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# 2013 NATURAL GAS ISSUES, TRENDS, AND OUTLOOK

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown, Jr., Governor

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# ABSTRACT

The *2013 Natural Gas Issues, Trends, and Outlook* report is produced to support the California Energy Commission's *2013 Integrated Energy Policy Report*. Energy Commission staff, in consultation with industry experts, developed scenarios, or "cases," depicting future natural gas demand and supply trends under a variety of assumptions. The reference case represents a business-as-usual scenario in which likely outcomes are based on current trends in natural gas markets, commercial activity, and economic developments. The high-demand/low-price and the low-demand/high-price cases were created by altering assumptions in ways that led to conditions that would move natural gas prices lower or higher than in the reference case. Staff also developed two additional cases that focus on future natural gas prices and demand from constructed scenarios centered on shale gas development, more renewable and less coal-fired generation, and varying levels of energy efficiency. This report also discusses recent trends in and future outlooks for issues that could play an influential role in supply, demand, and prices of natural gas. The report is intended to provide planners and decision makers the information to aid in near- and long-range procurement decisions and contingency planning.

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

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# EXECUTIVE SUMMARY

The *Natural Gas Issues, Trends, and Outlook* is produced every two years as part of the California Energy Commission's *Integrated Energy Policy Report*. State government has an essential role to ensure that a reliable supply of energy is provided consistent with the protection of public health and safety, promotion of the general welfare, maintenance of a sound economy, conservation of resources, and preservation of environmental quality (Public Resources Code Section 25300[b]). The Energy Commission's reporting, assessment, forecasting, and data collection are essential to serve the information and policy development needs of the Governor, the Legislature, public agencies, market participants, and the public (PRC Section 25300[c]). In this report Energy Commission staff, in collaboration with industry experts from Rice University and elsewhere, has developed future planning cases projecting natural gas prices, supply, and demand for the electric generation sector from 2013 to 2025 under a variety of assumptions.

## Modeling Approach

Energy Commission staff produced a range of scenarios using the North American Market Gas Trade Model, based upon plausible and transparent assumptions, to give planners and decision makers information about the possible supply, demand, and price of natural gas in the future. This information can then be used to help determine near- and long-term procurement needs and conduct contingency planning. Results are based on inputs about natural gas demand for residential, industrial, and commercial needs from the Energy Commission's Demand Analysis Office. Initial demand assumptions for natural gas for power generation were outputs from the production cost model, PLEXOS®, in the Energy Commission's Electricity Analysis Office. Initial demand for natural gas in the transportation sector was derived from historical trends.

## Natural Gas Outlook

Staff developed three "common cases" to illustrate projected trends in the natural gas market. The input assumptions were altered in each case to reflect the desired conditions affecting the natural gas market. The cases are referred to as "common" because they are common to several analyses performed for the *2013 Integrated Energy Policy Report* across several offices and staff units.

### *Common Cases*

The reference case, or the business-as-usual case, represents a future in which the economy and commercial activity in the gas market proceed as if the current state of the market and regulatory conditions continue. The reference case assumptions were modified to produce conditions favorable to a low-price environment in the high-energy-demand/low-price case

and conditions favorable to a high-price environment in the low-energy-demand/high-price case. These modified assumptions were constructed to yield the following modeling scenarios:

- In the low-energy-demand/high-price case, greater demand initially results in higher prices, which leads to lower demand over the projection period.
- In the high-energy-demand/low-price case, lower demand initially results in lower prices, which leads to higher demand over the projection period.

The basic input assumptions in the common cases address economic growth, technology improvements, combined heat and power targets, natural gas demand, Renewables Portfolio Standard targets (California will have 33 percent of its electricity load requirements met by renewable power sources by 2020.), coal-fired power generation changes, liquefied natural gas capacity additions, natural gas resource availability, environmental mitigation costs, energy efficiency savings, and production costs.

The low-energy-demand/high-price case was designed using the following assumptions as inputs in the model:

- A 3 percent gross domestic product growth rate, the highest of the three cases.
- A 5.5 percent reduction in the available natural gas resource, relative to the reference case.
- Higher natural gas production costs than in the other two cases.
- Greater combined heat and power demand and total installed capacity in California than in either of the other two cases.
- Additional environmental mitigation costs of $0.50 per thousand cubic feet for shale gas and $0.30 per thousand cubic feet for conventional gas.
- Additional liquefied natural gas export capacity additions built and begin exporting.
- A higher amount of coal generation capacity retired than in the other cases and a 10-year delay in meeting Renewables Portfolio Standard targets in California, the Western Electricity Coordinating Council (the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection), and surrounding states.
- Higher additional achievable energy efficiency savings provide incentives for more investment in energy efficiency technologies.
- The natural gas technology improvement rate is 1 percent, as in the reference case.

Conversely, the high-energy-demand/low-price case was designed using the following assumptions:

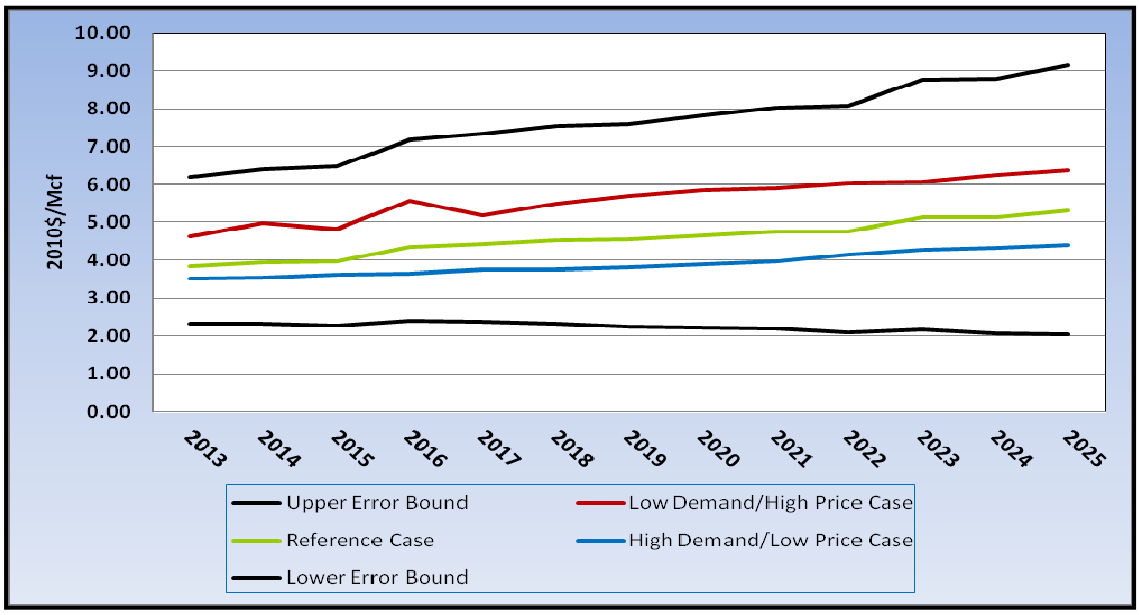
- A 2 percent gross domestic product growth rate.

- A 5.5 percent increase in the available natural gas resource, relative to the reference case.
- The lowest production cost assumption of the three cases.
- The lowest combined heat and power demand and installed capacity of the three cases.
- No additional environmental mitigation costs.
- No new liquefied natural gas capacity additions.
- The lowest amount of coal generation capacity retired among the three cases and no delay in meeting Renewables Portfolio Standard targets in California, the WECC, or surrounding states.
- The lowest level of additional achievable energy efficiency savings, which reduces the investment in energy efficiency technologies.
- A natural gas technology improvement rate of 2.5 percent, the highest among the three cases.

### *Natural Gas Prices*

The natural gas prices projected by staff's North American Market Gas Trade Model for this outlook are estimates that use annual inputs to produce annual average prices. The North American Market Gas Trade Model does not account for fluctuations that occur in the natural gas market seasonally and daily. The projected prices of natural gas at the Henry Hub from 2013 to 2025 for the three common cases are shown in **Figure 1**. The actual average price for natural gas at the Henry Hub (the distribution hub in Louisiana that generally sets the market price for North America) was $3.70 per thousand cubic feet in 2013. The projected prices in 2025 range from $4.40 per thousand cubic feet to $6.40 per thousand cubic feet. To account for inherent uncertainty in natural gas markets, staff used past natural gas price forecast results generated by the Energy Commission to produce error bands around price results of the three common cases. Staff used the percentage difference between Energy Commission forecasts and actual natural gas market prices to develop trend line equations that were applied to the current reference case price results. The error bands capture a much wider range of uncertainty than seen in the price differential of the common cases.

**Figure 1: Common Case Price Projections (Henry Hub) With Adjusted Error Bands**




Source: Energy Commission: Electricity Analysis Office.

### *Natural Gas Demand*

The reference case projects that overall demand for natural gas in California will reach 5,639 million cubic feet per day in 2025—down from 5,738 million cubic feet per day in 2011. In all cases, demand for the residential sector remains relatively flat as energy efficiency measures are expected to continue to reduce demand in this sector. For all cases, demand in the power generation sector increases in 2015, followed by a decrease in demand. This is because of the closure of the San Onofre Nuclear Generating Station in 2012, which will require some replacement generation from natural gas. However, by 2020, more installed renewable generation is projected to both decrease the need for natural gas in the power generation sector and to result in a 1 percent decrease in gas demand for power generation between 2011 and 2025.

In the Lower 48 states, a net demand increase is expected to occur because of population growth, increased demand from Mexico, potential liquefied natural gas exports, reductions in coal-fired generation, and modest increases in demand for natural gas vehicles. This net demand increase is expected to occur despite demand reductions caused by energy efficiency measures and increased generation from renewable sources. In 2025, overall demand for natural gas in the Lower 48 states is projected to be about 75 billion cubic feet per day in the reference case—up 25 percent from 2011.

### *Natural Gas Production*

The reference case projects overall natural gas production in the Lower 48 states growing at a rate of 1 percent per year between 2011 and 2025 to about 75 billion cubic feet per day by 2025. A growing portion of these future production increases is projected to come from shale gas formations.

## Natural Gas Supply Issues

### *Shale Gas and Hydraulic Fracturing*

The combination of horizontal drilling and hydraulic fracturing and three- and four-dimensional seismic surveys has increased drilling efficiency and is enabling production from formerly inaccessible natural gas-bearing shale formations in 31 of the Lower 48 states. Hydraulic fracturing is a process in which fractures in rocks below the earth's surface are opened and widened by injecting chemicals and liquids at high pressure. These technological advancements in exploration and drilling techniques have resulted in dramatic reassessments of North American gas resources. As a result, the amount of gas that is economically recoverable at a certain price has grown substantially. In 2007, 700 trillion cubic feet of gas was economically recoverable at a price of $6.00 per million British thermal units, while in 2013, the amount of gas economically recoverable at that price increased to nearly 1,400 trillion cubic feet, a 100 percent increase

Hydraulic fracturing has become very controversial because of health and environmental concerns, and decision makers are reexamining policies and regulations that apply to shale gas production. There has been public opposition to hydraulic fracturing in some states because of the large water demands (especially in arid climates), the potential for groundwater contamination, increased seismic activity, and methane emissions. There are also concerns about the impacts on wildlife, native plants, and habitat, including habitat fragmentation. New regulatory frameworks are being developed state by state, and the United States Environmental Protection Agency is conducting its own investigation and is considering new federal regulations.

In September 2013, California enacted Senate Bill 4 (Pavley, Chapter 313, Statutes of 2013). The legislation will require increased well testing, community notification, and the disclosure of the chemicals used in hydraulic fracturing. The California Department of Conservation released draft regulations concerning hydraulic fracturing in December 2012 and opened a rulemaking process in November 2013 to formally consider new rules. The California Department of Conservation anticipates that the process will be completed by January 2015.

### *California Shale Development*

Most of California's oil and gas production has been from vertical wells drilled into traditional oil and natural gas reservoirs (formations). California's Monterey Shale formation, located in San Joaquin Valley, is mainly an oil-bearing reservoir but may produce associated natural gas, though the industry has not yet developed reliable estimates of the amount of natural gas contained in the formation. The folding structure of the Monterey Shale makes it much more technically challenging to drill and fracture hydraulically than shale deposits in other areas of the United States (for example, the Bakken and Marcellus shale deposits).

## Natural Gas and Electricity Generation Industry Interface

### *Natural Gas Supply for Electricity Generation*

The natural gas and electricity industries have become increasingly interdependent as the use of natural gas for power generation increases nationwide. Many regions that have relied on coal-fired generation are now switching to natural gas-fired generation because of stricter greenhouse gas emission standards and the low price of natural gas. California already relies on natural gas generation for a large portion of its electricity supplies and has a minimal amount of power generation from in-state and out-of-state coal facilities. The rest of the Western Electric Coordinating Council area has about 37 gigawatts of coal-fired generation capacity. Fuel switching to natural gas could affect supplies to California.

California's Renewables Portfolio Standard mandate of 33 percent renewables by 2020 is leading to a buildout of renewable generating capacity that is producing energy that likely would have been met by natural gas-fired generating units. However, because of the intermittent nature of renewable generation, natural gas-fired units may be needed to fill in short-term mismatches between supply and demand. However, the exact amount of natural gas generation that will be needed in the future to integrate increasing renewable resources is not yet known.

### *Natural Gas/Electric Synchronization Case*

The issue of synchronizing natural gas supply with electricity generation has become more important as demand for natural gas in the power generation sector increases, more generation is produced from renewable energy sources, and more coal-fired units are replaced with gas-fired units. To address these trends, staff developed a natural gas/electric synchronization case to examine the *net effects* of increased renewable generation, coal-fired generation retirement, and no additional energy efficiency on natural gas demand in the power generation sectors in California and the Western Electricity Coordinating Council. This case differs from the reference case in assuming a more aggressive target of 40 percent renewables in California by 2025. This case also assumes that, nationwide, 80 gigawatts (rather than 61 gigawatts in the reference case) of coal-fired generation capacity will be converted to natural gas-fired generation beginning in 2014. Model results for California

project that aggressive energy efficiency has the potential to reduce demand for natural gas in the power generation sector more than a higher Renewables Portfolio Standard target. Model results showed no discernible differences in demand for power generation in WECC states—which have less aggressive energy efficiency targets—until after 2022, when more coal retirements are expected to occur.

## Natural Gas Infrastructure

### *Natural Gas Pipeline Changes*

In 2011-2012, new pipeline development in the United States was focused around removing bottlenecks in the Northeast for deliveries of natural gas from nearby shale gas reservoirs. In 2012-2013 there was far less new natural gas pipeline added since many of the Northeast bottlenecks have already been addressed. States with impending coal plant retirements are planning to increase their natural gas pipeline capacity to support the switch to gas-fired power generation. In California, the six interstate pipelines have more receipt capacity than take-away capacity. This provides more price competition and supply options and reduces the chance of gas shortages if bottlenecks occur outside the state. In Southern California though, fewer gas deliveries on El Paso Natural Gas's south mainline into the San Diego Gas & Electric Company service area, combined with the closure of the San Onofre Nuclear Generation Station, have resulted in Southern California Gas Company having trouble meeting its minimum gas requirements to serve core customers. If the minimum delivery requirements are not met, curtailments of noncore customers, such as electricity generators, could result.

### *California Pipeline Safety*

Pipeline safety, in the wake of the San Bruno pipeline explosion in 2010, is a critical concern of the Energy Commission, the California Public Utilities Commission, and the Legislature. Despite the gas utilities' pipeline safety enhancement plan filings and the reinvigorated focus on safety issues in California, safety issues have arisen. Pacific Gas and Electric Company filed with the CPUC an errata list to an earlier approved filing lifting the operating pressure on line 147, which delivers gas in the San Francisco area. The errata revealed that the pipeline records that were used to prove that this pipeline met the structural baselines necessary to safely raise its operating pressures were incorrect. The pipeline pressure was reduced to safe levels as a result, but the incident resulted in a $14.3 million fine for Pacific Gas and Electric Company. Not long after this incident, Pacific Gas and Electric Company reduced the operating pressures on line 300, the backbone transmission line delivering gas to the southern Bay Area and Peninsula, as well as the San Joaquin Valley. The pressure decrease reflected a "class location change" made in response to finding increased population density around certain areas along the pipeline. Such pressure reductions, while addressing safety concerns, can also subject gas customers to reliability issues during cold weather conditions.

### *Natural Gas Storage in California*

Storage continues to play an important role in California's natural gas market. California had 13 underground natural gas storage facilities with a total working gas inventory of 349.3 billion cubic feet as of 2011, with some 20 percent of that added within the last six years. There are four planned storage expansions that will raise the working inventory of the state's storage facilities to nearly 407 billion cubic feet by 2014.

About half of California's total storage capacity is owned and operated by its investor-owned utilities, 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. The other half of the storage is owned by independent providers that connect into the Pacific Gas and Electric Company gas system.

### *North American Gas Imports and Exports*

In 2012, Mexico imported an average of 1.7 billion cubic feet per day of natural gas from the United States—a 24 percent increase from 2011. Staff's reference case projects that United States exports to Mexico will increase close to 100 percent by 2018 (3.3 billion cubic feet per day) while a report by Bentek Energy similarly projects imports of 3.6 billion cubic feet per day. To accommodate the increase, there are seven pipeline expansion projects that are expected to be completed by 2014 for a total increase in exporting capacity of 4.3 billion cubic feet per day. Most of this increase is in response to greater natural gas demand for power generation in Mexico. Mexico has large natural gas reserves, and until recently, the country's constitution prohibited foreign direct investment in oil and gas production. The state-owned oil company, Petróleos Mexicanos, has no real experience developing shale reserves. The increase in Mexico's gas demand is, therefore, projected to be met with gas exported from the United States in the near term. Staff's North American Gas Trade Model assumptions reflect Mexico's lack of shale gas production experience by assuming higher finding and development costs for gas in Mexico, which in turn make it cost-effective for Mexico to import gas from the United States. Mexico plans to allow foreign investment in its oil and gas production in the future, but it is too early to tell how this change might affect the country's gas production.

All three cases in staff's model project increasing imports from Canada to the United States based on the fact that Canada is expected to have spare supplies of natural gas available for export that are priced lower than natural gas produced in the United States. The reference case shows imports from Canada increasing from 8.6 billion cubic feet per day in 2014 to 12.4 billion cubic feet per day in 2025.

The rapid increase in shale gas production in the United States along with the difference in the prices of natural gas in the United States versus prices abroad have led to increased interest in exporting liquefied natural gas. As of July 2013, there were 28 applications filed with the United States Department of Energy (U.S. DOE) for licenses to export liquefied natural gas to non-Free Trade Agreement countries. These planned facilities equal 10.6 trillion cubic feet per year of liquefied natural gas export capacity. Over the last three years,

four of these planned export terminals received licenses to export to non-Free Trade Agreement countries. Among the four export terminals with approved licenses, only the Sabine Pass liquefied natural gas terminal in Louisiana has begun construction. The DOE has been cautious about approving these licenses due to national debate among stakeholders about whether high levels of liquefied natural gas exports might cause natural gas shortages and price increases in the United States. Given the time and cost to build export terminals, the foreign market for liquefied natural gas might be more easily met by other sources closer to the demand centers. The prospects for California to be an exporter are extremely low as the state is neither a big producer nor a net exporter of natural gas.

## California Natural Gas Issues

### *Natural Gas Vehicles in California*

Staff's model used econometric demand inputs for natural gas demand in the transportation sector that were based on historical demand patterns provided by the United States Energy Information Administration. Demand for natural gas in California's transportation sector peaked in 2011 or 2012 and is projected to decline modestly until about 2020. After 2020, minimal growth is projected in all three cases. Most natural gas vehicles are heavy- and medium-duty vehicles because the low price of natural gas makes these less expensive to buy and maintain than gasoline- or diesel-fueled vehicles and because various market deficiencies in light-duty vehicles likely hinder widespread consumer acceptance of these natural gas vehicles. Staff expects this trend to continue.

### *Combined Heat and Power*

Despite the overall decline in natural gas for power generation in California, a significant amount of this natural gas could be redirected to onsite generation in California's industrial and commercial sectors. Governor Brown's *Clean Energy Jobs Plan* includes a target of 6,500 megawatts of new combined heat and power capacity by 2030. While future combined heat and power is expected to be in both the commercial and industrial sectors, Energy Commission staff analysis allocated the shift in natural gas demand from the power generation sector to generation for combined heat and power in the industrial sector. Growth in natural gas demand from combined heat and power is expected in both the reference and low-energy-demand/high-price cases. The high-energy-demand/low-price case assumes minimal combined heat and power additions. While increased combined heat and power generation will add to the amount of natural gas used on site, it will cause a net decrease in the amount of natural gas used to meet both the electrical and thermal needs of the facility. The increased use of combined heat and power is expected to reduce the natural gas demand for power generation.

### *Role of Biomethane in California*

The potential quantity of biomethane available in California today remains small relative to the state's overall demand for natural gas. The viability of biomethane production facilities

and the continued market demand for the gas depend on programs and policies that would remove barriers to its use.

### *Greenhouse Gas Cap-and-Trade Markets*

California's cap-and-trade program imposes an aggregate annual greenhouse gas emissions cap on stationary sources that emit 25,000 metric tons of carbon dioxide-equivalent. Emitting facilities are required to deliver (or surrender) to the California Air Resources Board enough allowances—an allowance is the equivalent of one ton of carbon dioxide—to cover their annual emissions. Covered entities can trade allowances among themselves as they find they have more or fewer allowances than they need to cover their emissions. The compliance obligation will rest with the entity making the final delivery to the customer. The initial implementation of cap-and-trade began January 1, 2013, and applies to a limited segment of the market, though it will expand in future years. In 2015, transportation fuels and residential and commercial gas use will be included in the program. It is too soon for Energy Commission staff to conclude how the program will affect prices for natural gas consumers or the possible effect on natural gas demand in California. Natural gas distributors will have to purchase allowances in the market, and the California Public Utilities Commission has not yet instructed the distributors how to pass this cost on to consumers, adding to questions about the price and demand effects in California.

## Conclusions

This report covers a great deal of information related to natural gas issues and trends in California and the Unites States. Staff believes the following are the most important conclusions of the report:

- Model results show Henry Hub natural gas prices (see **Figure 1**) will steadily increase over time (2013 – 2025)—the reference case projects a 38 percent increase over this time frame.
- Aggressive energy efficiency goals and the Renewables Portfolio Standard target in California are likely to reduce demand for natural gas in the state.
- Natural gas demand estimated for power generation in California assumes average annual precipitation. Dry conditions and associated reduction in potential electricity generation from hydroelectric facilities in California in 2013 and to date in 2014 are likely to make the estimate for 2014 demand low.
- Technology innovations have dramatically improved drilling efficiency and increased natural gas production, leading to decreased natural gas prices, a trend that looks likely to continue in the future.
- Liquefied natural gas exports and exports to Mexico could divert a significant amount of gas out of the United States and potentially increase prices, but it is too soon to tell how much gas might be exported or what, if any, price impacts there may be.

- Insufficient gas deliveries on the El Paso Natural Gas southern mainline in Southern California have led to difficulties meeting the southern system minimum gas requirements for core customers in the San Diego Gas & Electric Company service area. This issue must be addressed to avoid potential gas curtailments for non-core customers, such as electric generation plants.
- Many coal plants in the Western Electricity Coordinating Council are likely to be retired starting in 2014 because of more stringent national greenhouse gas emissions regulations and the competitive price of natural gas. These retirements are likely to increase gas demand in the Western Electricity Coordinating Council area after 2020, which, in turn, could cause tighter gas supplies and price increases in California due to its location at the end of many major interstate pipelines that pass through the Western Electricity Coordinating Council area.

# CHAPTER 1: Introduction

Natural gas is used in California for everything from generating electricity to cooking and space heating to an alternative transportation fuel. In 2012, total natural gas demand in California for industrial, residential, commercial, and electric power generation was 2,313 billion cubic feet per year (Bcf/year), up from 2,196 Bcf/year in 2010, as shown in **Table 1**. Demand in all sectors except electric power generation has been relatively flat for the last decade due in large part to energy efficiency measures, but demand for power generation rose about 22 percent between 2003 and 2012.

**Table 1: Natural Gas Demand in California by End Use From 2010 to 2012**

| Natural Gas Demand by End Use (Bcf/y) | 2010 | 2011 | 2012 |
|---|---|---|---|
| Residential | 509 | 519 | 485 |
| Commercial | 199 | 201 | 201 |
| Industrial | 548 | 559 | 577 |
| Natural Gas Vehicle | 18 | 16 | 17 |
| Electric Power | 922 | 796 | 1,032 |
| **Total Natural Gas Demand** | **2,196** | **2,091** | **2,313** |

Source: Energy Commission: Electricity Analysis Office (EAO).

Natural gas generation accounted for 61 percent of California's in-state and 43 percent of both in-state and out-of-state, or imported, power generation in 2012. (See **Table 2** and **Figure 2.**) The in-state generation represents a 30 percent increase from 2011, due in large part to low hydroelectric availability and ceased power operations at the San Onofre Nuclear Generation Station (SONGS). For much of the nation, efforts to reduce greenhouse gas (GHG) emissions will result in replacing coal-fired generation with gas-fired generation. Since the early 2000s gas demand for power generation in the United States rose from 22 to 36 percent of total gas demand.

**Table 2: California Total System Power Supplies in 2012**

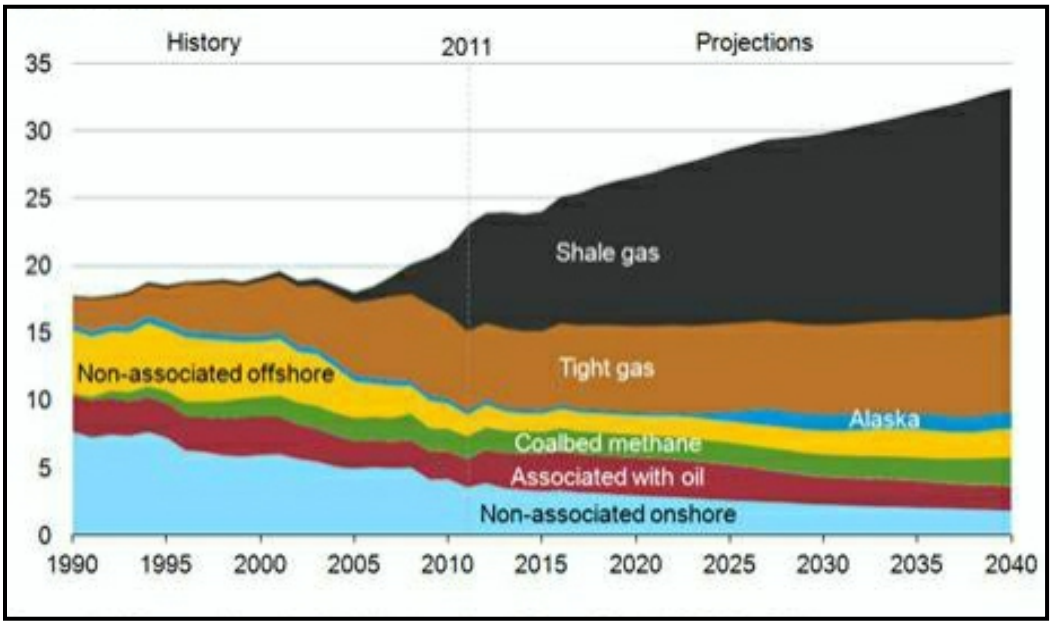
| Fuel Type | California In-State Generation (GWh) | Percent of California In-State Generation | Northwest Imports (GWh) | Southwest Imports (GWh) | California Power Mix (GWh) | Percent California Power Mix |
|---|---|---|---|---|---|---|
| Coal | 1,580 | 0.8% | 561 | 20,545 | 22,685 | 7.5% |
| Large Hydro | 23,202 | 11.7% | 12 | 1,698 | 24,913 | 8.3% |
| Natural Gas | 121,716 | 61.1% | 37 | 9,242 | 130,995 | 43.4% |
| Nuclear | 18,491 | 9.3% | - | 8,763 | 27,254 | 9.0% |
| Oil | 90 | 0.0% | - | - | 90 | 0.0% |
| Other | 14 | 0.0% | - | - | 14 | 0.0% |
| Renewables | 34,007 | 17.1% | 9,484 | 3,024 | 46,515 | 15.4% |
| Biomass | 6,031 | 3.0% | 1,025 | 23 | 7,079 | 2.3% |
| Geothermal | 12,733 | 6.4% | - | 497 | 13,230 | 4.4% |
| Small Hydro | 4,257 | 2.1% | 204 | - | 4,461 | 1.5% |
| Solar | 1,834 | 0.9% | - | 775 | 2,609 | 0.9% |
| Wind | 9,152 | 4.6% | 8,254 | 1,729 | 19,135 | 6.3% |
| Unspecified Sources of Power | N/A | N/A | 29,376 | 20,124 | 49,500 | 16.4% |
| **Total** | **199,101** | **100.0%** | **39,470** | **63,396** | **301,966** | **100.0%** |

Source: California Energy Commission (Energy Commission), Quarterly Fuel and Energy Report and SB 1305 Reporting Requirements. http://energyalmanac.ca.gov/electricity/total_system_power.html.[1]

Technological advances in exploration, drilling, and well completion and stimulation in the oil and gas industry have markedly expanded the natural gas resource base and production. In 2012, production in the Lower 48 of the United States, which is now occurring in natural gas-bearing formations that were previously inaccessible, increased 21.4 percent from 2000. Most of this change comes from a remarkable increase in shale production, which rose about 1,350 percent during this same time frame. Projections show this shift from production in conventional resources will continue, as shown in **Figure 2.**

1 The term unspecified sources of power refers to the situation where the original fuel type of the generator is unknown. This only applies to power imported from out of state.

**Figure 2: Historical and Projected Natural Gas Production by Source in the United States**




Source: United States Energy Information Administration (U.S. EIA). *2013 Annual Energy Outlook* (*2013 AEO* Early Release.

While the natural gas resource base and production in the Lower 48 has increased, California imported 90 percent[2] of natural gas used in 2012. Most of this comes from interstate pipelines carrying gas from the Southwest, Rocky Mountains, and Canada. Throughout the United States, additions in pipeline infrastructure have been built to better connect new supply sources to demand hubs. California, which is located at the end of the interstate pipeline system and, therefore, vulnerable to disruptions in supply or fluctuations in transportation prices, has increased both pipeline and gas storage capacity. These measures provide access to multiple supply sources and help reduce the impact of a disruption in supply or price spike on any supply basin or pipeline.

Because natural gas continues to represent a large percentage of California's energy mix, it is important to ensure reliable supplies and assess future natural gas demand, supply, prices, and infrastructure needs. Such estimates require an understanding of future issues and trends that could affect natural gas markets and disruptions in supply.

This report presents the results of the Energy Commission's 2013 scenario analysis of natural gas supply, demand, prices, and infrastructure issues. Energy Commission staff produced a range of cases based upon plausible and transparent assumptions to give

2 *2013 California Gas Report Supplement*. California Gas and Electric Utilities. See http://www.pge.com/pipeline/library/regulatory/downloads/cgr13.pdf, Page 16.

planners and decision makers information about the possible supply, demand, and price of natural gas in the future. This information can then be used to help determine near- and long-term procurement needs and perform contingency planning. Also discussed are the most influential issues affecting natural gas supply and demand in California, including production of natural gas from shale formations in North America, factors affecting changes in natural gas demand for electric generation, and natural gas infrastructure. Discussions on natural gas infrastructure issues, such as pipeline additions and safety, receipt constraints in Southern California, storage, imports, exports, liquefied natural gas (LNG), and combined heat and power (CHP), are included. Further, the report examines potential future issues in natural gas markets, including growth in natural gas vehicles, biomethane as a potential source of supply, and GHG cap-and-trade markets.

## Natural Gas Outlook

Staff examines historical trends in those variables known to cause cyclical changes in natural gas markets and then alters these variables by applying assumptions to project plausible trends that could occur in the future. 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—such as extreme weather events (for example, Hurricane Katrina), infrastructure accidents (for example, Louisiana Coast Deepwater Horizon explosion), and unforeseen technological advances (for example, horizontal drilling coupled with hydraulic fracturing)—are unpredictable, but history shows that these events have greater impact on natural gas markets than predictable variables. As such, the results of scenario analyses cannot accurately predict the future of the highly complex and vulnerable natural gas markets but can use a mix of plausible scenarios that incorporate transparent and vetted assumptions to model how the market may behave in the next decade. Staff held two public workshops on April 24, 2013, and July 17, 2013, to present the scenario assumptions used to build the cases, as well as preliminary modeling results.

For this assessment, staff is using a modification of the Rice World Gas Trade Model (RWGTM), constructed specifically for the North American gas market. Staff refers to this as the North American Market Gas Trade Model (NAMGas). Appendix A provides a detailed description of the modeling method and approach. Staff developed natural gas price and cost scenarios, or "cases," around trends that represent three possible future scenarios, a business-as-usual or reference case, a high-energy-demand/low-price case, and a low-energy-demand/high-price case. These three "common cases" illustrate trends in the natural gas market, with different assumptions about market and regulatory developments in each case. The cases are referred to as "common" because they are common to several analyses performed for the *2013 Integrated Energy Policy Report* (*2013 IEPR*) across several offices and staff units. The reference case, or business-as-usual case, represents a future in which the economy and commercial activity in the gas market proceeds as it has done in the past, with future projections related to likely outcomes based on current trends. The high-energy-

demand/low-price and low-energy-demand/high-price cases were created by altering assumptions in ways that would lead to plausible conditions that would move natural gas prices lower or higher than in the reference 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 (MW) historically provided by coal, once-through cooling and nuclear power plants that may be replaced with natural gas power plants, natural gas supply and demand, and costs.

## Scope and Organization of Report

Chapter 2 presents the assumptions used to construct the three natural gas market common cases and model results. Results are presented by comparing model outs of the three cases for natural gas price, supply, and demand. Prices are given for the Henry Hub (Louisiana) and Topock (California-Arizona border) market hubs. Prices to California consumers, which include the cost of transporting the gas through a series of pipelines, are also provided. Estimates of natural gas supply in the Lower 48 states are provided for all gas production and for production from unconventional shale gas only. Modeled natural gas demand is compared by case for all end-use sectors and for power generation only in both the Lower 48 and California.

Chapter 3 discusses in-depth natural gas supply in the United States. The advent of horizontal drilling coupled with hydraulic fracturing and improved drilling and exploration techniques have expanded the resource base. Production in shale natural gas formations has grown, while production in conventional formations has decreased. This chapter also provides an overview of regulatory changes and challenges surrounding hydraulic fracturing.

