the high demand/low price case. The low demand/high price case uses NAMGas model results exclusively. Staff produced all values from 2020 forward within the NAMGas model.

Henry Hub prices exhibit annual growth rates between 2.0 and 5.4 percent per year from 2015 to 2025 for the three cases. By 2025, prices in the high demand/low price case reach $3.72 (2014$) per Mcf, and prices in the low demand/high price case reach $6.20 (2014$) per Mcf. Between 2015 and 2025, prices in the mid demand case rise at an annual rate of about 3.7 percent per year. From 2015 to 2020, the gas market reflects traders' expectations of slowly rising gas prices combined with fundamental market forces driving prices upward.

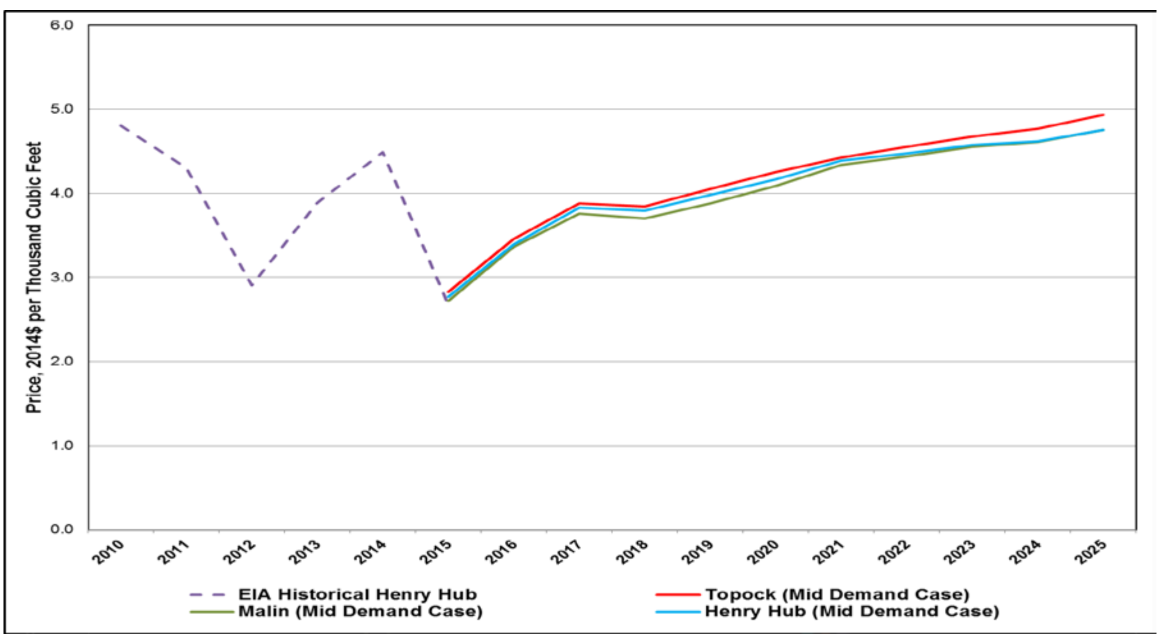
The majority of natural gas imported into California flows through two hubs—the Topock pricing hub, located at the California-Arizona border, and Malin pricing hubs located at the California-Oregon border. The relative variations at the Topock and the Malin pricing hub allow market participants to gauge the relative supply-demand balance in California. **Figure 5** shows the three price tracks (Malin, Topock, and Henry Hub).

**Figure 4: IEPR Common Cases for Henry Hub Pricing Point**




Source: Energy Commission, Supply Analysis Office.

**Figure 5: Mid Demand Case Natural Gas Prices at Malin, Topock, and Henry Hub**

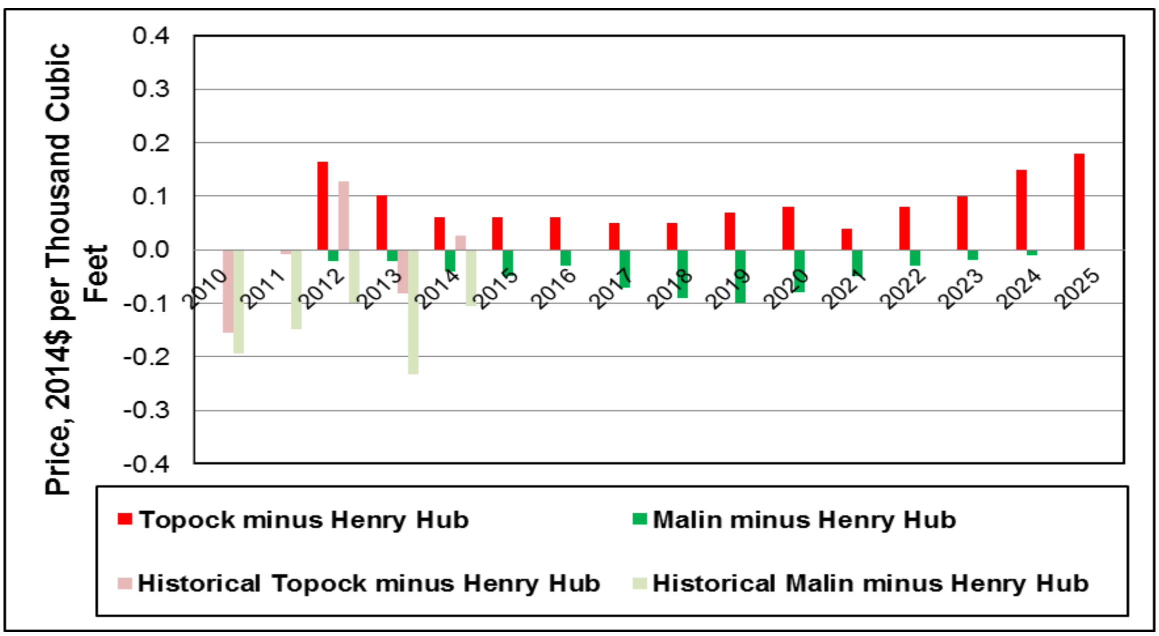



Source: Energy Commission, Supply Analysis Office.

While the patterns of price movements at the California pricing points parallel that of Henry Hub, California's gas sources and Henry Hub gas are physically separate and linked only by the market influence Henry Hub has in the larger U.S. market. **Figure 6** shows the price deviation of Malin and Topock relative to Henry Hub.

The negative price differential between Henry Hub and Malin persists over the forecast period. This difference reflects the fundamentally lower cost of gas production both in the Rocky Mountain and Canadian regions and competition between natural gas flowing south on the GTN pipeline (from Canada to the Malin Hub in Malin, Oregon) and natural gas flowing west on the Ruby pipeline (from the Rocky Mountains basin to the Malin Hub). The positive price differential between Henry Hub and Topock, California's main southern receiving hub persists throughout the forecast horizon. This positive price differential reflects relatively higher costs of resources produced in the San Juan basin and the added cost of transporting gas to the California border. There are no new projects likely to disrupt the current market dynamics, and, therefore, staff does not expect this relative cost to change over the next decade.

**Figure 6: Prices Differentials (Point of Interest—Henry Hub)**




Source: Energy Commission, Supply Analysis Office.

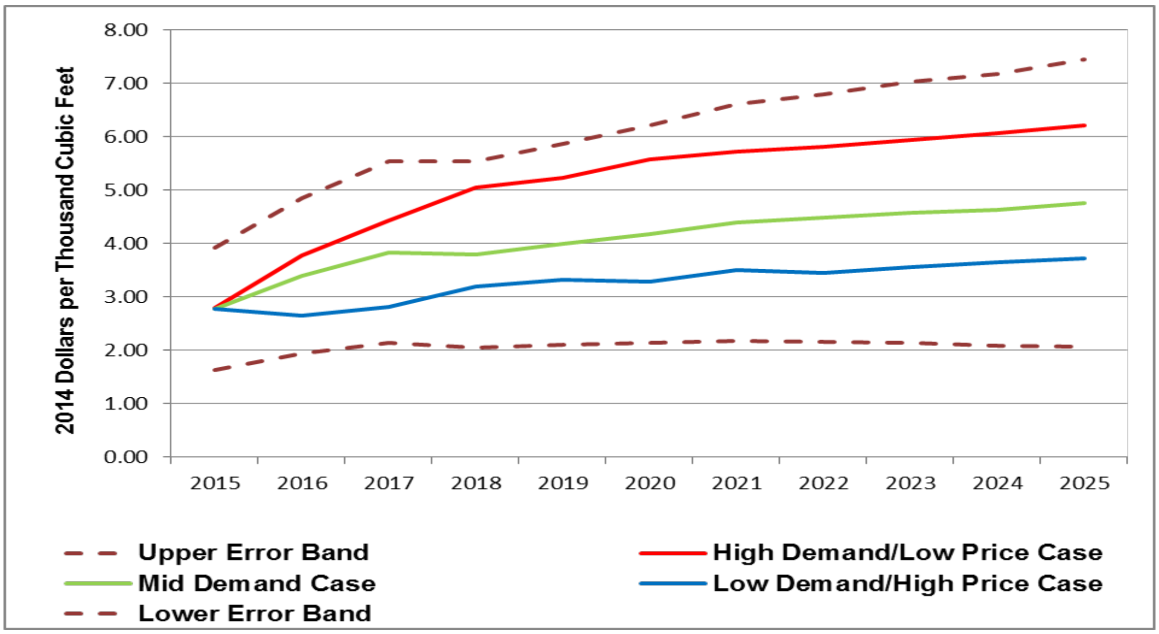
## Natural Gas Price Uncertainty

### Using Error Bands

The forecasting of natural gas prices depends on many factors, including, among them, economic growth rates, expected rates of resource recovery, integration of renewable resources, and retirement of coal-fired power generation. For example, higher rates of economic growth tend to lead to increased consumption of natural gas, leading to higher natural gas prices. Staff's NAMGas model uses annual inputs to produce annual average prices; it does not account for fluctuations that occur in the natural gas market on a seasonal, monthly, or daily basis. Furthermore, it does not account for extreme weather, infrastructure accidents, and unforeseen technological advances.

To account for inherent uncertainty in natural gas markets, staff used past natural gas forecast results generated by the Energy Commission to produce error bands around price results of the *2015 IEPR* mid demand case. These error bands capture a much wider range of price uncertainty than seen in the price differential between the IEPR common cases as the error bands take into account events that cannot be modeled and ensure that staff bases the IEPR common cases on reasonable assumptions. **Figure 7** shows the resulting error bands and the IEPR common cases.

**Figure 7: *2015 IEPR* Common Cases with Error Bands**




Source: Energy Commission, Supply Analysis Office

### Method for Creating Error Bands

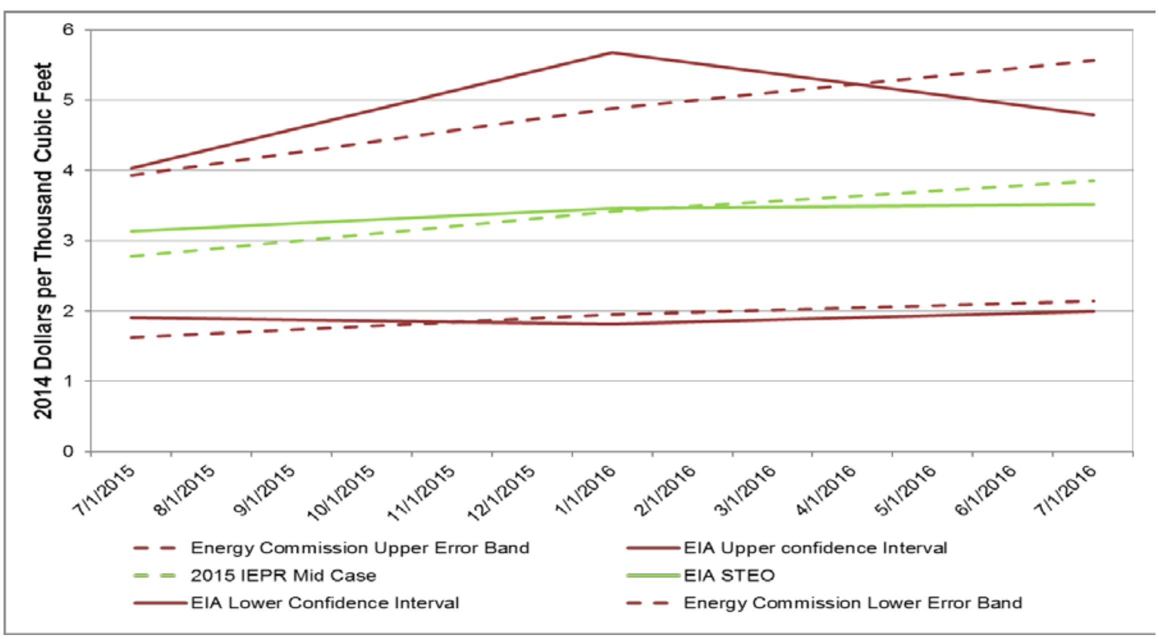
The first step was to collect previous Energy Commission natural gas price forecasts. These forecasts started in 2003 with the *2003 IEPR* and concluded with the *2013 IEPR* mid demand case. Staff used linear point-to-point interpolation to account for any missing data points. To simplify the mathematics, staff converted forecasted prices to nominal dollars and then calculated the percentage differences between actual Henry Hub prices and the forecasted prices for each year. Staff then aligned the values in a Microsoft Excel® spreadsheet for years forecasted by placing all the forecasts one year out in line with each other, then two years out, and so on. For example, the first year forecasted in the *2003 IEPR* was 2003 and in the *2013 IEPR* was 2013. These two years plus the first year forecasted of the other forecasts would be in the "first year forecasted" column in the Excel® spreadsheet.

The error bands were generated by using the statistical method of mean absolute percentage error (MAPE), which determines the goodness of fit of forecasts to actual prices. Staff then used the statistical method of MAPE on the percentage difference in values between the year's forecasted and actual Henry Hub prices. This method determines the goodness of fit of forecasts to actual prices. Only years forecasted with at least four values were used due to statistical significance, which amounted to 10 years of MAPE values. Staff developed a linear regression equation using MAPE values and then applied this linear equation to years forecasted to create a percentage error. The percentage error was applied positively and negatively to the *2015 IEPR* mid demand case results to produce the error bands.

### U.S. Energy Information Administration Price Uncertainty

The U.S. EIA analyzed natural gas price uncertainty using confidence intervals in its *Short-Term Energy Outlook*.[9] The *Short-Term Energy Outlook* forecasts out 12 to 14 months and uses NYMEX futures prices to forecast future prices of natural gas and price uncertainty. U.S. EIA also uses a more complex statistical and mathematical method to derive its price uncertainty. Due to these differences in forecasting and the plausible range of prices, the Energy Commission's and U.S. EIA's forecasts are difficult to compare. **Figure 8** compares the Energy Commission's and U.S. EIA's forecast uncertainty. Even with differences in data and method, U.S. EIA's *Short-Term Energy Outlook* and the IEPR mid demand case and lower error bands are close to each other.

**Figure 8: U.S. EIA and Energy Commission Price Uncertainties**




Source: Energy Commission, Supply Analysis Office; U.S. EIA

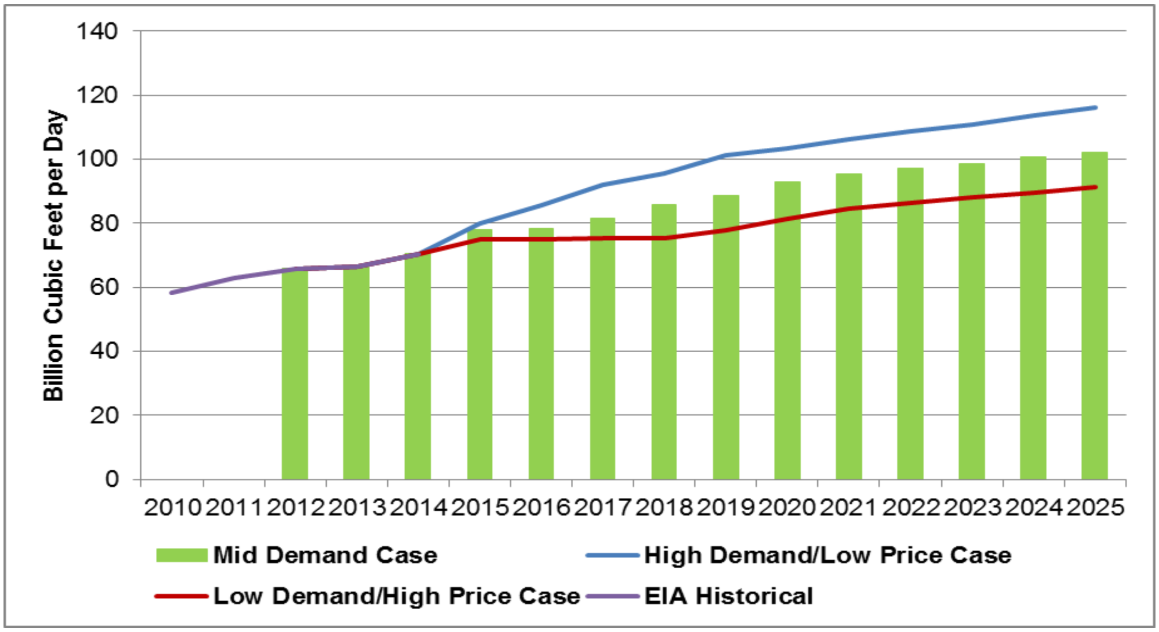
9 See http://www.eia.gov/forecasts/steo/.

## Supply Results

The net effect of any price variation involves a combination of two responses: consumers change the amount they purchase, and suppliers alter the amount they produce**. Figure 9** displays the dry natural gas (natural gas that has been stripped of all natural gas liquids and impurities) production for the three common cases. The NAMGas model does not simulate production; rather, the model uses more than 400 supply cost curves, each of which portrays a relationship between the marginal cost of the next unit of natural gas and the amount of natural gas available. As a result, each curve competes with the other curves to satisfy the determined demand.

In general, the highest dry natural gas production[10] in the United States arises from the high demand/low price case. Staff assumed a low-cost environment in the high demand/low price case, and this assumption strengthens the competitiveness of U.S. production against Canadian imports.

**Figure 9: United States Dry Natural Gas Production**



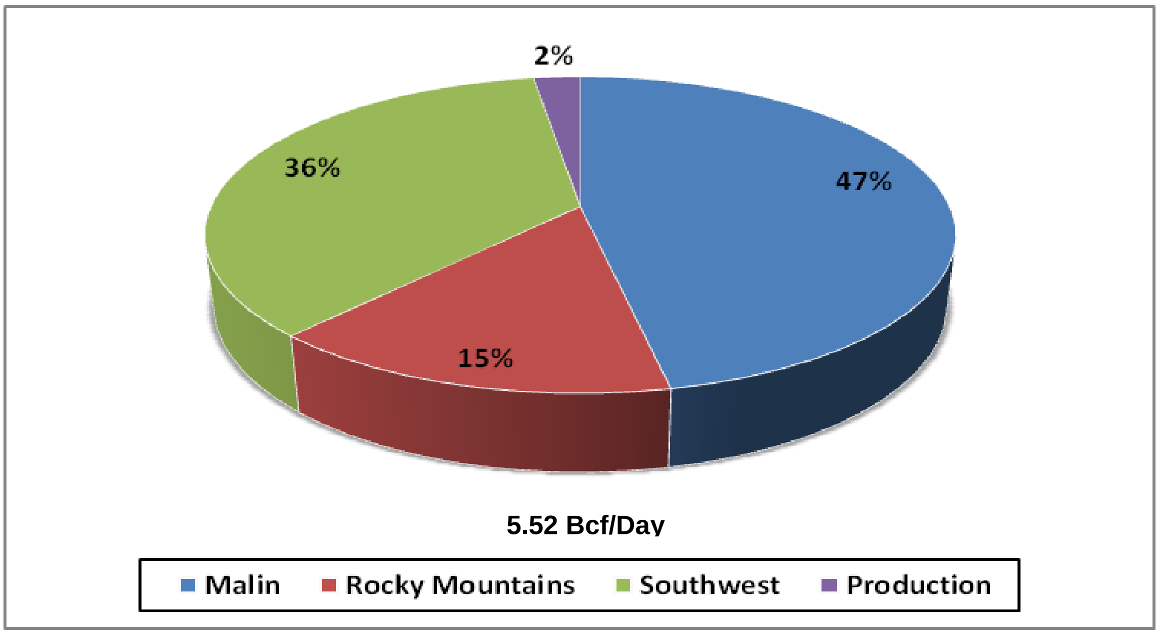

Source: Energy Commission, Supply Analysis Office

Staff expects California's total natural gas demand to reach 5.52 billion cubic feet (Bcf) per day. California natural gas enters the state at the northern hub of Malin, Oregon, and the cluster of southern hubs located near Topock, Arizona. Gas entering at Malin comes from a combination of natural gas from Canada and the Rocky Mountains, while gas entering at the southern end of the state can come from the Rocky Mountains via the Kern River pipeline or from the San Juan basin via the pipelines entering at either Topock or Ehrenberg, Oregon.

10 *Dry natural gas production* is the production of consumer-grade natural gas.

Staff expects California to continue to import gas from the Canadian, Rocky Mountain, and San Juan basins, with varying amounts coming into the state from each source depending on the price and availability. California imports about 90 percent of its natural gas demand, and imports are expected increase to about 98 percent in 2025. **Figure 10** represents the percentage of California's demand that the associated supply source satisfies. Staff expects California to receive gas imports through the Malin Hub (47 percent), the Southwest (36 percent) and the Rocky Mountains and Kern River (15 percent). The remainder of the state's gas supplies will come from long-standing in-state gas production basins in the Sacramento and San Joaquin valleys, Ventura County, and the Los Angeles basin.

**Figure 10: California 2025 Supply Portfolio (Mid Demand Case)**




Source: Energy Commission, Supply Analysis Office

# CHAPTER 3: California End-Use Natural Gas Demand Forecast

This chapter presents the revised baseline forecasts of end-use natural gas demand for California. These end-use forecasts include projected demand for Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal Gas), San Diego Gas & Electric Company (SDG&E), and aggregated other (AO). Staff prepares these forecasts in parallel with its electricity demand forecasts, which are organized along electricity planning area boundaries. These forecasts, though not including natural gas used by utilities or others for electric generation, include projections for natural gas vehicle fuel use.

The end-use natural gas demand forecast begins with historical consumption data, which ends in 2014, and incorporates three demand cases:

- High Demand/Low Price Case
- Mid Demand Case
- Low Demand/High Price Case

Each case contains the same economic/demographic assumptions used in the electricity demand forecasts. Staff presented preliminary versions of these assumptions at the February 23, 2015, workshop.[11] The economic/demographic data have been updated to reflect more recent projections by Moody's Analytics and IHS Global Insight. Further, in maintaining consistency with the electricity demand analysis, each of the three cases incorporated assumptions about natural gas prices and committed efficiency program impacts reflecting the variations intended in the high demand/low price case, the mid demand case, and the low demand/high price case.

The forecasts of end-use natural gas demand encompass agriculture, commercial, industrial, residential, transportation (light-duty vehicles, buses, medium- and heavy-duty trucks), and transportation, communication, and utilities (TCU).[12] Staff adjusted all forecasted numbers for gas savings as a result of the implementation of additional achievable energy efficiency (AAEE). AAEE results are located the planning area sections for PG&E, SoCal Gas, and SDG&E. The

11 See https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03 for presentation.

12 *TCU* is natural gas used to support the transportation system, such as natural gas used in an office building.

method for the AAEE results can be found in the *California Energy Demand 2016–2026, Revised Electricity Forecast*, *Volume 2*.[13]

## Statewide End-Use Natural Gas Forecast Results

**Table 4** compares the 2015 statewide baseline natural gas demand with that of the *California Energy Demand 2013 (CED 2013)* end-use natural gas mid demand case for selected years. Staff compared the forecasted 2013 value from *CED 2013* with the actual 2013 consumption. The new forecasts begin at a higher point in the 2015 forecasts, since actual natural gas consumption in California exceeded the forecasted *CED 2013* value. Staff attributes this to an expected steep increase in forecasted prices that did not materialize. Between 2013 and 2025, the mid demand and low demand/high price cases decline in average annual growth rates. During the same time, the high demand/low price case grows at an average annual rate of 0.36 percent. The mid demand and high demand/low price cases include potential climate change in their forecasts, while the low demand/high price case does not.

By 2025, the revised forecast for end-use natural gas demand is about 1.0 percent lower than the corresponding *CED 2013* forecast. By 2025, AAEE savings push total end-use natural gas demand lower in the new mid demand forecast compared to the *CED 2013* forecast. **Table 4** shows statewide historical consumption along with the forecasted demand for the three cases, including AAEE. Energy Commission staff developed five AAEE scenarios.[14] For the end-use natural gas forecasts, only three were used:

- High AAEE savings were used in the low demand/high price case
- Low AAEE savings were used in the high demand/low price case
- Mid AAEE savings were used in the mid demand case

**Figure 11** displays the 2015 revised end-use natural gas demand per capita consumption, both historical and projected, between 1990 and 2025. Annual per capita natural gas demand varies in response to changes in annual temperatures and business conditions. However, in general, annual per capita natural gas demand has been declining since the late 1990s. Staff expects the continuation of this trend as population grows faster than total natural gas demand. Added to this, energy efficiency contributes to the lower per capita usage. **Table 5** shows the statewide annualized growth rates by common case and selects sectors.

---

13 *California Energy Demand 2016–2026, Revised Electricity Forecast*, Volume 2, can be found at http://www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-200-2016-001-V2.

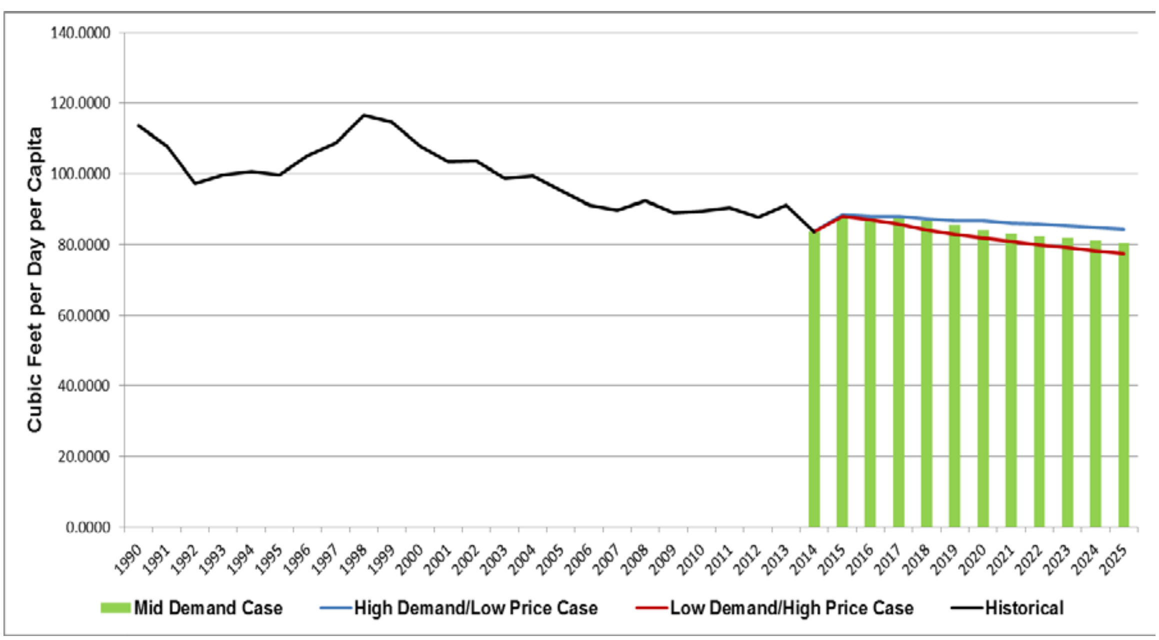
14 https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03.

**Table 4: Statewide 2013 and 2015 End-Use Natural Gas Forecast Comparison, Including AAEE**

| | 2013 CED End-Use Natural Gas Mid Demand Case (Mid AAEE Savings) | | 2015 End-Use Natural Gas High Demand/Low Price Case (Low AAEE Savings) | | 2015 End-Use Natural Gas Mid Demand Case (Mid AAEE Savings) | | 2015 End-Use Natural Gas Low Demand/High Price Case (High AAEE Savings) | |
|---|---|---|---|---|---|---|---|---|
| | MMTherms | Bcf | MMTherms | Bcf | MMTherms | Bcf | MMTherms | Bcf |
| 1990 | 12,896 | 1,238 | 12,896 | 1,238 | 12,896 | 1,238 | 12,896 | 1,238 |
| 2000 | 13,917 | 1,336 | 13,917 | 1,336 | 13,917 | 1,336 | 13,917 | 1,336 |
| 2013 | 13,042 | 1,252 | 13,240 | 1,271 | 13,240 | 1,271 | 13,240 | 1,271 |
| 2015 | 13,208 | 1,268 | 13,164 | 1,264 | 13,103 | 1,258 | 13,086 | 1,256 |
| 2020 | 13,260 | 1,273 | 13,545 | 1,300 | 13,136 | 1,261 | 12,782 | 1,227 |
| 2025 | 13,271 | 1,274 | 13,770 | 1,322 | 13,128 | 1,260 | 12,649 | 1,214 |
| **Average Annual Growth Rates** | | | | | | | | |
| 1990-2000 | 0.76% | | 0.76% | | 0.76% | | 0.76% | |
| 2000-2013 | -0.50% | | -0.38% | | -0.38% | | -0.38% | |
| 2013-2015 | 0.64% | | -0.29% | | -0.52% | | -0.58% | |
| 2013-2020 | 0.24% | | 0.33% | | -0.11% | | -0.50% | |
| 2013-2025 | 0.16% | | 0.36% | | -0.08% | | -0.41% | |
| Historical data appear in the shaded cells | | | | | | | | |

Source: Energy Commission, Demand Analysis Office

**Figure 11: Statewide End-Use Per Capita Natural Gas Consumption**




Source: Energy Commission, Demand Analysis Office

**Table 5: Statewide Annualized Growth Rates 2015-2025 (Percent)**

| Statewide Annualized Growth Rates 2015-2025 | | | |
|---|---|---|---|
| | Residential | Commercial | Industrial |
| **High Demand/Low Price Case** | 0.48% | -0.49% | 0.58% |
| **Mid Demand Case** | 0.40% | -0.15% | -0.15% |
| **Low Demand/High Price Case** | 0.40% | -1.31% | -0.40% |

Source: Energy Commission, Demand Analysis Office

# Planning Area Baseline Results

This section presents forecasting results for the three major planning areas along with the aggregation of the areas outside the majors:

- Pacific Gas and Electric
- Southern California Gas Company
- San Diego Gas & Electric
- Aggregated Other

## Pacific Gas and Electric Planning Area

The PG&E planning area encompasses the PG&E and the Sacramento Municipal Utilities District (SMUD) electric planning areas. This planning area includes all PG&E retail gas customers, customers of private marketers using the PG&E natural gas distribution system, and the city of Palo Alto gas customers.

**Table 6** compares the 2015 PG&E planning area revised end-use natural gas demand baseline forecasts with the *CED 2013* mid demand case. By 2025, staff expects demand to be about 1.9 percent higher in the 2015 mid demand case forecast than in the *CED 2013* mid demand case.

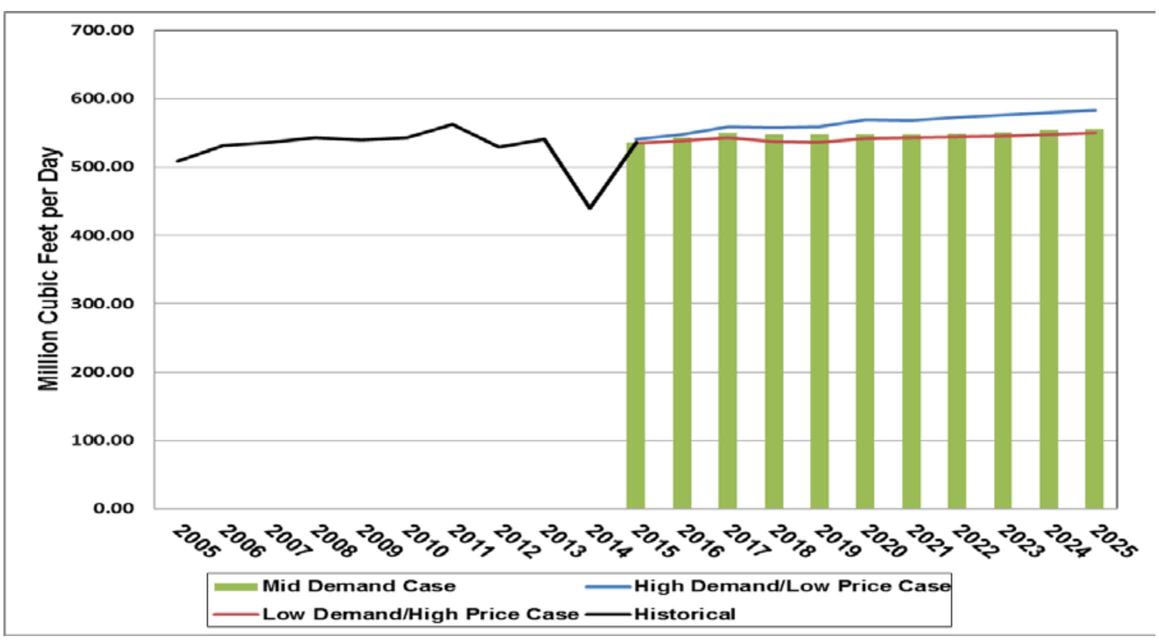
**Figure 12** displays the PG&E baseline residential forecasts. In the latter half of the forecast horizon, the effects of climate change pushes the mid demand case lower, causing this case to converge with the low demand/high price case. As a result, by 2025, the 2015 mid demand case residential forecast value almost matches that of the low demand/high price case.

**Table 6: PG&E End-Use Natural Gas Demand Forecast, Including AAEE**

| | 2013 CED End-Use Natural Gas Mid Demand Case (Mid AAEE Savings) | | 2015 End-Use Natural Gas High Demand/Low Price Case (Low AAEE Savings) | | 2015 End-Use Natural Gas Mid Demand Case (Mid AAEE Savings) | | 2015 End-Use Natural Gas Low Demand/High Price Case (High AAEE Savings) | |
|---|---|---|---|---|---|---|---|---|
| | MMTherms | Bcf | MMTherms | Bcf | MMTherms | Bcf | MMTherms | Bcf |
| 1990 | 5,271 | 506 | 5,271 | 506 | 5,271 | 506 | 5,271 | 506 |
| 2000 | 5,281 | 507 | 5,281 | 507 | 5,281 | 507 | 5,000 | 480 |
| 2013 | 4,618 | 443 | 4,802 | 461 | 4,802 | 461 | 4,802 | 461 |
| 2015 | 4,679 | 449 | 4,819 | 463 | 4,789 | 460 | 4,783 | 459 |
| 2020 | 4,720 | 453 | 5,040 | 484 | 4,820 | 463 | 4,734 | 454 |
| 2025 | 4,739 | 455 | 5,148 | 494 | 4,830 | 464 | 4,734 | 454 |
| **Average Annual Growth Rates** | | | | | | | | |
| 1990-2000 | 0.02% | | 0.02% | | 0.02% | | -0.53% | |
| 2000-2013 | -1.03% | | -0.73% | | -0.73% | | -0.31% | |
| 2013-2015 | 0.66% | | 0.18% | | -0.14% | | -0.20% | |
| 2013-2020 | 0.31% | | 0.69% | | 0.05% | | -0.20% | |
| 2013-2025 | 0.24% | | 0.64% | | 0.05% | | -0.13% | |
| Historical data appear in the shaded cells | | | | | | | | |

Source: Energy Commission, Demand Analysis Office

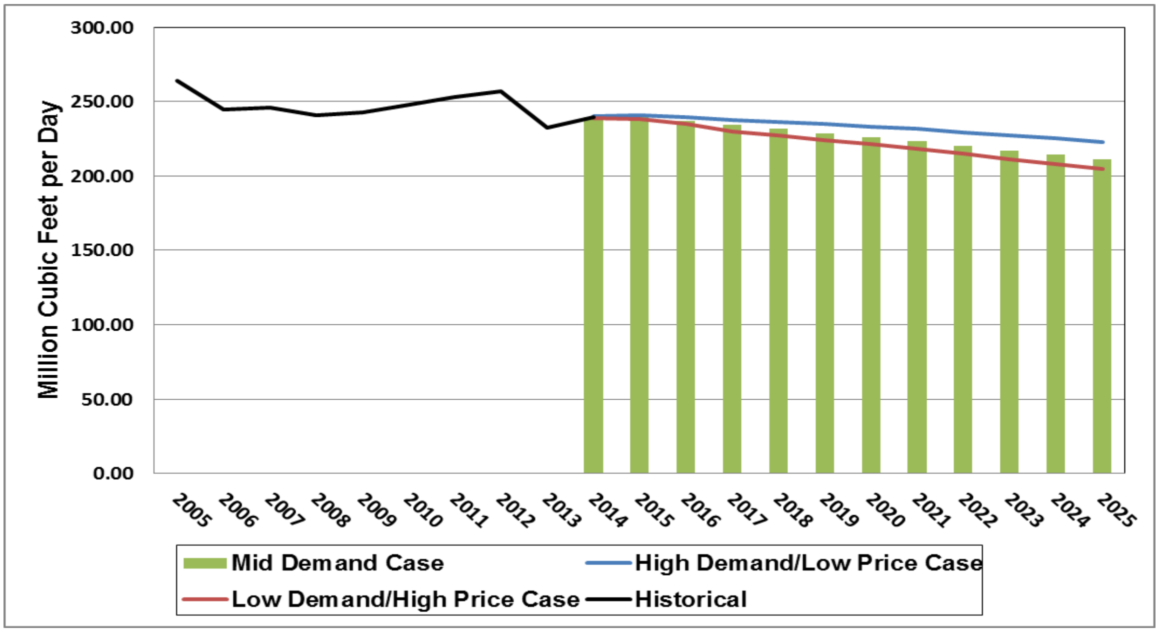
**Figure 12: PG&E Planning Area Residential Natural Gas Demand, Including AAEE**




Source: Energy Commission, Demand Analysis Office

Further, demand in the commercial sector in all three cases declines throughout the forecast horizon. The impacts of building and appliance efficiency standards are driving this outcome. **Figure 13** shows the forecasts for the PG&E planning area commercial sector.

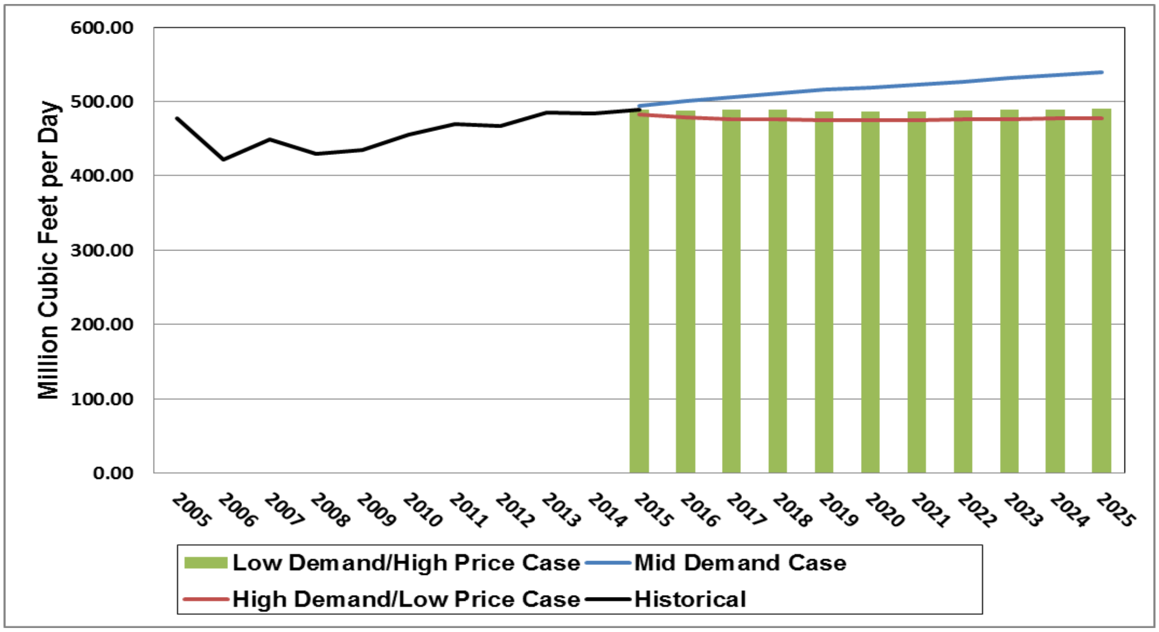
**Figure 13: PG&E Planning Area Commercial Natural Gas Demand, Including AAEE**




Source: Energy Commission, Demand Analysis Office

In the industrial sector, relatively high projected growth in manufacturing output, particularly from the high-tech sector, pushes natural gas demand higher in the high demand/low price case; the other two cases remain flat throughout the forecast horizon. In the high demand/low price case, between 2015 and 2025, demand grows by about 0.97 percent per year. **Figure 14** shows the forecasts for the PG&E industrial sector. **Table 7** displays the annualized growth rates for PG&E by common case.

**Figure 14: PG&E Planning Area Industrial Natural Gas Demand, Including AAEE**




Source: Energy Commission, Demand Analysis Office

**Table 7: Annualized Growth Rates in PG&E, 2015-2025**

| | Residential | Commercial | Industrial |
|---|---|---|---|
| **High Demand/Low Price Case** | 0.77% | -0.64% | 0.97% |
| **Mid Demand Case** | 0.38% | -1.09% | 0.12% |
| **Low Demand/High Price Case** | 0.27% | -1.37% | -0.13% |

Source: Energy Commission, Demand Analysis Office

AAEE savings were estimated for the PG&E planning area for the three cases. **Table 8** provides total natural gas savings by case and year. As with total state numbers, only three of the five AAEE scenarios were used:

- High AAEE savings were used in the low demand/high price case
- Low AAEE savings were used in the high demand/low price case
- Mid AAEE was used in the mid demand case

**Table 8: AAEE Savings by Case and Year for PG&E Planning Area (MMcf/Day)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High Demand/Low Price Case | 1.73 | 8.35 | 15.45 | 21.37 | 26.34 | 30.49 | 35.23 | 39.95 | 44.40 | 48.75 | 52.92 |
| Mid Demand Case | 1.84 | 9.08 | 16.99 | 26.88 | 33.91 | 40.15 | 47.03 | 53.73 | 60.12 | 66.27 | 72.15 |
| Low Demand/High Price Case | 2.18 | 10.38 | 19.55 | 30.91 | 39.07 | 46.30 | 54.10 | 61.76 | 69.29 | 76.69 | 83.85 |

Source: Energy Commission, Demand Analysis Office

## Southern California Gas Company Planning Area

SoCal Gas planning area includes the Southern California Edison Company, Burbank and Glendale, Pasadena, Los Angeles Department of Water & Power (LADWP), and Imperial Irrigation District electric planning areas. It includes customers of those utilities, city of Long Beach customers, customers of private marketers using the SoCal Gas natural gas distribution system, as well as customers receiving natural gas from the interstate pipeline companies without the use of the utility's distribution network.

**Table 9** compares the 2015 revised end-use natural gas demand SoCal Gas planning area baseline forecasts with the *CED 2013* mid demand case. The higher 2013 starting point reflects a higher actual consumption than projected in *CED 2013* and higher demand in the transportation and residential sectors.

By 2025, the *CED 2013* mid demand case forecast is slightly higher than the 2015 forecasts by about 6 Bcf. Growth in the residential sector is contributing to the overall expansion of demand in the SoCal Gas planning area. Staff attributes the higher residential demand to adjustments made to *heating degree-days*[15] in the model. In the *CED 2013* forecast, 2014 had fewer heating degree-days than average. Through the forecast horizon, the effects of climate change push the high demand/low price case below the mid demand case in the latter portion of the forecast.

In the 2015 forecast, 2014 had fewer than average number of heating degree days. In 2015, the first year of the forecasts, staff used historical average for heating degree days, which raised forecasted natural gas demand. **Figure 15** displays the 2015 revised residential end-use natural gas demand, including AAEE savings, for the three cases, along with the historical demand in the SoCal Gas residential sector.

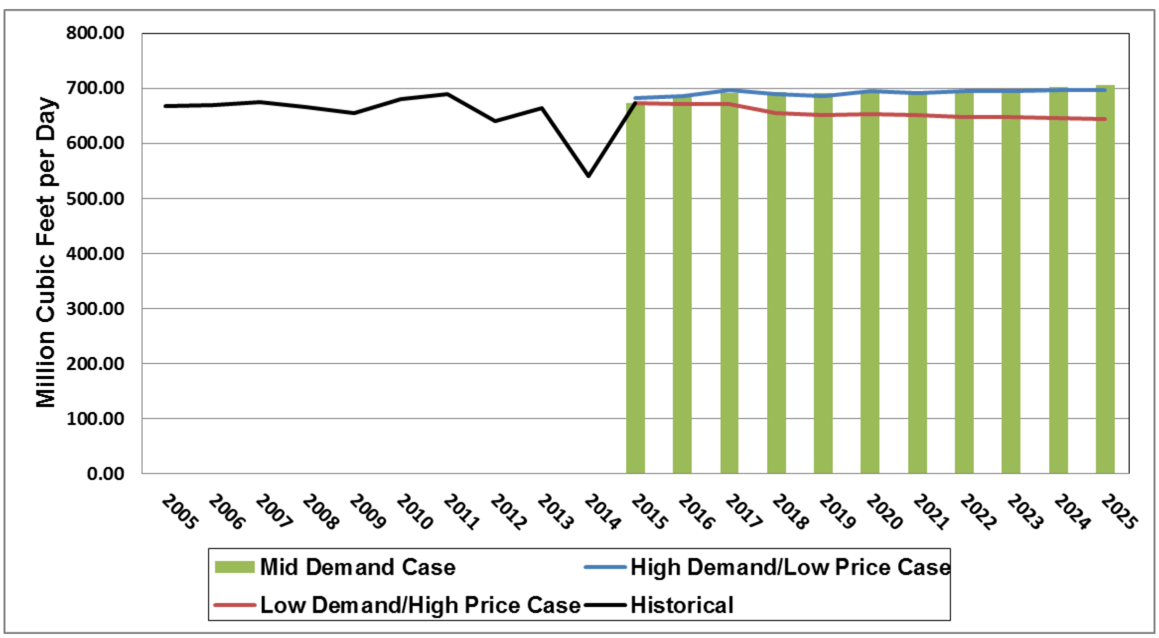
15 *Heating degree days* are indicators of household energy consumption for space heating. It is calculated by subtracting the daily average temperature from 65 and then summing over the year. The result is the number of heating degree days.