Chapter 4 presents the implications of increasing interactions between natural gas and electricity markets. As California and the rest of the nation strive to integrate a higher percentage of renewable-derived energy into their electricity generation portfolios, demand for natural gas may increase to help provide overall electricity system balance and stability. In addition, the closure of SONGS and retirement of once-through cooling generation facilities in California will require replacement generation, some of which will likely come from more natural gas-fired generation. California has very little electricity production from coal-fired plants, but the Western Electricity Coordinating Council[3] (WECC) area currently

3 The WECC is a regional entity recognized by the North American Electric Reliability Corporation and the Federal Energy Regulatory Commission (FERC) that exists to assure a reliable bulk electric system. This area includes all or parts of the 14 Western United States, 2 Canadian provinces, and the northern portion of Baja California, Mexico.

produces about 37 GW of electricity from coal. Competitive natural gas prices and efforts to reduce GHG emissions are spurring states to switch from coal-fired to gas-fired units.

Staff also developed an additional case that is focused on future natural gas demand from power generation, using simulations that explore the net effects of a high percentage of renewable generated power, energy efficiency measures, and the replacement coal-fired generation with gas-fired generation. This natural gas and electric synchronization case is also presented in Chapter 4. Results are presented for both the Lower 48 states and the WECC area.

Chapter 5 focuses on natural gas infrastructure, including pipeline additions, pipeline safety, and storage. Modeled estimates of future natural gas imports and exports to Mexico and Canada up to 2025 are also provided. Finally, renewed interest in exporting gas abroad in the form of LNG is discussed, and the volume of exports estimated in staff's model is compared to estimates provided by the United States Energy Information Administration's (U.S. EIA) *Annual Energy Outlook 2013*.

Chapter 6 describes how other trends and issues could affect natural gas supply or demand in California, including increased penetration of natural gas vehicles into the existing fleet, particularly in the medium- and heavy-duty vehicle markets; increasing gas supplies from biomethane, derived from biogas, into the supply chain; and the effect of cap-and-trade, a market-based mechanism designed to reduce emissions from greenhouse gas, on natural gas markets.

# CHAPTER 2: *2013 Integrated Energy Policy Report* Common Cases

## The 2013 Natural Gas Model

For this analysis, staff used a modification of the RWGTM, constructed in the MarketBuilder platform by Dr. Kenneth Medlock.[4] Staff's version largely accepts the topology of gas markets specified in that model but adds additional demand and supply nodes in the Western United States to capture more granular market hub details match supply to demand nodes including gas-fired power plants and represent natural gas demand in the transportation sector. Dr. Medlock assisted in implementing these changes to create the Energy Commission's World Gas Trade Model (WGTM). To further focus on North America's natural gas market, staff worked with Dr. Medlock to implement the following changes to the WGTM to develop the NAMGas model:

- Removed all non-North American structure
- Added functional nodes to allow for a simplified endogenously determined LNG imports and exports

Staff applied an iterative cross-modeling process coordinated between the Electricity Analysis Office (Generation Fuels Analysis Unit and Production Cost Modeling Unit) and the Demand Analysis Office (DAO) to produce model inputs and results. A detailed explanation of the modeling method is provided in Appendix A.

## The Common Cases

Energy Commission staff applied an iterative cross-modeling process to develop coordinated model inputs and results across the Generation Fuels and Production Cost Modeling Units in EAO and the DAO. A key advantage of the iterative cross-modeling process is that it allows coordinated use of common assumptions to produce internally consistent, coordinated results, where the output of one model that is used by another model as an input can cycle forward at least once to capture some of the feedback effects that separated models would otherwise ignore. Energy Commission staff created three cases to represent plausible scenarios of natural gas and electricity markets and applied them

4 Dr. Kenneth Medlock is the James A. Baker III and Susan G. Baker Fellow in Energy and Resource Economics and Deputy Director of the Energy Forum of James A. Baker III Institute for Public Policy at Rice University in Houston, Texas.

across the demand forecast, transportation forecast, and production cost model forecast. These three "common cases" depict trends currently seen in the natural gas market and apply key drivers as variables to illustrate how market trends may change in future years. **Table 3** illustrates the assumptions used to develop the reference case, or business-as-usual case, along with the assumptions used to develop the two other cases. These assumptions reflect potential vulnerabilities and opportunities to gas supply and demand, simulating a range of plausible conditions that account for uncertainty in the natural gas market, the economy, and policy outcomes.

The three cases also considered potential outcomes related to the successful implementation of relevant energy policies, including the Renewables Portfolio Standard (RPS), conversion of coal-fired generation to natural gas-fired generation, potential environmental mitigation as a result of shale development, and the licensing of LNG export capability.

The reference, or business-as-usual, case serves as a plausible starting point for staff's natural gas market assessment. This represents the current state of both market conditions and regulatory frameworks. Assumptions in the reference case were modified to produce conditions favorable to a low-price environment in the high-demand/low-price case and conditions favorable to a high-price environment in the low-demand/high-price case.

Model inputs for natural gas demand in the power generation sector were *hard wired* in for all model regions in the WECC. Hard wired means that demand was taken from the PLEXOS production cost model, and then the price elasticities in the NAMGas model were turned off for the WECC region so that demand responds to endogenous variations in price as NAMGas iterates toward equilibrium. Price elasticities for states outside the WECC region remain in effect. The price elasticities for all the sectors in the non-WECC states are in Appendix A. Demand inputs for power generation were generated by EAO staff using the production cost model, PLEXOS. Demand inputs for transportation were generated from using historical trends derived using econometric equations. Demand inputs for the remaining sectors (commercial, residential, and industrial) were obtained from the staff in the DAO using the method documented in staff's electricity and natural gas demand forecast.[5] Natural gas demand for CHP used in California to export electricity to the transmission grid was included in the power generation sector, while demand for on-site uses, expressed in **Table 3** as new cumulative capacity added from 2013 to 2024, was allocated to the industrial sector.

5 *California Energy Demand 2014 – 2024 Revised Forecast. Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency—Revised Draft Staff Report*. Publication # CEC-200-2013-004-SD-V1-REV. See http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC_200-2013-004-SD-V1-REV.pdf.

**Table 3: Assumptions for Common Cases**

| Assumptions | Reference Case | Low-Demand/High-Price Case | High-Demand/Low-Price Case |
|---|---|---|---|
| **GDP Growth Rate** | 2.50% | 3.00% | 2.00% |
| **Natural Gas Technology Improvement Rate** | 1% | 1% | 2.50% |
| **CHP Demand (Bcf)/Capacity (MW) for CA in 2024**[a] | 83/1424 | 130/3084 | 14/210 |
| **Total U.S. Natural Gas Demand (Tcf/yr)** | | | |
| 2014 | 24.5 | 24.1 | 24.4 |
| 2019 | 28.4 | 27.9 | 27.2 |
| 2024 | 30.5 | 29.9 | 28.1 |
| **Maximum RPS Target** | | | |
| CA Meets Target | On time | 10 year delay | On time |
| WECC Meets Target | On time | 10 year delay | On time |
| Other States Meet | 5 year delay | 10 year delay | On time |
| **Additional U.S. Coal Generation Converts to Natural Gas Starting in 2014 (GW)** | 61 | 80 | 31 |
| **LNG Capacity Additions** | No | Yes | No |
| **Grow or Shrink Natural Gas Resource Available (U.S.)** | N/A | Shrink by 5.5% | Grow by 5.5% |
| **Additional Environmental Mitigation Cost (2010$/Mcf)** | N/A | $0.50/Mcf Shale<br>$0.30/Mcf Conventional | N/A |
| **Additional Achievable Energy Efficiency**[b] | Mid Savings Scenario | High Savings Scenario | Low Savings Scenario |
| **Cost Environment**[c] | Mid (P50) | High (P10) | Low (P90) |

Source: Energy Commission: EAO.

a Includes only new CHP units added after 2014.

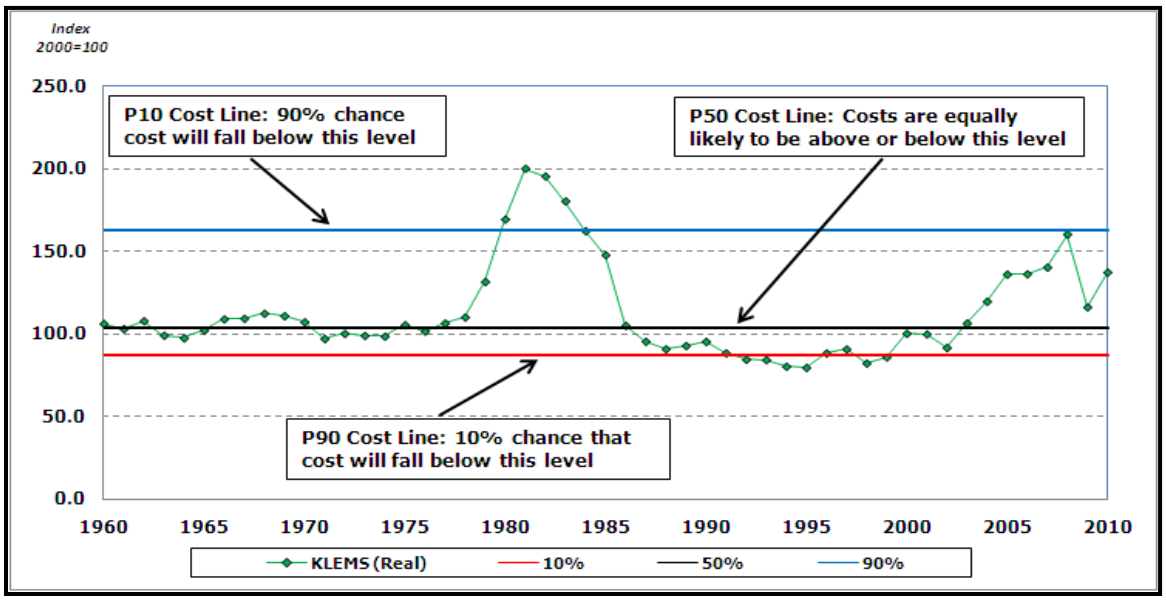
b 2014. *California Energy Demand 2014 – 2024 Final Forecast Volume 1*. Energy Commission. CEC-200-2013-004-V1-CMF.

c 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 P90 case) and lower probability but higher resource amounts (a P10 case).

Assumptions on the cost of producing natural gas and available reserves also differ for each case. Using historical costs (such as capital, labor, energy, manufacturing, and service costs) between 1960 and 2010, regression analysis was used to develop average, high-, and low-cost environments, as shown in **Figure 3**. High prices, such as that experienced from 1979 to 1984, are categorized as high-cost environments, or P10 (90 percent chance that costs will fall below this level). Costs decreased during 1992 to 2000, and these years are categorized as

having a low-cost environment, or P90 (10 percent chance that cost will fall below this level). The P50 cost line—a level where costs are equally likely to be above or below—is a regression line drawn through the average cost data points as witnessed from 1960 to 2010. For the three cases, a cost environment of P50 is assigned to the reference case, P10 to the low-demand/high-price case, and P90 to the high-demand/low-price case.

**Figure 3: Historical Natural Gas Cost Environments**

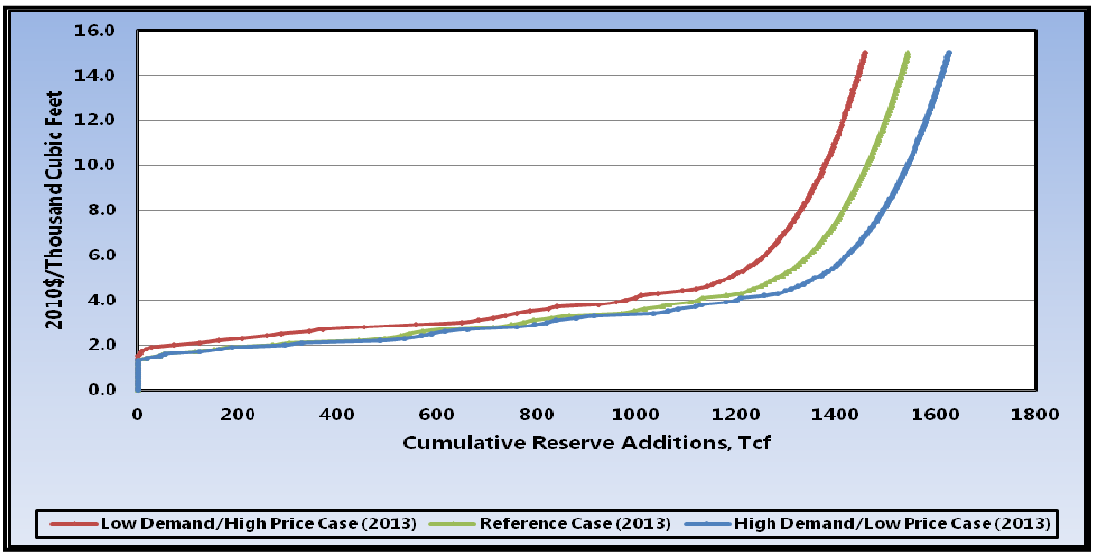



Source: Baker Institute.

KLEMS stands for Capital, Labor, Energy, Manufacturing, Service.

The supply cost curve depicts how much supply of natural gas will be available at a certain cost and is the assumption that has the most impact on model results, as shown in **Figure 4**. The flatness of the supply cost curve illustrates how prices change minimally with additional cumulative reserves becoming available for production. For example, about 1,300 trillion cubic feet (Tcf) of potential reserves will cost around $5/thousand cubic feet (Mcf) in the reference case, $7/Mcf in the low demand/high price case, and $4/Mcf in the high-demand/low-price case. Improvements in exploration and drilling techniques have resulted in a dramatic increase in the amount of economically recoverable reserves in the United States.

**Figure 4: Supply Cost Curve Comparison for the Modeled Common Cases**




Sources: Energy Commission: EAO; Altos Management Partners; National Petroleum Council.

## Reference Case

The reference case can also be referred to as the "business-as-usual case" because the current observable trend of all energy policies and market practices are adopted for the duration of the forecasting period. A probability of occurrence was not assigned to the assumptions imbedded in the reference case. As a result, this should not be considered "the expected case."

In addition to the cost and price environments described above, the reference 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 impact the use of natural gas as an electricity generation source. The Lower 48 states generate about 300 GW of electricity from coal; however, in response to emission policies and lower natural gas prices, some coal-fired generation will be retired. Staff relied on a report by the Brattle Group to determine levels of coal retirement.[6] The reference case assumes that coal-fired generation will start to retire in the Lower 48 states in 2014—until a total of 61 GW will be retired by 2025. It is expected that renewable power will make up for some of the generation loss due to coal-fired generation retirement. In the reference case it is assumed that California will meet its RPS mandate of having 33 percent of its load requirements being met by renewable power sources by 2020, and regions within the WECC will meet their RPS targets on time, but states outside the WECC will take an additional

6 The Brattle Group, *Potential Coal Plant Retirements: 2012 Update*, October 2012. See http://www.brattle.com/_documents/UploadLibrary/Upload1082.pdf.

five years to meet their RPS goals. Gross domestic product (GDP) annual growth rate is 2.5 percent. Further, this case assumes that there will be additional savings from energy efficiency initiatives that are neither finalized nor funded but are reasonably expected to occur. These, referred to as *additional achievable energy efficiency* (AAEE), include future updates of building codes and appliance standards and utility efficiency programs expected to be implemented after 2014. A moderate amount of energy savings as a result of the future implementation of energy efficiency programs is embedded in the initial demand inputs in all sectors of the reference case. This is the mid AAEE scenario described in the Energy Commission's California energy demand forecast.[7]

## Low-Energy-Demand/High-Price Case

This case combines a set of plausible assumptions to capture an environment of more expensive and less available natural gas that result in high prices. This case forms the upper band of projected Henry Hub prices. A high P10 cost environment, which assumes a 90 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. Environmental regulation fees of $0.50/Mcf additional for shale and $0.30/Mcf additional for conventional are enacted, increasing the production cost of natural gas and contributing to higher gas prices.

Natural gas supplies are limited. From 2013 to 2017, LNG export capacity at Kitimat, Sabine Pass, Lake Charles, Freeport, and Cove Point increase, creating less available natural gas for the United States market. The available natural gas resource that is economically recoverable is reduced in New York and the Rocky Mountains (Colorado and Wyoming) by 5.5 percent. A gas technology improvement rate of only 1 percent limits the future amount of natural gas development. The simulated supply reductions result in a given quantity of natural gas available at a higher price than for the other two cases.

The GDP growth rate of 3 percent, retirement of 80 GW of coal-fired generation, and the 10-year delay for the WECC region to meet the RPS target year will initially create greater demand for natural gas. Greater demand for an increasingly less available commodity will result in a higher price for that commodity. Consumers then respond to higher prices by reducing demand.

This case assumes energy efficiency savings in line with the AAEE high scenario.[8] Compared to the other two common cases, the low-energy-demand/high-price case will have the highest penetration of future efficiency programs. The high energy price in this

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7 2014. *California Energy Demand 2014-2024 Final Forecast Volume 1*. Energy Commission. CEC-200-2013-004-V1-CMF.

8 Ibid.

case works to provide incentives for investments in AAEE. The increased penetration of efficiency programs will ultimately reduce the demand for natural gas.

## High-Energy-Demand/Low-Price Case

This case combines a set of assumptions that produce an environment of low prices for natural gas compared to the other two common cases. This case forms the lower band of projected Henry Hub prices among the three common cases. The case assumes a low-cost environment of P90 where costs of materials and labor are lower and there is only about a 10 percent chance that costs will fall below the P90 line based on historical data. In addition, no environmental mitigation costs were added, keeping the price of producing natural gas lower than in the higher price case scenario. The WECC region will meet RPS targets on time, the GDP growth rate is 2 percent, and 31 GW of assumed coal-fired generation capacity will be retired, all of which will initially lessen demand for natural gas. Ultimately, consumers respond to low prices by increasing demand.

A greater supply of natural gas is available. LNG export is disallowed, keeping more natural gas supplies available in the U.S. market. Reserve assessments in the amount of available natural gas supplies in the Marcellus, Haynesville, and Western Canadian shale formations are adjusted to the highest published estimates, which are 5.3 percent above the reference case.

This case assumes the low penetration of additional energy efficiency programs, or the low AAEE scenario.[9] Low prices discourage incentives in investments in energy efficiency programs which increase natural gas demand in all sectors.

## Modeling Results of the Three Common Cases

### Price Results

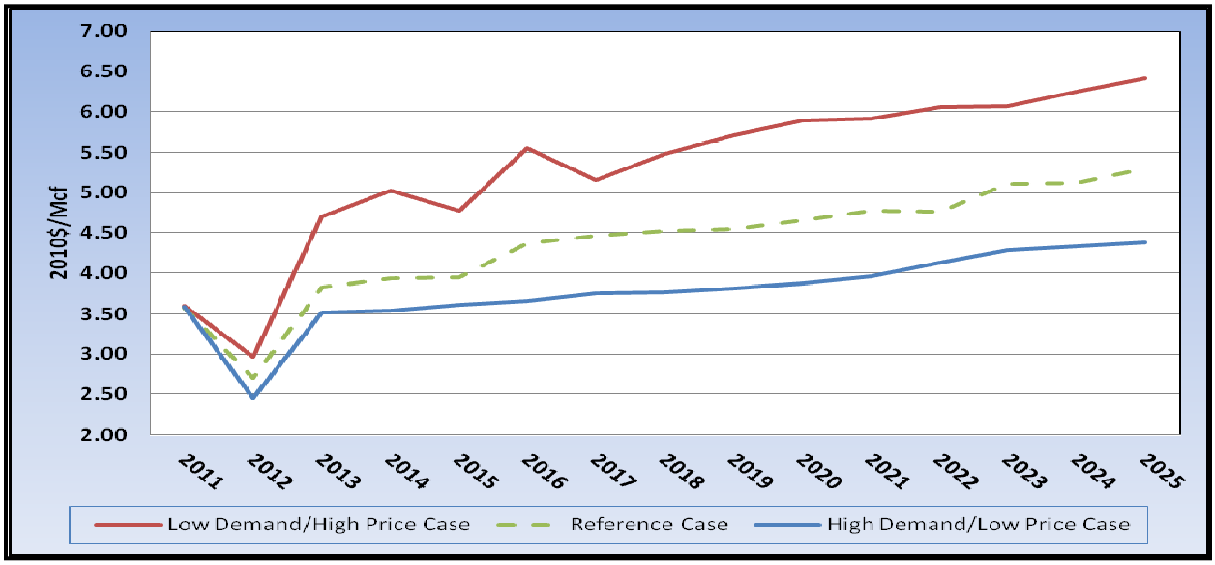
Theoretically, the price of natural gas is a result of the interaction of supply and demand, as well as a signal to market participants on how to adjust their behavior to maximize their desired outcomes: profit maximization among suppliers and cost minimization among consumers. For example, when the price of natural gas increases, consumers would be expected to reduce demand, and suppliers would be expected to increase supply, dampening the overall price effects and bringing the market into equilibrium. However, in reality price is only one factor among many that can affect supply and demand and, therefore, price in the market. While staff can provide inputs to the NAMGas model to

9 2014. *California Energy Demand 2014 – 2024 Final Forecast Volume 1*. Energy Commission. CEC-200-2013-004-V1-CMF..

capture actual variations in supply and demand from nonprice effects that were observed in years past, staff cannot predict when these external forces are going to occur again.

**Figure 5** shows the modeled historical and projected prices of natural gas at Henry Hub for the three common cases. Between 2011 and 2012, conditions created a supply glut. Demand was down due to a poor economy, but supply was up as producers were required to meet contractual land lease requirements. As a result, there was an oversupply of natural gas, and prices were very low. Between 2012 and 2013, the economy began to recover, increasing demand for natural gas, while producers were able to reduce supply. Higher demand combined with lower supply resulted in a price spike. Beyond 2013, the NAMGas model results create outcomes that mimic a market that reaches equilibrium, wherein supply aligns with demand and prices rise in response to increased demand. Economic equilibrium is a condition that provides maximum benefit to both market suppliers and market consumers.

**Figure 5: Common Case Natural Gas Price Results (Henry Hub Prices)**



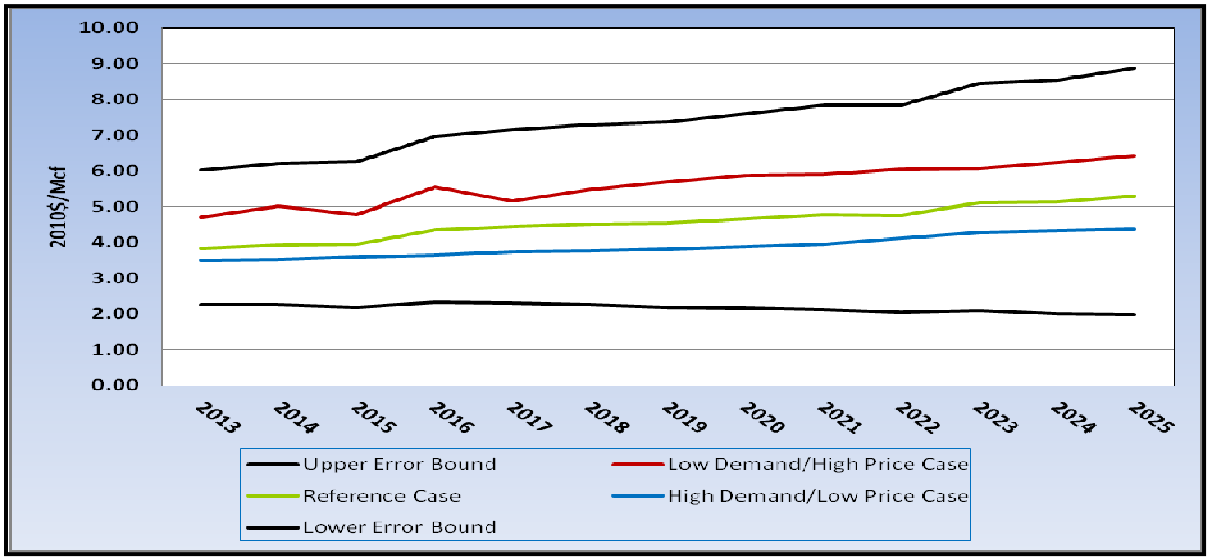

Source: Energy Commission: EAO.

In all three cases, between 2013 and 2025, prices exhibit steady growth; increases in average annual rates range from 1.8 percent to 2.6 percent. Natural gas demand in the Lower 48 states increases, which creates an increase in price. Also, the marginal cost of natural gas slightly increases with increased production of the cumulative reserves. By 2025, prices range from $4.40 to $6.40 per Mcf, as compared to a 2013 real average price to date of $3.70 per Mcf (Henry Hub).

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. 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 three common cases.[10] The error bands were generated by determining the cumulative error realized between previous natural gas price estimates, beginning in 1997, and actual prices observed at the Henry Hub. The maximum positive error and maximum negative error were used to calculate a percentage error estimate for each year after the forecast. This error calculation was then applied to the reference case to generate the upper and lower error bands, as shown in **Figure 6**. The error bands capture a much wider range of price uncertainty than seen in the price differential between the common cases.

**Figure 6: Common Case Price Results (Henry Hub) With Error Bands**




Source: Energy Commission: EAO.

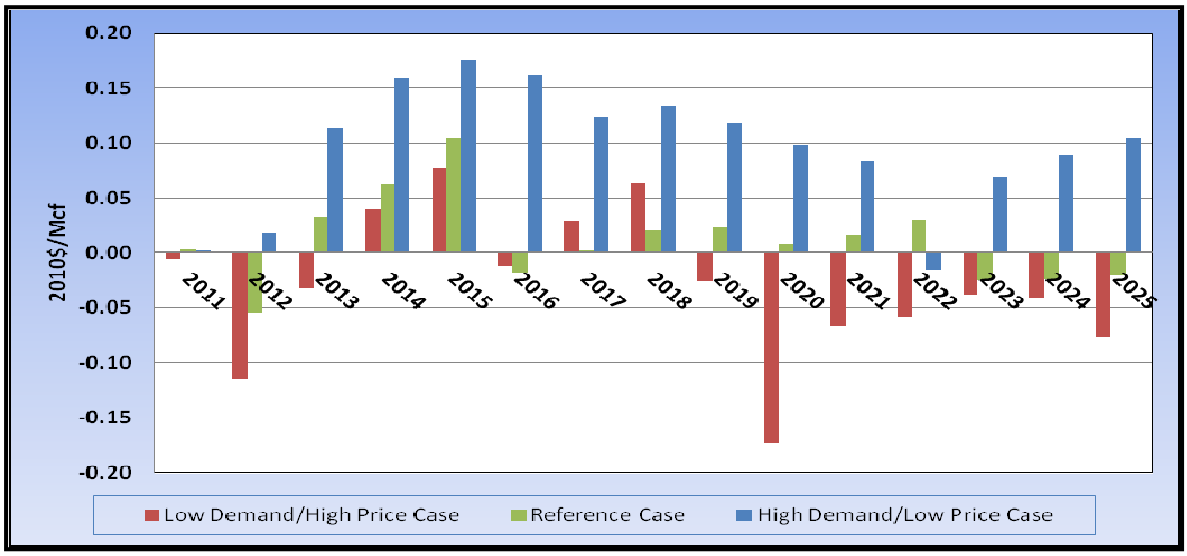
The price difference between the Topock Hub, located at the California-Arizona border, and the Henry Hub, located in Louisiana and generally viewed to be the primary pricing hub for the North American natural gas market, is shown in **Figure 7**. Data in the figure represent the price at Topock minus the price at Henry Hub; when prices are equal, the data point is zero.

Most shale gas development in the United States is located east of the Mississippi River; therefore, the Eastern United States is a supply region. California is at the end of several pipelines and imports 90 percent of its natural gas and, therefore, can be classified as a demand region. Because the Henry Hub is located closer to the supply region, prices at the Henry Hub are lower relative to Topock in the high-demand/low-price case and higher in the low-demand/high-price case. The assumptions in the low-demand/high-price case,

10 PG&E (Docket 13-IEP-1K) expressed concern that the price range produced by the three common cases was too narrow and did not capture enough uncertainty that exists in the United States natural gas market. See http://www.energy.ca.gov/2013_energypolicy/documents/2013-04-24_workshop/comments/PGandE_Comments_2013-05-08_TN-70694.pdf.

namely reduced resources and imposed environmental mitigation fees, will affect the area producing and supplying the gas more than the area receiving the gas.

**Figure 7: Topock-Henry Hub Price Differential**




Source: Energy Commission: EAO.

## Supply Results

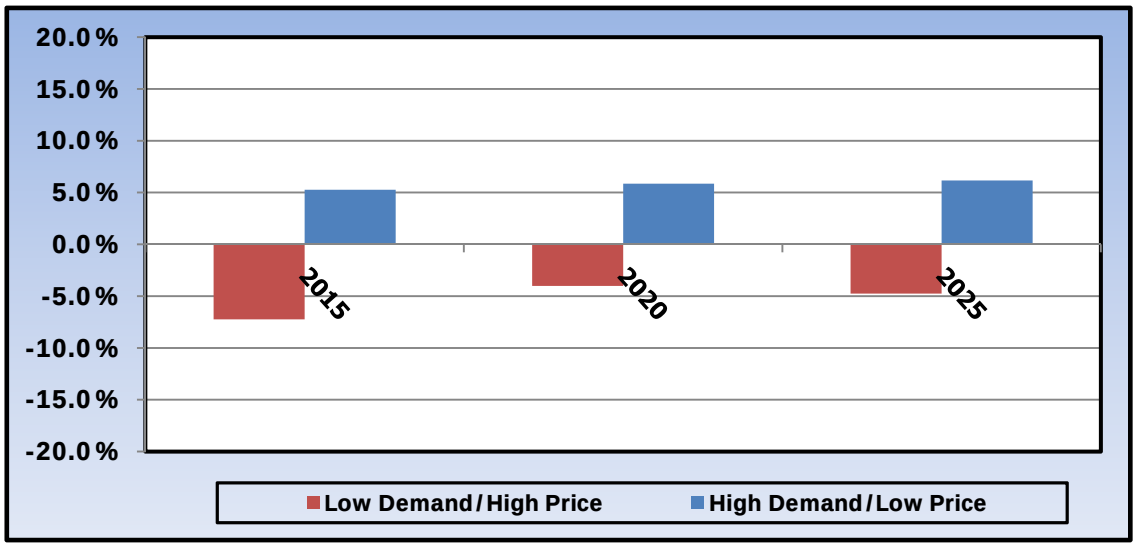
Price changes in a dynamic market such as the natural gas market can produce two responses:

- Consumers of natural gas often purchase more when prices fall and less when prices rise.
- Suppliers of natural gas may increase production when prices rise and decrease production when prices fall.

To understand the impact on natural gas production between the common cases, staff compared the percentage difference from the reference case in total Lower 48 natural gas production, which includes production from both conventional and shale resources. Staff developed a similar comparison for production from shale formations only.

Relative to the reference case, total gas production in the Lower 48 states is lower in the low-demand/high-price case and higher in the high-demand/low-price case, as shown in **Figure 8**, and there is little change in impact over the assessment period. These results reflect a reaction by suppliers to increase or decrease production in response to demand.

**Figure 8: Percentage Difference in the High-Demand and Low-Demand Cases From the Reference Case in Total Natural Gas Production in the Lower 48 States**



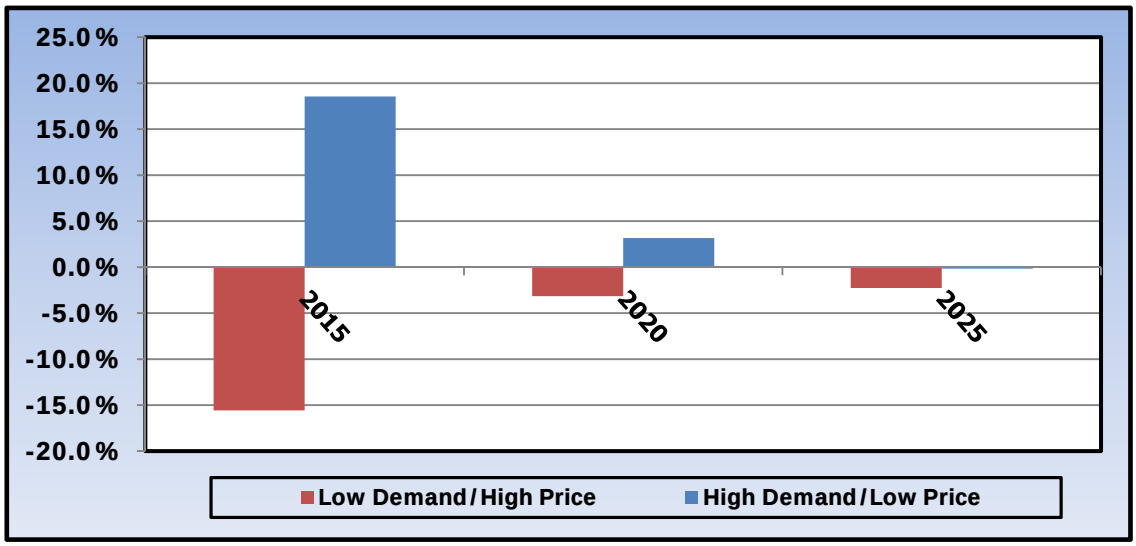

Source: Energy Commission: EAO.

Relative to the reference case, 2015 production of shale-only resources in the Lower 48 states decreases or increases by about 17 percent in the low-demand/high-price case and high–demand/low-price case, respectively. Shale producers are still a marginal supplier, while conventional gas producers are still the dominant supplier. Marginal suppliers[11] are more vulnerable to changes in price. However, during the forecast period, production levels of shale in the Lower 48 become similar in all three cases, regardless of the demand, as shown in **Figure 9**. It is profitable to produce shale in each demand scenario. Between 2015 and 2020, shale producers move from a marginal supplier to an inframarginal supplier[12] as the proportion of shale to total gas production increases. When this occurs, a change in the price of gas has a smaller effect on the level of shale production.

11 The marginal supplier sets the price at which a commodity clears the market. The marginal supplier is the last to enter the market when prices rise and the first to leave when prices fall. In essence, the marginal supplier sets the market price for all market participants.

12 The inframarginal supplier's product clears the market by the price set by the marginal supplier. In essence, the inframarginal supplier follows the product (or commodity) price set by the marginal supplier.

**Figure 9: Percentage Difference in the High-Demand and Low-Demand Cases From the Reference Case in Natural Gas Production From Shale in the Lower 48 States**




Source: Energy Commission: EAO.

## Demand Results

As mentioned previously, demand for a commodity tends to rise when prices fall. Conversely, demand for a commodity lessens when prices rise. In the NAMGas model, all sectors,[13] except power generation in the WECC, have price elasticities[14] in effect for natural gas demand and, thus, are responsive to endogenous changes in the natural gas price.