**Table 9: SoCal Gas End-Use Natural Gas Demand Forecast, Including AAEE**

| | 2013 CED End-Use Natural Gas Mid Demand Case (Mid AAEE Savings) | | 2015 End-Use Natural Gas High Demand/Low Price Case (Low AAEE Savings) | | 2015 End-Use Natural Gas Mid Demand Case (Mid AAEE Savings) | | 2015 End-Use Natural Gas Low Demand/High Price Case (High AAEE Savings) | |
|---|---|---|---|---|---|---|---|---|
| | MMTherms | Bcf | MMTherms | Bcf | MMTherms | Bcf | MMTherms | Bcf |
| 1990 | 6,802 | 653 | 6,802 | 653 | 6,802 | 653 | 6,802 | 653 |
| 2000 | 7,938 | 762 | 7,938 | 762 | 7,938 | 762 | 7,938 | 762 |
| 2013 | 7,552 | 725 | 7,760 | 745 | 7,760 | 745 | 7,760 | 745 |
| 2015 | 7,656 | 735 | 7,656 | 735 | 7,625 | 732 | 7,615 | 731 |
| 2020 | 7,677 | 737 | 7,792 | 748 | 7,625 | 732 | 7,365 | 707 |
| 2025 | 7,677 | 737 | 7,896 | 758 | 7,615 | 731 | 7,260 | 697 |
| **Average Annual Growth Rates** | | | | | | | | |
| 1990-2000 | 1.56% | | 1.56% | | 1.56% | | 1.56% | |
| 2000-2013 | -0.38% | | -0.17% | | -0.17% | | -0.17% | |
| 2013-2015 | 0.69% | | -0.67% | | -0.88% | | -0.94% | |
| 2013-2020 | 0.23% | | 0.06% | | -0.25% | | -0.75% | |
| 2013-2025 | 0.15% | | 0.16% | | -0.17% | | -0.60% | |
| Historical data appear in the shaded cells | | | | | | | | |

Source: Energy Commission, Demand Analysis Office

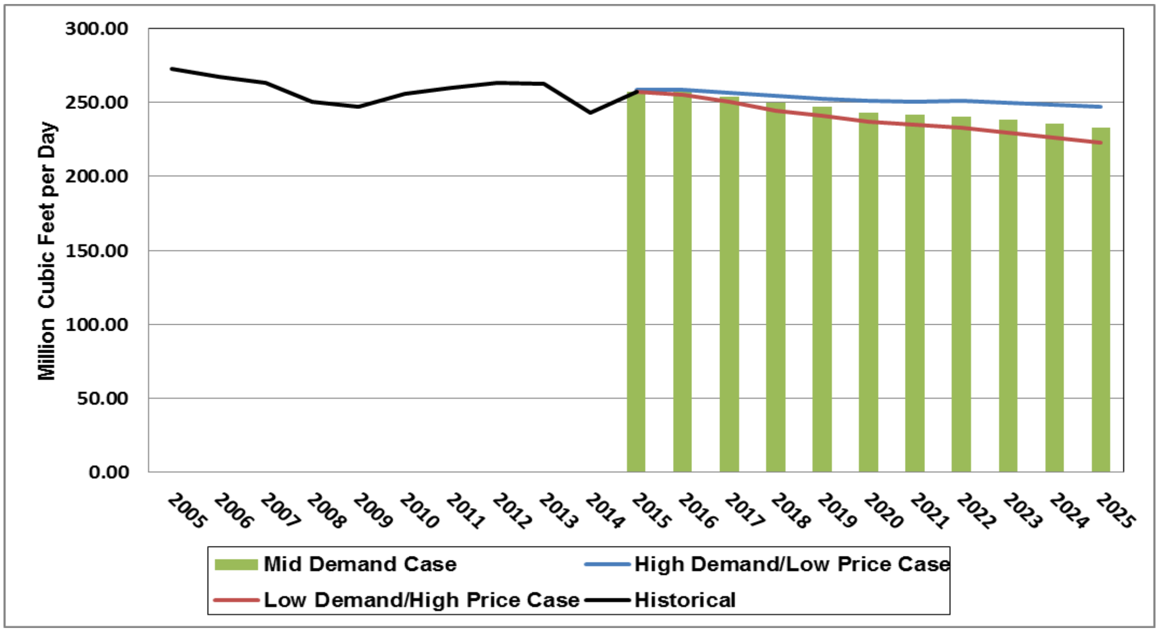
**Figure 15: SoCal Gas Planning Area Residential Natural Gas Demand, Including AAEE**




Source: Energy Commission, Demand Analysis Office

In the commercial sector, demand in all three cases is declining; this results from the effects of additional efficiency savings, climate change, and rate impacts. **Figure 16** shows the end-use natural gas demand forecasts for the SoCal Gas commercial sector.

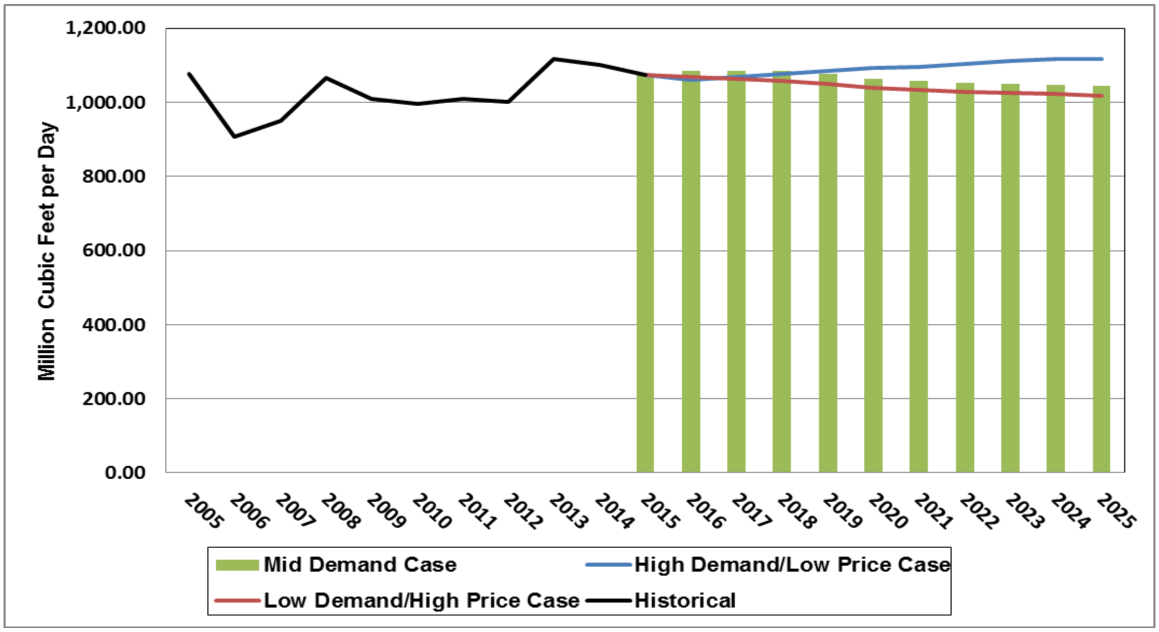
**Figure 16: SoCal Gas Planning Area Commercial Natural Gas Demand, Including AAEE**




Source: Energy Commission, Demand Analysis Office

The 2015 forecasts for industrial natural gas consumption reflect an expected long-term decline in this sector output in the Los Angeles region in the mid demand and low demand/high price cases; demand grows in the high demand/low price case because of relatively optimistic assumptions about industrial output. However, demand remains above the *CED 2013*. By 2025, projected consumption in the mid demand case 2015 forecasts exceeds the *CED 2013* mid demand case by 11.7 percent. The increased demand reflects the costs reduction in the resource extraction sector compared to the 2013 forecast. **Figure 17** shows the end-use natural gas demand forecasts, including AAEE savings, for the SoCal Gas industrial sector. **Table 10** displays the annualized growth rates for the SoCal Gas planning area by common case.

**Figure 17: SoCal Gas Planning Area Industrial Natural Gas Demand, Including AAEE**




Source: Energy Commission, Demand Analysis Office

**Table 10: Annualized Growth Rates for SoCal Gas 2015-2025**

| | Residential | Commercial | Industrial |
|---|---|---|---|
| **High Demand/Low Price Case** | 0.23% | -0.44% | 0.40% |
| **Mid Demand Case** | 0.47% | -0.99% | -0.28% |
| **Low Demand/High Price Case** | -0.44% | -1.43% | -0.52% |

Source: Energy Commission, Demand Analysis Office

AAEE savings were estimated for the SoCal Gas planning area for the three cases. **Table 11** provides total natural gas savings by scenario and year. As with total state numbers, only three of the five AAEE scenarios were used:

- High AAEE savings were used in the low demand/high price case
- Low AAEE savings were used in the high demand/low price case
- Mid AAEE was used in the mid demand case

**Table 11: AAEE Savings by Case and Year for SoCal Gas Planning Area (MMcf/Day)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High Demand/Low Price Case | 2.68 | 10.88 | 20.56 | 29.28 | 37.15 | 44.23 | 49.72 | 55.07 | 60.67 | 66.09 | 71.64 |
| Mid Demand Case | 2.81 | 11.79 | 22.40 | 35.70 | 45.94 | 55.33 | 63.11 | 70.61 | 78.36 | 85.74 | 93.07 |
| Low Demand/High Price Case | 3.30 | 13.66 | 25.78 | 40.57 | 52.15 | 62.74 | 71.59 | 80.34 | 89.52 | 98.28 | 106.89 |

Source: Energy Commission, Demand Analysis Office

## San Diego Gas & Electric Planning Area

The SDG&E planning area contains SDG&E customers and customers of private marketers using the SDG&E natural gas distribution system. **Table 12** compares the 2015 revised end-use natural gas demand SDG&E planning area baseline forecasts with the *CED 2013* mid demand case. The new forecasts begin at a higher level because actual demand in 2013 exceeded the forecasted demand of the *CED 2013.* The mid demand case in the 2015 forecasts declines by about 1.9 percent from 2013 to 2025. By 2025, projected demand is about 5.6 percent lower in the new mid demand case relative to the *CED 2013*.

Staff calibrated the SDG&E planning area forecast to 2013 instead of 2014 because 2014 consumption increased over that of 2013 even though this planning area experienced lower-than-average heating degree days in 2014. In that year, heating degrees-days fell below the previous record over the last 30 years. For this reason, calibrating to 2014 resulted in a forecast that was biased upward.

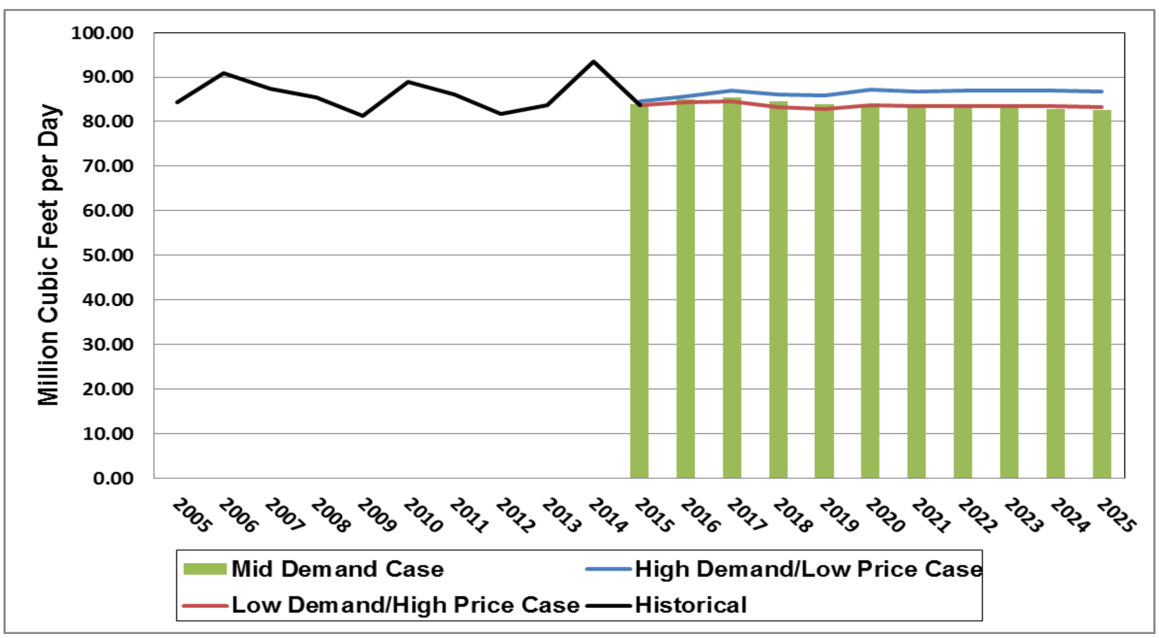
The mid-demand case residential demand has a higher starting point in the 2015 forecast by about 3.3 percent compared to the 2013 forecast. However, the forecasts flattened between 2016 and 2025. The lower growth in the residential sector of the SDG&E planning area compared to the other planning areas reflects the projected increase in natural gas rates compared to PG&E and SoCal Gas. **Figure 18** displays the 2015 revised residential end-use natural gas demand mid demand, low demand/high price, and high demand/low price cases with AAEE savings.

**Table 12: SDG&E End-Use Natural Gas Demand Forecast, Including AAEE**

| | 2013 CED End-Use Natural Gas Mid Demand Case (Mid AAEE Savings) | | 2015 End-Use Natural Gas High Demand/Low Price Case (Low AAEE Savings) | | 2015 End-Use Natural Gas Mid Demand Case (Mid AAEE Savings) | | 2015 End-Use Natural Gas Low Demand/High Price Case (High AAEE Savings) | |
|---|---|---|---|---|---|---|---|---|
| | MMTherms | Bcf | MMTherms | Bcf | MMTherms | Bcf | MMTherms | Bcf |
| 1990 | 708 | 68 | 708 | 68 | 708 | 68 | 708 | 68 |
| 2000 | 583 | 56 | 583 | 56 | 583 | 56 | 583 | 56 |
| 2013 | 510 | 49 | 531 | 51 | 531 | 51 | 531 | 51 |
| 2015 | 531 | 51 | 542 | 52 | 542 | 52 | 542 | 52 |
| 2020 | 542 | 52 | 552 | 53 | 531 | 51 | 531 | 51 |
| 2025 | 552 | 53 | 552 | 53 | 521 | 50 | 521 | 50 |
| **Average Annual Growth Rates** | | | | | | | | |
| 1990-2000 | -1.92% | | -1.92% | | -1.92% | | -1.92% | |
| 2000-2013 | -1.02% | | -0.72% | | -0.72% | | -0.72% | |
| 2013-2015 | 2.02% | | 0.98% | | 0.98% | | 0.98% | |
| 2013-2020 | 0.85% | | 0.55% | | 0.00% | | 0.00% | |
| 2013-2025 | 0.72% | | 0.35% | | -0.18% | | -0.18% | |
| Historical data appear in the shaded cells | | | | | | | | |

Source: Energy Commission, Demand Analysis Office

**Figure 18: SDG&E Planning Area Residential Natural Gas Consumption, Including AAEE**

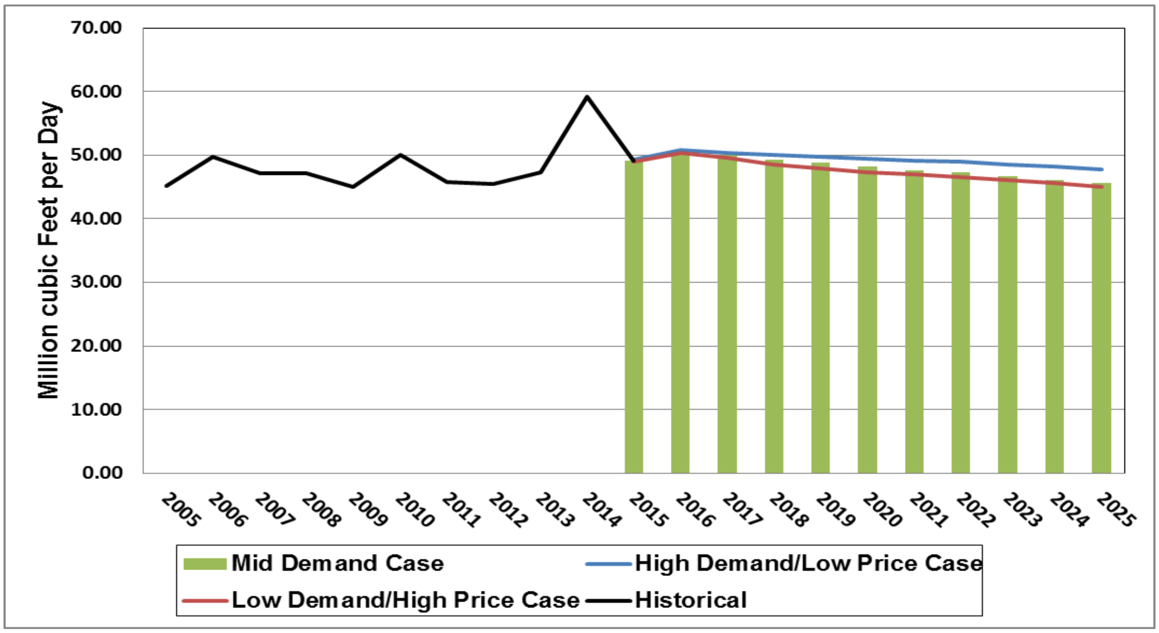



Source: Energy Commission, Demand Analysis Office

Commercial demand declines at a slower rate in the SDG&E planning area compared to the other two planning areas due to faster projected growth in commercial floor space that partially offsets the savings from building and appliance standards. **Figure 19** shows the end-use natural gas demand, including AAEE, forecasts for the SDG&E commercial sectors.

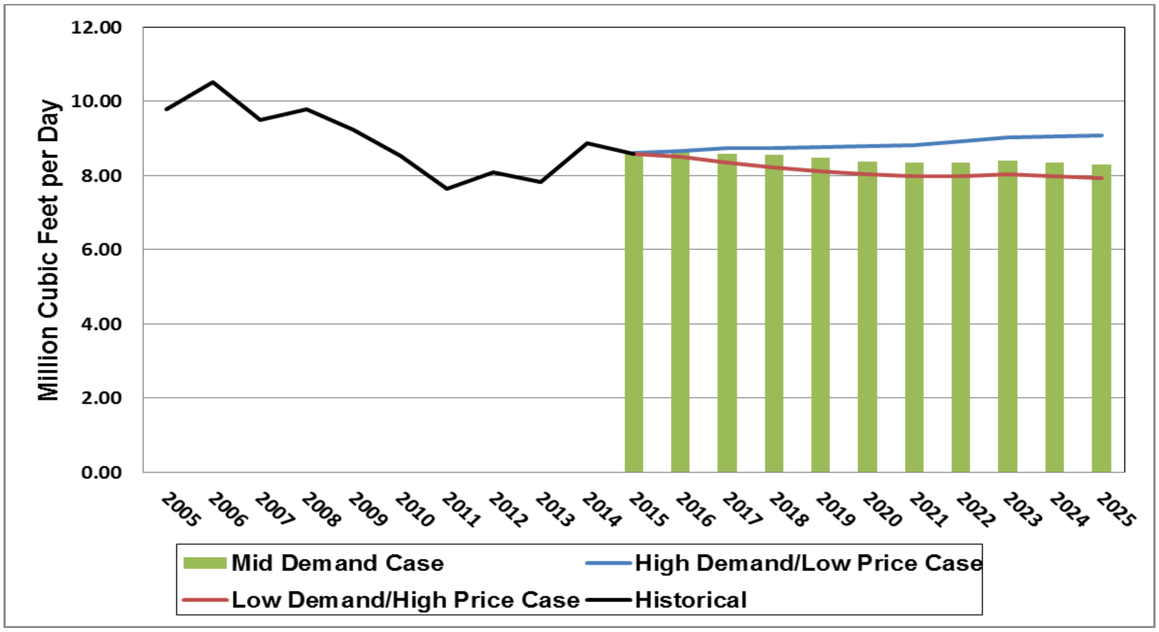
Projected industrial sector demand remains flat throughout the forecast period but, by 2024, still exceeds the *CED 2013* by 16.2 percent in the mid demand case. **Figure 20** shows the baseline forecasts for the SDG&E industrial sectors. Staff expects no major changes in industrial output between 2016 and 2025 in the SDG&E planning area. **Table 13** shows the annualized growth rates by common case.

**Figure 19: SDG&E Planning Area Commercial Natural Gas Consumption, Including AAEE**




Source: Energy Commission, Demand Analysis Office

**Figure 20: SDG&E Planning Area Industrial Natural Gas Consumption, Including AAEE**




Source: Energy Commission, Demand Analysis Office

**Table 13: Annualized Growth Rates for SDG&E 2015-2025**

| | Residential | Commercial | Industrial |
|---|---|---|---|
| **High Demand/Low Price Case** | 0.27% | -0.30% | 0.51% |
| **Mid Demand Case** | -0.16% | -0.74% | -0.35% |
| **Low Demand/High Price Case** | -0.06% | -0.84% | -0.80% |

Source: Energy Commission, Demand Analysis Office

AAEE savings were estimated for the SDG&E planning area for the three cases. **Table 14** provides total natural gas savings by scenario and year. As with total state numbers, only three of the five AAEE scenarios were used:

- High AAEE savings were used in the low demand/high price case
- Low AAEE savings were used in the high demand/low price case
- Mid AAEE was used in the mid demand case

**Table 14: AAEE Savings for the SDG&E Planning Area (MMcf/Day)**

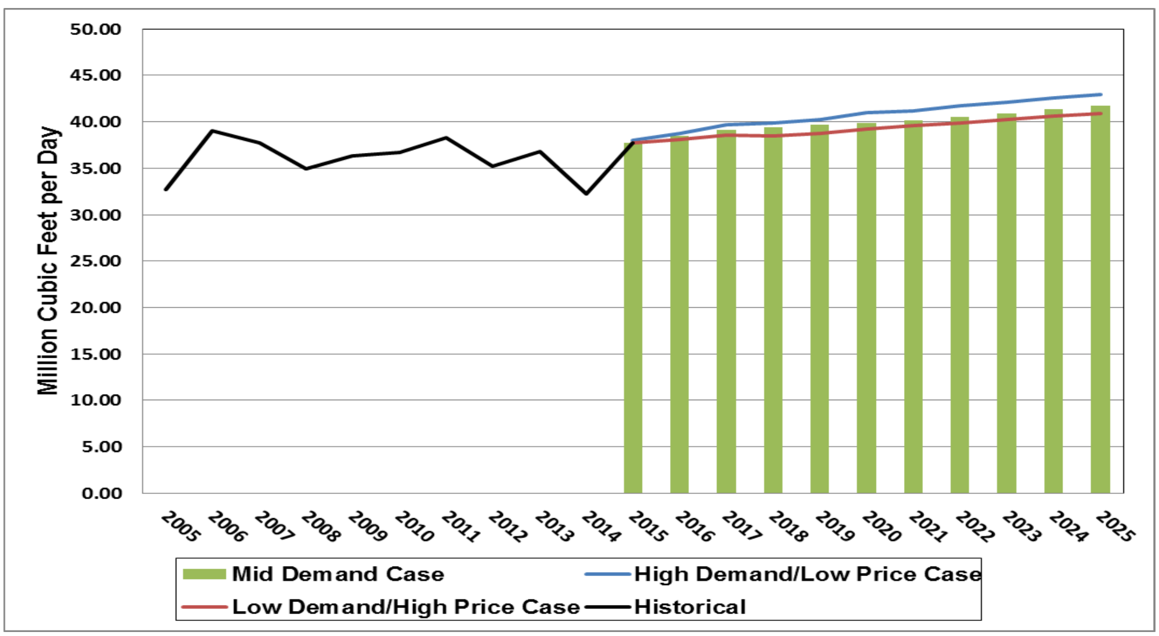
| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High Demand/Low Price Case | 0.22 | 1.73 | 3.40 | 4.65 | 5.67 | 6.50 | 7.47 | 8.43 | 9.47 | 10.50 | 11.55 |
| Mid Demand Case | 0.24 | 1.86 | 3.70 | 5.77 | 7.24 | 8.52 | 9.95 | 11.38 | 12.86 | 14.27 | 15.66 |
| Low Demand/High Price Case | 0.31 | 2.25 | 4.43 | 6.89 | 8.63 | 10.17 | 11.81 | 13.36 | 15.01 | 16.63 | 18.28 |

Source: Energy Commission, Demand Analysis Office

## Aggregated Other Planning Area

The aggregated other planning area consists of all areas and customers in the Southwest Gas and Avista Energy utility districts. **Figure 21** shows that the aggregated other planning area natural gas demand grows in all three cases by about 1 percent per year. The new forecasts begin at a higher level because actual demand in 2013 exceeded the forecasted demand of the *CED 2013* and grow at a faster rate from 2012–2025 in all three cases. By 2025, projected demand is about 7.1 percent higher in the new mid demand case relative to the old (15 Bcf vs. 14 Bcf). **Table 15** shows the annualized growth rates for the common cases in the aggregated other planning area. Staff does not forecast for this planning area directly but assigns the average growth from the other three regions (before adjustments for AAEE savings).