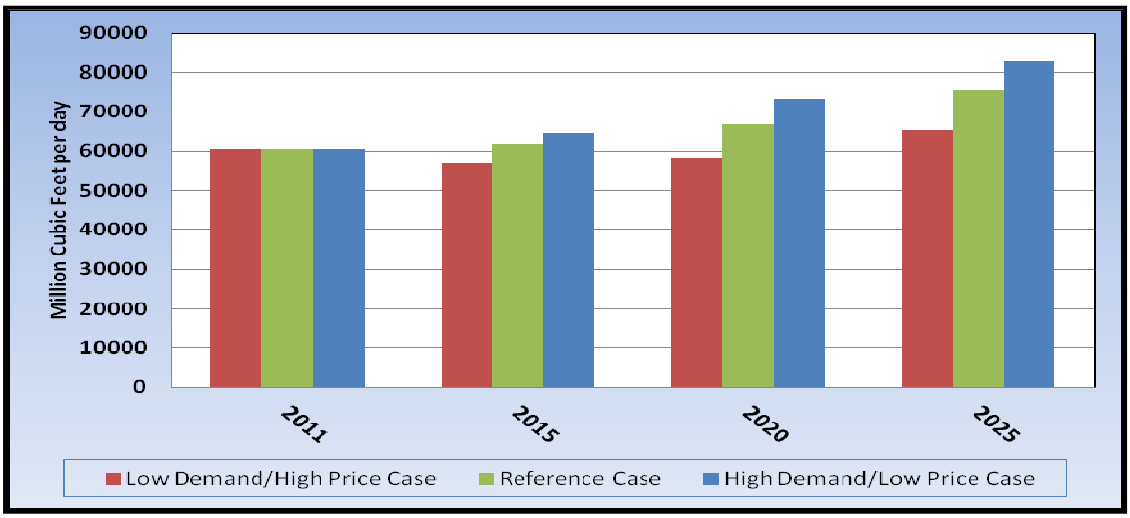
Natural gas demand for all sectors from 2011 and 2025 is shown for the Lower 48 in **Figure 10** and for California in **Figure 11**. For the Lower 48, in the low-demand/high-price case, natural gas demand is less in 2015 and 2020 than in 2011, possibly due to high prices. In all cases, demand increases in 2025, driven by population and economic growth. The rate of increase is greater in the reference and high-demand/low-price cases than in the low-demand/high-price case. For example, demand in the high-demand/low-price case is 37 percent higher in 2025 than in 2011.

In contrast, demand from all sectors in California declines in both the reference and low-demand/high-price cases and increases by 11.6 percent in high-demand/low-price case. The reason for this difference is likely the more aggressive RPS targets and energy efficiency measures practiced in California compared to the rest of the nation.

13 *Sectors* refers to industrial, commercial, residential, and power generation.

14 Price elasticity of demand measures the responsiveness of demand after a change in price.

**Figure 10: Modeled Natural Gas Demand for All Sectors in the Lower 48 States**




Source: Energy Commission: EAO

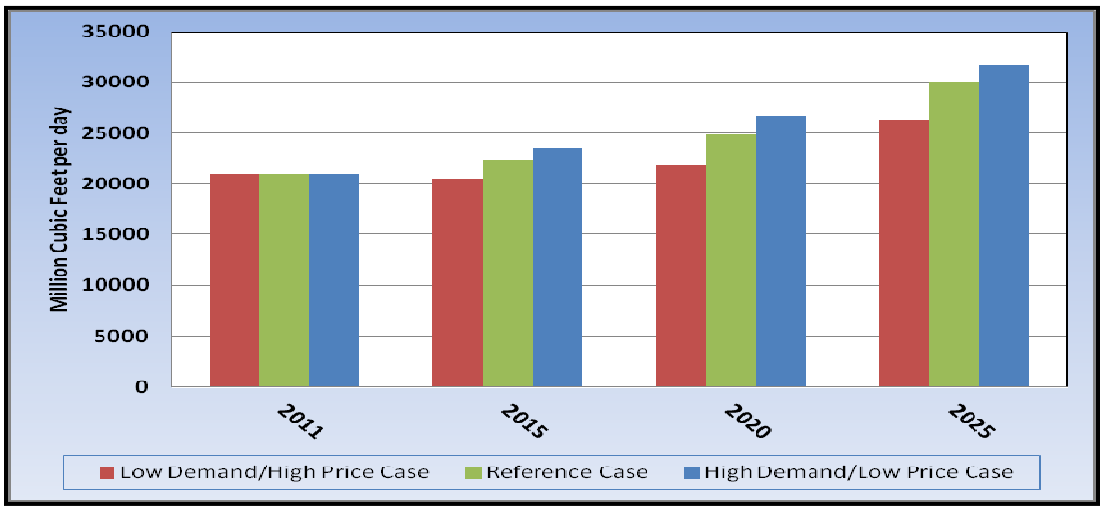
**Figure 11: Modeled Natural Gas Demand for All Sectors in California**

Source: Energy Commission: EAO.

**Figure 12** and **Figure 13** show demand for power generation only in the Lower 48 states and in California, respectively. In the Lower 48, demand for natural gas will increase as more coal-fired plants are replaced by gas-fired units, reaching 30 billion cubic feet per day (Bcf/d), a 50 percent increase from 2011, in the reference case by 2025. California's demand for natural gas for power generation rises by 22.5 percent between 2011 and 2015 in the reference case. This rise can be attributed, in part, to a recovering economy but even more to a greater dispatch of natural gas-fired units to make up for the loss of the SONGS. Also,

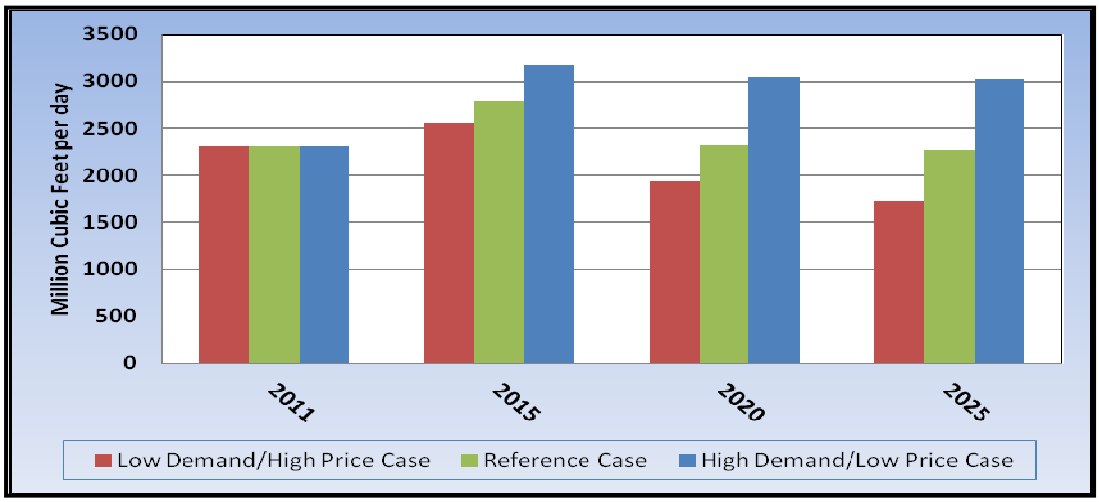
demand for power generation from natural gas fired units was low in 2011 as high precipitation that year resulted in higher supplies from hydroelectric power. By 2020 and beyond, more installed renewable generation replaces some natural gas-fired generation, reducing that earlier trend in all three cases. The reference case shows a 1.1 percent decrease in demand for power generation between 2011 and 2025.

**Figure 12: Natural Gas Demand for the Power Generation Sector in the Lower 48 States**




Source: Energy Commission: EAO.

**Figure 13: Natural Gas Demand for the Power Generation Sector in California**




Source: Energy Commission: EAO.

Note: Figure 13 includes natural gas demand for enhanced oil recovery for cogeneration for all cases.

Natural gas demand from the NAMGas model by sector is shown in **Table 4**. Values for 2011 are historical values that are model inputs, and values for subsequent years are model outputs. In all cases, demand for the residential sector remains relatively the same as energy efficiency measures are expected to continue to reduce demand in this sector. In all cases, demand for the power generation sector increases in 2015, followed by a decrease in demand. As mentioned above, more electricity generated from hydroelectric in 2011 and the closure of SONGS in 2012 account for this trend. By 2020, 33 percent of generation will be met with renewable sources, which will result in less natural gas needed to meet load. Some natural gas generation may be needed to integrate intermittent renewable resources, but daily or intraday analysis would be necessary to further examine this issue. The NAMGas model focuses on analysis of annual requirements, and it is not set up to perform daily or intraday assessments.

**Table 4: Actual (2011) and Modeled Natural Gas Demand for All Sectors in California**

| | Million Cubic Feet Per Day | | | | |
|---|---|---|---|---|---|
| **Reference Case** | **2011** | **2015** | **2020** | **2025** | **% Change 2011-2025** |
| Residential | 1,352 | 1,297 | 1,312 | 1,333 | -1% |
| Commercial | 554 | 544 | 574 | 593 | 7% |
| Industrial | 1,486 | 1,478 | 1,437 | 1,398 | -6% |
| Transportation | 42 | 40 | 40 | 42 | 0% |
| Power Gen | 2,180 | 2,670 | 2,204 | 2,157 | -1% |
| EOR/Cogen | 124 | 123 | 117 | 115 | -7% |
| **Total** | **5,738** | **6,152** | **5,684** | **5,639** | **-2%** |
| **Low-Demand/High-Price Case** | | | | | |
| Residential | 1,352 | 1,273 | 1,311 | 1,346 | 0% |
| Commercial | 554 | 530 | 556 | 582 | 5% |
| Industrial | 1,486 | 1,382 | 1,363 | 1,340 | -11% |
| Transportation | 42 | 38 | 37 | 39 | -8% |
| Power Gen | 2,180 | 2,446 | 1,825 | 1,616 | -35% |
| EOR/Cogen | 124 | 116 | 111 | 107 | -15% |
| **Total** | **5,738** | **5,786** | **5,203** | **5,030** | -14% |
| **High-Demand/Low-Price Case** | | | | | |
| Residential | 1,352 | 1,297 | 1,312 | 1,328 | -2% |
| Commercial | 554 | 549 | 579 | 593 | 7% |
| Industrial | 1,486 | 1,491 | 1,447 | 1,408 | -5% |
| Transportation | 42 | 40 | 42 | 45 | 6% |
| Power Gen | 2,180 | 3,026 | 2,895 | 2,864 | 31% |
| EOR/Cogen | 124 | 157 | 158 | 166 | 34% |
| **Total** | **5,738** | **6,561** | **6,433** | **6,404** | 12% |

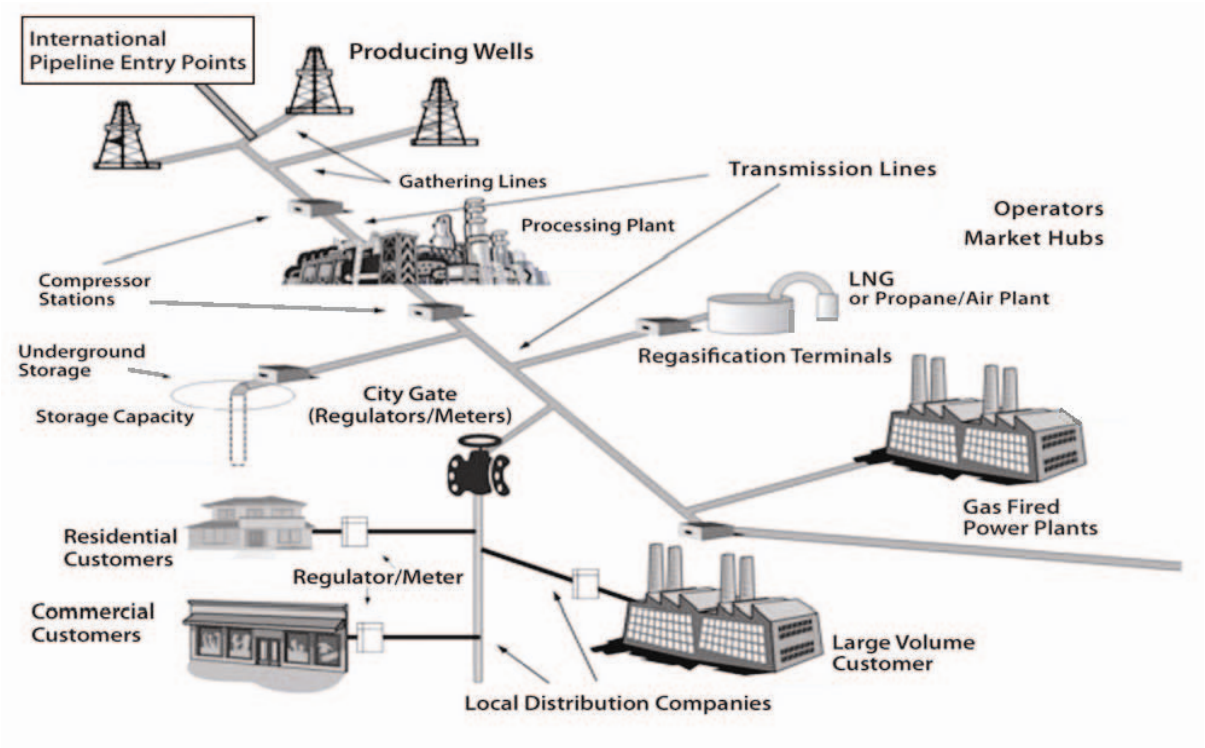
Source: Energy Commission: EAO. Natural gas demand for residential, commercial, and industrial sectors were provided by the DAO.

## Natural Gas Costs to California End Users

### Background

The prices of natural gas provided by NAMGas modeling above are estimates at interstate pipeline border crossings, utility citygates, and other hubs. These prices include the cost of producing natural gas, processing it for injection into a pipeline, and transporting it to a given hub. These hub prices are only a portion of the prices end-use customers in California pay to have natural gas delivered to their homes and businesses. California end-use customers also pay the added costs of transporting the natural gas through local utility pipeline networks. Some large-volume consumers are connected directly to the transmission pipelines so costs are lower, while others are connected by distribution and lateral pipelines operated by local distribution companies and therefore, transportation costs increase. **Figure 14** provides a schematic of how demand sectors are connected to sources of supply through the natural gas infrastructure. This section provides price estimates to end-use sectors based on added delivery costs from interstate pipeline border crossings, utility citygates, and other hubs.

**Figure 14: Natural Gas Infrastructure**




Source: *The Future of Natural Gas.* June 6, 2011, MIT. Modified by MIT from Chesapeake Energy Corporation.

## Current Trends

The state's three natural gas investor-owned utilities (IOU) are Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCal Gas), and San Diego Gas & Electric Company (SDG&E). The prices IOU customers pay are regulated by the California Public Utilities Commission (CPUC), and these prices cover all costs to purchase and deliver natural gas. They also account for investment in and maintenance of more than 164,400 miles of the IOUs' transmission and distribution pipelines,[15] compressor stations, storage, metering, and supervisory control and data acquisition (SCADA) facilities.

The IOUs' investment and maintenance costs are highest for the residential sector because the low-pressure natural gas distribution pipelines that serve this sector account for the largest share of the IOUs' pipeline, as homes greatly outnumber commercial, industrial, transportation refueling, and power generation facilities. Also, under CPUC rules the residential sector receives the highest level of reliable service. As a result, the CPUC authorizes the IOUs to charge the residential sector the highest prices, followed by commercial, industrial, and power generation sectors.

### *Method for Estimating End-Use Gas Prices*

Staff used the NAMGas model to estimate prices at North American natural gas hubs for the reference case, low-demand/high-price case, and high-demand/low-price case. Staff then added estimated transmission and distribution costs to these prices to obtain total estimated end-use costs by sector in 2015, 2020, and 2025. Natural gas demand for the residential, commercial, and industrial sectors is from the *CED 2014 – 2024 Revised Forecast, Volume 1*.[16] The reference case uses the mid case, the low-demand/high-price case uses the low case, and the high-demand/low-price case uses the high case from this forecast. Staff estimated natural gas demand for the power generation sector using the PLEXOS electric production cost model. The data used to estimate the transmission and distribution costs are taken from the CPUC's Biennial Cost Allocation Proceeding (BCAP) decision for each utility. Finally, staff used the NAMGas model to estimate transportation sector natural gas demand.

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15 PG&E. 2013. "Company Profile," at: http://www.pge.com/en/about/company/profile/index.page. SoCal Gas. 2013. "SoCal Gas' Approach to Pipeline Integrity," at: http://www.socalgas.com/safety/pipeline-integrity.shtml. SDG&E. 2013. "San Diego Gas & Electric Natural Gas Fact Sheet 2013," at: http://www.sdge.com/sites/default/files/newsroom/factsheets/SDG%26E%20Natural%20Gas%20Fact%20Sheet.pdf.

16 2013. *California Energy Demand 2014 – 2024 Revised Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency*. CEC-200-2013-004-SD-V1-REV.

## Outlook

Estimated end-use prices by sector for California customers are provided for 2015, 2020, and 2025, as shown in **Table 5**. Transportation prices remain fairly constant in all cases. For reasons stated earlier, residential customers have the highest prices, while power generation customers have the lowest prices. Price changes between 2015 and 2025 are more pronounced in the industrial, enhanced oil recovery, and power generation sectors as these historically have greater exposure to changes in the commodity price of gas (typically measured at Henry Hub). For comparison, today's prices are $10.94 residential, $8.05 commercial, $6.61 industrial, and $4.13 power generation.[17]

17 From the U.S. EIA's (October 31, 2013) natural gas survey results. In nominal dollars per Mcf for August 2013: http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_SCA_m.htm.

**Table 5: California Natural Gas End-User Prices in 2015, 2020, and 2025**

| | Low-Demand/High-Price Case | Reference Case | High-Demand/Low-Price Case |
|---|---|---|---|
| | **2015** | | |
| Residential | $10.23 | $9.43 | $9.42 |
| Commercial | $8.06 | $7.25 | $7.24 |
| Industrial | $5.92 | $5.11 | $5.10 |
| Power Generation | $5.34 | $4.53 | $4.54 |
| Transportation | $5.80 | $5.80 | $5.79 |
| EOR[1] | $5.45 | $4.65 | $4.61 |
| Average California[2] | $6.81 | $5.95 | $5.87 |
| | **2020** | | |
| Residential | $11.10 | $10.04 | $9.63 |
| Commercial | $8.92 | $7.87 | $7.45 |
| Industrial | $6.79 | $5.73 | $5.32 |
| Power Generation | $6.23 | $5.13 | $4.75 |
| Transportation | $5.79 | $5.79 | $5.78 |
| EOR | $6.31 | $5.26 | $4.81 |
| Average California | $7.89 | $6.70 | $6.13 |
| | **2025** | | |
| Residential | $11.72 | $10.67 | $10.16 |
| Commercial | $9.54 | $8.49 | $7.98 |
| Industrial | $7.40 | $6.35 | $5.85 |
| Power Generation | $6.81 | $5.73 | $5.28 |
| Transportation | $5.78 | $5.78 | $5.78 |
| EOR | $6.93 | $5.87 | $5.35 |
| Average California | $8.59 | $7.35 | $6.67 |

Source: Energy Commission: EAO.

[1]EOR is Enhanced Oil Recovery/Cogeneration

[2]Average for all sectors

# CHAPTER 3:
# Natural Gas Supply Issues

## Technology Innovation

### Background

Technological developments in exploration, drilling, and well completion and stimulation in the oil and gas industry have expanded the natural gas resource base and have enhanced production. As a result, some natural gas-bearing formations such as shale reservoirs, once inaccessible, are now producing (or will be producing) in 31 states of the Lower 48. The expansion of the resource base is a key factor driving natural gas prices in North America lower, with prices now hovering around $3.60/million British thermal units (MMBtu), about 75 percent lower than the peak of 2008.

#### *Hydraulic Fracturing*

In the mid-1990s, horizontal drilling combined with hydraulic fracturing (or fracking) to start what many now call the natural gas revolution. Previous drilling activity involved heavy reliance on vertical wells, limiting the wellbore exposure to the vertical footage that penetrated the formation of interest. However, horizontal drilling eliminated this limitation and facilitated wellbore exposure of more than 10,000 feet. Field operators can perforate more footage, and multistage hydraulic fracturing, the most notable technological innovation, can stimulate far lengthier zones within the formation of interest.

This stimulation process involves the pumping of a sand-laden viscous fluid, usually water, into the wellbore and into the formation. Most times, the mixture contains sand (or proppant[18]), water, and chemicals. The sand and water make up about 99.5 percent of the mixture and chemicals the remaining 0.5 percent. The operational pressure cracks the rock formation and creates an extensive network of artificial fractures, with each fracture open to a width of no more than 2 centimeters.[19] Usually, these fractures extend up to hundreds of feet from the wellbore.

After the sand settles from the fluid, the well operator retrieves the water by flowing it back to the surface through the wellbore. **Figure 15** demonstrates a typical "fracking" operation in a horizontal well, along with the creation of a network of artificial fractures after the

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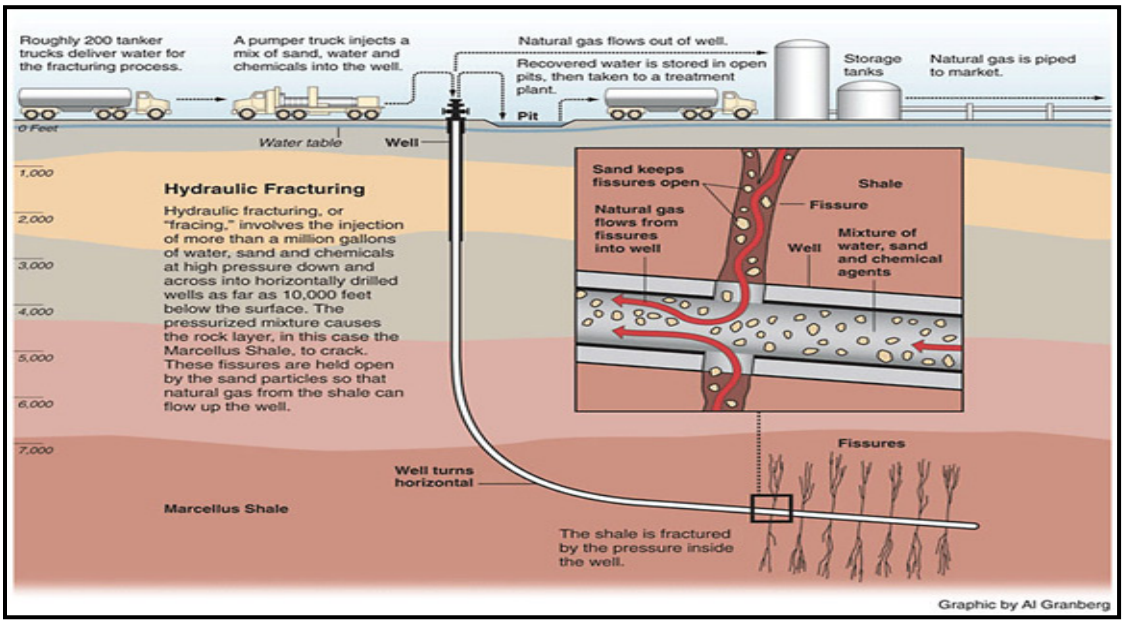
18 Proppants are granular substances (sand grains, walnut shells, or other material) carried in suspension by a fracturing fluid that keep the cracks in the shale formation open after the well operator retrieves the fracturing fluid.

19 One inch equals 2.54 centimeters

hydraulic fracturing treatment. The schematic also displays a typical multistage or multizone outcome of the subsurface treatment.

**Figure 15: Typical Hydraulic Fracturing Operation**




Source: U.S. EIA.

These fractures, held open by sand or another proppant, allow greater natural gas flow to the wellbore, and thus to the wellhead. In many instances, initial production may experience more than a ten- or twentyfold increase after stimulation. As a result of the technological developments in exploration, drilling, and completion, low effective permeability no longer hinders production from tight sandstone and shale formations. This exposure provided producers with greater opportunities to contact productive formations, whether sandstone or shale. The extended contact between the productive formation and the wellbore allows higher production and thus lowers the capital expenditure per unit of production.

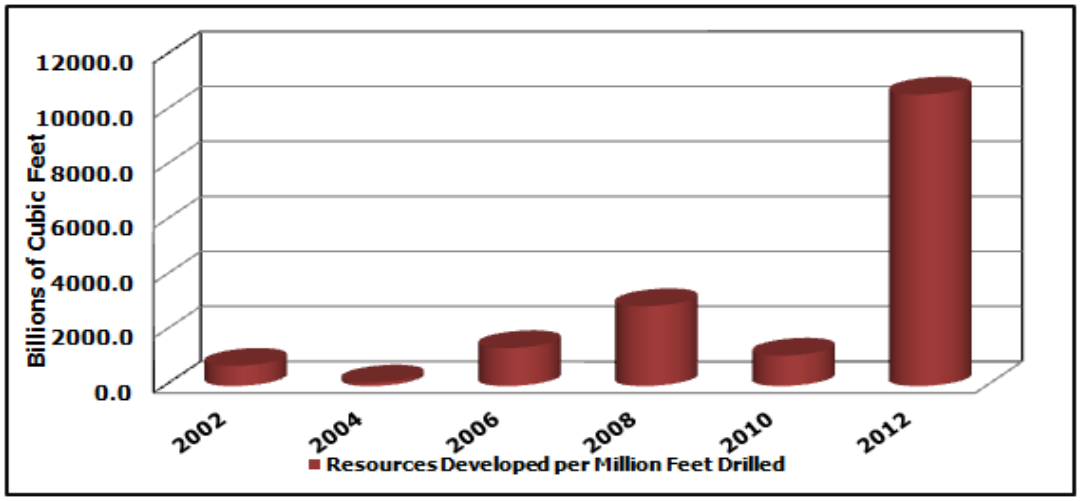
## Currents Trends

### *Improved Drilling Efficiency*

Exploration for natural gas deposits intensified with the development of three- and four-dimensional seismic surveys. This innovation improved the ability to delineate reservoir boundaries and identify the most productive area, or "sweet spot," of the reservoir. According to the American Petroleum Institute, success rates on exploratory wells reached 69.7 percent in 2012, up from 25.4 percent in 1990. The industry is now drilling

fewer dry[20] holes than it did 15 years ago and developing more potential resources per million feet drilled, as shown in **Figure 16**.

**Figure 16: Natural Gas Resources Developed per Million Feet Drilled**

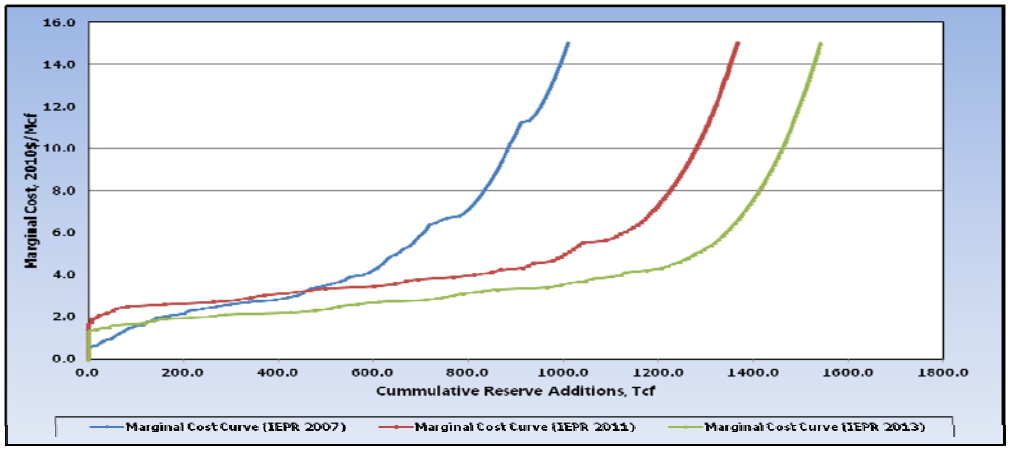



Source: American Petroleum Institute, Potential Gas Committee.

### *More Resources at Lower Cost*

**Figure 17** displays the cumulative marginal supply cost curves for 2007, 2011, and 2013. Improvements in exploration and drilling techniques have resulted in dramatic reassessments of North American gas resources. The gas supply outlook in 2013 is markedly different than what was predicted in 2007. For example, the quantity of gas economically recoverable at $6.00/Mcf was 700 Tcf in 2007 and 1,343 Tcf in 2013, almost a 100 percent increase.

**Figure 17: Cumulative Marginal Cost Profile**




Source: RGWTM.

20 Nonproductive wells.

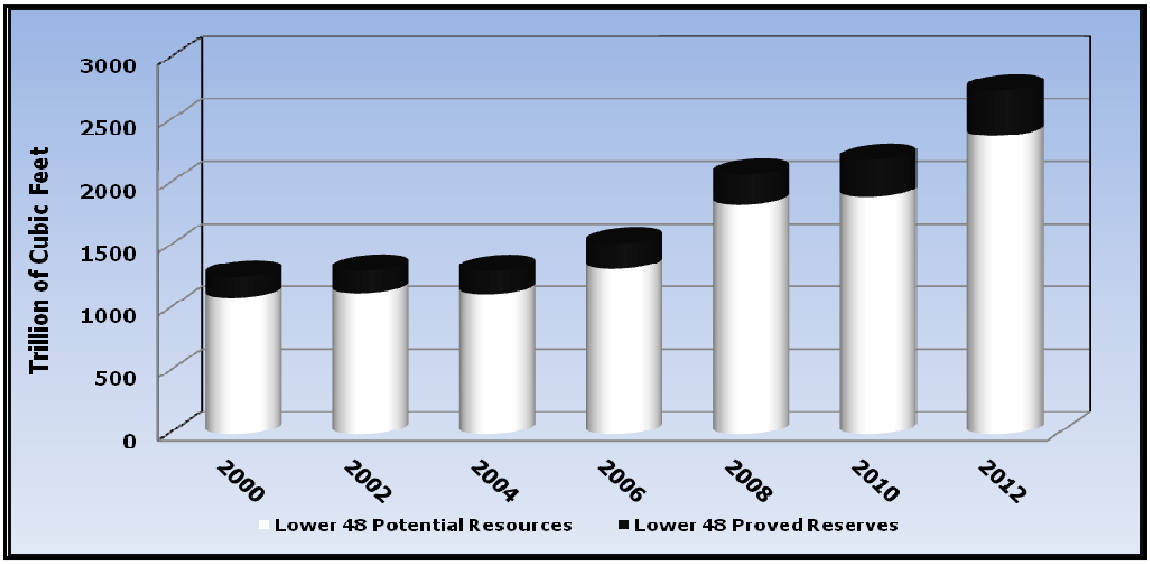
### *Expanded Resource Base*

The natural gas resource base, defined as the sum of the proved and potential natural gas reserves, has grown significantly between 2000 and 2012, as shown in **Figure 18**.

Proved reserves are all resources with the geological and engineering information that indicates with reasonable certainty that oil and gas operators can recover such reserves with existing technology under existing economic and operating conditions. Proved reserves in the Lower 48 states grew at about 3.2 percent per year until 2004 and then increased to 7.4 percent per year. Although the Lower 48 produces more than 20 Tcf of natural gas each year, proved reserves still climbed to greater than 350 Tcf in 2012, up from just over 150 Tcf in 2000.

Potential reserves include all undeveloped resources that qualify as probable, possible, or speculative, but that could be proved up in the future. These resources are geologically known but with decreasing levels of certainty. Between 2000 and 2004, total potential resources rose at a rate of 0.5 percent per year. Shale production technology, however, increased the growth rate dramatically resulting in the total Lower 48 resource base expanding to more than 2700 Tcf in 2012.

**Figure 18: Proved and Potential Reserves in the Lower 48**




Source: Potential Gas Committee, U.S. EIA (2012 proved reserves value estimated).

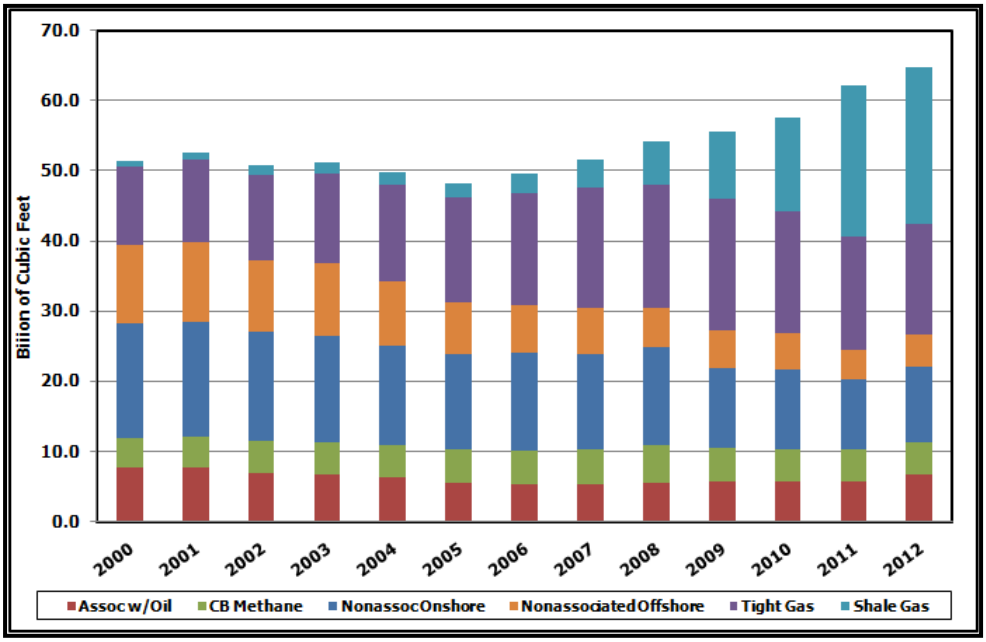
### *Increasing Production*

In 2000, total Lower 48 production averaged 52.4 Bcf/d, with shale gas providing about only 2.0 Bcf/d. However, by 2012, total production climbed to 65.8 Bcf/d, and shale gas production climbed to more than 29.0 Bcf/d. According to Lippmann Consulting, shale gas contributed more than 32 Bcf/d to total production in July 2013, which represents about 40

percent of the total Lower 48 wellhead production. **Figure 19** displays Lower 48 natural gas production by source and demonstrates three trends:

- Production from shale formations is expanding.
- Production from low-permeability sandstone formation ("tight gas") is expanding.
- Production from conventional sources is shrinking.

**Figure 19: Lower 48 Natural Gas Production by Source**



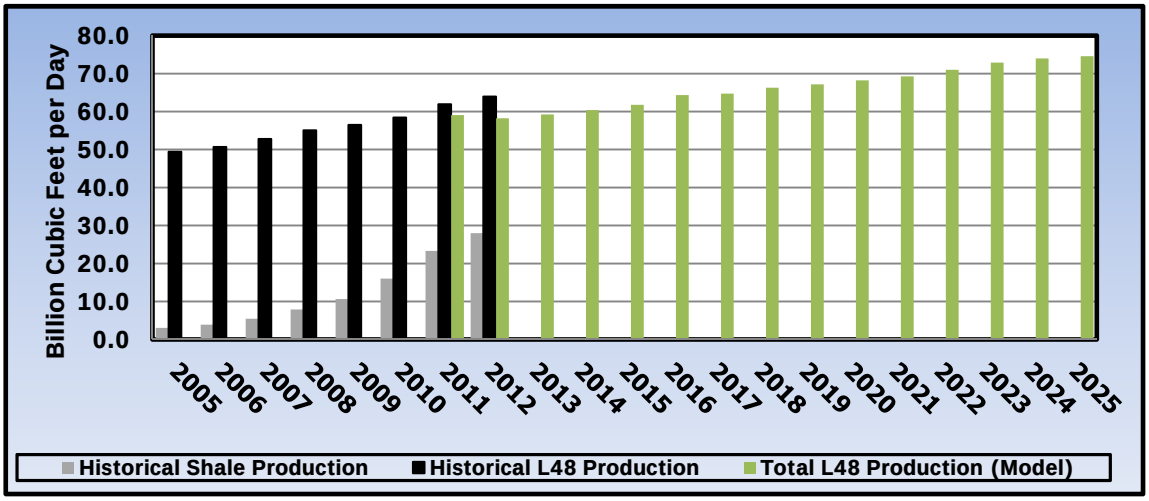

Source: U.S. EIA, Lippman Consulting.

## Outlook

**Figure 20** shows historical production of conventional and shale natural gas in the Lower 48 states from 2005 to 2012 and estimated production[21] of all natural gas resources from 2011 to 2025. The Energy Commission's reference case suggests that total natural gas production will grow at a rate of 1 percent per year from 2011 to 2025, reaching around 75 Bcf/d by 2025.

21 Results from the NAMGas model.

**Figure 20: Lower 48 Natural Gas Production (Historical and Forecasted)**




Source: Energy Commission: EAO, Lippman Consulting.

The natural gas industry is now pursuing production of "wet" shale formations that contain natural gas liquids, such as propane, ethane, and butane. These liquids are priced relative to oil, which on a per MMBtu basis is priced much higher than natural gas. The revenue from coproducing these natural gas liquids lowers the unit finding and development cost of natural gas and boosts economic feasibility. As a result, gas producers are shifting their exploration and development dollars to liquid-rich properties. Investments, represented by the rig count,[22] in "dry"[23] gas formations are falling but rising in so-called "wet" shale formations.

Technological innovations now extend to the development of methane hydrates. Huge untapped deposits of methane hydrates lay beneath sediments on the ocean floors. The United States Department of Energy (U.S. DOE) has been sponsoring research to determine the energy supply potential, drilling safety, and environmental issues associated with naturally occurring methane hydrate in accordance with its 2006 report *An Interagency Roadmap for Methane Hydrate Research and Development*[24].In early 2013, a consortium composed of Japan's Ministry of Economy, Trade and Industry; the state-run Japan Oil, Gas, and Metals National Corp; and the Japan Petroleum Exploration Company, announced their successful extraction of these resources. Japan expects commercial harvesting to commerce around 2018.

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22 The rig count is the number of active rigs drilling for oil and natural gas.

23 In most jurisdictions, regulators designate formations producing less than 0.01 bbl/Mcf of oil and natural gas liquids as "dry."

24 See http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/maincontent.htm.

## Regulatory Changes

### Background

Producing natural gas from shale formations requires the use of horizontal drilling coupled with hydraulic fracturing. While this has benefited resource development, there are environmental challenges, including potential impacts to air quality, water resources, habitat, and native species, and potential increased seismic activity. Moreover, there are environmental impacts of a socioeconomic nature created by economic "boom" conditions, such as noise, traffic, higher local prices for commodities like milk, and "man camps."[25] State and federal decision-makers and regulators are considering new regulatory frameworks to guide oil and natural gas development.

### Current Trends

In response to concerns regarding possible environmental impacts and the lack of regulations to address them, some jurisdictions such as New York have delayed development of their shale resources, while others have instituted environmental mitigation fees. States such as Texas, Ohio, and Pennsylvania have issued regulatory requirements for "responsible development" of oil and gas formations. These regulations include guidelines for the use and disposal of water, the protection of groundwater, and the disclosure and use of chemicals. Meanwhile, the development of the Fayetteville Shale formation in central Arkansas has increased the need for water storage and disposal. Several local communities, however, complained about an increased number of earthquakes, resulting from the operations of nearby water disposal facilities. Consequently, Arkansas regulators have ordered the closure of several underground water disposal sites. In Ohio, Oklahoma, and Arkansas, increased seismic activity has also caused concern.

The new regulatory frameworks are defining—in some cases redefining—the requirements and limits of oil and natural gas development. All states with major shale gas production have mandated (or are moving in the direction to mandate) the disclosure of chemicals used in hydraulic fracturing. Other rules that are trickling into the practices of the oil and gas industry include:

- Requirements for protecting and testing the groundwater.
- Requirements for well testing before and after hydraulic fracturing stimulations.

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25 *Man camps* are the temporary employee housing provided for oil and gas field workers in areas of active drilling. The camps are intended to be self-sufficient communities that provide living quarters dining, laundry, and recreational facilities for the transient oilfield worker. The camps are often associated with problems that affect the surrounding communities such as overwhelming population growth, sanitation issues, public safety issues and strains on interior roads, electricity and water providers, law enforcement agencies, emergency services, fire protection, and sewage disposal.

- Requirements for community notification.
- Requirements for the disposal of wastewater.
- Requirements to pay environmental mitigation fees.

The regulatory frameworks are developing state by state. As a result, mandates in one state may differ from those of another. Some stakeholders are advocating for a nationwide uniformity of the framework. Consequently, federal governmental agencies have moved in that direction. The United States Environmental Protection Agency (U.S. EPA) is investigating the use of the subsurface technique and is considering the issuance of new regulations. In May 2012, the United States Department of Interior Bureau of Land Management released an updated draft of regulations on hydraulic fracturing of wells on federal lands that may or may not be modified again before they become final.

### Outlook

The possible environmental impacts of hydraulic fracturing require more study. Such studies and scientific measures will improve regulatory design and implementation. As more information becomes available, decision-makers can balance between the development of natural resources *and* the protection of public health and the environment. Staff is unaware of studies produced to date that conclusively show hydraulic fracturing is or is not safe. In the meantime, producers continue to innovate by adopting waterless fracturing, reducing freshwater usage, or otherwise greening the “fracking' fluids.” Though not yet widespread, some oil and gas operators are now fracturing with a butane-rich fluid instead of water. Less than 5 percent of wells used nonwater-based fluids in 2012. Further, oil and gas entrepreneurs are developing nontoxic agents that may replace the chemicals used in fracture treatments. These new agents contain food-based products such as the sweetener maltodextrin and partially hydrogenated vegetable oil.

## California Shale Development

### Background

Hydraulic fracturing requires lengthy fracturing periods in many geologic formations along lengthy stretches of horizontally drilled production wells, as shown in **Figure 15**. In California, on the other hand, hydraulic fracturing jobs require much less water, and the period of pressurizing the reservoir rock extends to hours not days. Further, fracturing procedures tend to crack the rock along a narrow vertical band, generally starting at a point several thousand feet underground. As a result, the network of artificial fractures extends only tens to hundreds of feet away from the well (wellbore). To date, most of California’s oil and gas production has been from vertical wells drilled into traditional oil and natural gas

reservoirs (formations). As such, operators in California have executed few, if any, hydraulic fracturing jobs in horizontal wells.

The Monterey Shale, a mostly oil "play" located in the San Joaquin Valley, contains about 15 billion barrels of oil and natural gas liquids and an undetermined volume of associated natural gas, according to an estimate prepared for the U.S. EIA in 2011.[26] Due to numerous fault lines and pressure from historical seismic activity, the sedimentary strata of the Monterey Shale are bent into folds. This folding formation is not as conducive to horizontal drilling as the Bakken or Marcellus Shale deposits.[27] Some industry experts believe that performing advanced, three-dimensional seismic surveys will be necessary before the Monterey Shale can be extensively developed.[28] This shale formation, mainly an oil-bearing reservoir, may produce associated natural gas, but the industry has not yet developed reliable estimates of the amount.

## Current Trends

In California, the Department of Oil, Gas, and Geothermal Resources regulates the state's activities of the oil and gas industry. All oil and gas wells drilled in the state must adhere to requirements, such as:

- Laws and regulations regarding the protection of underground and surface water.
- Regulations regarding the integrity of the well casing (pipe in drilled hole cemented in the subsurface).
- Rules pertaining to the cement used to secure the well casing inside the drilled hole.
- Regulations pertaining to the cement and equipment used to seal off the well from underground zones bearing freshwater and other hydrocarbon resources.

The California Department of Conservation released draft regulations concerning hydraulic fracturing in December 2012. The California Department of Conservation opened a rulemaking in November 2013 to formally consider new rules and anticipates that the process will be completed by January 2015. In September 2013, California enacted Senate Bill 4 (Pavley, Chapter 313, Statutes of 2013) that will require increased well testing, community notification, and disclosure of chemicals used in the subsurface technique.

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26 INTEK, Inc., *Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays*, July 2011.

27 The Bakken Shale formation (predominantly oil) and Marcellus Shale formation (predominantly gas) are located in North Dakota and neighboring states and Pennsylvania and neighboring states, respectively. They are the most prolific hydraulically fractured shale plays in the United States and are used in this case for the sake of comparison to the Monterey Shale formation, which has a very different geologic structure than either of them.

28 "The Monterey Shale - Big Deal or Big Bust,"*AAPG Explorer*. November 2012.

## Outlook

Greater disclosure as required by Senate Bill 4 and more scientific study could alleviate public concern and reduce some of the opposition to hydraulic fracturing in California. The Monterey Shale is considered an oil play and contains an unknown volume of natural gas, so the effect on natural gas supply is unknown. Because California imports 90 percent of its natural gas requirement, a new indigenous resource could benefit the state, in addition to the economic benefit that would accrue from in-state oil production.

# CHAPTER 4:
# Gas and Electric System Interactions

Over the past decade, natural gas-fired generation nationwide has increased substantially, rising from 17 percent to 25 percent of total power generation. Natural gas is now the largest fuel source for electric generation capacity in the United States.[29] In response to clean energy policies, the electricity sector is undergoing major changes, which include the widespread deployment of renewable resources and the pending retirement of coal-fired power plants. Natural gas demand for the power sector is likely to increase as gas-fired power plants are used to replace coal plants and to integrate increasing amounts of renewable resources.

As the use of natural gas for power generation increases, differences inherent to the natural gas industry and electricity industries have become more apparent and present challenges. Pipeline systems that were designed for seasonal swings in residential and commercial demand are now increasingly being used to accommodate the daily and hourly demand patterns of electricity generation. Major industry participants and regulatory bodies have raised concerns regarding the ability to maintain electric system reliability when delivery of natural gas becomes constrained.

A cold weather incident that occurred in the U.S. Southwest in early February 2011 highlighted reliability issues associated with natural gas supply for electricity generation. The severe cold weather caused six coal-fired electric generating units to go offline in the Electricity Reliability Council of Texas-controlled area. Some natural gas power plants that would normally be called on to provide replacement generation were initially unavailable, while others could not operate because of low pipeline pressures caused by the freezing of natural gas wells and gathering lines. In addition, many of the remaining natural gas units had purchased only interruptible natural gas transportation service, which was unavailable due to high demand by higher priority customers. Significant power outages throughout the Southwest region soon followed. California did not suffer power outages but did experience reduced, and in some cases interruption of, deliveries of natural gas to SDG&E customers.

The FERC and the North American Electric Reliability Corporation investigation into this cold weather incident demonstrated the challenges associated with the increasing interdependence between electricity and natural gas industries.[30] FERC issued a notice soliciting comments on aspects of natural gas-electricity generation coordination, which revealed that the issues and challenges vary by region.[31] The power generation portfolio,

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29 North American Electric Reliability Corporation, *2013 Special Reliability Assessment: Accommodating an Increasing Dependence on Natural Electric Power*, May 2013, p. 1; see http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf.

30 FERC, *Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011; see* http://www.ferc.gov/legal/staff-reports/08-16-11-report.pdf.

31 Docket No. AD12-12-000.

available infrastructure, and level of demand vary by region. Some regions such as the Northeast, where demand for natural gas in growing the fastest and where insufficient firm pipeline capacity is available to serve power generation needs, appear to be having the most difficulties.

## Natural Gas Supply for Electricity Generation

### Scheduling Misalignment

A key difference between the natural gas market and the power market is in the scheduling of deliveries of the two commodities. Natural gas shippers have the opportunity to nominate, or order, natural gas deliveries on interstate pipelines one day ahead in what is called the *timely nomination cycle*. This cycle establishes the allocation of pipeline capacity for the next gas day. Once the nomination schedule has been submitted, there are three opportunities to revise the schedule. The first opportunity occurs in the day-ahead, while the other two opportunities occur during the gas day.

Electricity can be scheduled and dispatched much more frequently throughout the day than natural gas—at least hourly and sometimes subhourly—and travels near the speed of light. Natural gas has only two opportunities to have dispatch adjusted intraday and travels at low speeds through the pipelines (15 – 20 miles per hour[32]).

This mismatch of scheduling can cause natural gas system imbalances. If a natural gas-fired generating facility uses more gas than what was scheduled, a penalty fine may then be incurred. As natural gas generators are more frequently used to quickly ramp up and down to integrate intermittent renewable generation, gas imbalances are likely to become a bigger problem since natural gas systems were not designed to accommodate these sudden changes in demand. Better alignment of electricity generation schedules with the natural gas schedules was identified as an important operational issue in FERC's regional technical conferences in 2012.[33]

32 See http://www.ferc.gov/eventcalendar/Files/20120830220205-primer.pdf.

33 FERC, *Staff Report on Gas-Electric Coordination Technical Conference* (Docket No. AD12-12-000) November 15, 2012; http://www.ferc.gov/legal/staff-reports/11-15-12-coordination.pdf.

## Natural Gas Delivery Priority

In the natural gas industry, new or increased capacity on an interstate pipeline is usually contracted for in advance as firm capacity.[34] The amount of contracted capacity typically determines the design capacity on an interstate natural gas pipeline. In some cases an interstate pipeline can be constructed with spare capacity, which can later be sold under firm contracts or be made available on a secondary market as interruptible capacity.

Natural gas-fired generators that operate only a limited number of hours during the year, for example to meet peak demand, have less incentive to secure more expensive firm capacity on an interstate pipeline. As natural gas units are called on to help integrate intermittent renewable resources, their revenue streams will arguably be more difficult to predict. This uncertainty may lead these generators to sign up for interruptible rather than firm gas delivery services. Generation units may also be hesitant to subscribe for firm capacity on an interstate pipeline because of decreased scheduling flexibility as a result of the "no bump rule."[35] However, in some areas where electric service is provided by vertically integrated electric utilities (such as the Southeast), firm natural gas pipeline arrangements appear to be the norm.[36]

When there are capacity constraints on intrastate pipelines, established customer priorities come into effect.[37] In general, primary firm service has the highest priority, secondary firm is the next priority, and interruptible service is the lowest priority.[38] Although gas-fired power plants can secure firm service on interstate pipelines, these customers cannot secure the same level of firm service on intrastate pipelines. The natural gas system in California has largely been designed to serve the needs of the residential and small commercial sectors, which are considered to be firm or core customers. Noncore customers such as large commercial, industrial, and electric generation sectors are the first to be interrupted when

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34 With some exceptions, FERC approval of new pipelines or capacity expansions is generally contingent on commitments by firm shippers to pay proposed rates and a developer's acceptance of any remaining financial risk.

35 The *no bump rule* is a tariff provision applicable to interruptible transportation that provides that a shipper may temporarily lose its ability to receive its full contract volumes if it ships at a lower volume. Under the no bump rule, a shipper currently flowing natural gas cannot be bumped (lose capacity) because a shipper with a higher priority in the interruptible transportation queue decides to increase its receipt of natural gas within its transportation contract.

36 A *vertically integrated utility* controls the generation, transmission, and distribution of power.

37 In California, intrastate pipelines are regulated by the CPUC.

38 A *primary firm shipper* is a customer who holds capacity on a natural gas pipeline from a designated receipt point to a designated delivery point. Primary firm shippers have first call on the system, and pipelines are generally designed to meet aggregate demand from firm shippers. A *secondary firm shipper* is a firm customer who asks to use available firm capacity between a receipt and delivery point other than the designated receipt and delivery points. Interruptible customers hold no rights and use whatever is available between whatever receipt and delivery points they can get.

there is insufficient pipeline capacity to deliver natural gas. Because electric generators are interruptible customers in California, there is a potential risk to generation reliability.

## Communication and Coordination at the Federal Level

During FERC's regional conferences held over the last year, enhanced coordination and communication between natural gas and electricity industries were consistently identified as an important element to allow both systems to operate more efficiently and reliably.[39] Specifically, making available information about pipeline capacity release schedules (when spare pipeline capacity becomes available) and a power generator's expected burn rates were seen as ways to improve both system response time and reliability. Information sharing becomes especially important during emergencies. Improvements in communication and information sharing are most needed in areas where conditions are most stressed, such as the Northeast, where pipeline constraints are prevalent.

The approaches to communicating during an emergency vary on a regional level. For example, the Northwest Mutual Assistance Agreement aids utilities during a natural gas-related emergency by maintaining updated emergency contact information and conducting semiannual planning meetings. The California Independent System Operator (California ISO) amended its tariff to promote communication on gas-related maintenance activities within California.[40] Under the amended tariff, the California ISO can also now share generator outage information with natural gas pipeline operators, with or without notice to the affected market participant.

On a national level, FERC has issued several orders to help improve communication between the gas and electric industries. FERC Order No. 698, issued in 2007, requires that generators provide pipeline operators with hourly gas burn estimates upon request to improve gas-electric communication during normal business operations.[41] Amended FERC Order No. 587-V was issued in 2012 to incorporate Version 2.0 of the North American Energy Standard Board Wholesale Gas Quadrant business practice standards.[42] This order requires natural gas pipelines to provide notification to balancing authorities and/or reliability coordinators, and power plant gas coordinators of operational flow orders and other critical notices.

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39 Conducted under FERC docket AD12-12.

40 California ISO tariff Section 6.6.1.1(i); FERC Docket No. ER12-278-000 (December 8, 2011).

41 FERC, *Standards for Business Practices for Interstate Natural Gas Pipelines; Standards for Business Practices for Public Utilities,* Order No. 698-A, issued June 25, 2007; http://www.ferc.gov/whats-new/comm-meet/2007/062107/M-1.pdf.

42 FERC, *Standards for Business Practices for Interstate Natural Gas Pipelines* Order No. 587-V, issued July 19, 2012.

In August 2012, FERC conducted five regional technical conferences to address gas-electricity system coordination issues in the various regions, including the Northeast, Mid-Atlantic, Central, West, and Southeast. The power generation portfolio, available infrastructure, and level of demand vary by region. Therefore, the severity of challenges is unique within each of these regions.

Many stakeholders expressed concern that FERC rules and policies could impede improved communication between the industries. Some power generators are concerned that the sharing of information with pipeline operators could put the generators at a competitive disadvantage or could lead to a third-party member gaining access to proprietary information. Many suggested that FERC amend or provide guidance on the application of the Standards of Conduct to prevent undue discrimination and preference during the act of sharing information.[43] FERC is gathering more industry insight to enhance the Standards of Conduct. On July 18, 2013, FERC issued a notice of proposed rulemaking to remove communications barriers between gas pipelines and electric utilities to address concerns raised by stakeholders and to facilitate the information sharing process.[44]

## Communication and Coordination Issues in California

California appears to be in the best position to address challenges associated with increasing use of natural gas for electric generation for a number of reasons. Unlike other regions, California has relied heavily on natural gas for electric generation over the last two decades. California is also less dependent on coal-fired generation than other regions. Consequently, it has planned for natural gas infrastructure to serve electric generation demand. During the California energy crisis of 2001, it became apparent that the state's natural gas infrastructure was inadequate to handle significant weather- and hydro-related increases in gas demand.[45] Between 2001 and 2009, California made significant investments in expanding this infrastructure, including increased capacity along current intrastate natural gas pipelines and additions to natural gas storage capacity within the state. In addition, receipt capacity for interstate pipelines in California was added to accommodate increased in interstate pipelines serving the state.

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43 At the February 2013 conference on coordination between the two markets, staff at FERC explained that the Standards of Conduct already permit communications during "emergency circumstances."

44 FERC Docket No. RM13-17-000.

45 Californians have relied on natural gas for home heating and industrial uses for decades. Historically, gas demand was highest during the winter months. In the early 2000s there was a dramatic expansion of gas-fired generation in California that significantly increased natural gas consumption and contributed to tighter demand conditions year-round.

While fuel-switching capabilities, such as fuel oil, may be more limited than in other regions, California's spare pipeline and storage capacity near load centers has helped absorb the increased use of natural gas while maintaining system flexibility and reliability. It also allows the natural gas utilities to offer relatively liberal gas balancing tolerances and make-up provisions. Under these conditions, the need to divert supplies to higher priority customers will be less likely. However gas-fired power plants are noncore customers that are subject to curtailment when supplies or capacity are constrained. Even in California, demand conditions on an extreme peak day could be high enough to require curtailments of noncore customers.

The California ISO has established business practices that promote coordination between the natural gas and electric industries. For planning purposes, California ISO meets with gas pipeline representatives in advance of the summer peak seasons to discuss issues such as available gas inventory, projected supplies, planned maintenance on gas facilities, upcoming additions to the gas systems, capacity outages, and long-range weather forecasts. Similar meetings are held during the fall to examine the winter assessment for fuel capabilities of gas-fired generation and related outages.

Communication during daily operations is also conducted among the California ISO, natural gas pipeline operators, and generators, as needed. On the electricity side, these conversations focus on immediate operational concerns, such as changes in the load forecast after the day-ahead plan has been published, unplanned outages, and the occurrence of sudden extreme weather conditions. On the gas side, updated capacity release data are communicated. In addition, as part of implementing Pipeline Safety Enhancement Plans in response to the San Bruno explosion, maintenance is conducted primarily during shoulder seasons, when demand for natural gas is reduced.[46] The California ISO is made aware of utility pipeline maintenance schedules to allow for planning of alternative supplies. Furthermore, the California ISO and pipeline operators discuss communication procedures and protocols to identify opportunities for improvement.

The communications mentioned above are made possible by the nondisclosure clause that was specifically written into the California ISO tariff to specifically allow the gas and electric industries to communicate.[47] These efforts to enhance communication will help California to avoid curtailment due to maintenance activities or during emergencies.

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46 *Shoulder seasons* are periods between peak and off-peak seasons.

47 California ISO tariff 20.49(c)(iv).

## Role of Natural Gas in a High Renewable World

California's RPS mandate of 33 percent renewable power by 2020 has spurred the development of record amounts of renewable generating capacity in the state. The build-out of renewable generating capacity is displacing power demand that likely would have been met by natural gas-fired generating units. However, due to the intermittent nature of renewable generation, primarily solar and wind, some amount of natural gas-fired back-up units will be necessary.

Increasingly, large solar installations and many wind turbines are being counted on to meet California's electricity demand. However, when the sun sets, when it gets cloudy, or when the wind stops blowing, shifts in power output occur, and other supplies must be dispatched to keep the system in balance. As mentioned earlier, natural gas generators will need to more quickly ramp up and down to integrate renewable resources than they have in the past, which, in turn, will require a high level of flexibility on the natural gas pipeline systems. California is fortunate to have storage capacity that adds significant flexibility to a gas system and helps ensure the reliability of supply. However, the exact amount of natural gas generation that will be needed in the future to integrate increasing renewable resources is not yet known.

In addition to ramping up natural gas-fired generation, California is pursuing preferred resources, such as demand response and energy storage, to help with renewable integration needs. However, for the foreseeable future, the natural gas generation fleet will remain a critical element in backing up the increased use of renewable resources. Regional solutions could also help address renewable intermittency, such as the creation of a real-time energy imbalance market. FERC approved the creation of the real-time energy imbalance market between the California ISO and PacifiCorp (a Portland, Oregon-based utility), which is intended to leverage regional diversities so resources can be shared during times of under- or overgeneration to make greater use of renewable resources in the two regions.[48]

In recent years, stakeholders throughout the West, including the State and Provincial Steering Committee, have begun to recognize that increasing reliance on natural gas for electricity generation poses challenges to both the operation and planning of the electricity and natural gas systems in the region.[49] In October 2012, State and Provincial Steering

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48 See http://www.caiso.com/Documents/Jun28_2013-OrderAcceptingPacifiCorpEnergyImbalanceImplementationAgreement_ER13-1372-000.pdf.

49 The State and Provincial Steering Committee is a western regional entity that consists of representatives of the governors and the public utility commissions from each state in the Western Interconnection, plus representatives from Alberta and British Columbia and members of the Western Interstate Energy Board. The Western Interconnection includes 11 Western states, including Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming, two western Canadian Provinces (Alberta and British Columbia), and the northern part of Baja California, Mexico.

Committee formed a Western Gas-Electric Regional Assessment Task Force composed of representatives from the electricity and natural gas industries, regulatory organizations, and other stakeholders from around the West to identify critical issues and develop a scope of work for a regional study.

The regional assessment will determine whether the natural gas system can reliably deliver gas to electricity generators in the future. There are two primary issues that will be addressed:

- Will there be adequate natural gas infrastructure (interstate and intrastate), including storage, to meet the long-term needs of the electricity industry in the Western Interconnect?
- Will the natural gas system have adequate short-term operational flexibility to meet electric industry requirements in the Western Interconnection, in particular to meet rapid ramping requirements necessary to integrate intermittent renewable resources?

The Western Interstate Energy Board has retained a contractor to assess the gas and electricity systems and to address questions related to infrastructure adequacy. In addition, natural gas pipeline companies who have participated in the Western Gas-Electric Regional Assessment Task Force will perform detailed modeling of their gas systems. This system modeling is necessary to understand the operational challenges posed by the intermittent nature of renewable resources generation. The study is expected to be completed by September 2014.

## National Conversion of Coal to Natural Gas Generation

New challenges and opportunities have arisen for regions that have just recently turned to natural gas-fired generation. Lower natural gas prices have often made that commodity competitive with coal and have prompted fuel switching in areas that have traditionally relied on coal-fired generation. Some fuel switching to natural gas has occurred in anticipation of U.S. EPA's GHG and other regulations requiring substantial investments in control equipment to reduce emission of criteria pollutant and GHG at existing coal plants, which is likely to lead to retirements of some coal facilities. Some regions that have traditionally used coal for power generation will face challenges switching to natural gas because of the need for new infrastructure and the lack of experience working with the gas industry. The WECC area has about 37 GW of coal-fired generation capacity, and there is a great deal of uncertainty about how much of this may retire.[50]

50 *WECC State of the Interconnection Report:* http://www.wecc.biz/Planning/PerformanceAnalysis/Documents/2012_WECC_SOTI_Report.pdf.

The Emission Performance Standard created by Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) prohibits California utilities from signing new contracts that would increase the generating capacity or extend the life of any high GHG-emitting baseload generating facility that exceeds 1,100 pounds of carbon dioxide ($CO_2$) emissions per megawatt hour.[51] The Emission Performance Standard has prompted early divestment of coal-fired generators by California utilities. The amount of electricity produced from coal-fired plants in California has been decreasing and is currently only about 200 MW.[52]

Nationally, there will continue to be competition between coal and natural gas for electricity generation based on the relative costs of each fuel. In 2012, the average spot price for natural gas was well under $3.00 per MMBtu for most major trading hubs in the Lower 48. At that time, the price of natural gas was competitive with the price of coal and in some cases cheaper. This prompted changes in generation dispatch from coal to natural gas during the middle part of 2012 in regions that traditionally used coal and had the capability to switch to natural gas—mainly Midwestern and Eastern United States, as shown in **Figure 21**.

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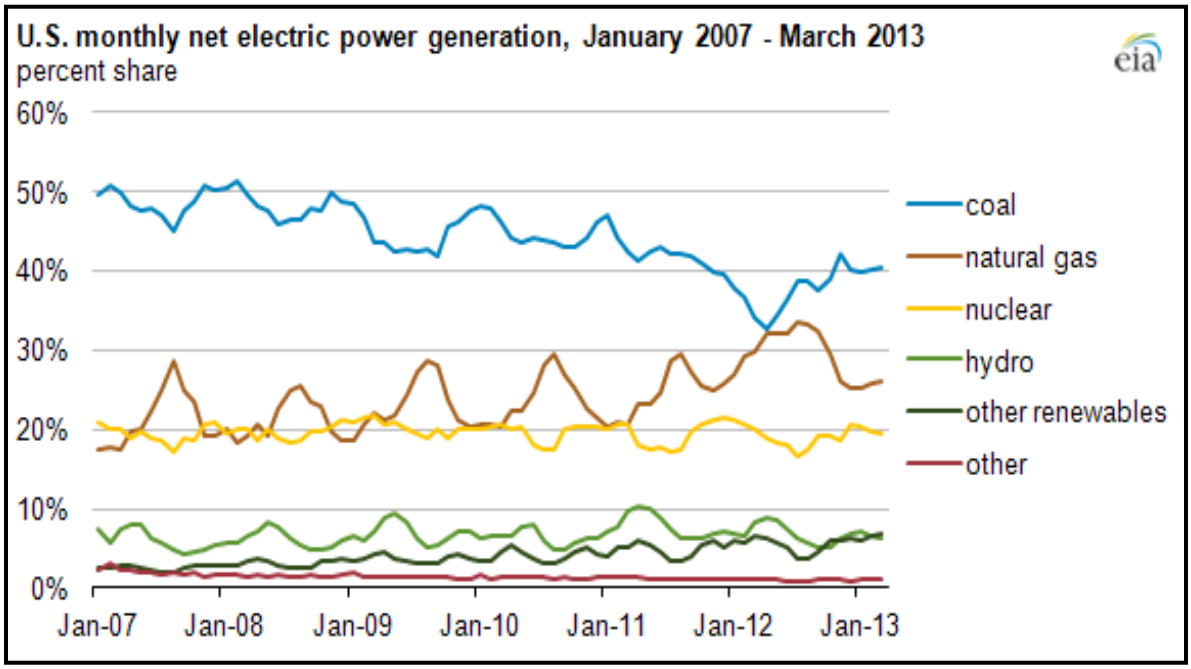
51 SB 1368 (Perata, Chapter 598, Statutes of 2006); http://www.energy.ca.gov/emission_standards/documents/sb_1368_bill_20060929_chaptered.pdf.

52 See WECC State of the Interconnection Report: http://www.wecc.biz/Planning/PerformanceAnalysis/Documents/2012_WECC_SOTI_Report.pdf.

California imports power from about 1,800 MW of coal-fired generation located outside the state. When combined with in-state production, coal represents 8 percent of California's total system power.

**Figure 21: Percentage Market Share of Power Generation by Fuel Source, 2007 – 2013**




Source: U.S. EIA, *Electric Power Monthly*.

## Gas Implication of San Onofre Nuclear Generation Station Closure

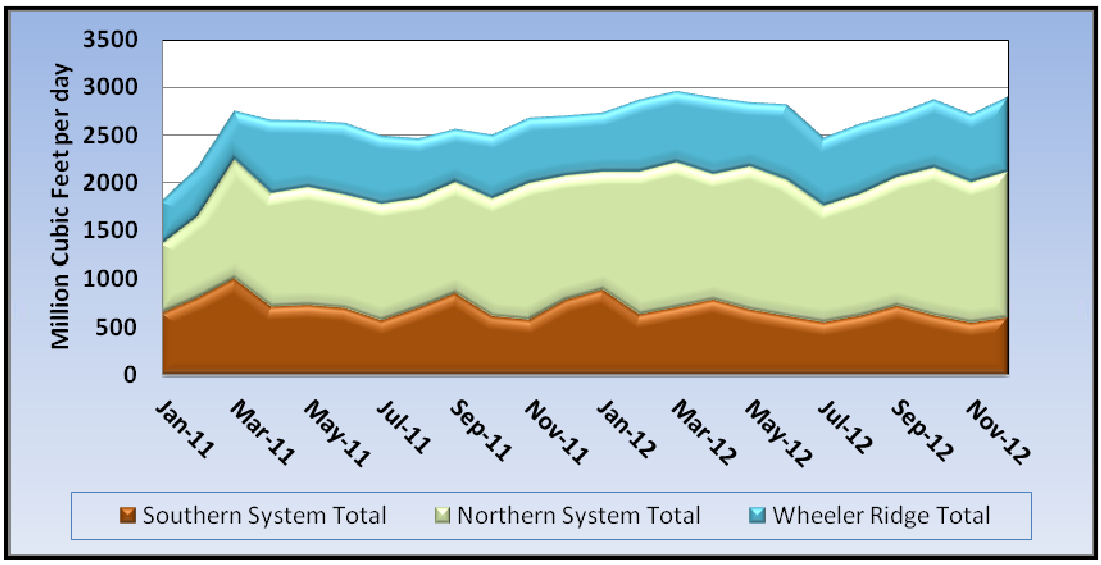
In early, 2012, the SONGS Units 2 and 3 were taken offline due to problems discovered during maintenance inspections. Combined, the units at SONGS provided 2,200 MW of generating capacity to the Southern California region (Orange County and San Diego area). In December 2011, daily average natural gas demand on the SoCal Gas system was about 2,693 million cubic feet per day (MMcf/d). Since the closure of SONGS, demand on the SoCal Gas system rose to 2,950 MMcf/d in March 2012, a 257 MMcf/d increase from December 2011 natural gas demand, as shown in **Figure 22**. The California ISO reported that thermal generation from other sources also increased by more than 1,000 MW. Having ample available natural gas storage inventory levels and spare interstate pipeline capacity was likely key in ensuring that additional demand for natural gas was met with no reliability issues.