**Figure 21: Historical and Forecasted Natural Gas Consumption for the Aggregated Other Planning Area**




Source: Energy Commission, Demand Analysis Office

**Table 15: Annualized Growth Rates for the Aggregated Other Planning Area 2015-2025**

| | Residential | Commercial | Industrial |
|---|---|---|---|
| **High Demand/Low Price Case** | 1.23% | 1.10% | 0.96% |
| **Mid Demand Case** | 1.00% | 1.00% | 0.16% |
| **Low Demand/High Price Case** | 0.79% | 0.86% | -0.08% |

Source: Energy Commission, Demand Analysis Office

# CHAPTER 4: Natural Gas for Electric Generation

## Introduction

In the *2015 IEPR*, the Energy Commission staff continued its use of the PLEXOS production cost model[16] to provide an estimate of natural gas demand in the electric generation sector for the WECC.[17] In this platform, staff developed a WECC-wide production simulation model dataset covering the years 2015–2026 for the three IEPR common cases. California's electricity supply and demand assumptions reflect current policy and mandates. For the rest of the WECC, staff begins with the Transmission Electric Planning and Policy Committee's (TEPPC) 2024 common case[18] and the most current year (2013) of historical supply and demand data to develop the 2015–2026 details missing from the single-year TEPPC common case.

The PLEXOS simulation dataset developed to provide fuel demand for natural gas generation for 2015–2026 uses two major sets of assumptions—California-specific and those for the rest of the WECC. Each has a set of electricity load forecasts and supply portfolios.

California's electricity supply portfolio is composed of in-state and out-of-state generation resources that provided a combined total of more than 292,000 gigawatt hours (GWh) of electricity in 2014. Various conventional and renewable types of generation resources supply California including, but not limited to, natural gas-fired, hydroelectric, solar, wind, nuclear, biomass, and coal-fired. Staff projects the composition of each type of generation resource to change by the mid-2020s. Imports of coal-fired generation are expected to decline as many of the utilities in California have begun divesting themselves from coal plants in anticipation of the proposed U.S. EPA's Clean Power Plan. Renewable generation is expected to increase contributions to California's electricity supply. However, staff expects natural gas-fired generating resources to remain dominant throughout the forecast period, due to the current amount of installed gas-fired capacity, maintenance of planning reserve margins, the availability of low-cost natural gas, and restrictions on the development of nuclear and coal-fired generation technologies in California. The energy demand met by natural gas fired generation is expected to decline by about 14.5 percent while renewables and AAEE are forecasted to increase by 12  percent and hydro generation returning to average levels to fill in the remainder share of natural gas decline by the end of the forecast period.

16 Platform owned by Energy Exemplar Ltd.

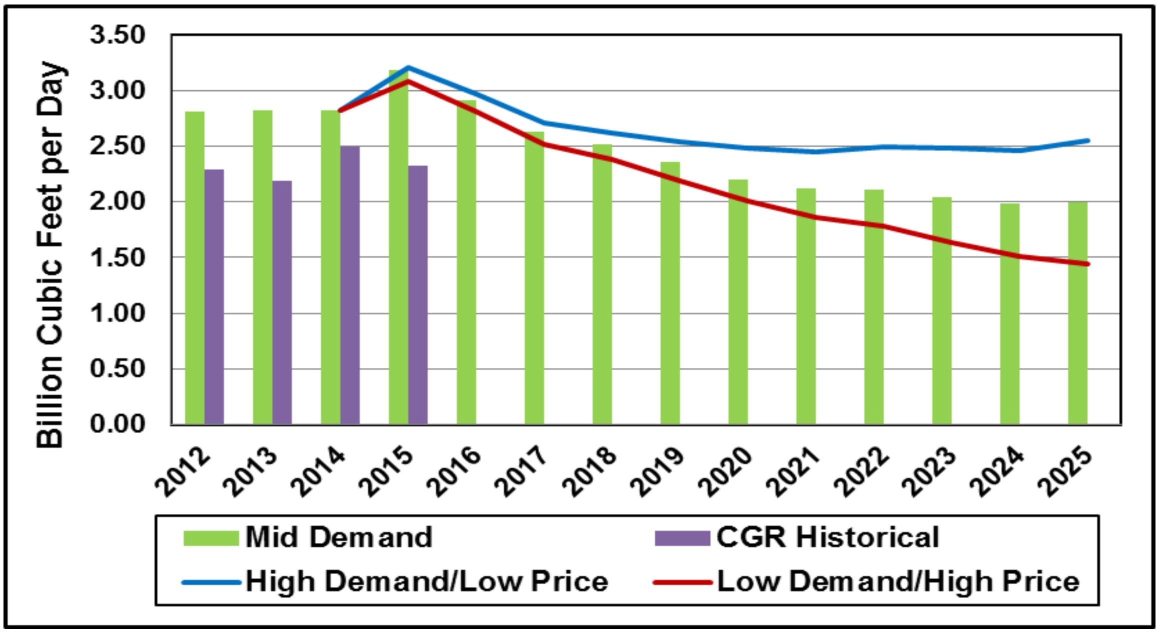
17 The WECC region extends from Canada to Mexico and includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California, Mexico, and all, or portions of, 14 western states in the United States.

18 The TEPPC, a WECC Board of Directors committee, guides WECC's Transmission Expansion Planning process and working groups consisting of stakeholders throughout the WECC to create this common case biennially.

## Natural Gas Demand for Electric Generation

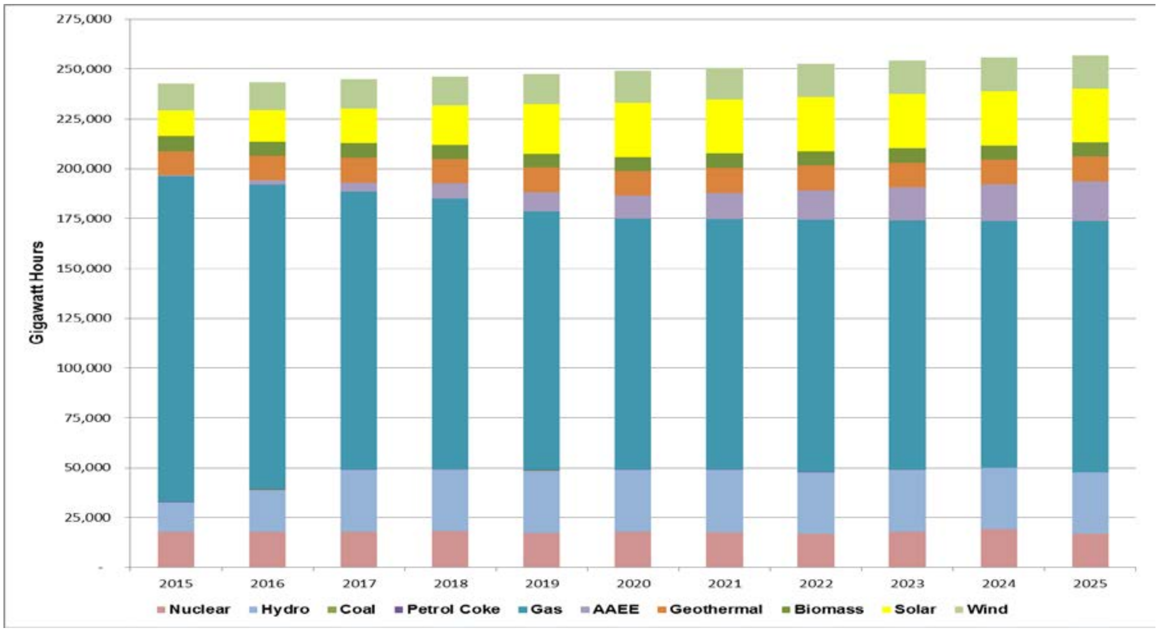
Natural gas demand for electric generation was estimated using electricity production cost modeling for electric generation in the WECC area, which includes California. Staff used these natural gas demand projections as fixed values in the NAMGas model similar to the way staff used natural gas end-use demand. Natural gas demand for electric generation for areas outside the WECC was estimated using the NAMGas model. **Figure 22** shows California natural gas demand for electric generation. In all three California cases, natural gas demand for electric generation falls over the forecast period. An increase in alternative electric generation sources, such as renewable energy, and AAEE has reduced the need for electric generation. **Figure 23** shows the breakdown of electric generation sources by type for all three common cases.

**Figure 22: California Natural Gas Demand for Electric Generation**




Source: Energy Commission, Supply Analysis Office, *California Gas Report*

**Figure 23: Mid Demand Case Generation Fuel Sources 2015 – 2026**




Source: Energy Commission, Supply Analysis Office

# Overview: Electricity Dispatch Production Cost Modeling Assumptions

The following section describes the production cost assumptions and the demand assumptions for the PLEXOS modeling efforts.

**Table 16** outlines specific production cost dataset assumptions for the *2015 IEPR* common cases**.** It is vital to understand how these assumptions are combined in developing each of the *2015 IEPR* common cases.

**Table 16: Production Cost Assumptions by Case**

| Key Assumptions Specific to Production Cost Model | High Demand/ Low Price Case | Mid Demand Case | Low Demand/ High Price Case |
|---|---|---|---|
| Demand Forecast | High | Mid | Low |
| Renewable Generation | High | Mid | Low |
| Additional Achievable Energy Efficiency | Low | Mid | High |
| New Combined Heat and Power | None | Mid | High |
| Carbon Price | Low | Mid | High |
| Coal Price | Low | Mid | High |
| Natural Gas Price[19] | Low | Mid | High |

Source: Energy Commission, Supply Analysis Office staff presentation at

https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=15-IEPR-03Demand Assumptions

## Demand Assumptions

### California 2015 to 2026

Staff used the revised 2015 California low demand/high price, mid demand, and high demand/ low price cases posted on December 17, 2015.[20] Compared to the adopted *CED 2014* update, all demand cases are lower throughout the forecast period. The main driver for these lower projections is behind-the-meter photovoltaic (PV). The revised *2015 CED* includes additional achievable energy efficiency (AAEE) projections for the three investor-owned utilities (IOUs), as well as SMUD and LADWP.

For the other publicly owned utility (POUs) AAEE projections, staff used the 2015 Supply Form filings.[21] The 2015 POU AAEE projections are lower overall than 2013 projections.

---

19 Final *2015 IEPR* monthly burner-tip natural gas price forecast (mid, high and low) can be found at http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN210495_20160222T143214_WECC_Gas_Hub_Burner_Tip_Price_Estimates_using_2015_IEPR_Natural.xls. These are based on October 2015 NAMGas annual hub prices.

20 Revised CED 2015 at http://www.energy.ca.gov/2015_energypolicy/documents/index.html#12172015.

21 POU high and low incremental EE forecast were developed by applying the same variability as observed between the mid demand case in comparison to the high demand/low price and low demand/high price cases AAEE forecast. IEPR forms and instructions can be found at http://www.energy.ca.gov/2015_energypolicy/.

**Rest of WECC 2015 to 2026**

Data submitted to the WECC by balancing area[22] authorities (BAA) for the historical year 2013 and the WECC TEPPC 2024 common case[23] load forecast were used as "bookends" to estimate the non-California BAA load. Staff used a compound annual growth rate formula to calculate the peak and energy demand for the intervening years (2015 to 2023). The period for PLEXOS simulations extended beyond the TEPPC common case year of 2024; therefore, staff used the compound annual growth rate to extrapolate the forecast by two years to 2026. The annual peak and energy forecasts were inputs to PLEXOS, and staff developed hourly energy profiles for each year using the "build"[24] function embedded in the PLEXOS software.

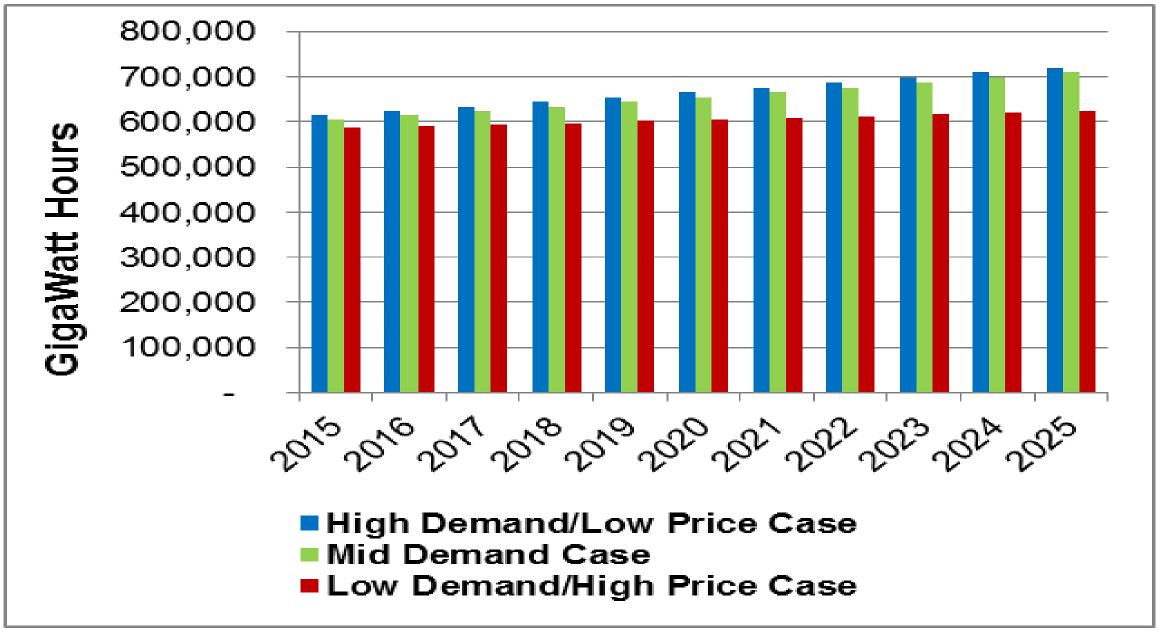
Staff developed peak and energy forecasts for the high demand/low price and low demand/high price cases using different multipliers for each BAA. To calculate the high demand/low price case, staff increased annual loads by an average of 1.15  percent above the mid demand case for each year. This was based on *TEPPC 2024 PC02* High Load Case. For the low demand/high price case, staff decreased the mid demand case annual energy forecast by an average of 10 percent. This was based on the *TEPPC 2024 PC03* Low Load Case. **Figure 24** displays the annual WECC (non-California) load forecast in GWh for the period of 2015–2026 for all three common cases. Staff calculated annual peak demand for each BAA using the same method.

22 A balancing area is an area for controlling electrical transmission flows and voltages, and ensuring that electrical frequency is held within the limits that ensure reliable operation of the power system.

23 See http://www.wecc.biz/committees/BOD/TEPPC/Pages/TAS_Datasets.aspx.

24 Linear programming model that uses the peak and energy forecast and an average hourly load profile for load-serving entities in the WECC to develop hourly profiles for 2015–2026.

**Figure 24: WECC (Non-CA) Electricity Load Forecast**




Source: Energy Commission, Supply Analysis Office

# Hydro Generation Forecast

## WECC-Wide

In a departure from the previous IEPR modeling technique, staff developed WECC-wide hydroelectric generation forecasts using a shorter and more recent set of historical hydro generation data from the U.S. EIA[25] and the Energy Commission's *Quarterly Fuels and Energy Report* (*QFER*) database.[26] This reflects the overall trend of reduced hydroelectric generation due to persistent or semi persistent drought conditions in the western United States and changes in hydroelectric operations from federal and state regulations concerning water flows for fish protection.

Historically, the hydroelectric generation data from 1991 to the most recent year for which data are available (currently 2014) was used. For this IEPR cycle, staff used hydroelectric generation data from 2001 to 2014 to calculate the average monthly generation by state. Using this much shorter and recent period resulted in roughly a 6 percent decrease to annual hydro generation WECC-wide. Due to a lack of available data, the Canadian hydroelectric generation forecast for Alberta and British Columbia was not updated.

25 See http://www.eia.gov/electricity/monthly/.

26 See http://energyalmanacca.gov/electricity/web_qfer/.

### California Adjustments for 2015 and 2016

The monthly projections for California hydroelectric generation are an average based on plant-level 2000–2014 monthly historical generation. Actual 2015 California hydro generation was not available in time for these IEPR simulations, so staff made different assumptions for the 2015 and 2016 average monthly hydro generation projections. Staff projects 2015 hydro generation to equal the lower-than-average actual 2014 monthly generation, while the 2016 monthly projections match the also lower-than-average actual 2013 historical monthly hydro generation. Similar 2015 and 2016 hydro generation assumptions were not made for the rest of WECC.

## Renewable Portfolio Development 2015–2025

California is assumed to meet the RPS legislation and mandates codified by Senate Bill X1-2.[27] Annual estimates for new renewable generation for each of the common cases are then developed. Staff refers to this as *renewable portfolio development*. SB X1-2 requires that electricity retailers in California procure renewables in the amount of 33 percent of their retail sales by 2020. Recent legislation increased this procurement goal to 50 percent by 2030; however, since guidelines and regulations are still under development, assumptions regarding achievement of this policy goal were not included in the renewable portfolio development. **Table 17** shows California-specific goals to meet the 33 percent RPS for all three cases as of December 31, 2015.

**Table 17: Summary of California RPS Goals (TWh)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Low-RPS Goal | 58.10 | 62.33 | 66.54 | 67.88 | 73.88 | 76.77 | 74.91 | 73.29 | 71.46 | 69.50 | 67.50 |
| Mid-RPS Goal | 58.66 | 63.39 | 68.15 | 70.15 | 77.09 | 81.28 | 80.65 | 80.41 | 80.03 | 79.57 | 79.16 |
| High-RPS Goal | 58.82 | 63.72 | 68.93 | 71.45 | 79.49 | 85.28 | 85.79 | 86.67 | 87.40 | 88.09 | 88.88 |

Source: Energy Commission, Supply Analysis Office

The method used to develop the renewable portfolio for California and the rest of the WECC was similar for all three common cases. The resource portfolio essentially adds new renewable generation such that the magnitude of renewable generation achieves policy and development assumptions across the WECC. The assumptions used include the following:

27 Senate Bill X1-2, Simitian, Chapter 1, Statutes of 2011.

- California achieves and maintains RPS of 33 percent by 2020 as a floor through 2025. Other WECC states achieve their RPS targets, growing linearly until the target is achieved. Staff chose new projects using input from CPUC's RPS Calculator and load-serving entities' RPS procurement contracts. Staff assumed in-state renewables to continue to provide 70 to 85 percent of the total RPS mandated procurement, consistent with historical generation and out-of-state procurement. The only exception occurs in the low demand/high price case, where the RPS procurement target decreases due to the low demand growth combined with energy efficiency and combined heat and power assumptions. No unplanned renewable facility retirements were assumed.
- For each state without an RPS target or mandate, staff assumed existing renewable energy generation to continue generating. Renewable generators following general assumptions regarding new development in the WECC TEPPC 2024 common case Version 1.5 were also added.
- Existing renewables continue to operate at average historical levels, except where information about facility retirement, refurbishment, or repowering was available. Staff used annual generation reported to the QFER to infer operation characteristics (such as net capacity rating, scheduled maintenance outages, and so forth) of biomass and geothermal projects.
- High demand/low price and low demand/high price cases:
  - Renewable portfolios were adjusted from the mid demand case both in and out of state to meet higher or lower RPS goals consistent with the high demand/low price or low demand/high price case. Staff allocated new capacity to maintain the general assumption that 70 percent to 85 percent of renewable procurement will come from in-state resources. For all cases, the renewable build in the WECC TEPPC 2024 common case Version 1.5 was used as a guide.
  - Staff assumed that the building of new out-of-state renewables would be influenced by higher and lower energy demands in California.[28] In the high demand/low price case, generic out-of-state renewable projects used in the mid demand case were assumed to expand primarily in regions with RPS targets. For the low demand/high price case, staff assumed generic out-of-state renewables lower than the mid demand case. Staff assumed either renewables with a higher relative capital cost, according to the CPUC RPS Calculator, [29] to be built or the scale was reduced to reflect the lower demand for the generation.

The production cost model used by the Energy Commission allows generation profiles, or *shapes*, as an input. These shapes represent hourly output levels and are used to represent the generation profiles for variable renewable resources, such as wind and solar projects. The output of wind and solar projects can vary significantly in different geographic regions because

---

28 Higher and lower energy demands, relative to the mid demand case, directly affect the RPS targets in each case.

29 The CPUC RPS calculator can be found at http://www.cpuc.ca.gov/RPS_Calculator/.

of differences in weather patterns. Staff updated wind and solar generation hourly profiles for the *2015 IEPR* simulation runs. The recent surge in solar generation and continuing growth in the wind industry necessitated special attention to the profiles used to model these resources. In addition, technology preferences and development strategies continue to evolve in the wind and solar industries, which affect generation profiles. Recent changes in industry practices include the following:

- Many existing wind generators are repowering older turbines with larger and more efficient turbines.
- By the end of 2014, solar PV development surged to more than 4,500 megawatts (MW) (nameplate MWac) [30] of interconnected generation in California with the expectation that another 1,000 MWac nameplate will become operational in 2015. The magnitude of capacity will provide meaningful impacts to the dispatch of natural gas generators and is highly correlated to the region of the state in which PV is located, owing to the natural variability of sunlight. Staff found that capacity factors for these PV resources could range from 20 percent to 30 percent, depending on solar resource, technology configuration, location, and local climate conditions. In addition, PV development has evolved to maximize generation over more hours of the day using tracking systems and modified inverter loading ratios. Staff expects these development strategies to continue.
- New solar thermal projects now operating, each with a particular operating profile can vary based on facility-specific factors, such as the thermal medium, solar-collecting technology, and use of fossil fuel. In addition, new solar thermal projects under development include the use of thermal storage, significantly altering the generation profile and shifting generation by up to six hours.

The California Independent System Operator collects and maintains five-minute operational data for most of the operating wind and solar projects in California. However, since the facility-specific data are confidential, staff collected the data by region, as defined by **Table 18**, using a capacity-weighted average to protect confidentiality. This approach is appropriate for modeling solar and wind generation by region because the regional climate and the technology deployment in the region are intrinsic factors.

30 Nameplate MWac is the rated capacity of the grid connection or the output transformers.

**Table 18: Counties by Region for the Solar Profiles**

| Region | County |
|---|---|
| | Alameda |
| Bay Area | Contra Costa |
| | San Francisco |
| Cascade-Sierra | Mariposa |
| | Mono |
| | Shasta |
| | Tuolumne |
| | Monterey |
| Central Coast | San Luis Obispo |
| Central Coast Inland | San Benito |
| | Santa Clara |
| North Coast | Sonoma |
| North Coast Inland | Napa |
| | Lake |
| | Butte |
| | Sutter |
| Sacramento Valley | Solano |
| | Yolo |
| | Sacramento |
| San Joaquin Valley | Fresno |
| | Kern |
| | Kings |
| | San Joaquin |
| | Tulare |
| South Coast | Los Angeles |
| | San Diego |
| Southeast Interior | Imperial |
| | Inyo |
| | Riverside |
| | San Bernardino |

Source: Energy Commission, Supply Analysis Office

For out-of-state projects, staff opted to use wind and solar profiles developed for the WECC TEPPC 2024 common case. Staff made adjustments to ensure these renewable profiles correlated with the synthetic[31] hourly load profiles used in the PLEXOS dataset. The TEPPC 2024 common case profile for solar thermal with 6-hour storage was also used to model in-state and out-of-state planned solar thermal projects. These profiles are developed differently. TEPPC used a National Renewable Energy Laboratory model to determine approximate shapes based on weather patterns, wind and solar resource, and geographic factors. Production levels were used to infer the output levels.