During the summer of 2012, the generation needed to make up for the loss of SONGS energy came almost entirely from the fossil-fuel plants in Southern California that do not use once-through-cooling.[53] In addition, Huntington Beach Units 3 and 4 (452 MW) were

53 The State Water Resources Control Board implemented a policy in May 2014 to phase out the use of once-through-cooling in coastal power plants that use ocean water. As a result, 20,704 MW of natural gas-fired generation will need to be retired, retrofitted, or repowered to satisfy the OTC policy if utilities can secure CPUC-approved power purchase agreements.

converted from generation capacity to reactive support devices.[54] Increased transmission capacity from Sunrise Powerlink and Barre-Ellis also helped ensure power quality and reliability.[55] All these efforts, along with energy efficiency and the potential to enact demand response and Flex Alerts, helped to ensure that load was met reliably in the Southern California region for the summer of 2012.

**Figure 22: SoCal Gas System Natural Gas Demand**




Source: SoCal Gas Envoy.

In June 2013, Southern California Edison Company decided to permanently close and decommission SONGS. California will need to make up for the loss of this generating capacity with natural gas, renewable resources, and purchased power in the immediate years ahead. Governor Brown established a task force to develop and assess options to shore up local area capacity requirements in the absence of SONGS. A draft plan was released in August 2013.[56]

Earlier this year, the CPUC issued a revised scoping order and assigned commissioner ruling, which focus on the need for resource procurement authority for capacity to satisfy local capacity requirements with SONGS offline.[57] California ISO studies were submitted on

54 *Reactive support device*: A device that helps improve and maintain power quality by keeping current and voltage levels in phase within acceptable parameters.

55 Barre-Ellis connects two key Southern California substations, while the 117-mile Sunrise Powerlink connects Imperial County (solar energy) to San Diego.

56 See http://www.energy.ca.gov/2013_energypolicy/documents/2013-09-09_workshop/2013-08-30_prelim_plan.pdf.

57 CPUC 2012 Long Term Procurement Planning proceeding, Track 4.

August 5, 2013, along with further studies and testimony on September 2013, and the CPUC hopes to issue a decision in late 2013 or early 2014. The CPUC will have to determine the amount of preferred resources, including demand-side and renewable resources, that should be used to address local capacity requirements.[58] Infrastructure requirements to support additional natural gas-fired generation will be studied as part of future Long Term Procurement Planning proceedings.

## Natural Gas/Electric Synchronization Case

The issue of synchronizing natural gas supply with electricity generation has become more important as demand for natural gas in the power generation sector increases. The natural gas/electric synchronization case explores this relationship, given California's unique mix of generation fuel options. The natural gas/electric synchronization case attempts to examine the *net effects* of increased renewable generation and coal-fired generation retirement combined, with no added energy efficiency in California and the WECC. This case does not attempt to examine the daily operational ramping requirements to facilitate the increased integration of renewable power generation. Instead, the impacts on annual average natural gas requirements for power generation were analyzed.

The natural gas/electric synchronization case assumes that California will surpass the RPS goal, and 40 percent of its generated power will come from renewable resources by 2025, as shown in **Table 6**. It is assumed that the rest of the Lower 48 states will meet their respective RPS standards on time.[59] This case also assumes that nationwide 80 GW of coal generation (27 percent of total United States coal-fired generating capacity) will be retired and replaced with natural gas-fired generation starting in 2014. However, in the WECC, the retirements of coal and replacement with natural gas do not begin until 2023. The natural gas/electric synchronization case also assumes there will be no demand savings from additional energy efficiency initiatives, while the reference case assumes there will be savings from such initiatives.[60]

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58 As with D.13-02-015, the CPUC may choose to provide procurement authority for only a portion of the amount identified in California ISO studies, reasoning that further studies could be useful in finalizing the mix of procurement authority and direction to pursue demand-side policy programs.

59 The RPS is based on each state's individually set goals for the percentage of renewable power generation in each portfolio.

60 AAEE—Additional savings from initiatives that are neither finalized nor funded but are reasonably expected to occur after 2014 (for example, building codes, appliance standards, and utility efficiency programs).

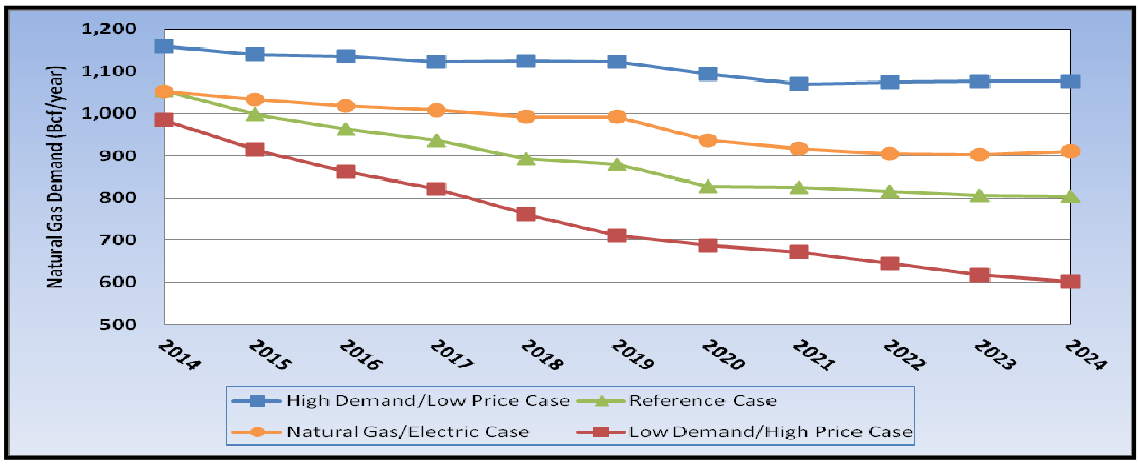
**Table 6: Natural Gas/Electric Case Assumptions**

| Assumptions | Reference Case | Natural Gas/Electric Synchronization Case |
|---|---|---|
| **Base Case** | N/A | Reference Case |
| **Average Annual GDP Growth Rate** | 2.50% | 2.50% |
| **Natural Gas Technology Improvement Rate** | 1.00% | 1.00% |
| **Maximum RPS Target** | | |
| **CA Meets Target** | On time | 40% RPS by 2025 |
| **WECC Meets Target** | On time | On time |
| **Other States Meet Target** | 5-year delay | On time |
| **Additional U.S. Coal Generation Converts to Natural Gas Starting in 2014 (GW)** | 61 | 80 |
| **Grow or Shrink Natural Gas Resource Available (US)** | N/A | N/A |
| **LNG Capacity Additions** | No | No |
| **Additional Environmental Mitigation Cost (2010$/Mcf)** | N/A | N/A |
| **Cost Environment** | Mid (P50) | Mid(P50) |
| **Additional Energy Efficiency** | Included | Not included |

Source: Energy Commission: EAO.

Results of the natural gas/electric synchronization case showing natural gas demand for power generation is provided for California in **Figure 23** and for the WECC in **Figure 24**. For California, the downward trend for natural gas power generation demand is similar in the reference case and the natural gas/electric synchronization case, but by 2024 the latter case is 12.5 percent higher. The downward trend is associated with more renewable energy displacing the need for gas-fired generation. However, less demand in the reference case indicates that the addition of aggressive energy efficiency in this case has a greater effect than the addition of a higher renewable portfolio target in the natural gas/electric synchronization case.

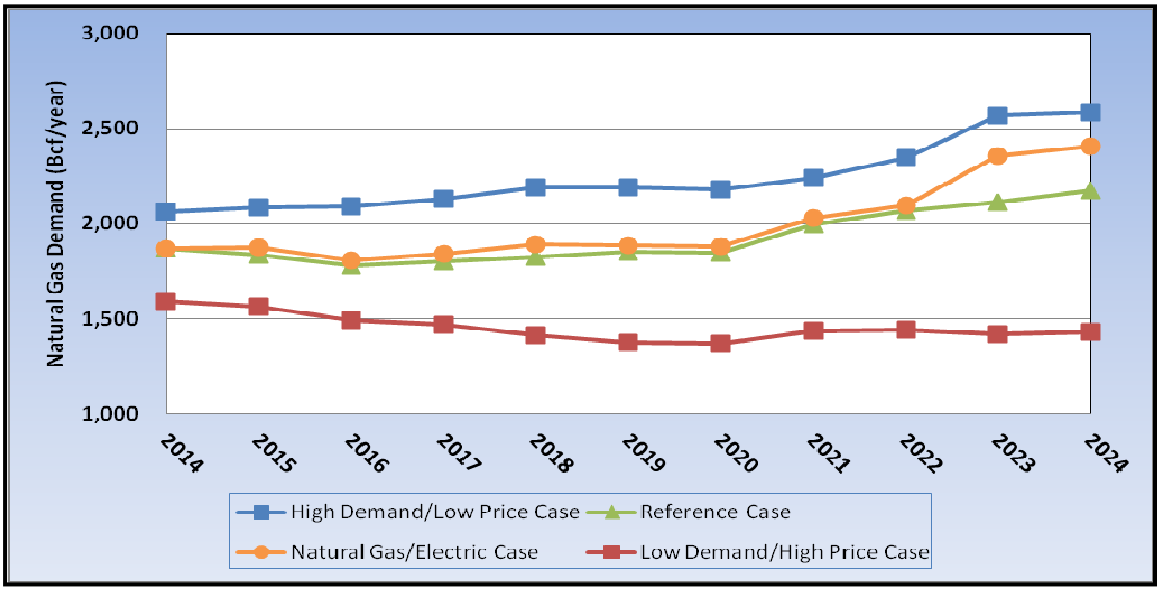
**Figure 23: Natural Gas Demand for Power Generation in California**




Source: Energy Commission: EAO.

The pattern for California is not seen in the WECC region, where natural gas demand for power generation is similar in both the reference and natural gas/electric synchronization cases. In the WECC, the RPS was not increased, and energy efficiency measures are not as aggressive as those in California. Coal retirement will be greater in the WECC than in California, as California has very little coal-fired generation remaining to retire. Higher GW of coal-fired retirement in the natural gas/electric synchronization case creates a greater demand for natural gas to provide replacement power, which accounts for differences beginning in 2020.

**Figure 24: Natural Gas Demand for Power Generation in WECC**



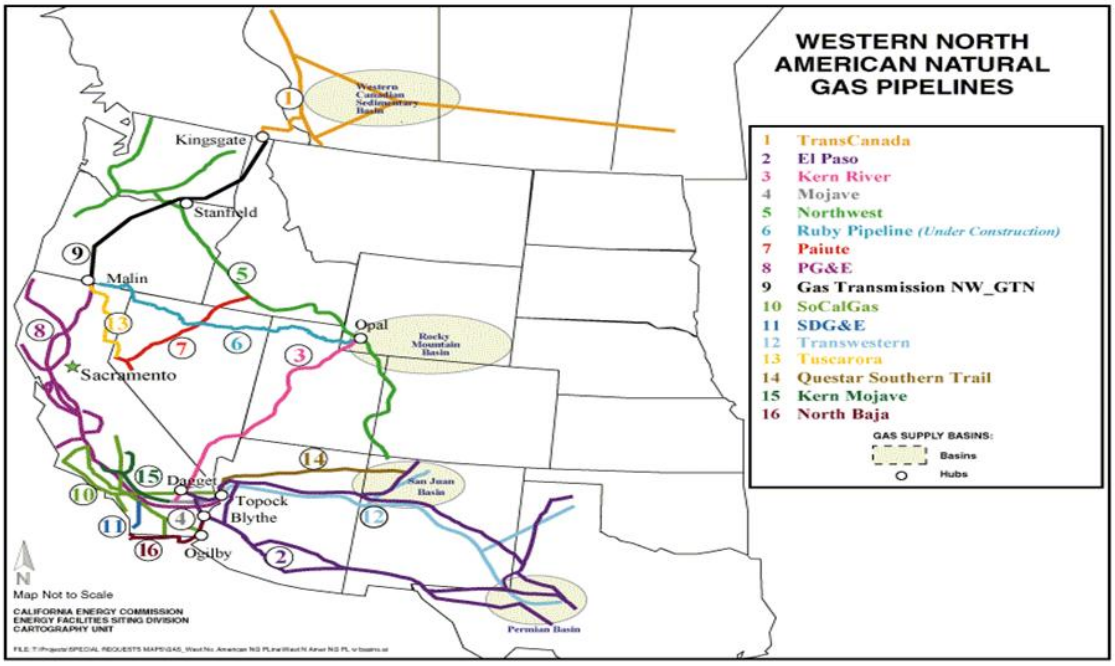

Source: Energy Commission: EAO.

# CHAPTER 5:
# Natural Gas Infrastructure

California's natural gas supply is delivered to its borders through several interstate pipelines that originate at production wells in the Southwest, the Rocky Mountains, and Canada. The state produces less than 10 percent of its own needs. Intrastate pipelines in California take the natural gas from the state border to the citygate and to the local distribution pipelines or to storage facilities for later use. **Figure 25** shows the major western interstate natural gas pipelines.

Recent additions of pipeline capacity across the country have allowed access to new shale gas supplies and have created more competition between supply and demand regions, putting downward pressure on prices. In California there are numerous natural gas infrastructure changes on the horizon that may affect the state's available supply of gas. Issues discussed in this chapter include new pipelines to Mexico to feed its increasing gas demands, exports to Canada, the potential construction of new LNG export facilities in the United States that could ship natural gas to foreign countries, and various changes to existing pipelines in the United States and California in response to the changing supply and demand landscape.

**Figure 25: Western United States Natural Gas Pipelines**




Source: Energy Commission: EAO.

## Natural Gas Pipeline Changes

### Background

In both 2010 and 2011 many new pipeline projects in the Lower 48 states led to thousands of miles of new pipeline and close to 27 Bcf/d of new capacity.[61] The new pipelines roughly equate to 13.7 Bcf/d of added capacity in 2011, which is very close to the amount added in 2010 and well above the 10 Bcf/d levels typically seen for each year from 2001 to 2006. In 2012, investment slowed significantly with only 367 miles of new pipe resulting in 4.5 Bcf/d of additional capacity.[62] More than half of the projects that entered service in 2012 were in the Northeast and were specifically targeted to remove bottlenecks for delivering gas produced in the Marcellus Shale. Historically, the focus was to build pipeline infrastructure to move natural gas from traditional gas plays to demand regions in the North, East, and West. Increasing production from shale plays like Marcellus and Utica in nontraditional natural gas-producing regions in the Northeast and Midwest have led to new pipeline infrastructure that transports natural gas from these shale plays to the western and eastern demand regions. Demand hubs are now more readily linked to supply regions and previous bottlenecks and congestion points have been relieved. All else equal, more pipelines mean demand hubs now have more options for obtaining gas from a given supply region. This flexibility contributes to greater reliability of the natural gas system should a single pipeline fail.

Despite these upgrades, there is uncertainty about how the United States pipeline markets will develop due to the changing supply-and-demand dynamics in the Lower 48. This uncertainty can be linked to the current abundance of shale gas, the expected increases in natural gas-fired electricity generation as coal generation is retired, and the estimated 40 Bcf/d of firm pipeline capacity contracts due to expire by 2015, which is causing pipeline companies to look for ways to replace lost revenue streams.

### Current Trends

In the Northeast, Pennsylvania's Marcellus Shale has brought gas supply much closer to demand. The long-haul Tennessee and Rocky Mountain Express pipelines, which carry gas from the Gulf and the Rocky Mountain Basin to the Northeast, respectively, are considering reversing or enabling bidirectional pipeline flow to deliver gas out of the Marcellus shale and thereby fill their unsubscribed capacity. While a number of pipelines have transported gas from the Gulf of Mexico to the Northeast, the Tennessee pipeline, in particular, is undersubscribed in the Midwest as the development of the Marcellus Shale has progressed. Adding bidirectional capability or reversing the flow in that section could enable delivery of

61 See http://www.eia.gov/todayinenergy/detail.cfm?id=5050.

62 See http://www.eia.gov/todayinenergy/detail.cfm?id=10511.

gas to potential future LNG export terminals in the Gulf region or to other demand markets within the United States.

In the Southwest, the El Paso Natural Gas (EPNG) pipeline from Texas to Southern California has unsubscribed capacity, and the pipeline owner, Kinder Morgan, has explored two plans to increase its revenue. The first was to abandon compressor facilities at six compressor stations to lower the pipeline's capacity and operating costs. The company filed an application on January 5, 2012, with FERC under Docket CP12-45-000 to abandon these facilities.[63] Numerous parties protested, and this plan was withdrawn. The second plan was to convert a segment of the EPNG pipeline from gas transmission to the new "Freedom Pipeline" transporting oil from the Permian Basin in Texas to California oil refineries. EPNG held a nonbinding open season to assess interest by shippers in committing to pay for the line and failed to attract sufficient interest. Consequently, that plan was also dropped. Both plans demonstrated EPNG's continuing effort to resolve underusage on its pipeline system.

Throughout the country, coal plant retirements, which are being driven by more stringent federal air quality regulations, are expected to increase demand for natural gas generation. A base case from an Interstate Natural Gas Association of America study projects a need for 25 Bcf of new pipeline capacity to accommodate the replacement of coal plants with gas.[64] An Aspen Environmental Group study provides the worst case scenario, estimating that replacing all existing coal generation with gas would cause gas demand to rise by 14.1 trillion cubic feet per year (Tcf/yr) or 61 percent and would require 70 Bcf of new pipeline capacity.[65]

The sum of receipt capacity from the six interstate pipelines that deliver into California[66] exceed the take-away[67] capacity of the intrastate transmission pipelines in California. This mismatch of upstream interstate capacity versus in-state takeaway capacity is to a great degree the deliberate outcome of policies by the Energy Commission and CPUC to

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63 FERC Docket CP12-45-000, *El Paso Natural Gas Company's Application for Permission and Approval to Abandon, in Place, Certain Compressor Facilities.* January 5, 2012. See http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12860976.

64 ICF International. *Natural Gas Pipeline and Storage Infrastructure Projections Through 2030*. Washington D.C.: The Interstate Natural Gas Association of America Foundation, October 2009. See http://www.ingaa.org/File.aspx?id=10509.

65 Elder, Catherine. *Implications of Greater Reliance on Natural Gas for Electricity Generation*. Prepared for the American Public Power Association. Aspen Environmental Group, July 2010, Pg.20.

66 The Gas Transmission Northwest Pipeline and Ruby Pipeline at Malin, Oregon, the Kern River Pipeline at Daggett, California, the Transwestern Pipeline, Southern Trails Pipeline and northern route of the EPNG Pipeline at Topock, Arizona, and the southern route of the EPNG Pipeline at Ehrenberg, Arizona.

67 *Take-away capacity* is what a downstream pipeline can accept and move (on downstream) from an upstream pipeline.

encourage price competition among multiple pipelines and access to multiple gas supply sources. This combination of excess upstream capacity and supply diversity also helps reduce the impact that a bottleneck in any supply basin or on a given pipeline can have on California as a whole, since gas is fed from many supply basins. As a result, the pipelines feeding California are typically used well below their full capacity. The Kern River Gas Transmission pipeline is a recent exception. Throughout 2013, the pipeline has been from 79 percent to 97 percent used each month because the Rockies-sourced natural gas it delivers is often the most attractively priced natural gas available to Southern California. California's access to adequate natural gas supply does not imply that all customers can access the most attractively priced gas. The relative balance between supplies delivered at the Malin receipt point via the Ruby pipeline or the Gas Transmission Northwest Corporation pipeline shifts day to day, ostensibly as prices in those two gas supply basins shift relative to each other.

NAMGas results display no production declines in the supply basins that serve California. Future increases in demand, both in California and along these pipelines in areas where demand is rising, could use a portion of the current excess pipeline capacity that benefits California. This would arguably force Californians to compete for access to that capacity and associated supply by paying higher prices.

Supply basin dynamics do create a situation that is of concern today. SoCal Gas often has less gas delivered to its Ehrenberg receipt point at the California-Arizona line than is required to serve customers that can be served only via that location. This requirement, known as the Southern System Minimum (SoSysMin), refers to the minimum amount of gas that must be delivered through the pipeline at Ehrenberg to serve all load in the SDG&E gas service area. On days when the gas deliveries at Ehrenberg are insufficient to serve all load in that part of the service area, SoCal Gas has permission from the CPUC to go into the market and purchase more gas to make up the deficiency. Without this permission, SoCal Gas is allowed to purchase gas only for its core customers, which, given the current gas delivery reductions at the Ehrenberg receipt point, would result in curtailments along the southern system, as discussed below.

Closing SONGS exacerbates this problem. SoCal Gas reported in testimony before the CPUC in September 2012 that the annual average SoSysMin requirement rose from about 420 thousand dekatherms per day (Mdth/d) in 2011 to 520 Mdth/d in 2012, an increase of 100 Mdth/day (converts to 100 MMcf/d) as shown in **Figure 26**.[68] The testimony noted, "The San Onofre outage has been a major contributor to this increase."[69] Meanwhile, deliveries on the southern system have decreased from around 800 Mdth/d (800 MMcf/d) in 2010 to 655

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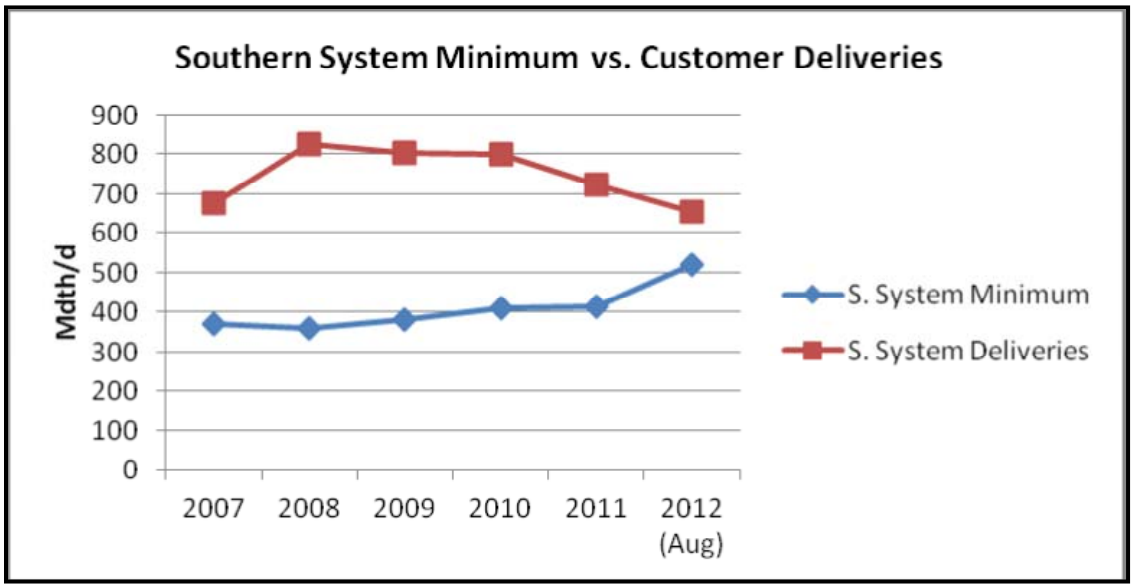
68 *Before the CPUC: Supplemental Direct Testimony of Beth Musich Regarding the Transfer of Southern System Minimum Flow Responsibility*. SDG&E and SoCal Gas. September 10, 2012, Pg. 13, Figure 1. See http://socalgas.com/regulatory/documents/a-11-11-002/2010-1023/Musich%20TCAP%20Supplemental%20Testimony%20_091012.pdf.

69 Ibid. Footnote 22, pg. 14.

Mdth/d (655 MMcf/d) in 2012, as shown in **Figure 26**. As the SoSysMin requirement has risen and deliveries to the Ehrenberg receipt point have dropped, SoCal Gas has had to make these spot market gas purchases to ensure the SoSysMin requirement is met.

**Figure 26: Annual Average Southern System Minimum (SoSysMin) Requirements and Actual Southern System Deliveries**




Source: Supplemental Direct Testimony of Beth Musich Regarding the Transfer of SoSysMin Flow Responsibility. SDG&E & SoCal Gas. September 10, 2012, Pg. 13, Figure 1: http://socalgas.com/regulatory/documents/a-11-11-002/2010-1023/Musich%20TCAP%20Supplemental%20Testimony%20_091012.pdf.

When the CPUC granted SoCal Gas permission to make these additional purchases of gas to serve load, the idea was that this would be an infrequent event for a small amount of gas. Instead, SoCal Gas has had to do so on over 100 days in the last 12 months, and purchases in January and February were as large as 800 MMcf/d. In some cases, SoCal Gas' effort to purchase additional gas has occurred in the third or fourth nomination cycle of the day (toward the end of the day). In these latter cycles, the market is less liquid, with higher prices and fewer sellers than earlier in the gas day. Gas from storage cannot be used to address this problem as gas storage is not directly connected to the SDG&E potion of the system. Should SoCal Gas encounter a day on which it cannot obtain sufficient gas supply at Ehrenberg, SoCal Gas would have to curtail gas service. As there is virtually no industrial load in the SDG&E gas service area, curtailments would directly affect electricity generators or smaller commercial and residential customers; neither is acceptable.

During 2013, SoCal Gas explored options such as requiring all shippers to deliver a minimum percentage of gas at Ehrenberg or building new facilities. On December 20, 2013, SoCal Gas and SDG&E filed an application at the CPUC to recover the $628 million cost to build a new pipeline, running roughly from Adelanto to Rainbow, and associated compression. The new facilities, known as the "North-South Project," will connect

SoCal Gas' northern system to its southern system. The new facilities will allow Sempra's gas customers to continue to deliver gas into northern system receipt points instead of using Ehrenberg. It will also allow gas from storage facilities a route into the southern system.

### Outlook

The dynamics of steadily increasing gas extraction from shale plays, especially Marcellus Shale, are likely to continue to cause pipeline owners to explore different business plans for existing underused pipes and look for pathways for new pipes to high-demand areas. The price relationships and basin market dynamics will fluctuate to cause capacity factors on the pipelines that serve California to change and will sometimes cause one basin or another to be preferred. While capacity to serve total California gas demand will remain adequate, all customers may not be able to obtain access to the lowest cost among the available gas supply basins.

## California Pipeline Safety

Pipeline safety in the wake of the San Bruno pipeline explosion in 2010 is a critical concern of the Energy Commission, the CPUC, and the Legislature. Since the incident, the CPUC ordered pressure reductions until the gas utilities verified important pipeline features to set pipeline maximum allowable operating pressures (MAOP) and directed that segments without acceptable records either be subject to hydrostatic or other strength testing, or be replaced. In the meantime, many high-pressure pipelines operated, either by CPUC or PG&E decision, at pressures as much as 20 percent below their previous maximum operating pressures.

The gas utilities were also required to submit pipeline safety enhancement plans. In December 2012, the CPUC approved PG&E's *2012 – 2014 Pipeline Safety Implementation Plan*, which spelled out criteria and a timetable as to how PG&E would upgrade its gas system, including the addition of remote or automatic valves and making more of its system able to use in-line inspection techniques. PG&E is allocating $2 billion toward pipeline safety enhancements,[70] while the CPUC authorized rate recovery for $299 million of the associated expenditures, which are estimated by PG&E to increase its rate for residential core service by 1.5 percent.[71] SoCal Gas similarly filed a Pipeline Safety Enhancement Plan with the CPUC. This plan outlines a multiyear pipeline testing and replacement effort that will target

70 See http://pgeseeourprogress.com/2013/10/1-billion-for-pipeline-safety/.

71 CPUC, "CPUC Approves Pipeline Safety Implementation Plan for PG&E; Increases Whistleblower Protections," press release, December 20, 2012. See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M040/K531/40531580.PDF.

upgrading, replacing, or adding about 487 valves on its system with remote control capability. SoCal Gas estimated Phase 1 of the plan to cost $2.5 billion over 10 years.

In April 2013, the CPUC released its updated *Natural Gas Safety Action Plan*,[72] which focuses on setting, monitoring, and enforcing rules for regulated utilities based on risk assessment and risk management. The CPUC is also tracking improvements being made that are responsive to recommendations made by the Independent Review Panel and the National Transportation Safety Board related to the PG&E San Bruno pipeline explosion. Specifically, the plan aims to ensure the safety of the existing gas system, upgrade and replace the gas system to make it safer, reform the CPUC to make safety its first priority, and instill a safety culture in gas operators.

On July 3, 2013, PG&E filed an "Errata to Pacific Gas and Electric Company's Supporting Documentation for Lifting Operating Pressure Restrictions on Line 101 and 147," pipelines, which are located in the Greater San Francisco Area. The errata list explains that the supporting information it filed in October 2011 in support of its request to lift operating pressure restrictions on line 147 was erroneous. That information contained PG&E records—developed as part of the pipeline records validation process ordered by the CPUC after the San Bruno explosions—showing that these pipelines contained double submerged arc welds or were seamless and had joint efficiency factors of 1.0. This justified an MAOP of 365 pounds per square inch gauge (PSIG). Based on this representation by PG&E, the CPUC granted permission to raise the MAOPs of the lines to no more than 365 PSIG in December 2011.

The errata filed on July 3, 2013, revealed that PG&E had learned upon repair resulting from a routine leak inspection that as many as six segments of line 147 actually have single submerged arc welds, implying a joint efficiency factor of 0.8, which effectively reduces the pipeline's MAOPs to 330 PSIG from the approved 365 PSIG. The implications from a pipeline safety perspective are clear. Due to PG&E's admitted error, the pipelines received approval to operate at pressures that are higher than the recommended MAOP. PG&E noted in the errata that it has reduced the operating pressures to safe levels in October 2012, but both the length of time it took PG&E to file the errata—18 months—and the 9-month period between PG&E reducing the pressure on the pipeline and their errata filing led the CPUC to order PG&E to appear at a hearing and show cause why it should not be sanctioned for violating Rule 1.1 of the CPUC's Rules of Practice and Procedure.

Rule 1.1 states that any person who transacts business with the CPUC agrees to "never mislead the Commission or its staff by an artifice or false statement of law or fact."[73] The show cause order also asks PG&E to show why all of the CPUC orders approving PG&E requests to restore operating pressures arising out of the post-San Bruno effort to verify

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72 See http://www.cpuc.ca.gov/PUC/safety/Pipeline/Natural_Gas_Safety_Action_PlanApril2013.htm.

73 See *CPUC Rules of Practice & Procedure*: http://docs.cpuc.ca.gov/WORD_PDF/AGENDA_DECISION/143256.PDF, Page 1.

pipeline features and maximum allowable operating pressures should not be rescinded until "competent demonstration that PG&E's natural gas system records are reliable."

PG&E indicated at the show cause hearing that significant curtailments of natural gas service to power plants, noncore customers on the San Francisco Peninsula, and core customers in San Francisco's Financial District would be triggered at cold temperatures expected to occur once in every 10 years. On December 19, 2013, the CPUC granted permission to operate line 147 at 330 PSI and fined PG&E $14.35 million for violations of Rule 1.1.

In late September 2013, PG&E reduced operating pressures on line 300, the backbone transmission line that comes from the interstate pipeline connections at the California-Arizona border and delivers natural gas to the southern Bay Area and Peninsula, as well as the San Joaquin Valley. The pressure decrease reflects a "class location change," made in response to finding increased population density around certain areas along the pipeline. Federal rules scale a pipeline's MAOP to population density, protecting the public by requiring that operating pressures on a given pipeline decline as population density around the pipeline increases. The reduced operating pressures reduce the maximum throughput capability of this important high-pressure transmission line. This additional pressure reduction, needed for safety purposes, can expose Californians to reliability issues under certain cold winter conditions.

In response to California's continued focus on pipeline safety, the Energy Commission continues to provide research, development, and deployment funding to projects that explore new technologies to monitor and address pipeline safety. The Energy Commission is also closely monitoring the effective capacity reductions imposed as PG&E reduces operating pressures and is prepared to assist the CPUC as necessary.

## Natural Gas Storage

### Background

Storage continues to play an important role in California's natural gas market. In the spring/summer, storage operators inject gas into their underground facilities and, in the fall/winter, withdraw to meet peak demand. Storage, therefore, serves as a market balancer.

Natural gas storage facilities are generally of three types:

- Underground depleted gas reservoirs
- Underground aquifers
- Underground salt caverns

Depleted gas reservoirs are the most common storage facilities, and they are typically the least expensive option to develop because they are large, already have extraction infrastructure built, and have well-known geologic structures. Many of the reservoirs that have been converted into underground storage facilities are located close to demand centers, though about a third of those in the United States are not. The structures also require less preinjection of gas since it is already present in the structure from when it was a working gas well. Up to 50 percent of the gas stored in a depleted well will be cushion gas, which keeps the gas pressure high enough for extraction, and the remainder of the gas is the "working gas," or the gas that can be extracted and used. Depleted reservoirs usually take about two years to develop.

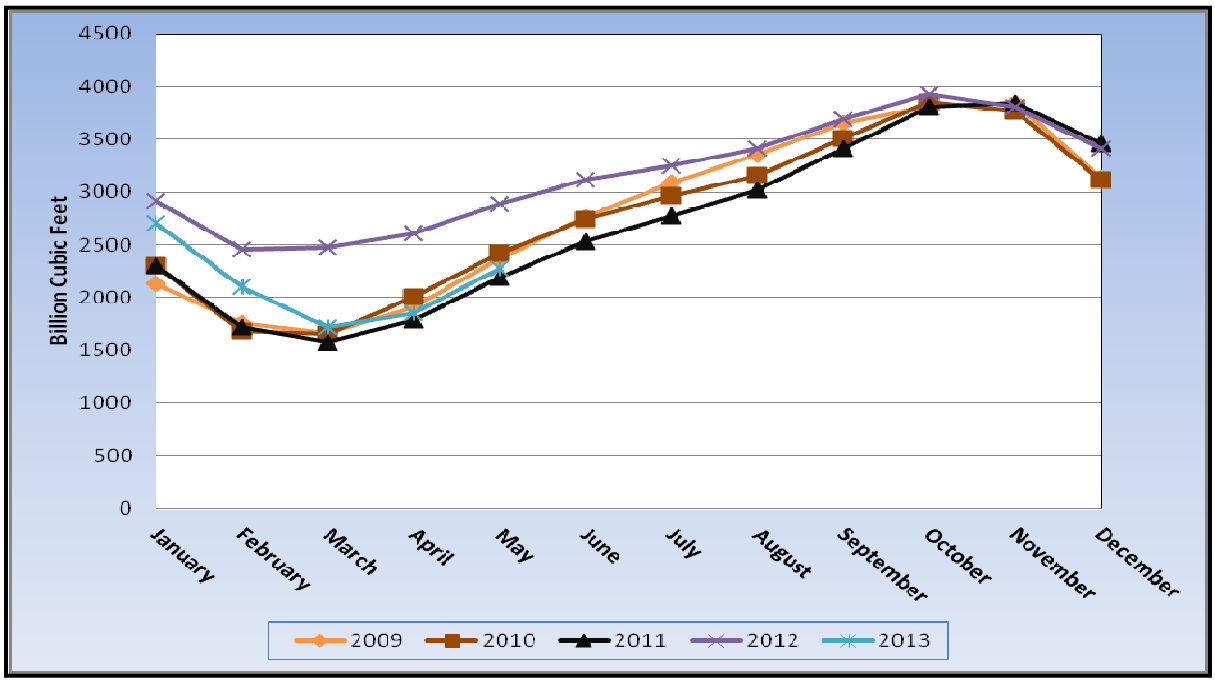
Aquifers are typically used only if a depleted gas reservoir is not present in the area. They are very expensive to develop, since the geologic structures are not well known and must be thoroughly explored using geologic tools. The necessary infrastructure for gas storage, injection, and extraction must be built, and the full capacity of the reservoir will not be known until development is completed. Aquifers are also less desirable because they require more cushion gas than depleted gas reservoirs, which can measure up to 80 percent of the injected gas. Some gas also escapes from the structure and must be gathered by collector wells. Aquifers can take up to four years to develop.