In the TEPPC 2024 common case, it is assumed that the balancing authorities intend to comply with state RPS for the loads in the states that they serve. **Table 19** shows the amount of renewables needed in the WECC states to achieve states' RPS goals, along with renewable resources in states without RPS policies and Mexico and Canada.

**Table 19: WECC Renewables to Achieve Policy Goals (TWh)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| WECC States With - No RPS | 17.05 | 17.53 | 18.02 | 18.51 | 19.00 | 19.49 | 19.98 | 20.47 | 20.96 | 21.45 | 21.94 |
| AZ* | 3.54 | 4.07 | 4.60 | 5.14 | 5.67 | 6.20 | 6.73 | 7.26 | 7.79 | 8.33 | 8.86 |
| CO* | 9.10 | 9.36 | 9.62 | 9.88 | 10.14 | 10.41 | 10.67 | 10.93 | 11.19 | 11.45 | 11.71 |
| MT | 0.88 | 0.90 | 0.92 | 0.94 | 0.96 | 0.98 | 1.00 | 1.02 | 1.04 | 1.06 | 1.08 |
| NM | 1.30 | 1.49 | 1.68 | 1.88 | 2.07 | 2.26 | 2.45 | 2.64 | 2.84 | 3.03 | 3.22 |
| NV | 6.69 | 6.88 | 7.07 | 7.26 | 7.45 | 7.65 | 7.84 | 8.03 | 8.22 | 8.41 | 8.60 |
| OR | 4.92 | 5.66 | 6.41 | 7.15 | 7.89 | 8.63 | 9.37 | 10.11 | 10.85 | 11.59 | 12.33 |
| TX (WECC portion) | 0.00 | 0.05 | 0.10 | 0.15 | 0.19 | 0.24 | 0.29 | 0.33 | 0.38 | 0.43 | 0.48 |
| UT | 0.64 | 1.18 | 1.72 | 2.26 | 2.80 | 3.34 | 3.88 | 4.42 | 4.96 | 5.50 | 6.04 |
| WA | 8.68 | 9.14 | 9.60 | 10.06 | 10.52 | 10.98 | 11.44 | 11.90 | 12.36 | 12.82 | 13.28 |
| **Total Other** | 52.81 | 56.29 | 59.76 | 63.23 | 66.71 | 70.18 | 73.65 | 77.12 | 80.60 | 84.07 | 87.54 |

Source: Energy Commission staff using the renewables goals in the WECC TEPPC 2024 common case Version 1.5 to develop a linear trajectory for 2026. See https://www.wecc.biz/TransmissionExpansionPlanning/Pages/Default.aspx.

31 TEPPC 2024 Common Case used the year 2005 hourly load profiles, while Energy Commission staff created a synthetic load shape based on hourly load profiles for 2002–2007.

# Thermal Portfolio Development

The existing fleet of natural gas generators in California is changing in response to the State Water Resources Control Board (SWRCB) policy for once-through-cooling (OTC) power plants.[32] To meet the OTC policy, generators are retiring and/or repowering power plants throughout the forecast period.

## California Once-Through-Cooling Retirement Schedule

The SWRCB approved an OTC policy that included many grid reliability recommendations made by the California ISO, as well as a joint implementation proposal developed by the Energy Commission, CPUC, and California ISO that became effective October 1, 2010. See **Table 20** for specific OTC retirement assumptions common to all IEPR cases.

32 The policy establishes technology-based standards to implement federal Clean Water Act section 316(b) and reduce the harmful effects associated with cooling water intake structures on marine and estuarine life. The policy applies to the 19 existing power plants (including two nuclear plants) that currently have the ability to withdraw over 15 billion gallons per day from the State's coastal and estuarine waters using a single-pass system, also known as once-through cooling. Closed-cycle wet cooling has been selected as Best Technology Available. Permittees must either reduce intake flow and velocity (Track 1) or reduce impacts to aquatic life comparably by other means (Track 2). See http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/policy.shtml for more information.

**Table 20: OTC Implementation Schedules for All IEPR Common Cases**

| Facility & Units | NQC[1] | SWRCB Compliance Date | IEPR Common Case Assumption |
|---|---|---|---|
| Humboldt Bay 1, 2 | 135 | Dec. 31, 2010 | Retired Sept. 30, 2010 |
| Potrero 3 | 206 | Oct. 1, 2011 | Retired Feb. 28, 2011 |
| South Bay | 296 | Dec. 31, 2011 | Retired Dec. 31, 2010 |
| Haynes 5,6 | 535 | Dec. 31, 2013 | Repowered as Air Cooled June 1, 2013 |
| El Segundo 3 | 335 | Dec. 31, 2015 | Repowered as Air Cooled July 27, 2013 |
| El Segundo 4 | 335 | Dec. 31, 2015 | Retire on Dec. 31, 2015 |
| Morro Bay 3, 4 | 650 | Dec. 31, 2015 | Retired Feb. 5, 2014 |
| Scattergood 3 | 450 | Dec. 31, 2015 | Repowered as 309 MW Air Cooled Jan. 1 2016 |
| Encina 1, 2, 3, 4, 5 | 946 | Dec. 31, 2017 | Retire on Dec. 31, 2017 |
| Contra Costa 6, 7 | 674 | Dec. 31, 2017 | Retired April 30, 2013[33] |
| Pittsburg 5, 6, 7 | 1,307 | Dec. 31, 2017 | Retire on Dec. 31, 2017[34] |
| Moss Landing 1, 2 | 1,020 | Dec. 31, 2017 | NQC derated by 15% Dec. 31,2020[35] |
| Moss Landing 6, 7 | 1,510 | Dec. 31, 2017 | Retire Dec. 31, 2020[36] |
| Huntington Beach 1, 2 | 452 | Dec. 31, 2020 | Retire Dec. 31, 2020[37] |
| Huntington Beach 3, 4 | 452 | Dec. 31, 2020 | Retired Nov. 1, 2012 |
| Redondo 5, 7 | 354 | Dec. 31, 2020 | Retire Dec. 31, 2020 |
| Redondo 6, 8 | 989 | Dec. 31, 2020 | Retire Dec. 31, 2020 |
| Alamitos 1, 2 | 350 | Dec. 31, 2020 | Retire Dec. 31, 2020 |
| Alamitos 3, 4 | 668 | Dec. 31, 2020 | Retire Dec. 31, 2020 |
| Alamitos 5, 6 | 993 | Dec. 31, 2020 | Retire Dec. 31, 2020 |
| Mandalay 1, 2 | 430 | Dec. 31, 2020 | Retire Dec. 31, 2020 |
| Ormond Beach 1, 2 | 1,516 | Dec. 31, 2020 | Retire Dec. 31, 2020 |
| San Onofre 2, 3 | 2,246 | Dec. 31, 2022 | Retired Jan. 31, 2011 |
| Scattergood 1, 2 | 367 | Dec. 31, 2024 | Repower With 2x100 MW NGCT Dec. 31,2015 |
| Diablo Canyon 1, 2 | 2,240 | Dec. 31, 2024 | Assumed Operational Through Forecast period[38] |
| Haynes 1, 2 | 444 | Dec. 31, 2026 | Beyond Common Case Forecast Period |

33 Although NRG retired Contra Costa 6-7, the Marsh Landing facility was constructed beside it. Unit 7 (682 MW) cannot operate independently of Units 5-6.

34 Unit 7 (682 MW) cannot operate independently of Units 5-6.

35 Staff assumed units 1 and 2 will continue operations with a compliance parasitic load of about 15 percent of net qualifying capacity (NQC). See Dynegy/SWRCB Settlement Agreement, http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/docs/energy_comp/settlement_dynegy_2014.pdf.

36 Ibid.

37 AES Huntington Beach, letter to SWRCB, November 8, 2013.

38 The OTC requirements for Diablo Canyon may be affected by an upcoming study of mitigation options overseen by the SWRCB's Review Committee for Nuclear Fueled Power Plants.

| Facility & Units | NQC[1] | SWRCB Compliance Date | IEPR Common Case Assumption |
|---|---|---|---|
| Harbor 1, 2, 5 | 229 | Dec. 31, 2029 | Beyond Common Case Forecast Period |
| Haynes 8 - 10 | 575 | Dec. 31, 2029 | Beyond Common Case Forecast Period |

1 Net qualifying capacity (NQC) based on (1) testing and verification; (2) application of performance criteria; and (3) deliverability restrictions.

Source: Energy Commission, Supply Analysis Office

The OTC regulation affected 19 California power plants. Of those, 16 power plants totaling about 17,500 MW are in the California ISO balancing area, and 3 are in the LADWP balancing area. The original regulatory compliance dates ranged from 2010 to 2024. In July 2011, LADWP obtained SWRCB consent to delay compliance for its three units until 2029. In return, LADWP agreed to exceed the ocean water best available control technology embodied in the OTC policy by eliminating use of ocean water for its repowered facilities.

## Non-OTC Retirements and Additions

Thermal power plant additions and retirements come from several sources. Staff uses utility integrated resource plans, POU supply form filings, various decisions from the CPUC 2014 Long Term Procurement Plan (LTPP), a combined heat and power (CHP) special study[39] in support of the IEPR, and the *QFER* database to determine recent and future power plant additions and retirements. ABB's Energy Velocity Suite,[40] an online data subscription service, also provides planned power plant additions and retirements. Lastly, staff uses the CPUC 2014 LTPP planning guidance on nonrenewable, non-OTC retirement planning assumptions to set expected retirement dates of thermal power that have operated more than 40 years.[41]

Following these identified portfolio additions and retirements, staff ran annual production cost simulations to identify any reserve deficits by transmission area. If reserves drop below currently observed levels, natural gas-fired turbines (GT) or natural gas combined-cycle plants (NGCC) have added to transmission areas with deficits.[42] Staff used GTs to meet peak and intermediate loads, while NGCCs serve forecasted baseload energy requirements. Further additions include new grid-connected and onsite CHP plants in support of Governor Edmund G. Brown, Jr.'s CHP goals outlined in the *Clean Energy Jobs Plan.*[43] After examining load profiles

39 Hedman, Bruce, Ken Darrow, Eric Wong, Anne Hampson. *Combined Heat and Power: 2011–2030 Market Assessment.* California Energy Commission ICF International, Inc. 2012. CEC-200-2012-002.

40 http://new.abb.com/power-generation.

41 See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M091/K181/91181771.PDF. See page 27, "other retirements."

42 By this stage, staff has exhausted its pool of preferred resources; for example, there are no additional energy efficiency or renewable energy resources available. In addition, staff adds GTs and NGCCs to meet electricity system reliability and to provide flexibility for integration of renewable energy resources. Staff does not add additional renewable resources beyond California's RPS targets.

43 Governor Edmund G. Brown, Jr.'s *Clean Energy Plan.* Available at http://gov.ca.gov/docs/Clean_Energy_Plan.pdf.

and simulation results, staff can choose among types of resources that best meet any identified need or simulated operating deficits. For example, a generic GT may be included in a certain geographic area if that area is deficient in generation for a few hours of the year during peak-load periods. Alternatively, staff may consider including a generic NGCC in an area that is deficient generation for many hours of the year.

## California Non-OTC Thermal Retirements

Non-OTC thermal retirement information is consistent with the assumptions set forth in the 2014 LTPP Assigned Commissioner Ruling dated May 14, 2014.[44] All cases include 48 MW of biomass, 18 MW of wind, 170 MW of coal and 785 MW of gas capacity retirements in 2015. Between 2016 and 2025, an additional 84 MW of coal and 2,384 MW of gas fired resources are expected to retire.

## California Thermal Additions

All cases include 620 MW of under-construction gas resources expected to be operational by the end of 2015. Between 2016 and 2025, cumulative additions for all cases include an additional 938 MW of new combined cycles. New generic onsite and grid-connected CHP, consistent with the Governor's CHP goals,[45] are added in the low demand/high price and mid demand cases starting in 2019, while the high demand/low price case includes no new CHP beyond that embedded in the revised *2015 CED*.

For the low demand/high price case, only new generic CHP is added to this case. There is no need for additional thermal resources beyond the cumulative 1,558 MW common to all cases. Between 2019 and 2025, new grid-connected CHP capacity of 2,023 MW and new onsite CHP capacity of 2,629 MW is included in the low demand/high price case. In addition to the 1,558 MW additions common to all cases, the mid demand case includes 741 MW of new generic NGCCs and 300 MW new generic combustion turbines (CTs) by 2025. Between 2019 and 2025, new grid-connected CHP capacity of 1,491 MW and new onsite CHP capacity of 1,339 MW is included in the mid demand case. The high demand/low price case also includes 1,558 MW common to these cases and includes 1,574 MW of NGCCs and 1,000 MW from a natural gas combustion turbine (NGCT) by 2025. No new CHP is added in this case beyond the amounts included in the *2015 CED*.

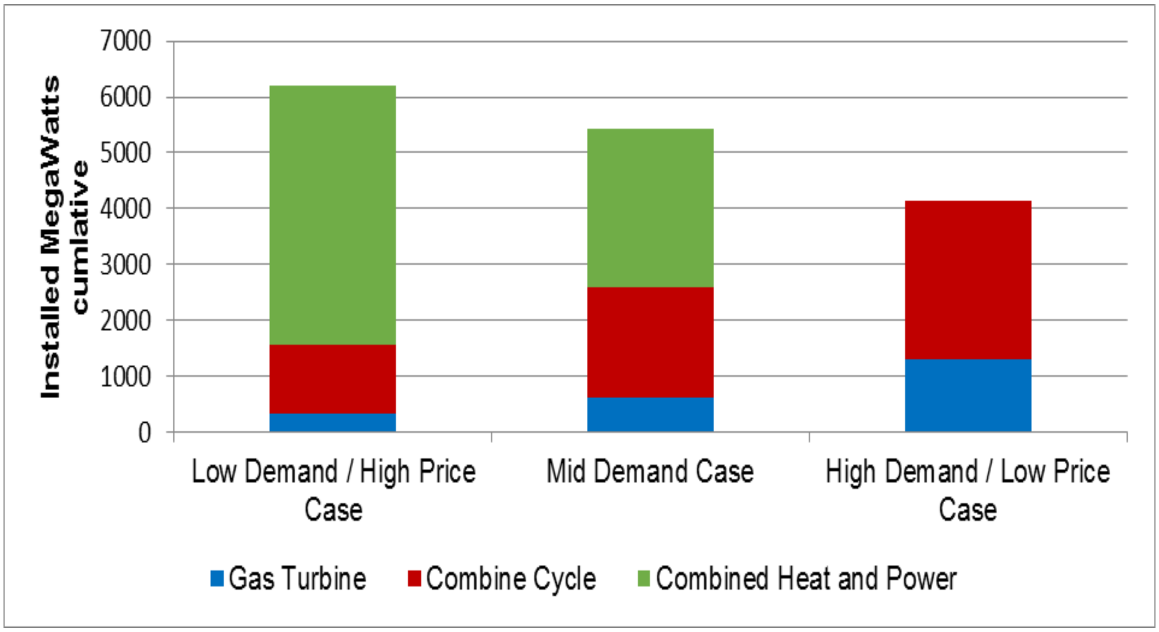
**Figure 25** shows assumed thermal power plant capacity additions in California between 2015 and 2025. All three common cases include identical thermal capacity additions in 2015. The high demand/low price case includes more NGCC and CT capacity than the mid demand and the low demand/high price cases; however, the low demand/high price case adds more CHP capacity than the mid demand and high demand/low price cases. This is due to the higher

44 See http://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=304572.

45 Governor Edmund G. Brown Jr.'s *Clean Energy Plan*. Available at http://gov.ca.gov/docs/Clean_Energy_Plan.pdf.

energy prices in the low demand/high price case, which offer incentives for large energy users to develop more CHP for their needs, as well as create opportunities for sales to the grid.

**Figure 25: California Thermal Power Plant Additions**

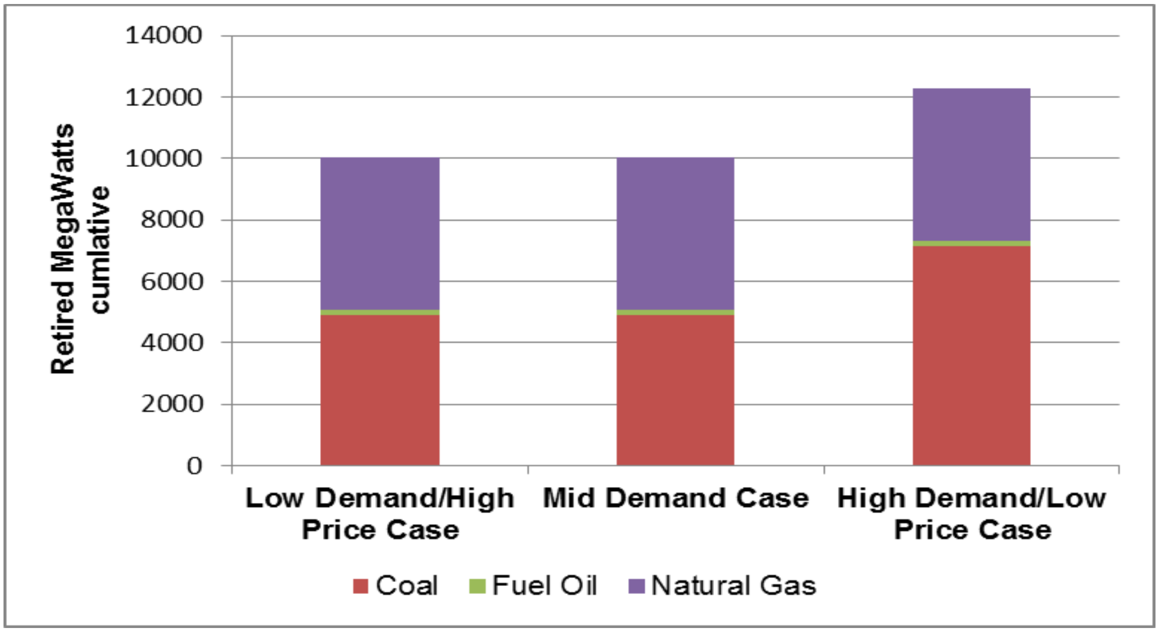



Source: Energy Commission, Supply Analysis Office

## Rest of the WECC Thermal Retirements

All three common cases include about 10,000 MW of retirements throughout the forecast period. These consist of about 5,080 MW coal and fuel oil capacity and 4,934 MW of natural gas capacity. The high demand/low price includes an additional 2,250 MW of coal retirements in 2023. **Figure 26** shows thermal plant capacity retirements for the remainder of the WECC territory.

**Figure 26: Thermal Power Plant Retirements for the Rest of WECC**



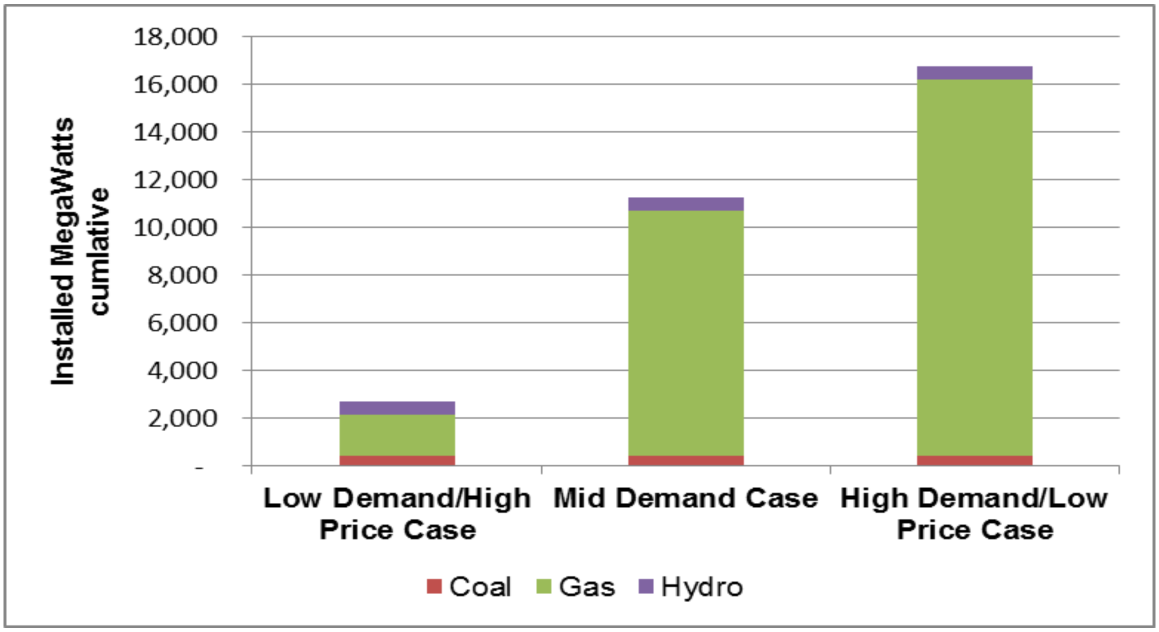

Source: Energy Commission; Supply Analysis Office

## Rest of the WECC Thermal Additions

The TEPPC 2024 common case includes new natural gas capacity additions of 8,263 MW and 428 MW of new coal capacity by 2024.

For the low demand/high price case, by 2025 an additional 1,284 MW of natural gas capacity is added, while the mid demand case includes 3,606 MW of natural gas capacity. The high demand/low price case includes more than double the total gas capacity added to the mid demand case. In the high demand/low price case, 9,128 MW of natural gas capacity are included by 2026. **Figure 27** shows thermal power plant capacity additions for the rest of WECC.

**Figure 27: Thermal Power Plant Additions Rest of WECC**




Source: Energy Commission, Supply Analysis Office

## California Renewable Curtailment or Overgeneration

Much discussion and analysis has focused on the issue of renewable curtailment or overgeneration in California. A review of the most recent summaries provided by the California ISO on this topic reveal 12 days over the past 17 months with manual renewable curtailment. Since April 27, 2014, no instances of supply/demand type of manual curtailments have been reported, only manual renewable curtailments due to transmission outages or transmission congestion.

In simulation modeling, renewable curtailment can be measured by the amounts of *dump energy* or ancillary service violations.[46] Dump energy in production cost simulation is caused by a lack of transmission or transmission constraints, as well as constraints imposed on generation within a given node. In a recent analysis by the California ISO using PLEXOS, a transmission constraint was included that created instances of renewable curtailment or dump energy as reported in simulation results. The transmission constraint that was imposed to create this overgeneration is referred to as *no net exports*. Specifically, the modeling convention for this constraint is that California cannot export more energy than is imported across all interties in all hours of the year. Energy Commission staff is gathering data to analyze if this is a reasonable simulation modeling constraint for use in production cost modeling. Given the

46 Violations are downward reserve and load-following shortfalls. These are not requirements specified by current tariffs; however, they are constraints that can be defined for simulation modeling of a future year.

shift toward an energy imbalance market and the possibility of more regional coordination with the proposed U.S. EPA Clean Power Plan, staff did not include this California-specific transmission constraint in model runs.

## Greenhouse Gas Price Projections

Assembly Bill 32 (AB 32, Núñez, Chapter 488, Statutes of 2006) requires California to reduce GHG emissions to 1990 levels by 2020. The California regulation is a key element of California's climate plan and is designed to provide covered entities the flexibility to seek and implement the lowest-cost options to reduce emissions. The ARB administers the California Cap-and-Trade Program. Quarterly auctions for GHG allowances are run by the ARB, but no source is available for future price projections of GHG allowance prices that are a key input to simulation models. Most market parties rely on private companies to forecast future GHG allowance prices. These are rarely published in a public forum. Energy Commission staff developed a method to estimate ranges of GHG price projections that can be used in publicly vetted forums and analysis. **Table 21** presents GHG price projections through 2025.