Salt caverns are well-suited to gas storage because they have low permeability in their walls, and high wall strength, leading to low structural degradation over time. The caverns are created by drilling into salt domes or salt beds and then carving spaces out of the salt by cycling large amounts of water through the area to hollow it out. While the process of building the caverns can be quite expensive, the resulting storage structure requires only about 33 percent cushion gas. Gas stored in the caverns can be injected and extracted quickly, and the small size makes them ideal for peak load storage with extraction times as short as one hour, but they are too small for seasonal storage.

## Current Trends

Natural gas storage inventory set record levels in 2012. **Figure 27** shows storage inventory totals by month for each of the past five years, as issued by the U.S. EIA and used by the industry as a standard market indicator. The record is explained by a mild winter, which left 2,500 Bcf of gas remaining in inventory at the end of the November 2011 to March 2012 withdrawal season. A combination of low demand through the following summer, continued high natural gas production, and recent capacity additions allowed the storage inventory to reach a record 3,800 Bcf at the start of the winter 2012 – 2013 withdrawal season.

**Figure 27: United States Natural Gas Storage**




Source: U.S. EIA.

California has 11 operating natural gas storage facilities, all of which are depleted oil or gas production fields, and several of which were completed within the last few years. PG&E and SoCalGas own and operate seven of the facilities, and four are independent facilities.[74] The total current working gas capacity of these facilities is 349.3 Bcf with a maximum daily delivery of 8.56 Bcf when the fields are full. The addition of so much independent storage in California in the last 20 years provides tremendous flexibility to end users with variable load profiles and allows more efficient use of California's gas transmission capacity.

## Outlook

Three facilities in California have planned expansions. Independently owned and operated Wild Goose Storage, Inc., applied for and was granted an amendment to its Certificate of Public Convenience and Necessity from the CPUC to expand from 50 Bcf working gas capacity to 75 Bcf working gas capacity.[75] Central Valley Gas Storage, LLC, received

74 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

75 CPUC, Proceeding A1210019, Decision D1306017. See http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423160.PDF.

approval in 2010 from the CPUC to build its storage facility with an initial capacity of 9 Bcf and plans to add an additional 3 Bcf of storage by 2014.[76] The Tricor Ten Section Hub, LLC.'s, storage project is a 22.4 Bcf working capacity facility, which is planned to complete construction in 2014. As of September 2013, the project's most recent status report (FERC Docket # CP09-432) from August 2013 noted that it has not commenced construction, but the filing also notes that the project developer is continuing to work with Department of Oil, Gas, and Geothermal Resources on their California Environmental Quality Act environmental analysis study and permit authorizations. In February 2012, Tricor Ten Section Hub, LLC, was granted an extension to its Certificate of Public Convenience and Necessity by FERC to allow it until November 5, 2014, to complete construction of the facility. The project developer requested the extension due to "delays in obtaining permits from Department of Oil, Gas, and Geothermal Resources and other local agencies that are required to drill and rework the storage wells."[77] Subscriptions to the project are not public information, so it is unclear at this time whether the project developer will be able to meet the deadline for construction completion. **Table 7** shows the existing and proposed working capacity totals in Northern and Southern California.

**Table 7: California Natural Gas Storage**

| Northern California | Maximum Working Capacity (Bcf) | Southern California | Maximum Working Capacity (Bcf) |
|---|---|---|---|
| Existing | | Existing | |
| Subtotal | 215.2 | Subtotal | 141.1 |
| Proposed | | Proposed | |
| Wild Goose | 25.0 | Tricor Ten Section Hub | 22.4 |
| Central Valley | 3.0 | | |
| **Subtotal** | **28** | **Subtotal** | **22.4** |
| **Northern CA Total** | **243.2** | **Southern CA Total** | **163.5** |
| **Statewide Total Existing and Approved** | | | **406.7** |

Source: Energy Commission: EAO, based on data from the U.S. EIA, CPUC and FERC filings.

The 2013 total existing and approved working storage capacity of 406.7 Bcf is 29.1 Bcf more than in 2011 when the Energy Commission last reported these storage numbers. Similarly, in 2013 the total existing working storage capacity is 349.3 Bcf as compared to 313.7 Bcf in 2011, an increase of 35.6 Bcf.

76 U.S. EIA, *Planned Storage Projects*. See http://www.eia.gov/naturalgas/data.cfm#storage.

77 FERC. See http://elibrary.ferc.gov/idmws/file_list.asp.

# North American Gas Imports and Exports

## Mexico

### *Background*

In 2012, Mexico imported an average of 1.7 Bcf/d of natural gas from the United States. Exports from the United States to Mexico have been increasing steadily since the late 1980s, and in recent years Mexico's natural gas consumption increased at an average of 4 percent per year as compared to a 1.2 percent yearly increase in Mexican gas production. U.S. EIA data report that United States gas exports to Mexico increased by 24 percent between 2011 and 2012. Staff's reference case shows Mexico's imports from the United States doubling by 2018 to 3.3 Bcf/d, as shown in **Figure 28**. A report by Bentek Energy similarly projects imports of 3.6 Bcf/d.[78] Most of the increase comes from increased gas demand for power generation in Mexico. To help meet this demand, pipeline developers have announced seven new projects that will increase the export capacity from the United States to Mexico by 4.3 Bcf/d.

### *Current Trends*

There are three new project groups and three pipeline expansion projects that comprise seven new proposed pipelines that will cross the border from the United States to Mexico. The Sierrita-Guaymas Project, Chihuahua-Topolobampo Project, and Los Ramones Project are laterals from the EPNG southern mainline. Three more pipeline expansion projects, the Mier Monterrey Expansion, TETCO South Texas Expansion, and Willcox Lateral 2013 Expansion, will increase the amount of gas that can be delivered into Mexico. These projects are explained in **Table 8** and displayed in **Figure 28**. These projects are projected to be in service by the end of 2014, represent a total of 4.3 Bcf/d in capacity expansion, and will increase the United States to Mexico export capacity to 9.6 Bcf/d by 2015.[79]

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78 Canonica, Rocco, Ellen Nelson, Darrell Proctor, and Tricia Bulson. *Growing Mexican Gas Market Creates Southwest Price Premiums. Energy Market Fundamentals Report.* Bentek Energy, Platts, May 2013, pg. 17.

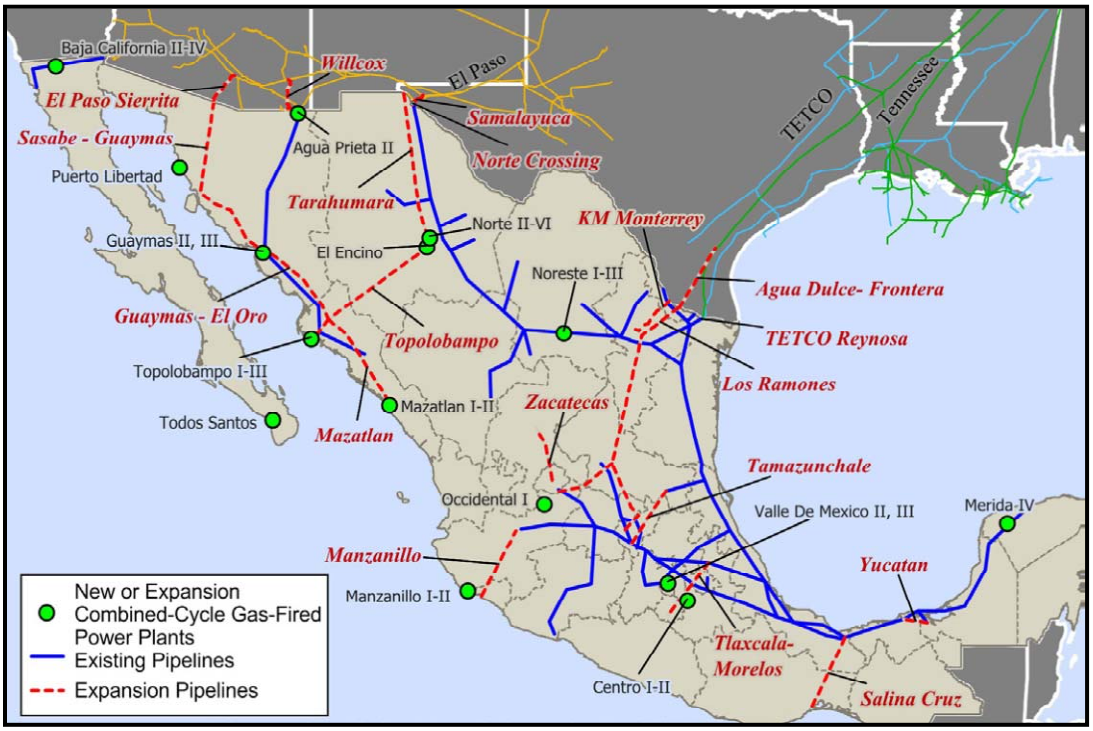
79 Ibid. Page 11.

**Table 8: United States to Mexico and Intra-Mexico Pipeline Projects**

| Project Name | Pipelines | Capacity (MMcf/d) | Location of Origin | Terminus Location | Contractor |
|---|---|---|---|---|---|
| **The Sierrita-Guayamas Project** | Sierrita Pipeline | 812 | Sasabe, AZ | U.S./Mexican border | Kinder Morgan |
| | Sasabe-Guaymas Pipeline | 770 | U.S./Mexican border | Guaymas, MEX | Sempra Energy |
| | Guaymas-El Oro Pipeline | 510 | Guaymas, MEX | Topolobampo, MEX | Sempra Energy |
| **The Chihuahua-Topolobampo Project** | Samalayuca Lateral/Norte Crossing Pipelines | 545 | Samalayuca Lateral, Texas | Tarahumara Pipeline, MEX | Kinder Morgan (El Paso) |
| | Tarahumara Pipeline | 850 | Samalayuca Lateral, Texas | El Encino, MEX | Fermaca, Energy Transfer |
| | Topolobampo Pipeline | 670 | El Encino, MEX | Topolobampo, MEX | TransCanada |
| | Mazatlan Pipeline | 202 | Topolobampo , MEX | Mazatlan, MEX | TransCanada |
| **The Los Ramones Project** | Net Midstream-Agua Dulce-Frontera Pipeline | 2,100 | Agua Dulce, TX | Apaseo el Alto, MEX | Net Midstream, PEMEX |
| | Los Ramones Pipeline | 2,100 | Apaseo el Alto, MEX | Central Mexico | PEMEX |
| **Other Pipeline Expansions** | Mier Monterrey Expansion | 275 | Salineno, TX | Monterrey, MEX | Kinder Morgan |
| | TETCO South Texas Expansion | 300 | Reynosa, TX | Mexico | Spectra Energy |
| | Wilcox Lateral 2013 Expansion | 185 | Douglas, AZ | Sonora, MEX | Kinder Morgan (El Paso) |

Source: Canonica, Rocco, Ellen Nelson, Darrell Proctor, and Tricia Bulson. *Growing Mexican Gas Market Creates Southwest Price Premiums. Energy Market Fundamentals Report.* Bentek Energy, Platts, May 2013.

**Figure 28: Proposed United States-to-Mexico Pipeline Projects**

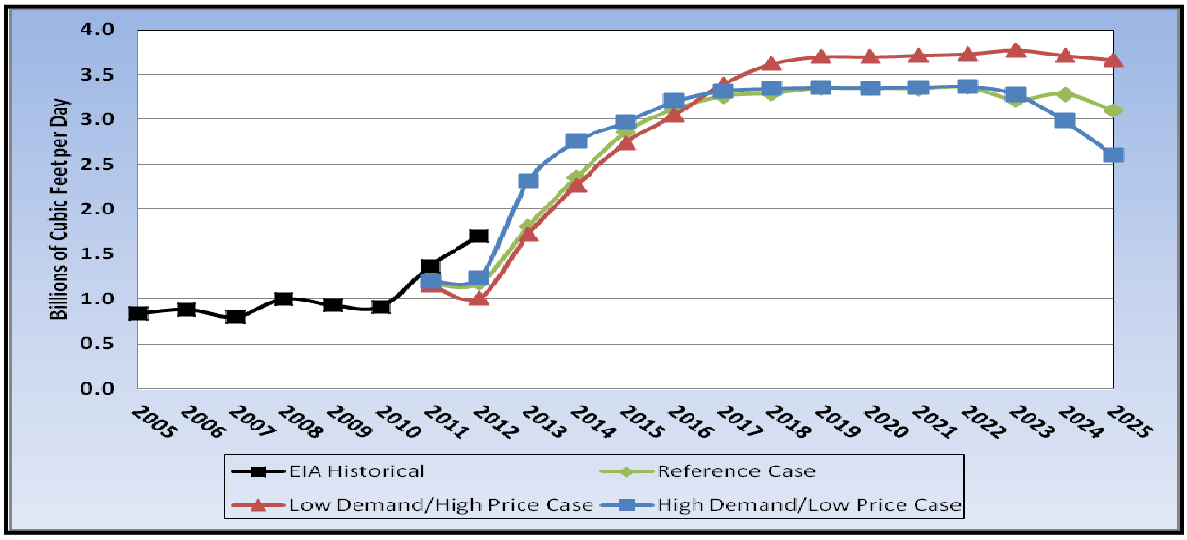



Source: Bentek Energy. Canonica, Rocco, Ellen Nelson, Darrell Proctor, and Tricia Bulson. *Growing Mexican Gas Market Creates Southwest Price Premiums. Energy Market Fundamentals Report*. Bentek Energy, Platts, May 2013. Pg. 13.

### *Outlook*

Increased United States exports to Mexico will facilitate Mexico's planned addition of more than 17 GW of additional gas-fired electricity generation capacity by 2018. Each of staff's "common cases" reflects very similar exports to Mexico, as shown in **Figure 29**. The low-demand/high-price case suggests low energy demand due to high gas prices and assumes a higher—2.8 percent—average annual GDP and 5.5 percent less available natural gas resource in the United States. **Figure 17** (Chapter 4) shows the *2013 IEPR* marginal cost curve in the United States, which projects that 1,343 Tcf of gas is economically recoverable at $6/Mcf. Given Mexico's lack of experience developing unconventional gas, staff's NAMGas assumptions are that finding and development costs are much higher, which consequently make it cost-effective for Mexico to import gas from the United States. In the low-demand/high-price case in **Figure 29**, staff added pipeline capacity from the United States to Mexico, and consequently, in 2017 more gas is flowing into Mexico than in the reference or high-demand/low-price cases. The high-demand/low-price results are fairly similar to the reference case in that exports hit about 3.3 Bcf/d by 2018. The high-demand/low-price case differs from the reference case in that there is a faster increase in exports from 2012 – 2017 and a faster drop-off after 2022.

**Figure 29: Historical and Forecasted Lower 48 Exports to Mexico**




Source: Energy Commission: EAO, U.S. EIA.

Mexico produces its own natural gas, but most analysts do not believe the country can increase its production at a pace that can match its growth in demand. Petróleos Mexicanos (PEMEX), the state-owned oil company that controls all oil and gas reserves in Mexico, has long focused its efforts on oil production, given the higher price for oil versus natural gas. Furthermore, liquid markets with robust natural gas transmission and distribution infrastructure in Mexico do not exist. In December 2013, Mexico passed a constitutional reform that will allow foreign companies to share profits with PEMEX and explore and drill for oil and gas in Mexico. This reform could provide PEMEX with some of the expertise and equipment to properly extract its natural gas resources instead of having to rely on imports from the United States.

Mexico also has three LNG import terminals, though only two of these 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, and 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 rise anytime soon; therefore, imports from the United States are Mexico's cheapest and best option in the near term.

The United States is expected to see natural gas price increases over the coming years. Although these increases in United States exports to Mexico are significant, staff's modeled scenarios estimate that they are not large enough to cause significant increases in U.S. prices.

## Canada

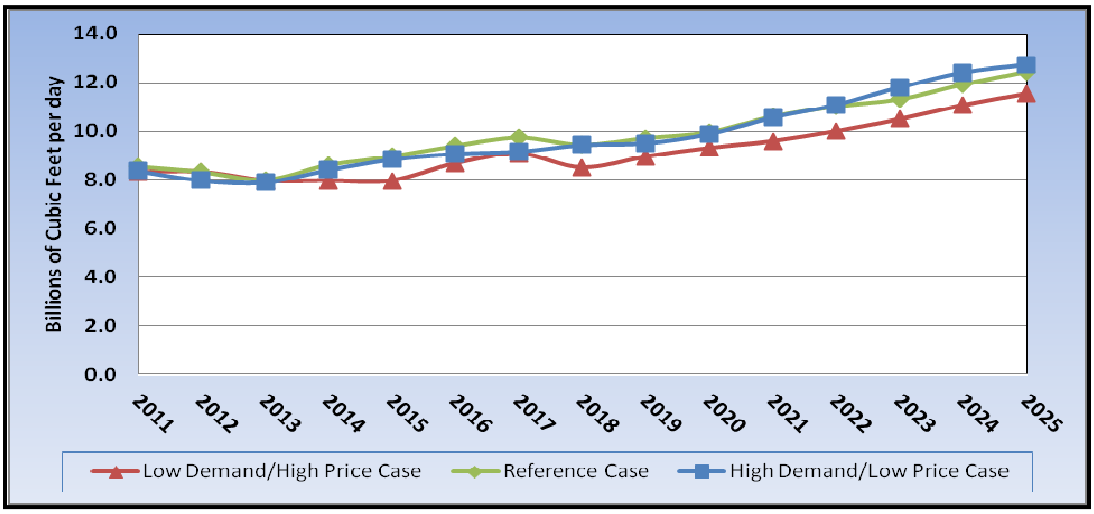
### *Background*

The United States has a long history of purchasing natural gas from the Western Canadian Sedimentary Basin, and at least six pipelines (Gas Transmission Northwest Corporation, Northern Natural, Northern Border, Alliance, Great Lakes, Iroquois, and Maritimes & Northeast) were built to move production far in excess of Canada's requirements from either the Western Canadian Sedimentary Basin or Sable Island (off the coast of Nova Scotia) to the United States. The successful application of hydraulic fracturing and horizontal drilling in eastern United States shale formations is now producing gas in the Northeast, mainly in shale plays in Pennsylvania, New Jersey, and New York. Historically, the northeastern United States was served by a combination of U.S. Gulf Coast production and/or Canadian production. Today, consumers in Ontario are closer to U.S. production from Pennsylvania than they are to the Western Canadian Sedimentary Basin. As a result, United States gas is being delivered to Canada in much greater quantities than it once was. Staff's three common cases demonstrate a continuation of this trend, with exports to Canada staying fairly consistent at the 2.8 Bcf/d – 3.1 Bcf/d level in 2014 and a very slight gradual rise through 2025.

### *Current Trends and Outlook*

As shown in **Figure 30**, the NAMGas reference case projects imports from Canada increasing from 8.6 Bcf/d in 2014 to 12.4 Bcf/d in 2025. The low-demand/high-price case and high-demand/low-price case show similar trends. The low-demand/high-price case projects 8.1 Bcf/d of imports from Canada in 2014, rising to 11.6 Bcf/d in 2025, while the high-demand/low-price case projects 8.5 Bcf/d in 2014 rising to 12.7 Bcf/d in 2025.

**Figure 30: Lower 48 Imports From Canada**




Source: Energy Commission: EAO.

The increasing imports from Canada in this modeled scenario can be attributed to three factors: First, Canada is projected to increase its shale gas production, while its demand for gas is projected to rise at a slower rate, leading to a production surplus that favors exporting gas. Second, the NAMGas model projects that LNG exports will not be economic in Canada, leaving the United States as the most likely purchaser of the surplus gas. Third, Canadian natural gas prices are projected to stay lower than United States prices, as they have been historically.

The handful of LNG export terminals that have been proposed in Canada are far from producing areas, meaning that the cost of transportation to the terminal will cut into netbacks.[80] This leads to the model's projection that LNG exports will not be economic in Canada.

## Liquefied Natural Gas Exports Abroad

### *Background*

In April 2012, U.S. natural gas prices reached a low of $1.95 per MMBtu,[81] while global prices have stayed quite high. This price disparity caused some natural gas producers to seek permission to export natural gas abroad as LNG. These applicants are drawn to landed LNG prices of $10/MMBtu to $15/MMBtu in Europe; $15/MMBtu to $20/MMBtu in India, South Korea, China, and Japan; and $17/MMBtu in Rio de Janeiro and Buenos Aires.[82] Such large differences are enough for producers to believe they can liquefy, transship, and regasify United States-produced natural gas and earn higher returns from doing so than they can earn selling their gas into low-priced U.S. markets.
**Figure 31** displays nominal natural gas prices for major global markets versus U.S. prices.[83]

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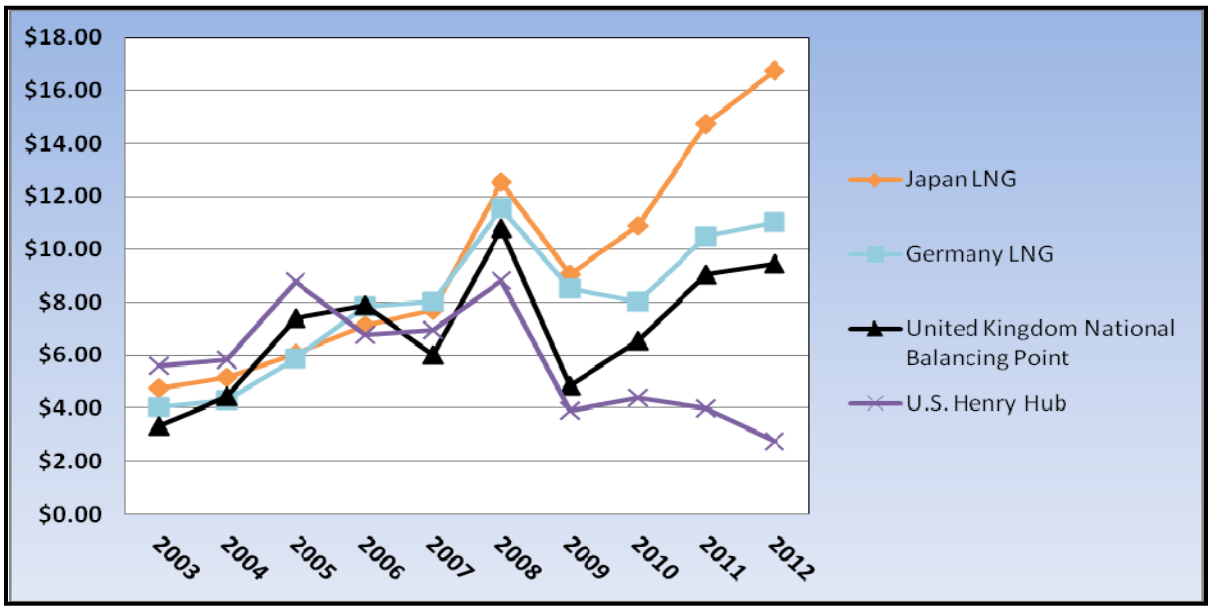
80 A pricing assessment or pricing formula is based on the effective price to the producer or seller at a specific location or defined point. For example, LNG netback prices may be determined by the market natural gas price at market destinations less the cost of pipeline transportation, regasification, waterborne shipping, and liquefaction. From Risk.net at http://www.risk.net/energy-risk/glossary/2040843/netback-price.

81 Henry Hub prices are recorded by the U.S. EIA series RNGWHHD at http://www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

82 Office of Enforcement, FERC (U.S. DOE). February 2013. "Western Region Monthly Energy Market Snapshot Report," slide 24, at http://www.ferc.gov/market-oversight/mkt-snp-sht/2013/01-2013-snapshot-west.pdf.

83 *BP Statistical Review of World Energy 2013*, June 2013, p. 27, at http://www.bp.com/content/dam/bp/pdf/statistical-review/statistical_review_of_world_energy_2013.pdf.

**Figure 31: Selected Global Natural Gas Prices (Nominal U.S.$/MMBtu)**




Source: *BP Statistical Review of World Energy, 2013*.

### *Current Trends*

As of July 2013, 28 applications with a combined export capacity of 10.6 Tcf per year (about half of current U.S. natural gas production[84]) awaited approval by the United States Department of Energy Office of Fossil Energy (U.S. DOE/FE) for LNG export licenses. Export licenses are required under Section 3 of the 1938 Natural Gas Act, which requires a demonstration that any export to nations that do not have a free-trade agreement with the United States must first be found to be in the national or public interest,[85] meaning that exports would not reduce supply necessary to meet U.S. domestic needs or cause U.S. prices to rise significantly. At this time, South Korea is the only country that imports significant amounts of LNG and that has a free-trade agreement with the United States. Other major LNG importers such as Japan, India, China, and Europe do not have a free-trade agreement with the United States and, therefore, are subject to the 1938 Natural Gas Act's public interest test before an export license would be issued.

84 Office of Fossil Energy (U.S. DOE). "Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of September 19, 2013)," at http://energy.gov/sites/prod/files/2013/09/f2/LNG%20Export%20Summary_1.pdf.

85 See http://www.ustr.gov/trade-agreements/free-trade-agreements for a complete list of free-trade agreement countries.

The U.S. DOE/FE requested analyses of the impact of LNG imports on domestic supplies and prices from the U.S. EIA[86] and from NERA Economic Consulting.[87] Both analyses found that relatively small price impacts should be expected from LNG exports. In contrast, at a U.S. Senate Energy and Natural Resources Committee hearing earlier this year, opponents of LNG exports, such as industrial and power generation sector natural gas consumers, argued that granting all applicants an LNG export license will drive up domestic natural gas and electricity prices and eliminate thousands of industrial sector jobs. A Charles River Associates economic analysis funded by Dow Chemical Company later showed that LNG exports, U.S. natural gas prices, and unemployment would, in fact, be considerably higher than projected by the U.S. EIA and NERA Economic Consulting, while GDP growth would be lower. This analysis claimed that faulty assumptions, such as unreasonably high LNG export netback costs, low-granularity aggregation of manufacturing activities, and misrepresentation of energy-intensive, trade-exposed industries, artificially suppressed LNG export forecasts, therefore minimizing United States economic impacts, in the NERA Economic Consulting modeling.[88]

Export opponents also cited persistent and high natural gas prices in Australia as a result of the expansion of LNG exports from that country, similar to the analysis used to support the Charles River Associates price forecast.[89] Industrial and power generation sector natural gas consumers urged DOE/FE to maintain caution and authorize only a few LNG export projects every few years. This, they argued, would permit analysis of the costs and benefits accruing to the United States economy from incremental LNG exports and protect U.S consumers from price risks. A third perspective argues that U.S. LNG ultimately will not be competitive in any case, making the matter moot. Rice University energy economist Kenneth B. Medlock, III, reported model results suggesting that North American LNG will not be competitive in overseas markets because technically recoverable natural gas reserves, such as those in Australia, Indonesia, Malaysia, North Africa, the Middle East, and former Soviet states, are located closer to major European and Asian demand centers and enjoy lower production costs than North American supply. [90]Once the netback costs of

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86 U.S. EIA (U.S. DOE). January 19, 2012. *Effect of Increased Natural Gas Exports on Domestic Energy Markets*, at http://www.eia.gov/analysis/requests/fe/.

87 W. David Montgomery, et. al. (NERA Economic Consulting). December 3, 2012. *Macroeconomic Impacts of LNG Exports from the United States*, at http://www.fossil.energy.gov/programs/gasregulation/reports/nera_lng_report.pdf.

88 Ditzel, Ken, Jeff Plewes and Bob Broxson (Charles River Associates). February 25, 2013. *US Manufacturing and LNG Exports: Economic Contributions to the US Economy and Impacts on US Natural Gas Prices*. See http://www.crai.com/uploadedFiles/Publications/CRA_LNG_Study_Feb2013.pdf.

89 Oral testimony of Dow Chemical Company Chief Executive Officer Andrew Liveris before the United States Senate Energy and Natural Resources Committee. February 12, 2013, at http://www.energy.senate.gov/public/index.cfm/2013/2/opportunities-and-challenges-for-natural-gas.

90 2012. Medlock, Kenneth B. *U.S. LNG Exports: Truth and Consequence*. James A. Baker III Institute for Public Policy of Rice University.

liquefaction, shipping (which may range from $4.00 per MMBtu to $5.00 per MMBtu alone), and regasification of United States gas are added, other supplies will force U.S. LNG exports to very small levels. DOE/FE reported nearly 200,000 comments submitted to the docket for this proceeding.[91]

### *Outlook*

To date only 4 of 28 applications for LNG export terminals in the United States have been permitted, and of those, only one (Cheniere Energy Partners' Sabine Pass terminal) has secured a long-term sales agreement.[92] In the near term, high amounts of LNG exports from the United States are unlikely because the gap between world and U.S. prices is too narrow to justify the costs of building the export terminals, plus liquefaction, shipping, and regasification costs. Existing import terminals in the United States could be converted to export or hybrid terminals at less than half the capital cost of building an entirely new terminal. These projects are, therefore, in a better position to gain financing and conclude sales agreements with overseas LNG customers.

EIA's *AEO 2013* reference case estimates U.S. LNG exports growing from almost nothing in 2015 to 0.4 Tcf in 2017, and 1.2 Tcf by 2025, as shown in **Figure 32**. These estimated LNG volumes represent 2 percent of Lower 48 total dry gas production in 2022 and 4.4 percent in 2025. The Energy Commission reference case results are higher, yet otherwise similar to the U.S. EIA reference case results, estimating no U.S. LNG exports until 2016. Both staff's reference case and the U.S. EIA reference case show little or modest growth through 2025. In the low-demand/high-price case, the first LNG export terminals also come on-line in 2016 and match the NAMGas reference case exports until 2018, when the model assumes additional LNG export projects begin sales. The low-demand/high-price case also models more U.S. LNG export demand from abroad, which leads to this higher export total. Exports peak in 2020 at 2.69 Tcf before trending flat through 2025.

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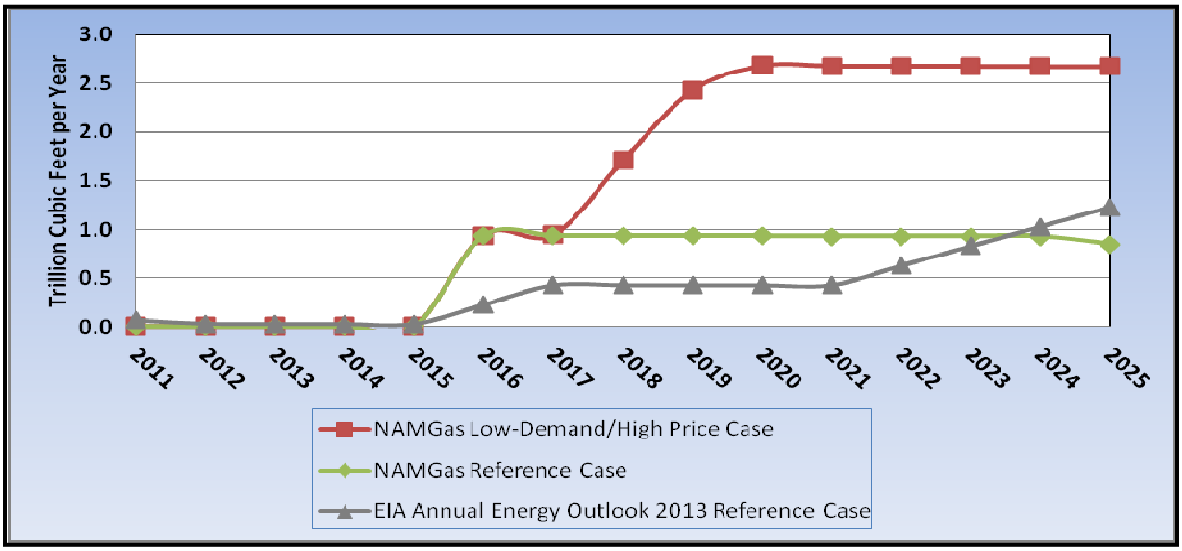
91 Northey, Hannah (*Energy & Environment News*). May 17, 2013. "DOE Approves Second Export License."

92 Office of Fossil Energy (U.S. DOE). "Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of September 19, 2013)," at http://energy.gov/sites/prod/files/2013/09/f2/LNG%20Export%20Summary_1.pdf.

**Figure 32: United States LNG Exports (Tcf/year)**




Source: Energy Commission: EAO, EIA *AEO 2013.*

The Energy Commission expects minimal impact to California from LNG exports. None of the 28 LNG export projects now before federal regulators would be located in California. This is due in large part to the fact that California lies farther from its supplies of natural gas—the U.S. Southwest, the Rocky Mountains and Canada—than most other sites for LNG export terminals, which are on the Canadian, Gulf of Mexico, or Atlantic coasts. Because natural gas transportation costs increase with increasing distance from the supply source, California is not expected to deliver natural gas to other North American LNG facilities.

# CHAPTER 6:
# Other California Natural Gas Issues

## Introduction

This chapter discusses current issues in the natural gas industry that could affect demand, supply, and prices. These include natural gas vehicles (NGV), combined heat and power generation, biomethane, and California's GHG cap-and-trade program.

## Natural Gas Vehicles in California

### Background

A 2010 inventory of emissions found that California's transportation sector emits 38 percent of the state's GHGs, more than any other sector.[93] NGVs have lower emissions than gasoline-fueled vehicles, and the cost of natural gas relative to gasoline is lower,[94] making NGVs an attractive alternative to conventional vehicles. Average September 2013 retail regular unleaded gasoline sold in California for about $3.94,[95] while PG&E sold the energy-equivalent amount of compressed natural gas (126.7 cubic feet) to retail customers for $2.30.[96] Most NGVs, though, are heavy- and medium-duty commercial vehicles (transit buses, delivery trucks). Staff expects that trend to continue for two key reasons.