**Table 21: GHG Price Projections (nominal dollars per metric ton)**

| | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High Demand/ Low Price Case | 12.44 | 13.36 | 14.42 | 15.58 | 16.81 | 18.10 | 19.48 | 20.97 | 22.57 | 24.31 | 26.18 |
| Mid Demand Case | 12.44 | 13.36 | 14.42 | 15.58 | 16.81 | 27.15 | 29.22 | 31.45 | 33.86 | 36.46 | 39.26 |
| Low Demand/ High Price Case | 37.31 | 40.08 | 43.27 | 46.75 | 50.43 | 54.29 | 58.44 | 62.90 | 67.72 | 72.92 | 78.53 |

Source: Energy Commission, Supply Analysis Office

The 2015 beginning price is calculated based on the vintage settlement price  for all 2015 auctions (February, May, August, and November) weighted by the quantity (metric ton) sold. Prices increase in calendar year prices subsequent to 2015 will be equal to the offer price for each tier from the previous calendar year increased by 5 percent plus the rate of inflation as measured by the Consumer Price Index for all urban consumers.

The high demand/low price and mid demand cases assume identical carbon prices through 2019 due to a high probability that complementary policies reduce emissions. From 2020 on, for the mid demand case,  staff is assuming less availability of these complementary programs, resulting in carbon prices increasing 1.5 times the high demand/low price scenario. The low demand/high price case assumes GHG prices at three times the high demand/low price case, but below the containment price, because of assumed lower amounts of credits due to higher loads and less abatement from complementary policies. These assumptions are based on analysis presented in the report *Forecasting Supply and Demand Balances in California's Greenhouse Gas Cap-and-Trade Market*.[47]

47 Bailey, Elizabeth, Severin Borenstein, James Bushnell, Frank Wolak, and Matt Zaragoza. *Forecasting Supply and Demand in California's Cap and Trade Market*. Energy Institute at Haas. Berkeley School of Business, March 12, 2013. Please see https://ei.haas.berkeley.edu/ for more information.

# CHAPTER 5: Natural Gas Resources and Infrastructure

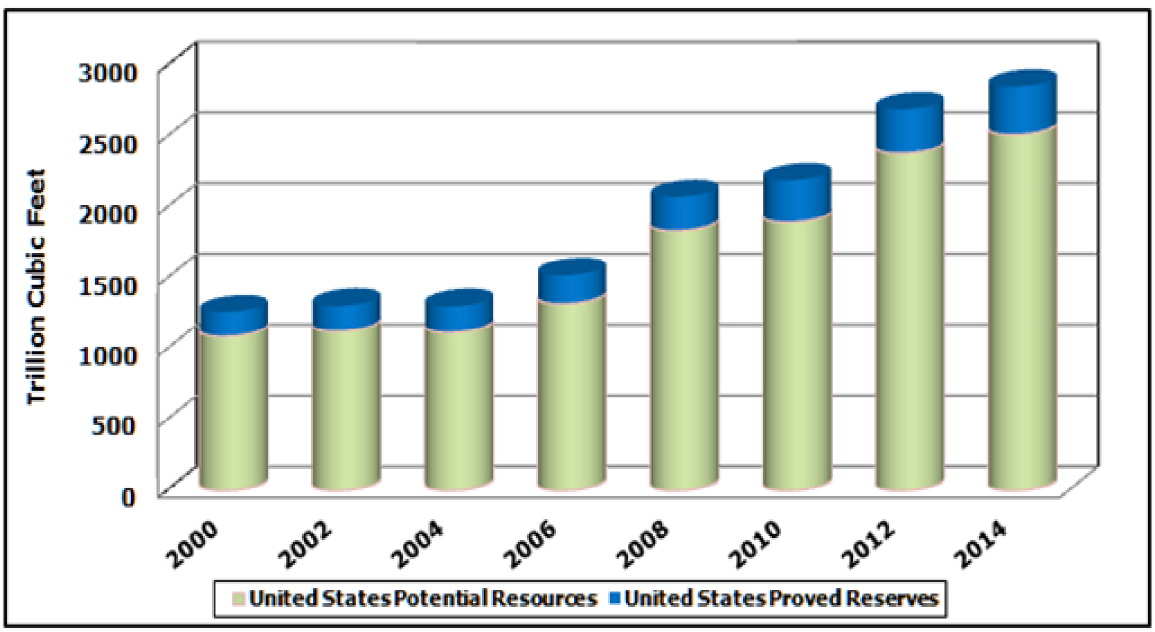
## Natural Gas Resources

### Natural Gas Reserves in the United States

The natural gas resource base, defined as the sum of the proved and potential natural gas reserves, expanded between 2000 and 2014. *Potential reserves* include all undeveloped resources in the future. These resources, geologically known but with decreasing levels of certainty, require operating and maintenance costs and the full expenditures of capital dollars for the production of these resources. As total demand for natural gas grows, producers will bring more of these resources on-line, beginning with the lowest-cost resources.

**Figure 28** shows proved and potential reserves in the United States. *Proved reserves* comprise all resources with sufficient geological and engineering information indicating with reasonable certainty that oil and gas operators can recover such reserves using existing technology under existing economic and operating conditions. Production of proven resources requires the expenditure of operating and maintenance funds and few capital dollars.

**Figure 28: Proved and Potential Reserves in the United States**



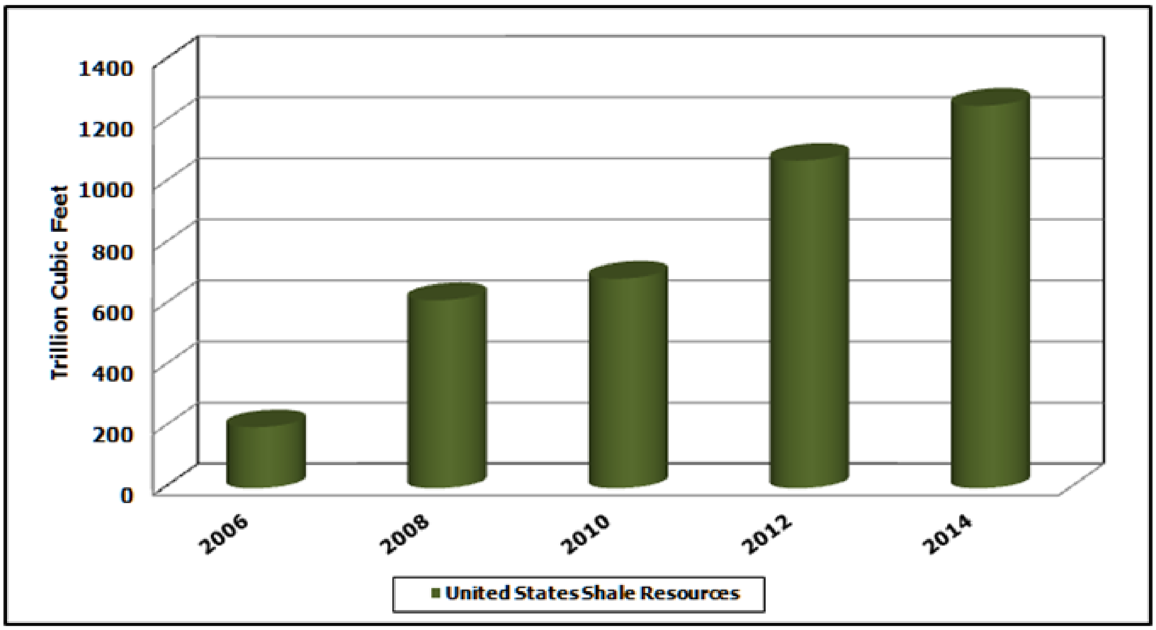

Source: U.S. EIA; Potential Gas Committee (PGC)

Proved reserves in the United States grew at about 3.2 percent per year until 2004 and then increased to 7.4 percent per year. Although the United States produces more than 20 trillion cubic feet (Tcf) of natural gas each year, proved reserves still climbed to almost 340 Tcf in

2014, up from just more than 150 Tcf in 2000. A growing percentage of the new proved reserves originate from the development of liquid-rich shale resources.

Between 2000 and 2004, total potential resources rose at a rate of 0.5 percent per year. Because of the development of shale natural gas, however, the rate of expansion of the resource base accelerated, climbing to an annual rate of 8.4 percent between 2006 and 2014. **Figure 29** shows total shale natural gas resources (proved and potential). Between 2006 and 2014, the shale gas resource base expanded at an annual of rate 25.8 percent. Shale gas development technology increased the growth rate, resulting in the total U.S. resource base expanding to more than 2,850 Tcf in 2014.

**Figure 29: Total Proved and Potential Shale Natural Gas Resources in the United States**




Source: U.S. EIA; PGC

## Hydraulic Fracturing and Associated Environmental Concerns

The development of natural gas from shale formations has expanded the resource base and boosted production. However, the production of this resource type requires the use of horizontal drilling combined with the technique known as *hydraulic fracturing (fracking).* Oil and gas operators have used some form of this technique in the United States since 1947. United States field operators have fractured more than 1 million wells. However, in the last 20 years, the technique level has accelerated and changed to incorporate new and different types of fracturing liquids and higher pressures. This has raised several environmental concerns:

- GHG emissions: Methane, the primary component of natural gas, contributes to GHG emissions
- Surface disturbance: Development requires surface preparation and may create environmental stresses in some sensitive areas

- Freshwater usage: Fracking requires between 2 million and 12 million gallons of freshwater per treatment; high usage may divert freshwater from other important and essential requirements.
- Disposal of retrieved water: After completion of a fracture treatment, operators retrieve about 30 percent to 70 percent of the injected fluid. Disposal of the retrieved water raises environmental concerns, such as spillage and groundwater contamination.
- Increased seismic activity: Studies are examining possible links between oil and gas operations and increased seismic activity in some areas of the United States.
- Groundwater contamination: Ongoing studies are examining possible links between hydraulic fracturing and groundwater contamination. All oil and gas operations pose some level of risk to groundwater aquifers.
- Socioeconomic impacts: Added noise and traffic are changing life in many communities that are first experiencing the "boom" conditions of shale gas development.

State and federal decision makers and regulators have developed, and continue to develop, regulatory frameworks to guide oil and natural gas activities within their jurisdictions. The protection of public health and the environment has collided, at times, with responsible development of natural resources. The state of New York, under which lies a portion of the Marcellus Shale (the largest source of natural gas in the United States), has banned all fracking activities. At the federal level, the Bureau of Land Management (BLM) is developing rules and regulations to:

- Strengthen existing well-integrity standards
- Require proper management of wastewater with the goal of minimizing environmental impacts
- Require the disclosure of chemicals used in hydraulic fracturing

This regulatory framework, when developed, will apply to oil and gas activities on federal lands managed by BLM. The Energy Policy Act of 2005 originally exempted the injection of fluids or propping agents, other than diesel, in fracking operations.[48] Further, in February 2014, the U.S. EPA adopted additional regulations to restrict the use of diesel in all fracking stimulations.

State regulatory agencies are also developing frameworks. All states with major natural gas production have mandated the disclosure of chemicals used in fracking; however, the degree of disclosure varies from state to state. In general, regulatory frameworks that are shaping oil and gas activities include varying degrees of the following requirements:

48 Energy Policy Act of 2005; see http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.

- Protecting and testing the groundwater
- Well testing before and after fracking stimulations
- Notifying the community
- Disposing of wastewater
- Paying environmental mitigation fees
- Responsibly developing oil and gas subsurface formations

In California, efforts are continuing to develop a workable regulatory framework. In 2013, the Legislature passed, and the Governor signed, Senate Bill 4 (Pavley, Chapter 313, Statutes of 2013) (SB 4). This bill establishes a comprehensive regulatory program for oil and gas well stimulation treatments (for example, hydraulic fracturing, acid well stimulation) that includes, among other things, a study, the development of regulations, a permitting process, and public notification and disclosure. In November 2013, the California Department of Conservation began the formal rulemaking process for *Well Stimulation Treatment Regulations*. As part of SB 4, on July 1, 2015, the Division of Gas and Geothermal Resources (DOGGR) certified the final environmental impact report, *Analysis of Oil and Gas Well Stimulation Treatments in California*.[49] Also under SB 4, on July 9, 2015, the California Council on Science and Technology released its final reports on well stimulation, *An Independent Scientific Assessment of Well Stimulation in California*.[50]

The California Department of Conservation adopted regulations on July 1, 2015, requiring oil and gas well operators "…to submit notification of well stimulation treatments and various types of data associated with well stimulation operations, including chemical disclosure of well stimulation fluids, to the Division [DOGGR]."[51] This information is available to the public in a searchable database.

## Production Types and Trends

The supply portfolio in the United States contains five main resource types:

- Shale natural gas: Methane from shale formations[52]
- Tight sands natural gas:[53] Methane from low-permeability[54] sandstone formations

49 For more information on the EIR, see http://www.conservation.ca.gov/dog/Pages/SB4_Final_EIR_TOC.aspx.

50 For more information on California Council on Science and Technology's *An Independent Scientific Assessment of Well Stimulation in California*, see http://ccst.us/projects/hydraulic_fracturing_public/SB4.php.

51 California Department of Conservation website, http://www.conservation.ca.gov/dog/Pages/WellStimulation.aspx.

52 A *formation* is a rock stratum that spreads over a geographic area in the earth's subsurface and contains natural gas.

53 *Tight gas sands* refer to natural gas obtained from very low permeability sand formations.

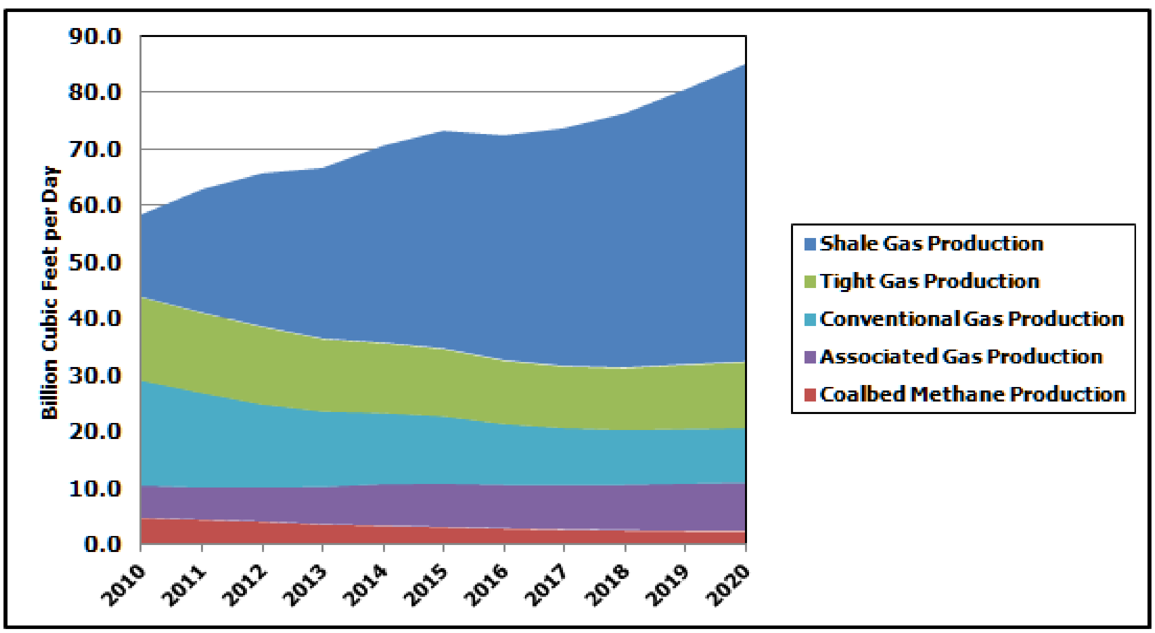
54 Measures the ability of any fluid to flow through a rock formation.

- o Conventional natural gas: Methane from high-permeability sandstones and limestone formations
- o Associated natural gas: Methane produced with crude oil and natural gas liquids
- o Coalbed methane: Methane from coal seam formations

In addition to the NAMGas model, staff acquired and used the Lippman Consulting (LCI) supply model to evaluate the dynamics of natural gas production. The forecast horizon of this model extends five years into the future, which in this version is 2020. The LCI supply model does not equilibrate supply and demand and does not assume or incorporate an explicit price trajectory. However, this model assumes a drilling rate projection unique to each supply basin in the United States. Since all supply models assume that economic agents will not act unless a market price provides the incentive, the LCI supply model imbeds the price assumptions within the assumed drilling rates. **Figure 30** shows United States production by resource type along with the relative share each occupies in the supply portfolio. The growth of shale gas production has reconfigured, and will continue to affect, the supply portfolio.

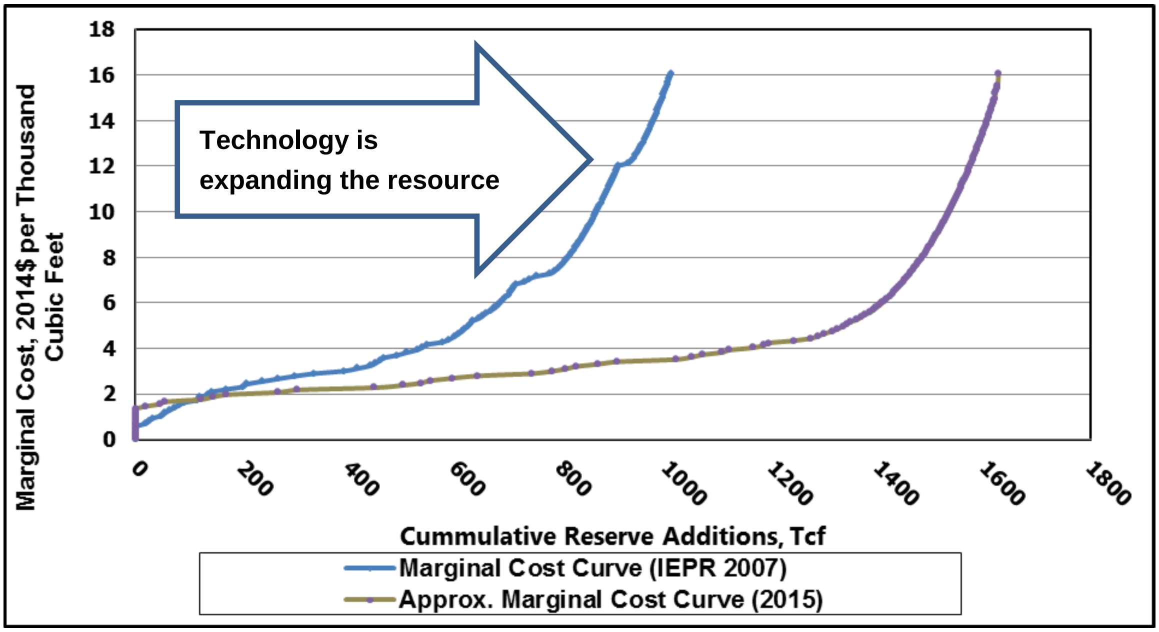
**Figure 31** shows expansion of the resource base is contributing to declining natural gas prices in North America; monthly Henry Hub prices in 2015 averaged $2.52/Mcf, about 80 percent lower than the 2008 peak price.

**Figure 30: U.S. Historical and Projected Natural Gas Production by Resource Type**




Source: Derived from PointLogic Energy Database

**Figure 31: The Expanding Natural Gas Resource Base (2007–2015)**



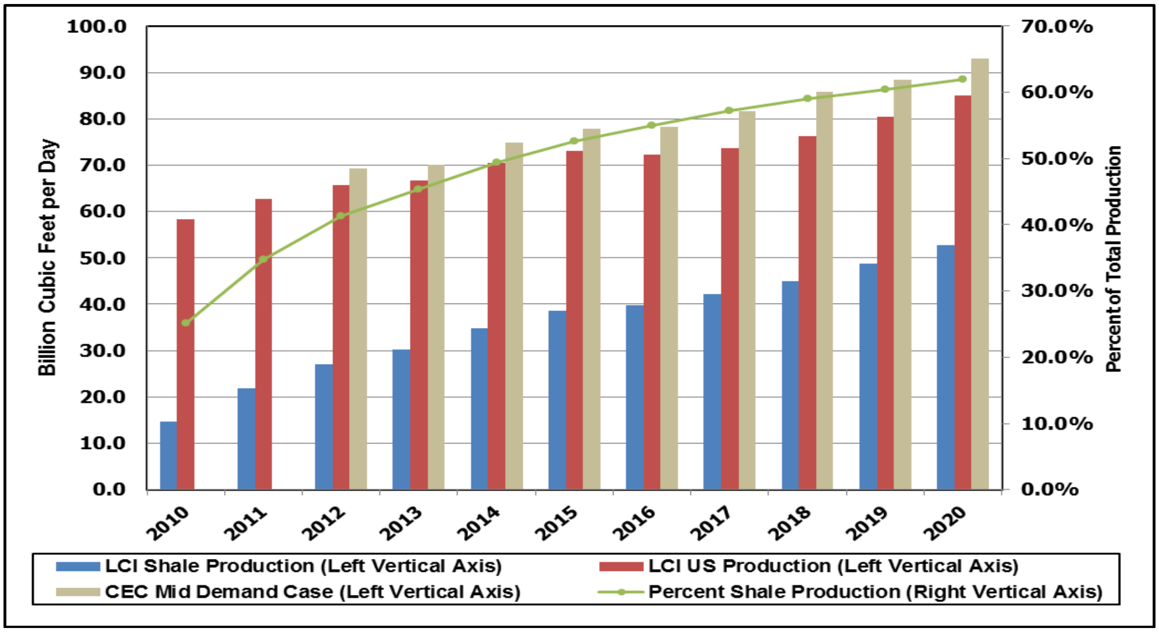

Source: Energy Commission, Baker Institute, National Petroleum Council

**Figure 32** demonstrates the growth of production from shale formations between 2010 and 2020.[55] As shown in **Figure 32**, shale gas production rises and surpasses 50 Bcf per day by 2020. Natural gas from this resource type now dominates the supply portfolio. By 2020, total production should range between 84 Bcf and 93 Bcf per day, of which more than 60 percent should originate from shale gas formations. The oil and gas industry is investing more of its capital dollars in the development of shale resources. As a result, nearly all of the increase in natural gas production originates from shale development.

**Figure 33** shows the decline in coalbed methane production; both actual production and share of total production have dropped. In 2010, coalbeds in the United States produced about 4.7 Bcf per day; by 2020, the LCI supply model estimates this resource type to produce about 2.4 Bcf per day. The percentage share of total production provided by coalbed methane, depicted with a green line on the right axis, has declined from 8.1 percent of total U.S. production to an expected value of 2.8 percent by 2020.

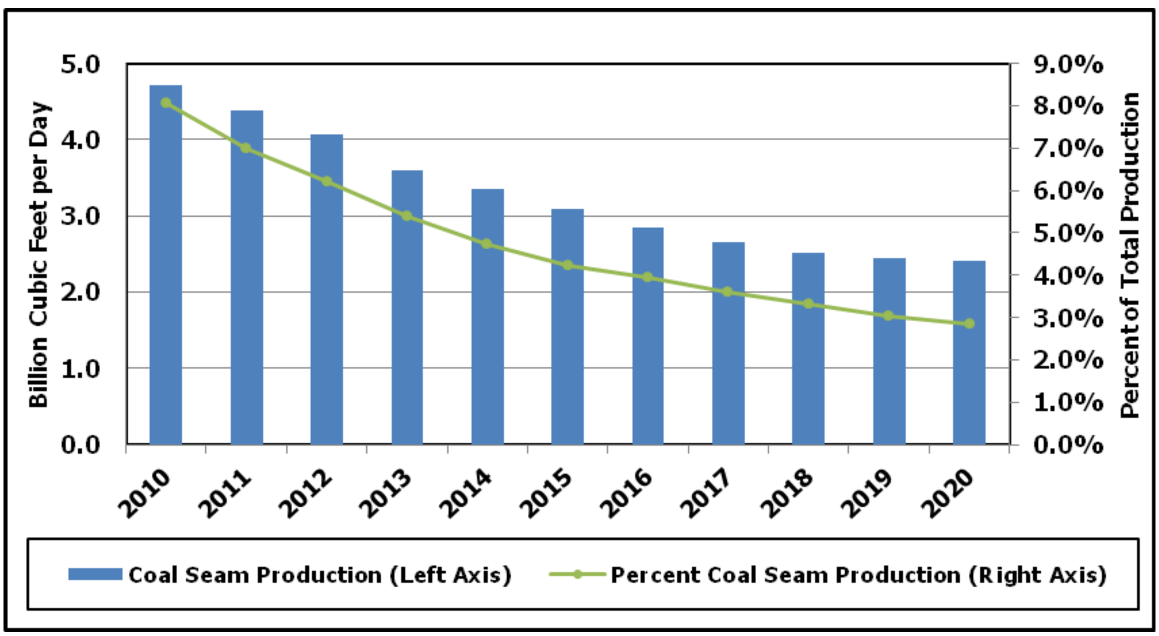
55 Staff compares results to 2020 as the LCI supply model ends in 2020

**Figure 32: Total U.S. Natural Gas Production and Shale Natural Gas Production**




Source: Derived from PointLogic Energy Database; Energy Commission, Supply Analysis Office

**Figure 33: Total U.S. Coalbed Methane Production**



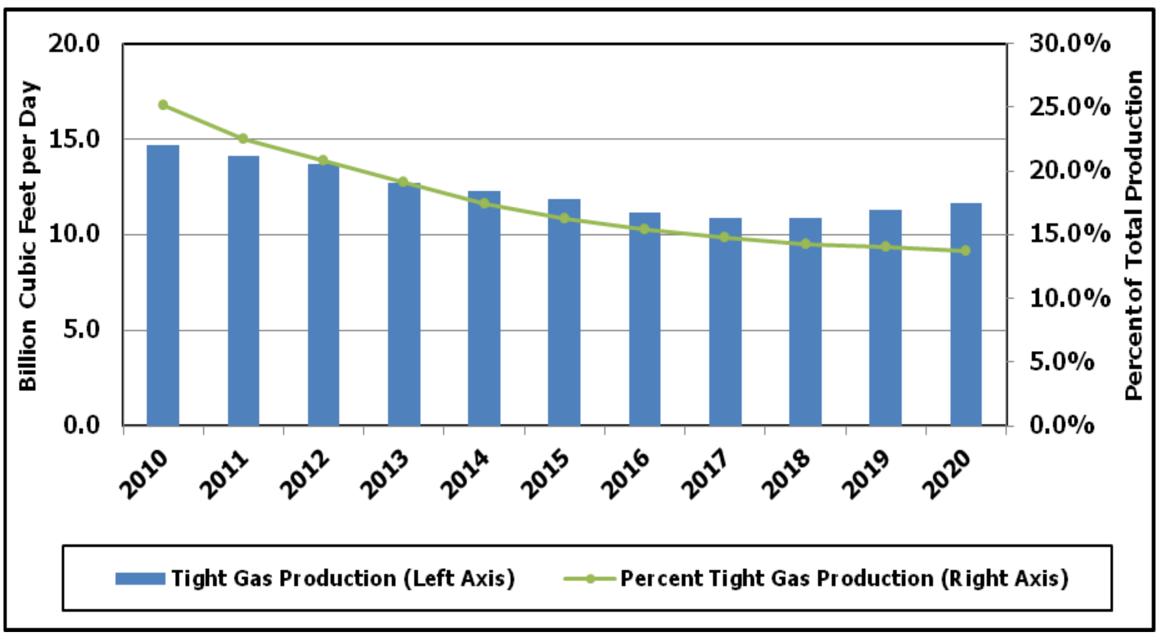

Source: Derived from PointLogic Energy Database, Energy Commission, Supply Analysis Office

The share of total production provided by tight gas sands has displayed similar erosion, though not as steep as coalbed methane. **Figure 34** exhibits the actual production and the share of total production, both historical and forecasted, for tight gas sands. The development of shale resources has diverted capital dollars away from tight sands. In 2010, tight gas sands in the United States produced 14.7 Bcf per day; by 2020, staff expects this resource type to contribute about 11.7 Bcf per day. The 2020 production value represents an increase from the low of 10.9 Bcf per day, expected to occur in 2017.

Even though production rises between 2017 and 2020, the share of production provided by tight gas sands declines in the same period. Total production is rising faster than tight gas production.

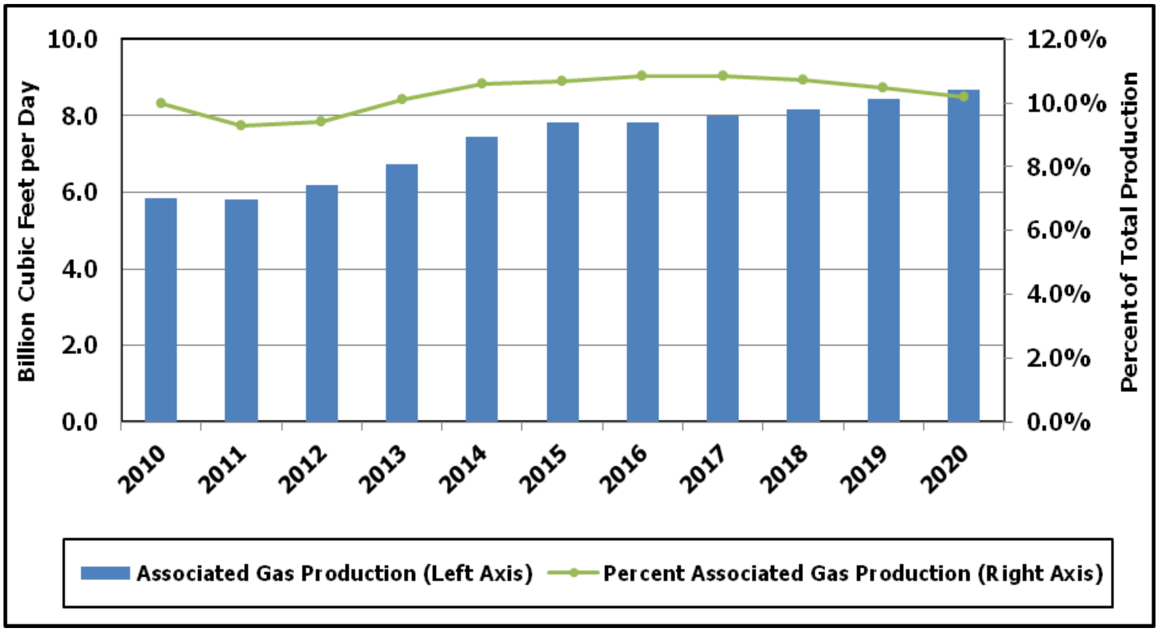
Associated natural gas production occupies between 9.3 percent and 10.8 percent throughout the forecast horizon. **Figure 35** displays the production from this resource type. Associated natural gas production rises and is expected to reach 8.7 Bcf per day by 2020. However, the production of this resource type is rising slower than total production, caused by decreased investments in crude oil wells and the decreased natural gas by-products from those wells.

**Figure 34: Total U.S. Tight Gas Sands Production**




Source: Derived from PointLogic Energy Database, Energy Commission

**Figure 35: Total U.S. Associated Natural Gas Production**

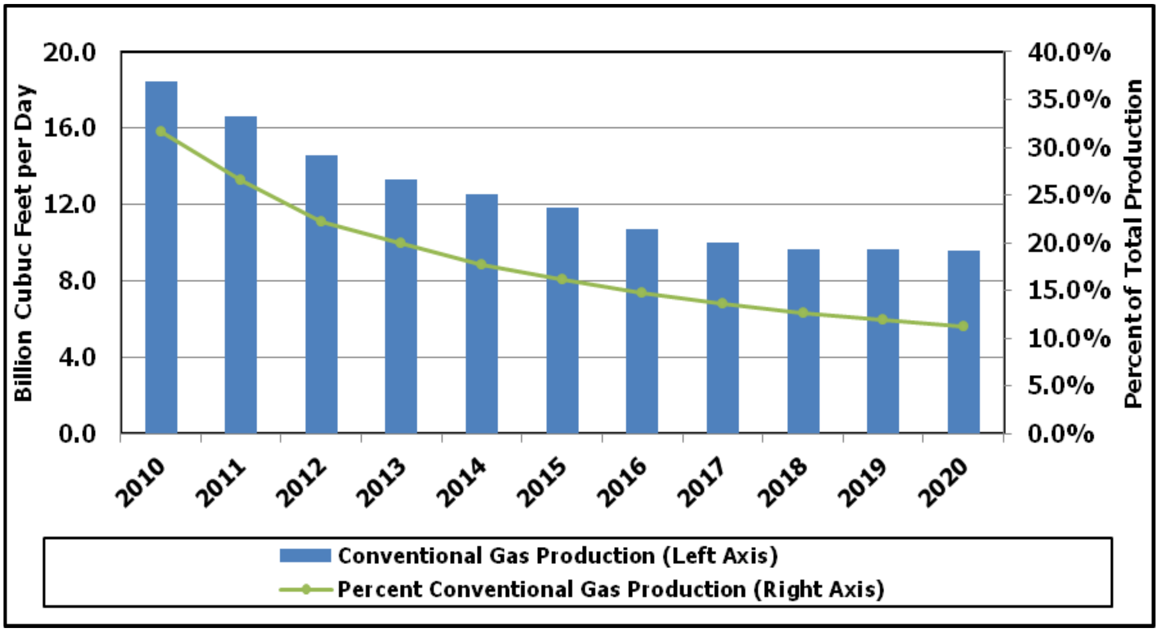



Source: Derived from PointLogic Energy Database, Energy Commission

Conventional natural gas production, once dominant among resource types, supplied more than 30 percent of the total U.S. production in 2010. However, the development of natural gas from shale gas formations has decreased the share of conventional gas production in the supply portfolio. **Figure 36** shows the U.S. conventional gas production between 2010 and 2020. In 2010, conventional gas production totaled 18.5 Bcf per day. Staff expects, by 2020, that this resource type will produce about 9.6 Bcf per day and will command a market share of about 11.2 percent.

**Table 22** summarizes U.S. production by resource type. Two trends emerge from this table. First, the growth of shale gas production has positioned this resource type as the dominant element of the natural gas supply portfolio. Staff expects shale gas production to grow at an annual rate of 13.6 percent between 2010 and 2020 and to occupy about 62 percent of the supply portfolio by 2020.

**Figure 36: Total U.S. Conventional Natural Gas Production**




Source: Derived from PointLogic Energy Database, Energy Commission, Supply Analysis Office

Second, coal seam, tight gas, and conventional gas production experience losses in both production and market share. The gains exhibited by associated natural gas result from the development of shale gas resources. The oil and gas industry is expending large quantities of capital dollars developing the so-called *wet shales.*[56] Because of the price differential between natural gas liquids and natural gas, producers are searching for liquid-rich shale formations. These formation types, such as the Bakken Shale, contain three fossil fuel components: natural gas, natural gas liquids, and crude oil. As a result, the discovery of such formation types leads to the production of associated natural gas, along with the other components.

56 *Wet shales* are formations with above-average quantities of liquids, such as crude oil and *natural gas liquids. Natural gas liquids* are naturally occurring elements found in natural gas that are typically used to produce petrochemical feedstock, propane, and butane.

**Table 22: Summary of Changes in Production by Resource Type (2010–2020)**

| | Supply Portfolio | | Production, Bcf/Day | | |
|---|---|---|---|---|---|
| | Market Share | | Actual Production | Expected Production | Annual Expected percent Change |
| | 2010 | 2020 | 2010 | 2020 | 2010-2020 |
| Shale | 25.1% | 62.0% | 14.7 | 52.7 | 13.6% |
| Coal Seam | 8.1% | 2.8% | 4.7 | 2.4 | -6.5% |
| Tight Gas | 25.2% | 13.7% | 14.7 | 11.7 | -2.3% |
| Associated Gas | 10.0% | 10.2% | 5.8 | 8.7 | 4.0% |
| Conventional | 31.7% | 11.2% | 18.5 | 9.6 | -6.4% |

Source: Derived from PointLogic Energy Database, Energy Commission, Supply Analysis Office

### Biogas and Biomethane in California

*Biogas* is typically derived from organic fuel sources, such as biomass, digester gas, or landfill gas. Biogas is composed principally of methane and carbon dioxide. *Biomethane* is the treated product of biogas where $CO_2$ and other contaminants are removed. Biogas is a by-product of normal operations at many landfills (operating and closed), dairies, and wastewater treatment plants. Biogas can also be produced by stand-alone facilities either directly through biochemical conversion (anaerobic digestion) or indirectly through gas reformation of producer gas from thermochemical conversion.

End-use opportunities include electricity production, temperature control, and transportation fuel production. In each of these cases, biogas (or biomethane) can supplement or directly replace the use of natural gas. Staff does not specifically model biogas in the NAMGas model.

## Natural Gas Infrastructure

### Natural Gas Pipeline Changes

The United States natural gas pipeline network consists of an integrated[57] transmission and distribution system that transports natural gas from numerous producing basins to users all over the country via 305,000 miles of interstate and intrastate transmission lines. More than 1,400 compressor stations aid the flow of natural gas by maintaining pressure on the natural gas pipeline network. As a result, natural gas reaches the intended delivery points and intended demand centers. Not all supply areas are connected to all demand centers, and bottlenecks and constraints arise at various locations that drive differences in regional natural gas market dynamics.

57 Canada is connected with the United States, the United States is connected with Mexico, and the whole North American natural gas system is integrated.

The development of shale natural gas has outpaced the expansion of the associated infrastructure. Bottlenecks in moving natural gas from supply basins to demand centers have spawned the capacity additions to the transmission and distribution network. The natural gas development of the Marcellus Shale Formation in Pennsylvania is motivating the pipeline capacity expansion in the Northeastern and Midwestern United States. **Table 23** shows the capacity additions in the United States between 2011 and 2015.

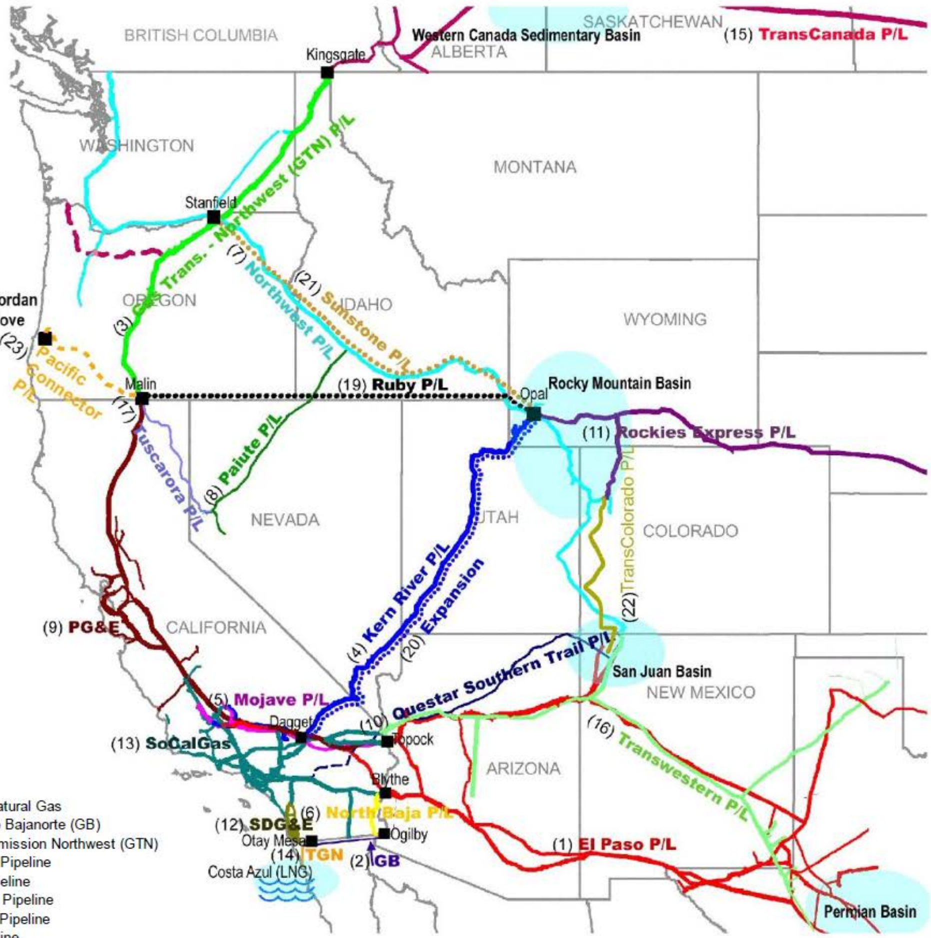
**Table 23: Capacity Additions in the United States (2011–2015)**

| | Pipeline Capacity Additions, Bcf/Day |
|---|---|
| 2011 | 15.6 |
| 2012 | 4.8 |
| 2013 | 5.2 |
| 2014 | 4.9 |
| 2015 | 0.4 |

Source: U.S. EIA

Recent additions of pipeline capacity across the country have allowed access to new shale gas supplies. Capacity added since 2011 totals more than 30 Bcf per day. While the northeastern United States is experiencing the most pipeline building activity, shale gas development in the Southwest has required the construction of some larger natural gas pipelines, such as the Eagle Ford Shale Pipeline system with capacity of 2.3 Bcf per day. In addition, developers in the Utica and Bakken Shales have announced projects to alleviate their bottlenecks. The Utica Ohio River Project, with an anticipated capacity addition of 2.1 Bcf per day, expects to flow natural gas in late 2016. **Figure 37** displays the major western North American natural gas pipelines.

## Figure 37: 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

Source: *2014 California Gas Report*

**Table 24** lists the major interstate pipelines serving California and the maximum capacity per day for each.

**Table 24: Main Pipeline Systems Serving California**

| Pipeline System | Maximum Capacity, Bcf/Day |
|---|---|
| Gas Transmission Northwest (GTN) | 2.27 |
| Ruby | 1.68 |
| Kern River | 1.9 |
| El Paso North | 2.15 |
| El Paso South | 1.41 |
| Transwestern | 1.21 |
| Mojave | 0.88 |
| Southern Trails | 0.24 |
| **Total** | **11.74** |

Source: Compiled from various sources, including the *California Gas Report*

Together, these pipelines provide the state with a total capacity of 11.74 Bcf per day, far exceeding the state's average consumption of about 6.0 Bcf per day. The internal pipeline capacity within California, however, restricts how much of the interstate capacity can serve California at any time. This in-state receipt capacity equals about 7.7 Bcf per day.[58] On an average day, the difference between interstate and intrastate capacity presents no problems in meeting demand requirements. However, on peak demand days, *choke points*[59] could develop, and this situation can lead to the issuance of *operational flow orders*[60] and possibly interrupt the flow of natural gas to some natural gas end-use sectors in California.

## California Pipeline Safety

The explosion of a PG&E high-pressure transmission pipeline in a residential neighborhood in San Bruno on September 9, 2010, killing eight people, injuring 58, and destroying or damaging more than 100 homes, has changed how citizens, energy regulators, and other public officials view natural gas pipeline safety. Lapses in pipeline safety led to that explosion. A natural gas

58 Estimated using data from the *2014 California Gas Report*, 2014.

59 A *choke point* is where the natural gas supply at a receipt point exceeds the take away capacity at that point.

60 *Operational flow orders* are when expected total transportation delivery quantities for a specific gas flow day exceeds total forecasted system capacity (including storage) on that flow day or when expected total transportation delivery quantities for a specific gas flow day are below total forecasted system demand (including maximum storage withdrawal) on that flow day.

system that does not protect the health and safety of Californians, by definition, does not satisfy the requirements of the Public Utilities Code and cannot meet California's future need for natural gas. Staff discusses issues pertaining to pipeline safety such as the California Legislature's response and the utilities' and the CPUC's work toward insuring a safer natural gas system, in detail in the companion report, *Assembly Bill 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained From Natural Gas as an Energy Source.*[61] This report includes a discussion of SoCal Gas' southern system minimum flow issues and the alternative solutions to address the issue.

## California Storage

Underground storage of natural gas plays a vital role in balancing California's demand requirements with supply availability. California has 14 natural gas storage facilities: four owned by SoCal Gas, three by PG&E, and seven by independent operators.[62] The 14 storage facilities have a working gas capacity of 374.3 Bcf and a maximum daily delivery of 8.56 Bcf.[63] As of December 31, 2015, the inventory of working gas in storage averaged 200 Bcf, about 22 Bcf lower than the previous month and 2 Bcf higher than the same time last year.[64] **Figure 38** shows California utilities' storage level over the last five years. Throughout most of 2015, natural storage inventories in California have tracked above the five-year average. A milder-than-expected winter left inventory levels in the state higher than the five-year historical average. The large drawdown in December can be attributed partly to the withdrawal of natural gas from Aliso Canyon to reduce pressure on the storage facility in effort to reduce emissions from the leaking storage well.

IOUs own and operate about half of California's total storage capacity, which brings gas closer to load centers during off-peak months and allows the gas utilities to provide relatively flexible balancing terms to their shippers. Independent providers that connect into the Pacific Gas and Electric Company gas system own the other half of the storage.

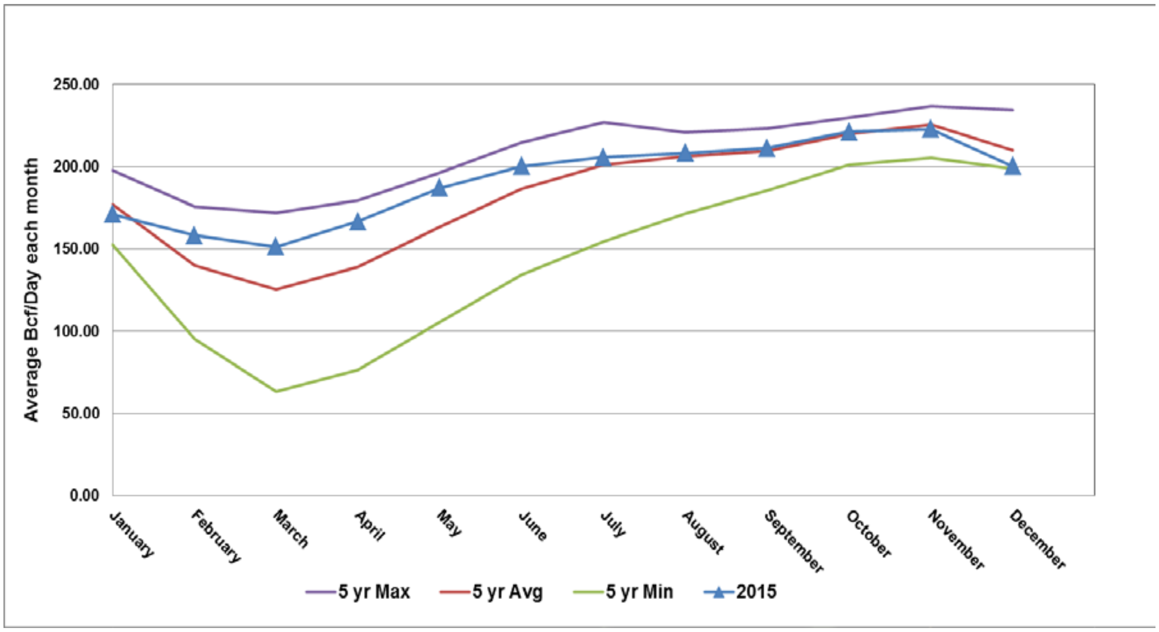
61 The *AB 1257* can be found at http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-04/TN206470_20151030T160233_STAFF.pdf.

62 The independent facilities are Wild Goose Storage, Central Valley Storage, Gill Ranch Storage, and Lodi Gas Storage. Lodi Gas Storage operates four storage reservoirs. U.S. EIA, *Field Level Storage Data*. See http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7.