First, heavy- and medium-duty NGVs outnumber light-duty NGVs (passenger cars and pickup trucks) because the low price of natural gas makes heavy- and medium-duty NGVs less expensive to buy and maintain than gasoline- or diesel-fueled vehicles. Second, the market deficiencies in light-duty vehicles, such as the limited variety of models offered, the reduced cargo space to accommodate the specialized natural gas fueling equipment, the

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93 California Air Resources Board (ARB). 2013. "2010 GHG emissions by Sector (from 2000 – 2010 emission inventory)."See (http://www.arb.ca.gov/cc/inventory/data/graph/graph.htm).

94 A given volume of gasoline contains more energy than natural gas. While gasoline ranges from about 112,000 Btu to about 114,000 Btu per gallon, depending on seasonal or other blend, LNG provides only 75,000 Btu per gallon. A gallon of gasoline has about the same energy content as 126.7 cubic feet of compressed natural gas.

95 U.S. DOE (U.S. EIA.). September 2013. "Retail Gasoline and Diesel Prices," at http://www.eia.gov/dnav/pet/pet_pri_gnd_dcus_sca_m.htm.

96 PG&E. September 2013. "Compressed Natural Gas Service on PG&E's Premises: Schedule G-NGV2," at http://www.pge.com/tariffs/GRF0713.pdf.

mileage range, and the lack of refueling stations, likely hinder widespread consumer acceptance of these NGVs. In 2012, 14.5 million new cars and trucks were sold in the United States, but only 20,381 of these were NGVs.[97] In California, the share of registered gasoline-fueled vehicles fell from 95.9 percent to 92.0 percent between 2003 and 2011, but diesel, flex ethanol, and hybrid vehicles, not NGVs, replaced this share. Consequently, the share of NGVs registered in California remained unchanged at 0.1 percent of all vehicles.[98]

### Current Trends

California has implemented various policies to replace petroleum demand with alternative fuels in the motor vehicle fleet. These include the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program, which was created by Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) (AB 118); Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) (AB 32); and the California Low Carbon Fuels Standard (LCFS), which is incorporated into the *State Alternative Fuels Plan*, adopted pursuant to Assembly Bill 1007 (Pavley, Chapter 371, Statutes of 2005) (AB 1007).[99] The principal objective of these policies is the reduction in GHG emissions through greater use of low- or zero-carbon fuels, such as renewable energy, zero-emissions energy, and natural gas. Implementation of these policies could add modest increases to the current growth in natural gas demand for NGVs.

### Outlook

Staff estimated natural gas demand in the transportation sector using the NAMGas model. This model does not assume any future improvements in NGV range, engine design or other technologies, variety of vehicle models, or the number of refueling stations. Instead, the model uses historical natural gas demand from the U.S. EIA and price elasticity of demand coefficients for the commercial sector as inputs, because these provide the best econometric estimates of natural gas demand in this sector. The demand history, however, also implicitly accounts for preceding NGV technology and refueling infrastructure improvements, and changes in consumer tastes.

Model results for natural gas demand in California's transportation sector, as shown in **Figure 33**, share a trend common with the other U.S. and California sectors. The trend seen

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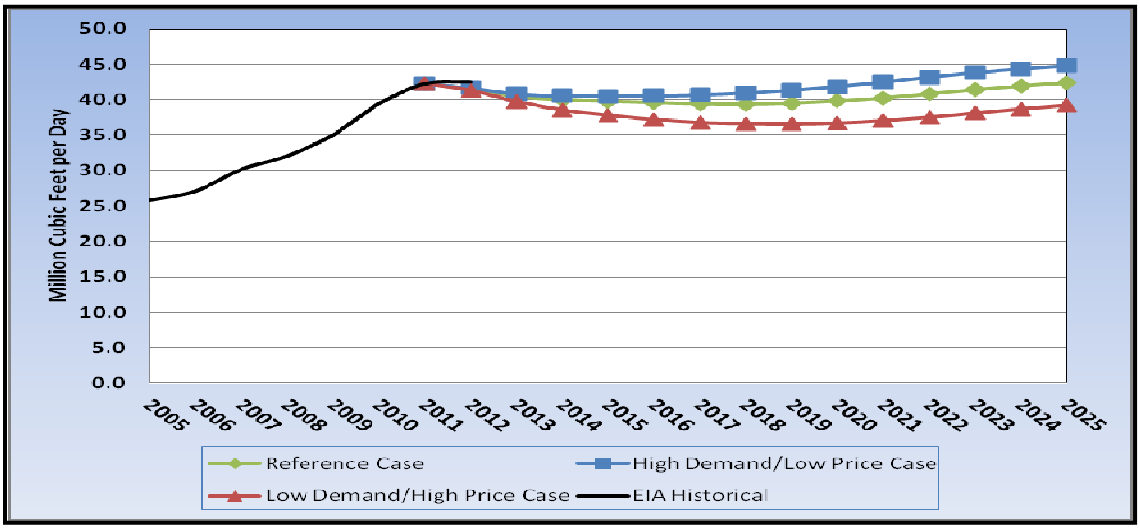
97 Plumer, Brad, *The Washington Post*. May 2, 2013. "Natural-gas vehicles haven't caught on yet. Could that ever change?"See (http://www.washingtonpost.com/blogs/wonkblog/wp/2013/05/02/natural-gas-vehicles-havent-caught-on-yet-heres-how-that-could-change/).

98 Eggers, Ryan (Energy Commission). 2013. "2011 California Vehicle Stock Estimates for the 2013 *IEPR*," Slide 7.

99 Energy Commission. 2007. *State Alternative Fuels Plan*. Publication Number: CEC-600-2007-011-CMF.

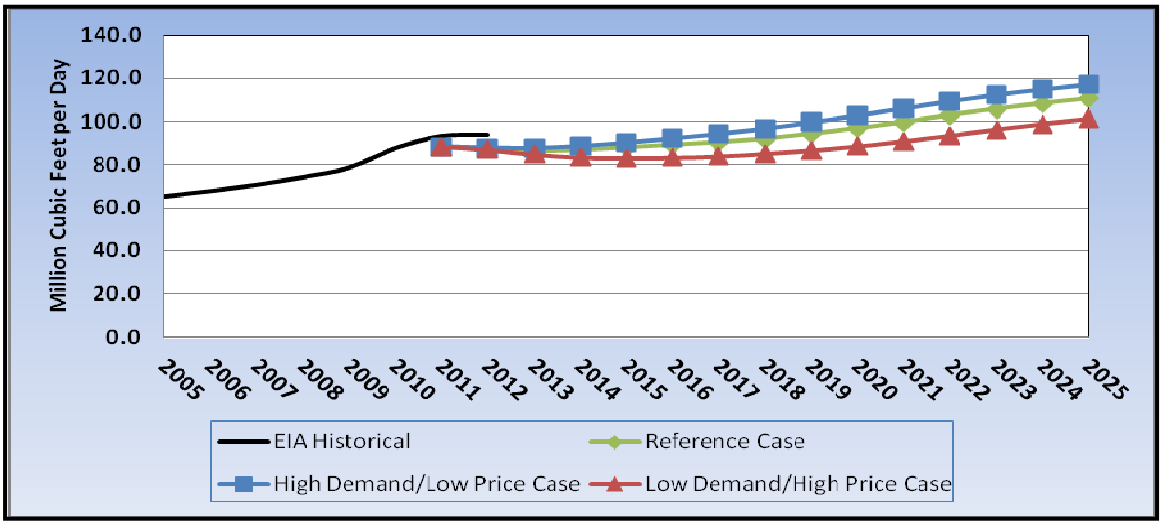
in all three common cases is that demand peaked in 2011 or 2012 and then declines modestly until about 2020, after which minimal growth resumes in all three cases. This similar trend in all cases suggests that general economic and policy factors account for most of the demand behavior, as shown in **Figure 33** and **Figure 34**. One key economic factor is the slow recovery from the recent recession. The modest differences between the common case results are due to the differences in assumptions. The low-demand/high-price case assumptions mostly responsible for driving prices up and demand down from the reference case are the export of about 11 percent of United States natural gas supply as LNG, and the removal of some shale resources in the Rocky Mountains and Northeastern United States from the resource base. The most important high-demand/low-price case assumption driving prices down and demand up from the reference case is the larger natural gas resource base. For California, demand in the low-demand/high-price case in 2020 and 2025 is 7.8 percent and 7.5 percent less than the reference case, respectively. Demand in the high-demand/low-price case is 5.2 percent and 5.7 percent higher than the reference case in 2020 and 2025, respectively.

**Figure 33: California Transportation Sector Natural Gas Demand (MMcf/Day)**




Source: Energy Commission: EAO; U.S. EIA.

**Figure 34: U.S. Transportation Sector Natural Gas Demand (MMcf/Day)**




Source: Energy Commission: EAO; U.S. EIA.

United States demand increases sooner than California's demand because California is expected to meet a larger share of additional demand with low- and/or zero-carbon fuels than the rest of the United States. For the United States, the low-demand/high-price case in 2020 and 2025 is 8.6 percent and 8.4 percent less than the reference case, respectively. United States-wide natural gas vehicle fuel demand in the high-demand/low-price case is 6.0 percent and 6.1 percent higher than the reference case in 2020 and 2025, respectively. One very interesting observation is that California transportation sector natural gas demand is almost half of U.S. transportation demand.

## Combined Heat and Power

CHP, also known as cogeneration, is an integrated system that generates both electricity and thermal energy using a single fuel source, such as natural gas, biogas, biomass, coal, waste heat, or oil. Less fuel is consumed in a typical CHP system than would be required to obtain electricity and thermal energy separately. Since less fuel is consumed, CHP systems offer GHG reduction benefits over the conventional method of obtaining heat from a boiler and power from the electric grid.

California policy supports the use of CHP as a GHG emissions reduction measure and to support California's industrial economy. The California Air Resources Board's AB 32 *Climate Change Scoping Plan* includes a target of 6.7 million metric tons of carbon dioxide

equivalent reductions from new and existing CHP resources,[100] and Governor Brown's *Clean Energy Jobs Plan* sets a goal of 6,500 MW of new CHP capacity by 2030.[101]

California has several programs to support these policies and promote clean and efficient CHP systems. These include the Self-Generation Incentive Program,[102] the Waste Heat and Carbon Emissions Reduction Act[103] (also known by its founding legislation Assembly Bill 1613 [AB 1613]), and a program for competitively bid CHP resources established by the Qualifying Facility and Combined Heat and Power Settlement Agreement.[104]

In 2011 the Energy Commission contracted with ICF Consulting to identify existing CHP capacity and quantify the long-term market potential for CHP in California and the degree to which CHP can reduce potential GHG emissions over the next 20 years. The resulting *Combined Heat and Power: 2011-2030 Market Assessment* identified 8,518 MW of installed CHP at the end of 2011 and indicated that cumulative market penetration for new CHP in 2030 varies between 1,888 MW and 6,108 MW.[105] Existing capacity has decreased by roughly 330 MW with the closure of some CHP facilities that used coal or petroleum coke, as well as the economic closure of the Campbell's Soup plant in Sacramento.

With very few exceptions, CHP generation uses natural gas or biofuel. Two exceptions are ACE Cogeneration and Argus Cogeneration, which currently use bituminous coal for fuel. ACE Cogeneration has announced its intention to convert its 108 MW facility to natural gas by 2017. Argus Cogeneration generates 55 MW of electricity, and it is unknown if the facility will convert to an alternate source of fuel or cease operation. Other facilities, known as bottoming-cycle CHP or waste heat recovery, capture the waste heat from an industrial process to generate electricity and use no additional fuel. An example of this is Wilmington

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100 ARB. *Climate Change Scoping Plan: A Framework for Change*. 2008. See http://arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm, pp. 42 – 43.

101 "Brown Announces Clean Energy Jobs Plan," at http://www.jerrybrown.org/Clean_Energy.

102 CPUC Decision 01-03-073 implementing Assembly Bill 970 (Ducheny, Chapter 329, Statues of 2000) (AB 970), later amended by Assembly Bill 1685 (Leno, Chapter 894, Statutes of 2003) (AB 1685), Assembly Bill 2778 (Lieber, Chapter 617, Statutes of 2006) (AB 2778), Senate Bill 412 (Kehoe, Chapter 182, Statutes of 2009) (SB 412), and Assembly Bill 1150 (Pérez, Chapter 310, Statutes of 2011) (AB 1150).

103 Assembly Bill 1613 (Blakeslee, Chapter 713, Statutes of 2007) (AB 1613), later amended by Assembly Bill 2791 (Blakeslee, Chapter 253, Statutes of 2008) (AB 2791).

104 CPUC. 2010. *Decision Adopting Proposed Settlement.* Decision 10-12-035, at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128624.PDF.

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

Calciner, which generates 36 MW of electricity using the steam that is created as a by-product of its industrial process: producing calcined coke from green coke.[106]

Some CHP applications are a natural fit for the use of onsite digester biogas. These applications include wastewater treatment facilities and dairy processing facilities. The creation and use of biogas at these facilities offset the need for natural gas or electricity from the grid. A 2009 Energy Commission study, *Combined Heat and Power Potential at California's Wastewater Treatment Plants*,[107] estimates the market potential for additional capacity at wastewater treatment plants as 100 MW. However, the capacity could be increased to 450 MW by adding biodegradable waste from California dairies and food processing plants and restaurant oil and grease to the sludge in the anaerobic digesters.

The main economic driver for CHP development is the difference between the price of natural gas and the price of avoided electricity, more commonly known as the "spark spread." For example, extended forecasts of low natural gas prices coupled with forecasts for increased electricity and electrical infrastructure costs result in an even greater spark spread, which should result in increasing the numbers of CHP projects that are financially feasible.

Despite the overall decline in natural gas for power generation in California, a significant amount of this gas could be redirected to onsite generation in California's industrial and commercial sectors. While future CHP will be in both commercial (for example, big box retail and restaurants) and industrial (such as food processing and water treatment) sectors, staff analysis allocated the market shift in natural gas demand from the power generation sector to generation for CHP in the industrial sector. A shortcoming of the model is that it is unable to distinguish end-use detail because natural gas use reports lack end-use detail data. When analyzing CHP, the model assumes that the increase in natural gas is solely associated with electricity generation. It does not consider the fact that fuel used in CHP facilities generates both electricity and thermal energy, nor the reduction of natural gas previously used in boilers to meet the thermal need of the host site prior to the installation of a CHP unit. The model also assumes that all new CHP would be topping-cycle CHP.

**Figure 35** shows the net additional natural gas demand shifted to CHP for industrial sector customers in each of staff's forecast scenarios. Average annual growth in natural gas demand is expected in both the reference and low-demand/high-price cases. The high-demand/low-price case assumes minimal CHP addition in the industrial sector.

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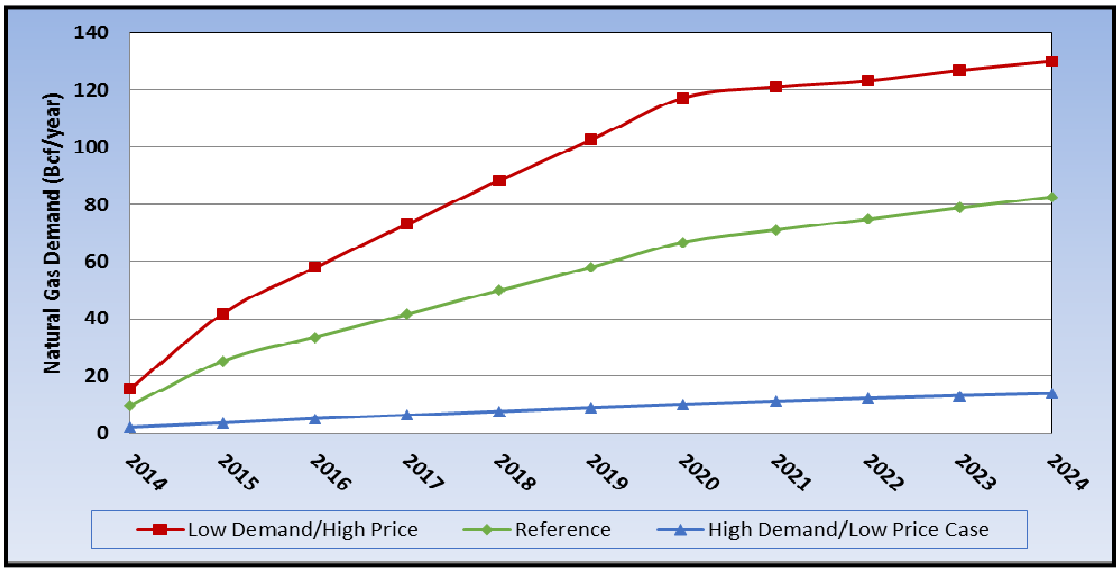
106 *Quarterly Fuels and Energy Reports* submitted to the Energy Commission in 2011 and 2012, available at http://energyalmanac.ca.gov/electricity/web_qfer/.

107 Kulkarni, Pramod, 2009. *Combined Heat and Power Potential at the California Wastewater Treatment Plants*. Energy Commission. CEC-200-2009-014-SF.

**Figure 35: Natural Gas Demand for New CHP to Generate Electricity for California's Industrial Sector Customers**




Source: Energy Commission: EAO.

While increased CHP generation will add to the amount of natural gas used on site, it will cause a net decrease in the amount of natural gas to meet both the electrical and thermal needs of the facility. The increased use of CHP will reduce the natural gas demand for power generation. Therefore, widespread adoption of on-site CHP would result in a cumulative reduction in natural gas use for electricity statewide. This trend is an underlying component of the natural gas demand, where the largest increase in CHP development occurs in the low-demand/high-price case and the smallest increase in the high-demand/low-price case.

## Role of Biomethane in California

### Background

Biomethane is defined as biogas that has been treated to remove impurities, creating acceptable pipeline-quality methane. Biogas is produced from landfill gas or by anaerobic digestion of nonfossil organic waste, such as animal manure, sewage, and municipal solid waste. Once biogas is processed to reduce impurities ($CO_2$, hydrogen sulfide, arsenic, and vinyl chloride), the resulting biomethane can be a renewable substitute for natural gas. In California, the largest potential sources of renewable biomethane are landfills (termed *landfill gas*) or wastewater treatment plants and dairy farms (termed *digester gas*). Harvesting the biomethane from these sources provides an environmentally attractive alternative to the

otherwise natural or planned releases of methane, a potent greenhouse gas, into the atmosphere.

The statutory and regulatory landscape for biomethane projects is changing. For example, the RPS no longer allows biomethane delivered through the natural gas pipeline to be eligible as a renewable resource unless the project provides environmental benefits to California.[108] Also, the utilities and the CPUC must develop nondiscriminatory open-access pipeline quality standards for biomethane.

In the *2011 Bioenergy Action Plan*, the Energy Commission found that the varying pipeline quality standards and approaches to applying standards were limiting development of pipeline biomethane projects.[109] In addition, a statute referred to as "the Hayden Bill"[110] resulted in biomethane produced from landfill gas being restricted from injection into natural gas pipelines. In 2012, the Legislature passed Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012) (AB 1900), which requires the CPUC to adopt pipeline access rules that ensure gas corporations will provide nondiscriminatory open access to the pipeline system for biomethane, regardless of the type or source of the biogas.

In addition to providing biomethane producers open access to the utility pipeline system, AB 1900 requires the CPUC to develop standards for constituents of concern[111] in biogas to protect human health and promote pipeline integrity and safety. The CPUC opened Rulemaking 13-02-008 for this proceeding. The bill further requires the Office of Environmental Health Hazard Assessment and ARB to recommend health-based exposure limits and constituents of concern in raw biogas. The agencies released their recommendations to the CPUC on May 15, 2013.[112]

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108 Assembly Bill 2196 (AB 2196) (Skinner, Chapter 605, Statutes of 2012).

109 Energy Commission, *2011 Bioenergy Action Plan*, March 2011, see http://www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF.

110 Assembly Bill 4037 (Hayden, Chapter 932, Statutes of 1988).

111 *Constituents of concern* are components of biogas that could pose a health risk and that are at levels that significantly exceed the concentrations of those constituents found in natural gas.

112 California Air Resources Board, *Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline*, May 2013, see http://www.arb.ca.gov/energy/biogas/documents/FINAL_AB_1900_Staff_Report_&_Appendices_%20051513.pdf.

## Current Trends

The CPUC will develop final standards for constituents in biomethane by December 31, 2013, pursuant to the requirements laid out in AB 1900. These standards must protect both human health and pipeline integrity and safety. The statute also requires the Energy Commission "to determine, for new certifications, whether a source of biomethane results in new displacement of fossil fuels and directly achieves air quality improvements in an air basin in or affecting California." While the bill is intended to remove barriers to use of California-produced biomethane, stakeholders such as The Coalition for Renewable Natural Gas, Inc., claim it will instead create new barriers by expanding the scope of standards beyond vinyl chloride to include any compounds that may create health and safety hazards, damage pipeline facilities, or inhibit the marketability of the gas.[113]

In May 2013, after the Office of Environmental Health Hazard Assessment and ARB reviewed and studied the constituents in biogas and the health risks to utility workers and the public in support of the CPUC's biomethane standards development, they released *Recommendations to the California Public Utilities Commission Regarding Health Protective Standards for the Injection of Biomethane into the Common Carrier Pipeline*.[114] In this document, health protective levels of these constituents, along with Office of Environmental Health Hazard Assessment health risk assessment methodologies, were recommended, and it was reported that the majority of the constituents in biogas were either not detected or were reduced to concentrations below the Office of Environmental Health Hazard Assessment's recommended health protective levels during the upgrading process to biomethane. On the basis of this finding, the ARB determined that from a public health perspective, the injection of biomethane into natural gas pipelines does not present additional health risks as compared to natural gas.

## Outlook

The viability of biomethane production facilities and the continued market demand for the gas depend on programs and policies that would remove barriers to its use. The passage of Assembly Bill 2196 (Chesbro, Chapter 605, Renewable Energy Resources, Statutes of 2012) (AB 2196) and AB 1900 and revisions to the RPS guidelines are initial steps in the process. The new RPS guidelines allow use of biomethane injected into a common carrier pipeline located within the WECC region or interconnected to a natural gas pipeline system in the WECC region that delivers gas into California. Of particular significance in the RPS

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113 Cox, D., and Escudero, J. Pre-Hearing Conference Statement by the Coalition for Renewable Natural Gas, Inc. , CPUC Rulemaking R013-02-008 (2013). Page 5. Retrieved from http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M062/K835/62835340.PDF.

114 See http://www.arb.ca.gov/energy/biogas/documents/FINAL_AB_1900_Staff_Report_&_Appendices_%20051513.pdf.

regulations is that the capture and injection of biomethane into a common carrier pipeline directly result in at least one of the following environmental benefits to California:

- Reduction or avoidance of the emission of any criteria air pollutants (or their precursors) in California.
- Reduction or avoidance of pollutants that could have an adverse impact on any surface water or groundwater in California.
- Mitigating a local nuisance in California associated with the emission of odors.

After the suspension of biomethane RPS eligibility in 2012, developers started focusing on California's Low Carbon Fuel Standard program as a regulatory framework that offers another possible market for their gas. The program, which is run by the ARB, calls for a 10 percent reduction in carbon intensity of California transportation fuels by 2020 and lists as eligible fuels either biomethane compressed natural gas or biomethane LNG, among numerous other eligible fuels. The program uses a performance-based market mechanism with tradable and bankable credits that are used to measure compliance with the regulations of the program. Biomethane is measured by its life-cycle global warming intensity on a per-unit basis, measuring all the activities included in the production, transport, storage, and use of the fuel and of all the mechanisms that affect the global climate.[115] For biomethane developers, the tradable and bankable credits are desirable as a type of currency to provide incentives for the emissions reductions outlined in the program and the market for their gas.

The potential quantity of biomethane available in California today remains small relative to the state's overall demand for natural gas. Nonetheless, AB 2196 and AB 1900 recognize that using it in place of conventionally produced natural gas is an important alternative to allowing it to be flared or combusted in less efficient power generation plants that are increasingly being phased out by local air districts. Biomethane, thus, has the potential to add a renewable source of fuel to California's natural gas supply and help California create new jobs while reducing the release of methane into the atmosphere.

## Greenhouse Gas Cap-and-Trade Markets

### Background

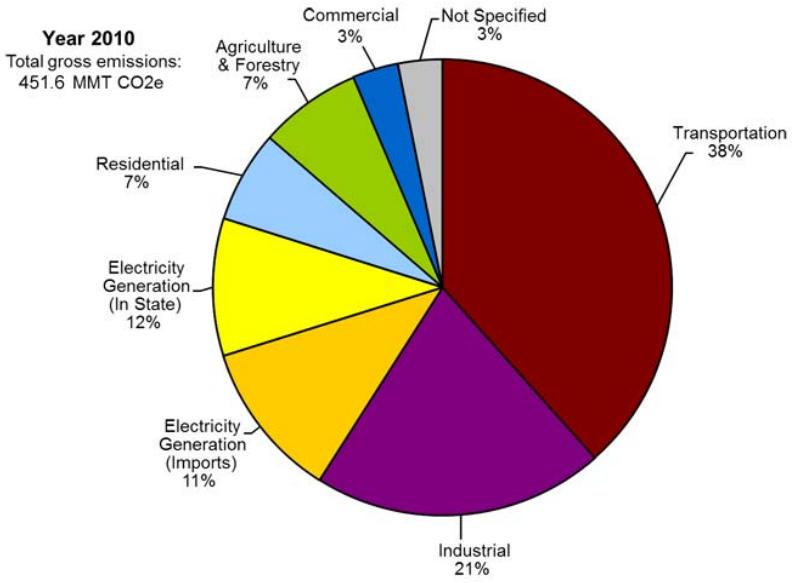
AB 32 set for California a goal of reducing the state's GHG emissions to 1990 levels by 2020. This goal represents a reduction of about 30 percent from business as usual emission levels

115 Farrell, Alexander, and Daniel Sperling. *A Low-Carbon Fuel Standard for California Part 1: Technical Analysis.* UC Berkeley, May 2007. See http://www.arb.ca.gov/fuels/lcfs/lcfs_uc_p1.pdf.

projected for 2020. AB 32 called for adoption of "market-based compliance mechanisms."[116] Among these is the GHG cap-and-trade program. Cap-and-trade imposes an aggregate annual GHG emissions cap on stationary sources that emit 25,000 metric tons of carbon dioxide-equivalent, shown in **Figure 36**. Known as "covered entities," the emitting facilities are required to deliver (or, surrender) to the ARB enough allowances to cover their annual emissions. The number of allowances available is set equal to the level of capped emissions for that year; the 2013 cap is set at about 2 percent below the 2012 emissions level, and it declines by about 3 percent each year thereafter. The ARB awards some allowances directly to certain covered entities and holds two auctions per year to sell additional allowances into the market. Covered entities can trade allowances among themselves as they find they have more or fewer allowances than they need to cover their emissions.

The implementation of cap-and-trade began January 1, 2013. Only entities that generate or import electricity, produce oil or natural gas, refine oil, or manufacture cement are currently required to participate. Beginning January 1, 2015, the ARB will expand the program and require transportation fuels and residential and commercial use of natural gas to participate.

**Figure 36: 2010 Greenhouse Gas Emissions by Sector**




Source: See http://www.arb.ca.gov/cc/inventory/data/graph/graph.htm.

116 Health and Safety Code §§ 38561, 38570, 38580.

## Current Trends

When residential and commercial natural gas use becomes covered in 2015, the compliance obligation will rest not on individual customer, but instead on the entity making the final delivery of natural gas to the customer. These entities are the state's gas corporations (as defined under the Public Utilities Code), plus municipal gas utilities, municipal utility districts that own their own gas distribution lines such as Sacramento Municipal Utility District, joint powers authorities, and any other intrastate gas pipelines that distribute natural gas to customers. The ARB also requires that natural gas deliverers report to the ARB all deliveries to other covered entities in California (such as electricity generators using natural gas) to avoid double-counting emissions and to accurately account for natural gas deliveries and overall resulting compliance obligations.

## Outlook

The cap-and-trade program began in 2012 and applies to a limited segment of the market. The market–clearing price of allowances sold in the first six auctions was slightly above the floor price set by the ARB. In Decision No. 12-12-033, the CPUC directs that 85 percent of allowance revenue collected by the state's electric utilities as they auction the "free" allowances they are given must be returned to residential ratepayers via a semiannual "climate dividend." In this way, electricity ratepayers are meant to be compensated for the higher electricity prices they may encounter as a result of cap-and-trade, while still capturing in electricity rates a price signal that reflects the costs utilities incur for carbon compliance (for example, purchasing allowances or modifying their generation portfolio to reduce emissions).

In contrast to its treatment of electric generators and other types of covered entities to which it is offering some free allowances during the program's first five years, the ARB is not giving free emissions allowances to natural gas distributors. This means that natural gas distributors will have to purchase allowances in the market. The CPUC has not yet told the investor-owned gas corporations how to show this cost on customer bills; distributors not subject to CPUC rate regulation will presumably make their own decisions about how to pass these costs on to consumers. ARB staff estimates the impact on natural gas customers, based on their estimate of likely emissions and an assumed $15 per ton allowance cost, at 7 percent for residential customers, 8 percent for commercial, and 6 percent for industrial.[117] It is too soon for Energy Commission staff to reach additional conclusions about how the

117 "California Cap on Greenhouse Gas Emissions; Implications for the Natural Gas Sector," ARB, presentation at April 24, 2013, *IEPR* workshop. See http://www.energy.ca.gov/2013_energypolicy/documents/2013-04-24_workshop/presentations/02_Carb_MAYEUR.pdf.

program will affect prices to natural gas consumers or the impact on natural gas demand in California.

# CHAPTER 7: Conclusions

This outlook is intended to assess the current issues and trends affecting natural gas supply, demand, and prices in the United States and California, and project forward to explore the possible natural gas issues and trends that will occur in the future. The projections rely on various assumptions about natural gas supply, demand, and price and represent the Energy Commission staff's assessments of appropriate inputs to the NAMGas, along with the help of consultants from Rice University. The following conclusions are from staff's modeling projections and represent the highlights on this outlook:

- Model results show Henry Hub natural gas prices (**Figure 5**) will steadily increase over time (2013 – 2025)—the reference case projects a 38 percent increase over this time frame.[118]
- Aggressive energy efficiency goals and the RPS target in California are likely to reduce demand for natural gas in the state.
- Natural gas demand estimated for power generation in California assumes average annual precipitation. Dry conditions and associated reduction in potential electricity generation from hydroelectric facilities in California in 2013 and to date in 2014 are likely to make the estimate for 2014 demand low.
- Technology innovations have dramatically improved drilling efficiency and increased natural gas production, leading to decreased natural gas prices, a trend that looks likely to continue in the future.
- LNG exports and exports to Mexico could divert a significant amount of gas out of the United States and potentially increase prices, but it is too soon to tell how much gas might be exported or what, if any, price impacts there may be.
- Insufficient gas deliveries on the EPNG southern mainline in Southern California have led to difficulties meeting the SoSysMin gas requirements for core customers in the SDG&E service area. This issue must be addressed to avoid potential gas curtailments for noncore customers, such as electric generation plants.

  Many coal plants in the WECC are likely to be retired starting in 2014 because of more stringent national GHG emissions regulations and the competitive price of natural gas. These retirements are likely to increase gas demand in the WECC area after 2020, which, in turn, could cause tighter gas supplies and price increases in California due to its location at the end of many major interstate pipelines that pass through the WECC area.

118 The adopted final *California Energy Demand Forecast* for 2014 – 2024 (CEC-200-2013-V1-CMF) reports an 83.6 percent increase in natural gas price from 2012 – 2024 for the mid demand case. The price of natural gas in 2012 was very low (~$2.70/Mcf) versus ~ $3.70/Mcf in 2013, which is the initial year shown in the comparison above.

# ACRONYMS

| Acronym | Definition |
|---|---|
| *2013 AEO* | *2013 Annual Energy Outlook* |
| AAEE | Additional achievable energy efficiency |
| AB 1150 | Assembly Bill 1150 |
| AB 1613 | Assembly Bill 1613 |
| AB 1865 | Assembly Bill 1865 |
| AB 1900 | Assembly Bill 1900 |
| AB 2196 | Assembly Bill 2196 |
| AB 2778 | Assembly Bill 2778 |
| AB 2791 | Assembly Bill 2791 |
| AB 32 | Assembly Bill 32, the Global Warming Solutions Act |
| AB 970 | Assembly Bill 970 |
| ARB | California Air Resources Board |
| BCAP | Biennial Cost Allocation Proceeding |
| Bcf | Billion cubic feet |
| Bcf/d | Billion cubic feet per day |
| California ISO | California Independent System Operator |
| CBM | Coal bed methane |
| *CED 2014 – 2024* | *California Energy Demand, 2014-2024* |
| CHP | Combined heat and power |
| $CO_2$ | Carbon dioxide |
| CPUC | California Public Utilities Commission |
| DAO | Demand Analysis Office |
| EAO | Electricity Analysis Office |
| Energy Commission | California Energy Commission |
| EPNG | El Paso Natural Gas |
| FERC | Federal Energy Regulatory Commission |
| GDP | Gross domestic product |
| GHG | Greenhouse gas |
| GW | Gigawatt |
| *IEPR* | *Integrated Energy Policy Report* |
| IOU | Investor-owned utility |
| LNG | Liquefied natural gas |
| MAOP | Maximum allowable operating pressures |
| Mcf | Thousand cubic feet |
| Mdth/d | Thousand dekatherms/day |
| MMBtu | Million British thermal unit |
| MMcf/d | Million cubic feet per day |

| Acronym | Definition |
|---|---|
| MW | Megawatt |
| NAMGas | North American Market Gas Trade Model |
| NGV | Natural gas vehicle |
| NWPCC | Northwest Power and Conservation Council |
| PEMEX | Petróleos Mexicanos, the National Oil and Gas Company of Mexico |
| PG&E | Pacific Gas and Electric Company |
| PSIG | Pounds per square inch gauge |
| RGWTM | Rice World Gas Trade Model |
| RPS | Renewables Portfolio Standard |
| SB 1389 | Senate Bill 1389 |
| SB 412 | Senate Bill 412 |
| SB 665 | Senate Bill 665 |
| SCADA | Supervisory control and data acquisition |
| SDG&E | San Diego Gas & Electric Company |
| SoCal Gas | Southern California Gas Company |
| SONGS | San Onofre Nuclear Generating Station |
| SoSysMin | Southern System Minimum |
| Tcf | Trillion cubic feet |
| Tcf/yr | Trillion cubic feet per year |
| U.S. DOE | United States Department of Energy |
| U.S. EIA | United States Energy Information Administration |
| U.S. EPA | United States Environmental Protection Agency |
| U.S.DOE/FE | Department of Energy, Office of Fossil Energy |
| WECC | Western Electricity Coordinating Council |
| WGTM | World Gas Trade Model (Energy Commission) |

# 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 its 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 (CAT):** 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 (greenhouse gas) 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 its 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 (EIM):** 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 is allowed to 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 time frame.