63 U.S. EIA, *Field Level Storage Data*. See http://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7.

64 U.S. EIA, *Weekly Storage Report* (May 22, 2015).

**Figure 38: Utility Storage Levels (2011–2015)**




Source: SoCal Gas Envoy, PG&E Piperanger

On October 23, 2015, SoCal Gas discovered a leaking well at its Aliso Canyon Storage facility. The gas utility, with assistance from local, state, and expert consultants and confirmation from DOGGR, permanently sealed the well on February 18, 2016. According to ARB estimates, the leaking well emitted 5.4 Bcf of methane into the atmosphere.[65]

In response to the leak, Governor Edmund G. Brown Jr. issued an emergency order that details the administration's ongoing efforts to help stop the leak. The order also directs further action to protect public health and safety, ensure accountability, and strengthen oversight of gas storage facilities.[66]

On February 1, 2016, the impacted joint agencies sent a letter to Governor Brown indicating that studies were underway, along with a reliability action plan that would be developed and discussed during a public workshop. The reliability action plan will identify issues, risks, and needed steps to address regional reliability risks for summer 2016. Further collaboration will include the City of Los Angeles, South Coast Air Quality Management District, and other relevant public agencies.

California's gas storage infrastructure has grown over the past decade with the addition of new storage capacity from independent owners. The current low gas prices create few arbitrage opportunities and are unlikely to spur the construction of new storage facilities. As a result, gas

65 http://www.arb.ca.gov/research/aliso_canyon_natural_gas_leak.htm.

66 Details on Governor Edmund G. Brown's order can be found at https://www.gov.ca.gov/news.php?id=19264.

storage capacity is expected to remain constant absent more volatile seasonal prices or some circumstance that cannot be foreseen.

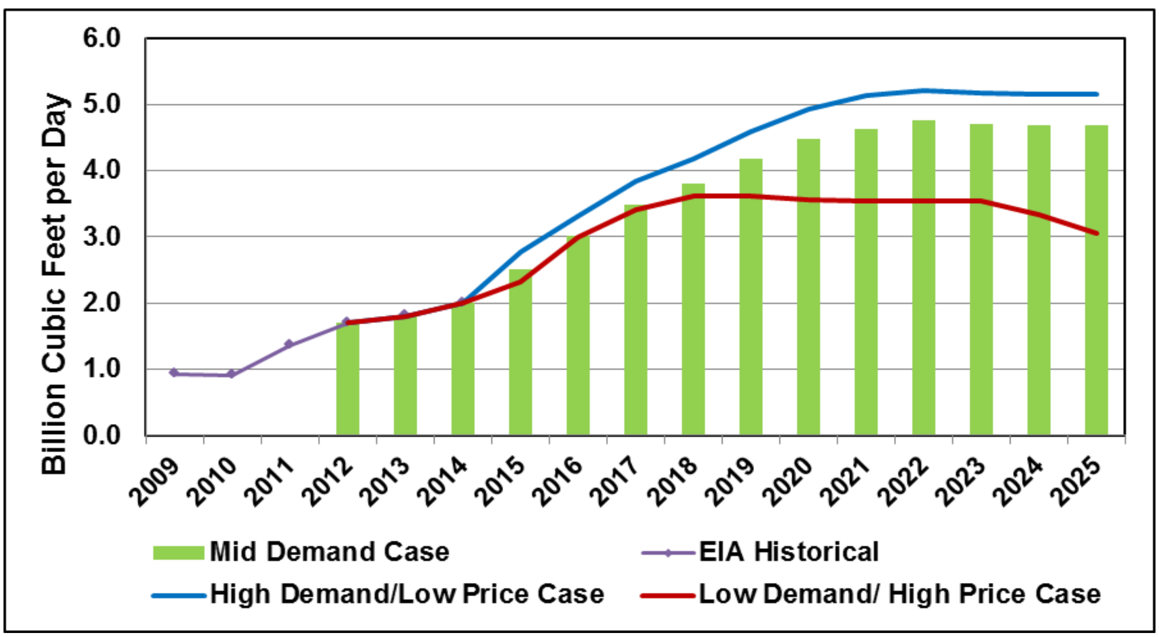
# North American Export and Import Issues

## Mexico

The increasing quantity of reserves available in the U.S. resource base, in part, is motivating natural gas producers to seek new markets. Demand for natural gas in the electric generation sector in Mexico is soaring. As a result, pipeline exports to Mexico have doubled between 2008 and 2014. Several U.S. pipeline operators have proposed building cross-border pipelines to export natural gas from the United States to Mexico. **Figure 39** shows historical and forecasted exports to Mexico from the United States.

By 2025, the mid demand case shows U.S. exports to Mexico reaching about 4.7 Bcf per day. The mid demand and high demand/low price cases stabilize exports between 3.1 and 5.2 Bcf per day. In the low demand/high price case, exports drop off starting in 2020. Low-cost gas production in the high demand/low price case offers incentives for exports to Mexico and, as a result, exports to Mexico in the high demand/low price case continue to grow for a longer period before Mexican gas resources become economically competitive.

**Figure 39: Historical and Forecasted United States Exports to Mexico**



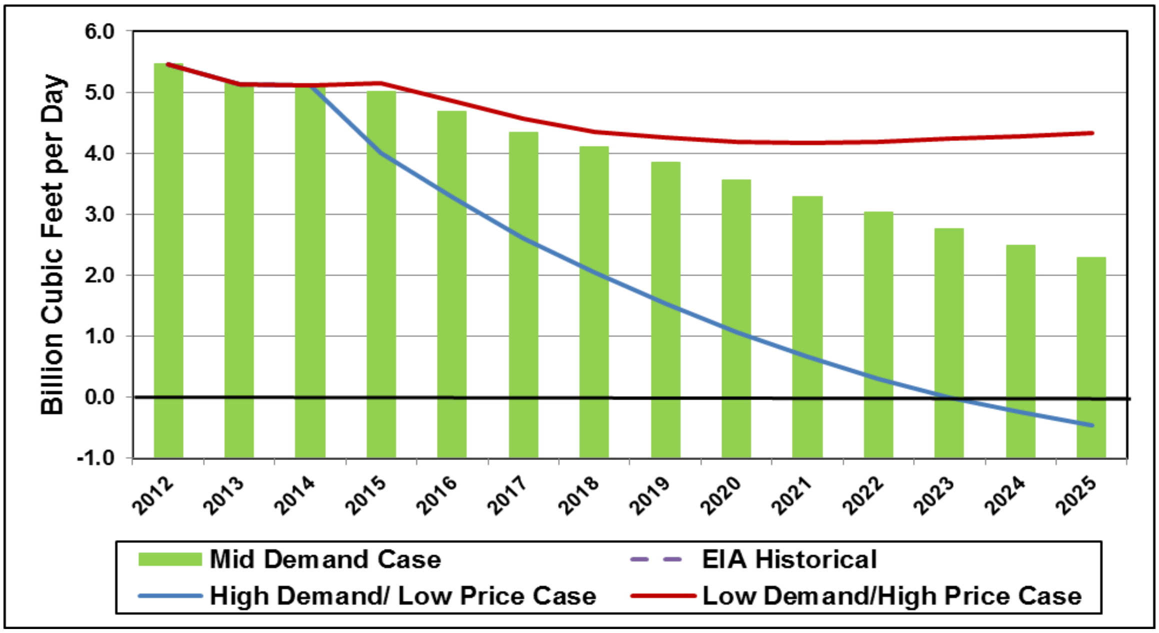

Source: U.S. EIA; Energy Commission, Supply Analysis Office

Mexico also has three liquefied natural gas (LNG) import terminals, though only two are operating. Sempra Energy's Costa Azul LNG terminal in Ensenada, Baja California, Mexico, was placed into service in 2008 but has been underused. Many LNG shipments have been redirected to Asia, where prices are higher; Southern California markets have shown little interest due to cheaper supply being available from interstate pipelines. Given the cost of LNG versus the cost of pipeline imports from the United States, LNG imports are not expected to increase anytime soon. Imports from the United States are Mexico's cheapest and best option in the near term.

## Canada

Natural gas produced in Canada has served several markets in the lower 48 states, some for more than 50 years. At least seven pipelines (GTN, Northern Natural, Northern Border, Alliance, Great Lakes, Iroquois, and Maritimes & Northeast) transport natural gas from supply basins in Canada to demand centers in the United States. **Figure 40** displays the historical and forecasted natural gas imports from Canada.

**Figure 40: Net Natural Gas Imports from Canada**




Source: Energy Commission, Supply Analysis Office

As stated in Chapter 2, in general, the highest dry gas production in the United States increases in the high demand/low price case. Staff assumed a low-cost environment in the high demand/low price case, and this assumption strengthens the competitiveness of U.S. production against Canadian imports. As a result of this increased competitiveness, Canadian imports in the high demand/low price case fall to the point of leading to net exporting of gas to Canada by the end of the forecast horizon. In both the mid demand and low demand/high price cases, imports from Canada decline consistent with recent trends.

## Liquefied Natural Gas Exports

The boom in shale gas production and resulting low gas prices have motivated the United States natural gas producers to seek international markets through LNG exports. Ten years ago, most market observers believed that the lower 48 would become a LNG importer; however, the vast quantities of shale gas now available have changed that prognosis.

To date, the U.S. DOE has approved eight LNG liquefaction terminals:

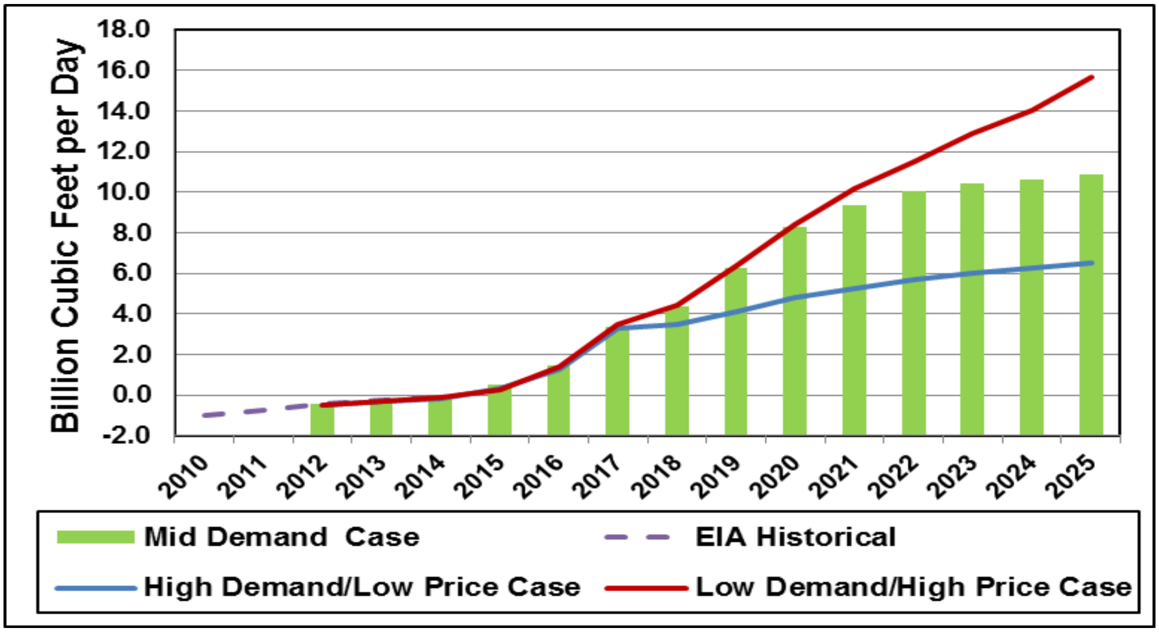
- Alaska LNG Project (Nikiski, Alaska) with maximum capacity of 2.55 Bcf per day
- Cameron LNG Terminal (Hackberry, Louisiana) with maximum capacity of 1.7 Bcf per day
- Corpus Christi Liquefaction Project (Texas) with maximum capacity of 2.1 Bcf per day
- Cove Point LNG (Lusby, Maryland) with maximum capacity of 0.77 Bcf per day
- Freeport LNG Terminal (Texas) with maximum capacity of 1.8 Bcf per day
- Lake Charles LNG Terminal (Louisiana) with maximum capacity of 2.0 Bcf per day
- Sabine Pass LNG (Cameron Parish, Louisiana) with maximum capacity of 2.2 Bcf per day

Together, these terminals total 14.4 Bcf per day of export capacity. Several applications with total capacity of another 14 Bcf per day await approval. All approved export licenses limit LNG sales only to countries having free trade agreements with the United States. Two facilities, Cameron and Corpus Christi, have begun construction. On October 1, 2015, Sabine Pass started receiving natural gas started exporting LNG in February 2016.[67] The Jordan Cove LNG terminal in Coos Bay, Oregon, received the final FERC's environmental impact statement on June 22, 2015, however FERC voted not issue a notice to proceed for the project on March 11, 2016. Cameron LNG filed to expand its liquefied natural gas export capacity in February 2015.[68] **Figure 41** shows estimated U.S. LNG exports.

67 See https://client.pointlogicenergy.com/#article-detail/pipelines/5666.

68 See http://www.naturalgasintel.com/articles/103851-cameron-lng-files-at-ferc-for-trains-4-5.

**Figure 41: U.S. Net LNG Exports**




Source: Compiled by Energy Commission staff from NAMGas model results and U.S. EIA data

# ACRONYMS

| Acronym | Proper Name |
|---|---|
| AAEE | Additional achievable energy efficiency |
| AB 1257 | Assembly Bill 1257 |
| BAA | Balancing area authorities |
| Bcf | Billion cubic feet |
| BLM | Bureau of Land Management |
| California ISO | California Independent System Operator |
| *CED* | *California Energy Demand* |
| CGR | California Gas Report |
| CHP | Combined heat and power |
| CPUC | California Public Utilities Commission |
| CT | Combustion turbine |
| EE | Energy efficiency |
| Energy Commission | California Energy Commission |
| Fracking | Hydraulic fracturing |
| GDP | Gross domestic product |
| GHG | Greenhouse gas |
| GT | Natural gas-fired turbines |
| GTN | Gas Transmission Northwest Company |
| GW | Gigawatt |
| GWh | Gigawatt hours |
| *IEPR* | *Integrated Energy Policy Report* |
| IOU | Investor-owned utility |
| LADWP | Los Angeles Department of Water and Power |
| LCI | Lippman Consulting, Inc. |
| LNG | Liquefied natural gas |
| MAPE | Mean absolute percentage error |
| MMBtu | Million British thermal unit |
| MW | Megawatt |
| NAMGas | North American Market Gas-Trade Model |
| NGCC | Natural gas combined-cycle |
| NGCT | Natural gas combustion turbine |
| NYMEX | New York Mercantile Exchange |
| NQC | Net qualifying capacity |
| OTC | Once-through cooling |
| PEMEX | Petróleos Mexicanos |
| PG&E | Pacific Gas and Electric Company |

| Acronym | Proper Name |
|---|---|
| POU | Publicly owned utilities |
| PSEP | Pipeline Safety Enhancement Plan |
| PV | Photovoltaic |
| *QFER* | *Quarterly Fuels and Energy Report* |
| RPS | Renewables Portfolio Standard |
| SB 4 | Senate Bill 4 |
| SCE | Southern California Edison Company |
| SDG&E | San Diego Gas & Electric Company |
| SMUD | Sacramento Municipal Utility District |
| SoCal Gas | Southern California Gas Company |
| SWRCB | State Water Resources Control Board |
| Tcf | Trillion cubic feet |
| TEPPC | Transmission Electric Planning and Policy Committee |
| U.S. | United States |
| U.S. EPA | United States Environmental Protection Agency |
| U.S. EIA | United States Energy Information Administration |
| WECC | Western Electricity Coordinating Council |

# APPENDIX A: Glossary

**Absorbed gas:** Methane molecules attached to organic material contained within solid matter.

**Aquifer:** An underground formation that usually contains water.

**Baseload generation:** A power plant that produced electricity to meet minimum demand requirements.

**Biogas:** Typically refers to gas that is a mixture of methane and carbon dioxide that results from the decomposition of organic matter, often from landfills.

**Burner tip prices**: Refers to the price paid for the end use of natural gas at the point of consumption, which includes items such as stoves and heaters. This price reflects all the costs throughout the process, such as exploration, development, and transportation, along with the price of the natural gas.

**Cap and trade:** Used to refer to environmental policy that places a limit, or cap, on emissions, while allowing sources to trade for extra credits in order to exceed the cap.

**Carbon footprint**: The total set of GHG emissions caused by the direct and/or indirect action of an individual, organization, event, or product.

**Carrier pipeline**: A pipeline in a system that transports gas to another region or local delivery system.

**Casing pipe:** Set with cement in a hole drilled in the earth.

**Clean energy:** An energy source that results in little to no environmental impacts. An example would be renewable energy.

**Coal generation conversion**: The process of switching energy dependence on coal generation to another resource.

**Coal-bed methane (CBM)**: Natural gas from coal deposits.

**Combined heat and power generation**: A form of generation that creates electricity and uses the heat that is produced during electric generation.

**Compressed natural gas (CNG)**: Natural gas that has been subject to a high amount of pressure that lowers the volume.

**Curtailment:** The restriction of natural gas usage.

**Demand response:** The responsiveness of consumer demand to changes in the market price.

**Digester gas**: Methane that is derived from the decomposition of organic matter, usually agricultural waste.

**Drilling**: The process of boring a hole in the earth to find and remove subsurface fluids, such as oil and natural gas.

**Electric generation**: Creating electricity for use.

**Energy imbalance market:** An energy market formed by California ISO and PacifiCorp that determines and reconciles system energy imbalances. An *energy imbalance* is the difference between load and generation.

**Energy-intensive, trade-exposed (EITE) industries**: Industries with considerable energy usage that face market competition.

**Environmental impact**: Adverse effect upon natural ambient conditions.

**Equilibrium:** A balancing point.

**Error bounds**: A statistical measure that establishes a range that an estimate can reasonably lie within.

**Finding and development (F&D):** The cost associated with exploring for and developing a resource.

**Firm gas delivery**: A contract agreement that reserves pipeline capacity for delivery of natural gas, causing it to be available during a period.

**Flex Alerts**: An emergency alert that urges Californians to save energy.

**Formation**: A bed or rock deposit composed, in whole, of substantially the same kind of rock; also called reservoir or pool.

**Fuel-switching capabilities:** The ability to switch from one type of fuel to another efficiently.

**Gas shippers**: Anyone who owns rights on a natural gas distribution system

**Greenhouse effect:** Greenhouse gases, such as carbon dioxide, methane, and nitrous oxide, trap radiant energy from the Earth's surface.

**Greenhouse gas emissions**: Gases, primarily carbon dioxide, methane, and nitrous oxide, that are released and contribute to the greenhouse effect.

**Groundwater** Water in the Earth's subsurface used for human activities, including drinking.

**Groundwater contamination:** Pollution of water resources, specifically groundwater.

**Henry Hub:** Located in Southern Louisiana, it is a major pricing point in the Lower 48.

**Horizontal well:** A hole at first drilled vertically and then horizontally for a significant distance (500 feet or more).

**Hub price:** A pricing point.

**Hydraulic fracturing:** The forcing into a formation of a proppant-laden liquid under high pressure to crack open the formation, thus creating passages for oil and natural gas to flow through and into the wellbore.

**Hydroelectric generation**: Creating electricity using hydrologic resources.

**Infrastructure:** The structures needed to support civilization, specifically pipelines, LNG compressor stations.

**Interruptible supply:** A contract agreement that allows service to be unavailable for a period.

**Interstate pipeline system**: Pipeline systems that run from state to state.

**Intrastate pipelines:** Pipeline systems that run within a state.

**Iterative process**: A function that is performed repeatedly.

**Liquefied natural gas:** Natural gas that has been cooled to a certain temperature or subjected to pressure to change it from a gas to a liquid. This reduces the volume of the gas and makes it easier to transport.

**Local distribution companies**: Utility companies that distribute gas to consumers, after receiving it from transmission lines.

**Locally distributed generation**: The production of electricity from local sources.

**Mitigation costs**: Costs that offset existing or potential environmental impact.

**Moratorium:** The restriction or banning of a proposed activity.

**Natural gas nominations**: The act of declaring how much natural gas will be needed during a specific period.

**Natural gas-fired generation**: Creating electricity from natural gas.

**Net present value**: The process of finding the current-date value of a stream of cash flows occurring in multiperiods. Present value of revenues minus present value of costs gives the net present value.

**Nondisclosure clause**: A confidentiality agreement.

**Nuclear generation**: Creating electricity using radioactive elements.

**Once-through cooling:** The use of water from a nearby water source to cool the pipes in a power plant. The water is then returned to the source from which it came.

**Open season process**: The process where interested parties submit bids for new transportation capacity to pipelines companies.

**Operating and maintenance cost**: The variable cost of producing natural gas.

**Original gas-in-place**: The total initial volume (both recoverable and nonrecoverable) of oil and/or natural gas in-place in a rock formation.

**Oversupply**: An abundance of supply.

**Permeability**: The ability of a fluid (such as oil or natural gas) to flow within the interconnected pore network of a porous medium (such as a rock formation).

**Petroleum coke**: A by-product of oil refinery or cracking that comes in different grades, some of which can be used for fuel.

**Pipeline capacity**: The amount of gas that can be safely transported through a pipeline.

**Pipeline-quality methane**: Gas that meets certain quality specifications that make it suitable for transportation in a pipeline.

**Porosity**: The condition of a rock formation by which it contains many pores that can store hydrocarbons.

**Power generation portfolio**: The different energy sources used to generate electricity.

**Price elasticities**: A measure of how responsive a commodity is to changes in price.

**Procurement:** The acquisition of a resource, for example, would be obtaining fuels for electricity generation.

**Production decline profile**: A chart demonstrating the depletion of a producing well.

**Proppant**: A granular substance (sand grains, walnut shells, or other material) carried in suspension by a fracturing fluid that keep the cracks in the shale formation open after the well operator retrieves the fracturing fluid.

**Ramping**: The ability to increase or decrease electricity generation to meet load requirements.

**Recoverable reserves:** The unproduced but recoverable oil and/or natural gas in-place in a formation.

**Regression analysis**: The statistical method of finding a trend line from data, then using this information to determine a relationship between the variables.

**Renewable generation:** Creating electricity from hydro, solar, or wind energy sources. These sources are renewable, meaning they are easily and naturally replenished.

**Renewables Portfolio Standard**: A regulation that determines how much energy should be produced from renewable resources.

**Rig count**: The number of drilling rigs actively punching holes in the earth.

**Salt cavern:** A salt dome formation that is flushed with water to create caverns.

**Shale**: A fine-grained sedimentary rock in which the original constituents were clay minerals or mud.

**Shale gas**: Natural gas produced from shale formations.

**Shoulder season**: The period between peak and off-peak season.

**Spot market:** A market in which natural gas is bought and sold for immediate or very near-term delivery, usually for a period of 30 days or less. The transaction does not imply a continuing agreement between the buyers and sellers. A spot market is more likely to develop at a location with numerous pipeline interconnects, thus allowing for a large number of buyers and sellers. The Henry Hub in Southern Louisiana is the best-known spot market for natural gas.

**Stimulation**: The process of using methods and practices to make a well more productive.

**Technological innovation**: The improvement of existing technology.

**Tight gas**: Natural gas from very low permeability rock formations.

**Transmission Expansion Planning Policy Committee (TEPPC):** TEPPC has four main functions: oversee and maintain public databases for transmission planning; development, implement, and coordinate planning processes and policy; conduct transmission planning studies; and prepare interconnection wide transmission plans. (See https://www.wecc.biz/TEPPC/Pages/Default.aspx.)

**Unconventional production**: Natural gas from tight formations or from coal deposits or from shale formations.

**Well**: A hole in the earth caused by the process of drilling.

**Well completion**: The activities and methods necessary to prepare a well for the production of oil and natural gas.

**Well stimulation technologies:** Use of different injection fluids such as petroleum, acid, or steam to release oil and natural gas trapped underground.

**Wellbore**: The hole made by drilling. It may be cased, that is, pipe set by cement within the hole.

**Wellhead**: The mouth of the gas well.

**Western Electricity Coordinating Council (WECC):** Through reliability-related activities, the WECC provides critical support to entities throughout the Western Interconnection in carrying out their reliability missions. The WECC region extends from Canada to Mexico and includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California, Mexico, and all, or portions of, 14 western states in the United States.

**Wind turbines:** The rotating blades that are used to generate electricity.