**Flex Alerts**: An emergency alert that urges Californians to reduce energy consumption because of system needs.

**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 in an efficient manner.

**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 states.

**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 receive 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 multiple periods. 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 process of using 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 in order 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 wherein 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.

**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.

**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.

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

# APPENDIX A:
# 2013 Modeling Approach

## Building the Natural Gas Market Model

### Background

Staff continues to license and use a form of the same basic general equilibrium resource depletion model it has used since 1989. Now owned by Deloitte LLP Market Point Services, the MarketBuilder platform simulates interconnected networks of economic agents[119] seeking utility maximization. The result of that utility maximization are regional prices, regional supply and demand, and interregional natural gas flows for the defined network, optimized across regions and time such that no further arbitrage or economic activity can improve any agent's result. This approach continues to set the standard for modeling natural gas markets.

Building a model in MarketBuilder essentially means defining a physical, geographic network, or a topology for the natural gas market. This means defining natural gas demand centers, including large gas consumers such as power plants; locating of the interconnecting interstate and intrastate pipelines; locating of import and export terminals; and locating of all supply sources of natural gas.

Input assumptions for the network include estimated demand for gas at all demand locations (or nodes), the price elasticities of demand for gas and its competing fuels, the capacities and transportation costs along each route from supply to load, the size of the various gas supply resources, rate of technological innovation, the cost over time to develop and extract natural gas resources, and investment criteria for the endogenous construction of new pipeline capacity. Furthermore, staff must specify time-points (periods) for the forecasting horizon of the model, for example, annual time-points between 2011 and 2040.

### The 2013 Natural Gas Model

For the *2013 IEPR*, staff is using a modification of the RWGTM, constructed in the MarketBuilder platform by Dr. Kenneth Medlock.[120] Staff's version largely accepts the topology of gas markets specified in RWGTM but adds additional demand and supply

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119 Economic agents are actors or decision-makers in the marketplace.

120 Dr. Medlock is the James A. Baker III and Susan G. Baker Fellow in Energy and Resource Economics and Deputy Director of the Energy Forum of James A. Baker III Institute for Public Policy at Rice University in Houston, Texas.

nodes in the western United States to capture more granular market hub details, match supply to demand nodes including gas-fired power plants, and represent natural gas demand in the transportation sector. Dr. Medlock assisted in implementing these changes to create the Energy Commission's WGTM.

For the *2013 IEPR*, staff also decided to limit its focus to North America. This focus is in keeping with a more realistic assessment of the quantity of data needed to support use of a worldwide model and a sense that staff did not need to model world markets for natural gas given its access to Dr. Medlock and his extensive work in that area. To generate this refocus of the model, staff worked with Dr. Medlock to implement the following changes to the WGTM:

- Removed all non-North American structure
- Added functional nodes to allow for a simplified endogenously-determined LNG imports and exports

Staff refers to the resulting model as the NAMGas model.

## Developing the Starting (Reference) Demands

RWGTM, NAMGas, and any other formulation specified in the MarketBuilder platform requires starting, or reference, demands and prices.[121] Staff obtained these from Dr. Medlock, who developed a set of econometric models that calculate the initial reference demands. Staff refers to this as the "small m" model. Housed in an Excel spreadsheet, the "small m" 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 are as follows, where "f" is defined as a function of:

- Residential reference demand = f(recent historical demand for natural gas, heating degree days, population, natural gas price, income, and heating oil price).
- Commercial reference demand = f(recent historical demand for natural gas, heating degree days, income, natural gas price, population, and heating oil price).
- Industrial reference demand = f(recent historical demand for natural gas, heating degree days, natural gas price, coal price, and industrial production).
- Power generation reference demand = f(total electricity generation, cooling degree days, natural gas price, fuel oil price, renewable electricity generation, and coal price).

121 This use of the term "reference" does not mean "reference case" but merely indicates that it is the starting input value.

- Transportation reference demand = f(recent historical demand for natural gas, income, natural gas price, population, oil price, and cold weather).[122]

Performing a regression analysis using historical data for the variables by end-use sector yields the coefficient estimates needed to calculate the reference demand quantities. These starting values are calculated for all the years in the forecasting period and geographic areas specified in the model. Staff then inputted these demand (or reference) quantities into NAMGas.

## Producing Model Results

With the specified topology and the input data, the NAMGas model performs a dynamic spatial equilibrium linked through time by Hotelling-type[123] optimization of resource extraction. The Hotelling optimization applied in NAMGas outlines the process by which a depletable resource becomes uneconomic to develop. The model allows for advances in technology to offset the depletion effects. The equilibrium criteria are the classical economic criteria that require all suppliers maximize utility (defined as profits) and all consumers maximize utility (defined as seeking the lowest possible cost of available supply resources relative to their willingness to pay).

To produce a solution, the model iterates back and forth by "producing" natural gas, "transporting" it to the demand centers along pipelines, and then checks whether the produced gas can satisfy demand requirements at the assumed price. While the model is iterating, the model:

- Adds pipeline capacity if needed and 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.

The model stops when it converges at a new equilibrium when, at a particular price, supply equals demand such that supplier and consumer utility are maximized in all regions in all periods. The model solution consists of the annual average market price of gas based on the

122 The econometric equation used to estimate natural gas demand for vehicles was estimated using the same equation as for the commercial sector. This approach was deemed reasonable because NGV demand is likely a subset of commercial demand and data was not available to produce a more robust estimate using more precise explanatory variables.

123 Hotelling: As resources are depleted, prices rise at a real associated rate of interest.

marginal cost of gas supply,[124] the annual natural gas production over the forecast horizon, the annual natural gas demand over the forecast horizon, and new capacity constructed during the forecast horizon.

## Commission's Iterative Cross-Modeling Process

For the *2013 IEPR*, Energy Commission staff applied an iterative cross-modeling process to develop coordinated model inputs and results across the Generation Fuels and Production Cost Modeling Units in EAO and the DAO. A key advantage of the iterative cross-modeling is that it allows coordinated use of common assumptions to produce internally consistent, coordinated results, where the output of one model that is used by another model as an input can cycle forward at least once to capture some of the feedback effects that separated models would otherwise ignore.

The cross-modeling was applied for developing the reference case, the low-energy-demand/high-price case, and a high-energy-demand/low-price case. (A more detailed description of the assumption inputs to these cases appears in Chapter 3). A key feature of NAMGas is the ability, as it iterates, to reflect or ignore price elasticities. In other words, NAMGas can either let the price elasticity affect demand for natural gas as prices change, or a user can turn that feature off and require demand to stay at the original input level. For the *2013 IEPR*, staff ran NAMGas using the initial demand as calculated in "small m" and left the elasticities on. To the resulting hub prices, staff added the firm transportation rates required to move natural gas from market hubs to natural gas-fired power plants. This creates burner tip prices that gas-fired power plants will face in making electricity dispatch decisions.[125] These burner tip prices are then used as inputs to the PLEXOS production cost model.

PLEXOS is a well-known electricity production cost model that calculates, for each hour of a year and subject to constraints, how each electricity generation facility in a regional network must operate to serve all electricity demand on a least-cost basis. PLEXOS will also output how much natural gas a power plant must burn to produce the calculated electrical output. Because PLEXOS performs this optimization to minimize cost, the price of natural gas can affect the degree and timing of when gas-fired units are dispatched (or ordered to operate). In short, PLEXOS will simulate the need of the electricity market to operate gas-fired units and to calculate demand for gas by electricity generators reflecting, among other inputs to PLEXOS, the prices from NAMGas.

Staff then took the electricity generation gas demand produced by the PLEXOS dispatch routine and back-entered these as inputs into the NAMGas model.[126] The PLEXOS results

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124 *The marginal cost of natural gas supply* is the cost to develop the next unit of natural gas.

125 Deaver, Paul. 2013. *Estimating Burner Tip Prices, Uses, and Potential Issues*. CEC-200-2013-006-SD.

126 This process also occurs with other scenarios developed by staff.

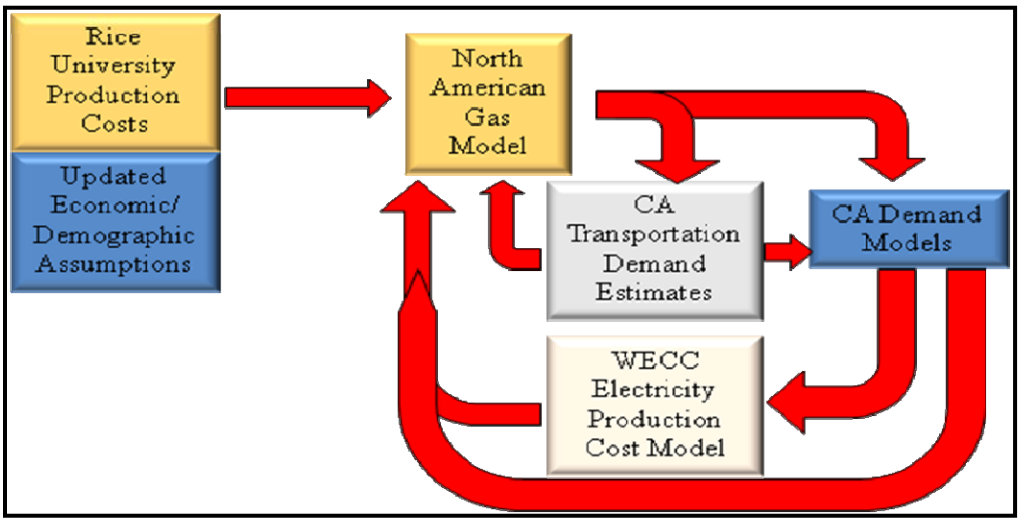
replace the reference values for natural gas demand in the power generation sector (for WECC regions only) that were initially derived in "small m." In this second iteration of NAMGas, staff turned off the price elasticities for all NAMGas model regions within the WECC so that demand response to changes in natural gas price is not allowed. Essentially natural gas demand for power generation within the WECC from the PLEXOS production cost model is now "hard-wired" into the reference case NAMGas model and represents the projected least-cost economic dispatch of the electricity system. For power generation, areas outside the WECC included in the NAMGas model are unchanged and still have the initial econometric demand inputs from "small m" and price elasticities in effect.

The DAO at the Energy Commission projects natural gas demand for California's residential, industrial, and commercial sectors as part of the *IEPR,* and its forecasts are reviewed and vetted by the gas utilities, among others. The DAO takes gas prices from the NAMGas model as an input to its modeling. Model results that yield natural gas demand in the industrial, residential, and commercial sectors replace initial demand inputs from the econometric model for the California region. These demand inputs are "hard-wired," and the price elasticities are turned off.

A diagram that outlines how the models in the various units and offices interact with each other is shown below in **Figure A-1**. The process begins with running NAMGas using starting natural gas demand estimates from "small m." NAMGas results become inputs to each of the other staff models. Their results, in turn, replace the "small m" starting demands, the econometrically estimated elasticities are turned off and NAMGas is rerun. After each iteration, staff compares demand results for each sector to demand results from the previous iteration. Iterations will continue until the difference between demand results from the previous iteration is reasonably small.

Assumptions for natural gas demand in the transportation sector were based on historical trends. These trend estimates were derived using econometric equations in the "small m" model. These initial demand inputs for natural gas demand in the transportation sector are subject to price elasticities that are also based on historical trends. New levels of demand for natural gas in the transportation sector were achieved as the NAMGas model iterated and reached equilibrium.

**Figure A-1: Iterative Modeling Process Diagram**




Source: Energy Commission: EAO.

# APPENDIX B:
# Price Elasticities Used in the NAMGas Model

**Table B-1** displays the price elasticities developed by Dr. Kenneth Medlock that staff deployed in the NAMGas model. The elasticities determine the size of the demand adjustment when prices vary in the model.

**Table B-1: Price Elasticity in NAMGas Model by Sector**

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

Source: Energy Commission: EAO.

# APPENDIX C:
# Comparisons of Key Modeling Case Assumptions

**Table C-1: Comparisons of Key Modeling Case Assumptions**

| | Reference Case | Low-Demand/High-Gas-Price Case | High-Demand/Low-Gas-Price Case | Gas/Electric Case |
|---|---|---|---|---|
| **Key Assumptions** | | | | |
| Average Annual GDP Growth Rate | 2.50% | 3.00% | 2.00% | 2.50% |
| Gas Technology Improvement Average Annual Growth Rate | 1.0% | 1.0% | 2.5% | 1.0% |
| CHP Demand (Bcf)/Capacity (MW) for CA in 2024 | 83/1424 | 130/3084 | 14/210 | 83/1424 |
| When CA Meets Maximum RPS Target | On time | 10 year delay | On time | 40% RPS by 2025 |
| When WECC Meets Maximum RPS Target | On time | 10 year delay | On time | On time |
| When Other States Meet Individual Maximum RPS Targets | 5 year delay | 10 year delay | On time | On time |
| Additional U.S. Coal Generation Converts to Natural Gas (GW) | 61 | 80 | 31 | 80 |
| Grow or Shrink Natural Gas Resource Available (U.S.) | N/A | Shrink by 5.5% | Grow by 5.5% | N/A |
| LNG Capacity Additions | No | Yes | No | No |
| Additional Environmental Mitigation Cost ($2005/Mcf) | N/A | $0.50/Mcf Shale<br>$0.30/Mcf Conventional | N/A | N/A |
| Additional Achievable Energy Efficiency | Mid Savings Scenario | High Savings Scenario | Low Savings Scenario | Not Included |
| Cost Environment | Mid (P50) | High (P10) | Low (P90) | Mid(P50) |
| **Results in 2020** | | | | |
| **DEMAND** | | | | |
| U.S. Tcf/yr | 24.35 | 21.29 | 26.68 | 24.47 |
| U.S. Gas-Fired Electricity Generation Tcf/yr | 9.09 | 8.01 | 9.75 | 9.24 |
| CA Tcf/yr | 2.07 | 1.90 | 2.35 | 2.18 |
| CA Gas-Fired Electricity Generation Tcf/yr | 0.85 | 0.71 | 1.11 | 0.95 |
| **SUPPLY** | | | | |
| U.S. Natural Gas Dry Production Tcf/yr | 25.02 | 23.92 | 26.64 | 25.02 |
| U.S. Shale Tcf/yr | 16.69 | 16.05 | 17.36 | 16.64 |
| U.S. LNG Tcf/yr | 0.06 | 0.00 | 0.00 | 0.05 |
| Canadian Imports Tcf/yr | 3.75 | 3.40 | 3.64 | 3.71 |
| U.S. Exports Tcf/yr | 3.22 | 5.08 | 2.40 | 3.27 |
| **PIPELINE CAPACITY** | | | | |
| Cumulative New Capacity to CA (Tcf) (aggregated from 2011 to 2020) | 0.03 | 0.00 | 0.08 | 0.06 |

Source: Energy Commission: EAO.

**Table C-1 Continued**

| | Reference Case | Low Demand/High Gas Price Case | High Demand/Low Gas Price Case | Gas/Electric Case |
|---|---|---|---|---|
| Pipeline Utilization; % of total (EPNG+TW+MJ/Gas Transmission Northwest Corporation/KRGT/Ruby)* | 39.9/75.3/62.4/22.6 | 34.7/68.8/55.8/26.6 | 43.5/77.2/75.9/28.0 | 41.8/76.6/67.5/23.7 |
| **PRICES** | | | | |
| Price at Henry Hub ($2010)/MMBtu | 4.80 | 6.04 | 4.00 | 4.74 |
| Basis to CA Border at Topock ($2010)/MMBtu | 0.01 | -0.17 | 0.10 | 0.04 |
| Basis to Malin ($2010)/MMBtu | -0.33 | -0.48 | -0.22 | -0.31 |
| **Results in 2025** | | | | |
| **DEMAND** | | | | |
| U.S. Tcf/yr | 27.54 | 23.90 | 30.23 | 28.06 |
| U.S. Gas-Fired Electricity Generation Tcf/yr | 10.97 | 9.62 | 11.57 | 11.57 |
| CA Tcf/yr | 2.06 | 1.84 | 2.34 | 2.16 |
| CA Gas-Fired Electricity Generation Tcf/yr | 0.83 | 0.63 | 1.11 | 0.93 |
| **SUPPLY** | | | | |
| U.S. Natural Gas Dry Production Tcf/yr | 27.12 | 25.83 | 29.03 | 27.56 |
| U.S. Shale Tcf/yr | 18.79 | 18.40 | 19.01 | 19.12 |
| U.S. LNG Tcf/yr | 0.09 | 0.00 | 0.03 | 0.09 |
| Canadian Imports Tcf/yr | 4.56 | 4.22 | 4.65 | 4.62 |
| US Exports Tcf/yr | 3.17 | 5.15 | 2.20 | 3.09 |
| **PIPELINE CAPACITY** | | | | |
| Cumulative New Capacity to CA (Tcf) (aggregated from 2011 to 2020) | 0.16 | 0.02 | 0.64 | 0.35 |
| Pipeline Utilization; % of total (EPNG+TW+MJ/Gas Transmission Northwest Corporation/KRGT/Ruby)* | 38.9/85.6/60.7/19.9 | 34.6/75.6/55.9/17.6 | 38.5/93.8/72.7/23.7 | 35.0/92.5/67.5/21.4 |
| **PRICES** | | | | |
| Price at Henry Hub ($2010)/MMBtu | 5.47 | 6.575 | 4.52 | 5.48 |
| Basis to CA Border at Topock ($2010)/MMBtu | -0.03 | -0.06 | 0.11 | 0.05 |
| Basis to Malin ($2010)/MMBtu | -0.44 | -0.52 | -0.28 | -0.41 |

Source: Energy Commission: EAO.

# APPENDIX D:
# Comparisons of Staff's Natural Gas Price Results to Others' Forecasts

This appendix makes several comparisons of staff's NAMGas Model results for the annual average equilibrium price of natural gas at Henry Hub to forecasts of Henry Hub prices made by others. Because the details of assumptions and methods underlying many of the other forecasts are not well-described or fully documented, extensive point-to-point comparisons to staff's assumptions and methods are not feasible to make.

The following forecasts along with the date of release are included in this appendix:

- U.S. EIA, *AEO* (April 2013)
- Northwest Power and Conservation Council, *The Seventh Power Plan Proposed Fuel Price Forecasts* (July 2013)
- Bentek Energy, LLC, Forward Curve Quarterly (3rd Quarter 2013)

## United States Energy Information Administration, *Annual Energy Outlook 2013*, April 2013

The U.S. EIA ran several natural gas price cases[127], but cases examined are those that are most comparable cases to the Energy Commission's staff assessment of natural gas price forecast.

The *AEO* reference case assumes world gas prices (in 2011 dollars) will rise from $109 per barrel in 2011 to $163 in 2040. It also assumes GDP will increase by 2.5 percent per year from 2011 through 2040, and it captures the continuing trend of communities pushing for investment in technology that is less GHG-intensive, which is represented through a 3 percentage-point increase in capital costs.

The *AEO* low oil and gas resource case assumes an estimated ultimate recovery per shale gas, tight gas, and tight oil well 50 percent lower than in the reference case. In this case, domestic crude oil production peaks in 2016 at 6.9 million barrels per day, declines to 5.9 million barrels per day in 2028 and remains flat through 2040. The assumed low productivity in effect causes natural gas prices rise, resulting in lower demand and production. In 2040, U.S. natural gas production is 27 Tcf compared to 33 Tcf in the reference case.

The *AEO* high oil and gas resource case assumes U.S. crude oil production will continue to expand after 2020 due to assumed higher technically recoverable tight oil resources, as well

127 See http://www.eia.gov/forecasts/aeo.

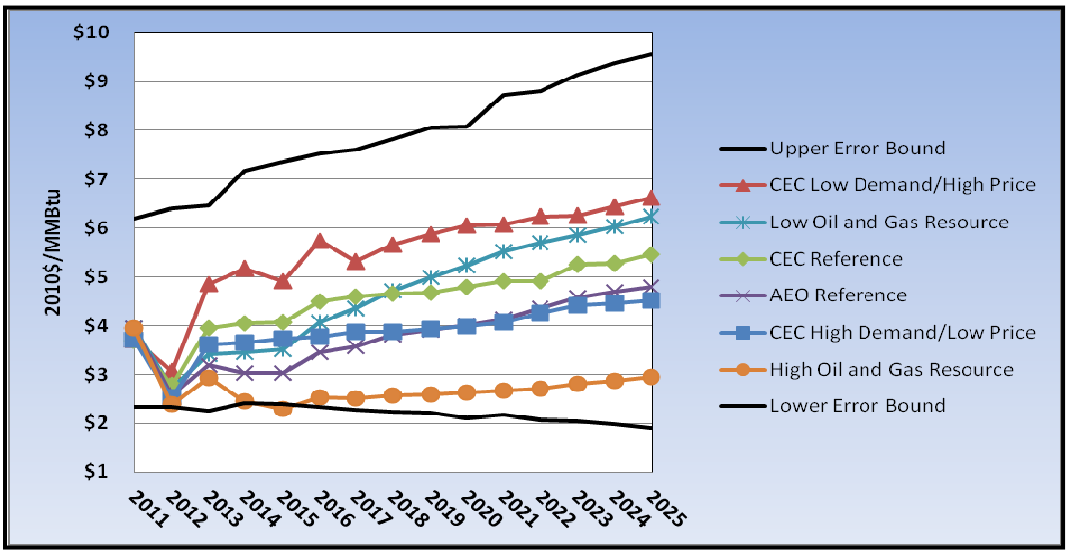
as undiscovered resources in Alaska and the Lower 48 states. These assumptions lead to more natural gas production, and the assumed higher productivity of shale and tight gas wells puts a downward pressure on natural gas prices, thus encouraging increased domestic demand of natural gas (38 Tcf compared to 30 Tcf in the reference case in 2040). As a result, the projected domestic natural gas production in 2040 is higher in the high oil and gas resource case (45 Tcf) than in the reference case (33 Tcf).

## Comparison to Staff Assessment

The U.S. EIA uses the National Energy Modeling System, while the Energy Commission staff uses the MarketBuilder platform. Due to the different algorithms used in both software, it may not be possible to have exactly the same assumptions in both models, and even with the same assumptions, it may not be possible to see exactly the same results.

The cases from the *AEO 2013* used for comparisons are the reference case and the *AEO* low and high oil and gas resource cases. While the Energy Commission's staff assessments seem to have higher price expectancy than the *AEO* cases, both reference cases for the Energy Commission and *AEO* have a 5 percent price growth rate per year. The *AEO* reference case is very similar to the Energy Commission's staff high-demand/low-price case, while the *AEO* high oil and gas resource case is much lower than the Energy Commission's staff high-demand/low-price case ($1.58 per MMBtu lower by 2025). As previously stated, these differences can be due to the different assumptions and/or different platforms used; yet, because they are within the Energy Commission's staff error boundaries, these differences are reasonable. **Figure D-1** illustrates these cases.

**Figure D-1: Comparison of the U.S. EIA Price Forecast to the Energy Commission Staff Analysis**




Source: See http://www.eia.gov/forecasts/aeo/.

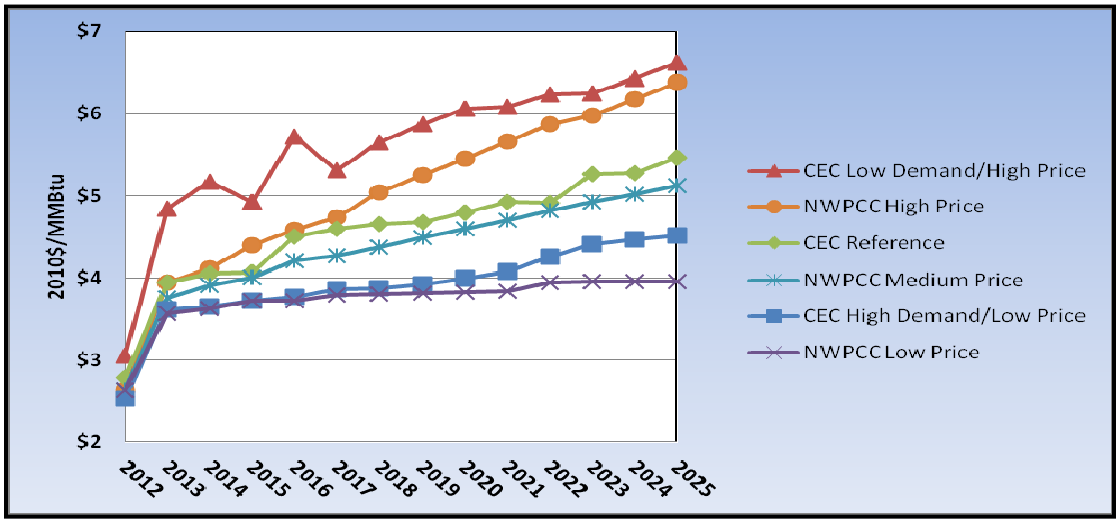
Data: See http://www.eia.gov/oiaf/aeo/tablebrowser.

## Northwest Power and Conservation Council, *Fuel Price Forecast*, July 2013

The Northwest Power and Conservation Council (NWPCC) [128] developed several cases including a low price, medium low price, medium price, medium high price, and high price. In this comparison, however, only the NWPCC low price, medium price, and high price cases will be compared to the Energy Commission staff's reference case, low-demand/high-price case, and high-demand/low-price case, as shown in **Figure D-2**.

In the NWPCC fuel price forecast, the high-price forecast assumes a rapid economic recovery in the United States and worldwide. The high-price forecast also relates to environmental restrictions on shale gas development and aggressive regulation of carbon emissions, increasing the demand for natural gas generation instead of coal. The low-price forecast, on the other hand, is consistent with conditions that would limit the demand for natural gas and increase the development rate of supply.

**Figure D-2: Henry Hub Prices, NWPCC vs. Energy Commission**




Source: The Seventh Power Plan Proposed Fuel Price Forecasts.

### Comparison to Staff Assessment

The NWPCC and Energy Commission's cases seem to start off at the same price level, and although they diverge as time goes on, the cases stay within a reasonable range from each other with the exception of the low-demand/high-price case, which shows prices of about $1 dollar higher during 2013 through 2016. However, as shown in **Figure D-2**, this range later becomes smaller as both the NWPCC's high case and the Energy Commission's low-demand/high-price case are similar by 2025.

128 See http://nwcouncil.org/media/6870894/FuelPriceForecast.pdf.

## Bentek Energy, LLC, Forward Curve Quarterly, Third Quarter, 2013

Bentek Energy, LLC, generates quarterly natural gas forecasts for the following five years, showing the expected prices at Henry Hub. The prices are annual averages that Energy Commission staff derived from the monthly forward curve that Bentek produced.[129]

**Bentek Assumptions:** Bentek's forecast for the third quarter of 2013 assumes there will not be extreme storage surpluses or deficits created by weather events, thus putting the Henry Hub price at $4.21. It assumes LNG exports will average 4.1 Bcf/d in 2018, which will increase Henry Hub spot average to as high as $5.00 in 2018. This forecast also assumes natural gas production in 2013 will average 65.5 Bcf/d as growth primarily from the Marcellus and Eagle Ford shale plays will more than offset declines in dry gas plays, such as the Haynesville. It assumes the increased activity in Niobrara Shale play will help offset the declining production in other Rocky Mountains plays, as well as key operators such as the Noble and Anadarko will ramp up horizontal drilling efforts in Niobrara.

In this forecast, Bentek assumes U.S. imports will increase during the 2013 peak summer months and then decrease later in the year. Bentek assumes U.S. imports will average 4.8 Bcf/d in 2013. In addition, due to current prices, Canadian natural gas producers are minimizing their natural gas drilling since they do not cover the full costs of developing most natural gas prospects. Therefore, Bentek assumes that total Canadian exports will decline to an average of 4.0 Bcf/d in 2015.

Because of the continued efficiency improvements in natural gas-powered heating and cooling units and appliances, Bentek also assumes growth in the residential/commercial sector, partly due to the switch from oil to natural gas in areas such as the Northeast. Bentek assumes this growth will slowly be shown over the next five years to average about 25.7 Bcf/d in 2018.

### Comparison to Staff Assessment

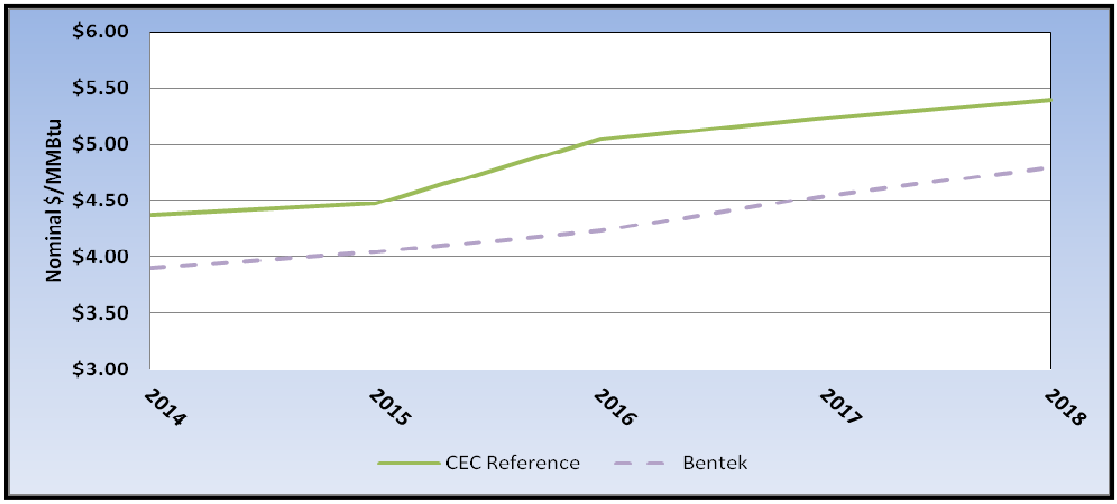
The model Bentek uses is a proprietary model created in-house. Because Bentek evaluates only one scenario in its forecast, that case will be compared to the Energy Commission's reference case. Because Bentek does not disclose whether the forecasted prices shown in its forecast are in nominal or real dollars, and their forecasts are usually compared to the one produced by NYMEX, Energy Commission staff assumes the prices to be in nominal dollars.

While the Energy Commission's reference case starts at a higher price ($4.38) than Bentek's forecast ($3.90), this difference is only of $0.48/MMBtu, which is a reasonable range due to the different assumptions and software both the Energy Commission and Bentek have used

129 See http://www.bentekenergy.com/Benport/DisplayReportNewsContent.aspx?LOC=1&ID=0&doc=BENTEK_MarketCall_US_Natural_Gas_Long_Term.pdf.

to produce this forecast, as shown in **Figure D-3**. As **Figure D-3** shows, the Energy Commission's reference case is always above Bentek's forecast, but the slope these two forecasts follow are remarkably close as the Energy Commission's forecast has a slope of 0.28, while Bentek's forecast has a slope of 0.23, and toward 2018, the two prices differ by $0.61/MMBtu

**Figure D-3: Henry Hub Price, Bentek vs. Energy Commission**




Source: See http://www.bentekenergy.com/Benport/DisplayReportNewsContent.aspx?LOC=1&ID=0&doc=BENTEK_MarketCall_US_Natural_Gas_Long_Term.pdf.

# APPENDIX E:
# Cap-and-Trade Greenhouse Gas Price Projections

To estimate the natural gas consumed for electric generation, Energy Commission staff uses the PLEXOS production cost model. The PLEXOS model is populated with assumptions regarding electricity demand growth and generation resource mixtures to generate simulated hourly electricity dispatch, fuel burn, and electricity flows across regional high-voltage lines. These models use estimates of the cost of producing electricity to determine which plants are dispatched in what order. In California, the implementation of a cap-and-trade program for GHG emission credits involving the electric power generation industry created the need to add estimates of the greenhouse emissions credit price to the PLEXOS model input assumptions.

The cap-and-trade program sets caps, or maximum limits, on GHG emissions from covered entities including electricity generators. Authorizations to emit are purchased in the form of emission allowances sold at auctions overseen by the California Air Resources Board (ARB). To account for costs of the cap-and-trade allowances, Energy Commission staff developed price projections as direct cost inputs to the Electricity Demand Forecast and the Cost of Generation Model. The outputs of those modeling efforts are then used as inputs into the reference, low-energy-demand/high-price, and high-energy-demand/low-price cases of the natural gas NAMGas model. The price projections provided in this section were developed in consultation with ARB, CPUC, and consultants.

Price projection scenarios are based on analyses in *Forcasting Supply and Demand Balances in California's Greenhouse Gas Cap-and-Trade Market*.[130] The range of price projections take into account uncertainties in the amount of greenhouse gas reduction savings that may be realized from other complementary policies (such as RPS, energy efficiency programs, CHP targets, and the California Solar Initiative) and the low cost abatement during each compliance period. The first three compliance periods set in cap and trade regulation are 2013 – 2014, 2015 – 2017, and 2018 – 2020. Staff assumes an extension of the cap-and-trade regulation will occur beyond 2020 with no significant change to the current regulation.

The PLEXOS Production Cost model stimulation results for the low, mid and high energy consumption cases were used as inputs to the NAMGas model. For cross-referencing, the simulation results from these scenarios would provide inputs into the NAMGas low-energy-demand/high-price, reference, and high-energy-demand/low-price cases, respectively.

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130 Bailey, Borenstien, Wolak Bushnell, and Zarogoza-Watkins. 2013. http://ei.haas.berkeley.edu/pdf/Forecasting%20CA%20Cap%20and%20Trade.pdf.

As part of the cap-and-trade program, ARB holds quarterly allowance auctions and reserve sales to allow market participants to acquire allowances directly from ARB. Auction participants apply to participate in an auction or reserve sale or confirm their intent to bid, submit a bid guarantee, and meet financial regulatory requirements to participate in an auction or reserve sale. For the cases presented here, the 2013 price was calculated based on a weighted average of the 2013 vintage allowances for all five auctions (November 2012, February 2013, May 2013, August 2013, and November 2013).

**Table E-1: Settlement Price Weighted by Quantity Sold**

| | 2013 Vintage Settlement Price ($/metric ton) | Quantity Sold (metric tons) |
|---|---|---|
| **14-Nov-12** | 10.09 | 23,126,110 |
| **19-Feb-13** | 13.62 | 12,924,822 |
| **16-May-13** | 14.00 | 14,522,048 |
| **16-Aug-13** | 12.22 | 13,865,422 |
| **19-Nov-13** | 11.48 | 16,614,526 |
| **Weighted Average Price in 2012 $** | 11.69 | |
| **Allowances Not Auctioned** | | 81,747,072 |
| **Total Allowances for 2013** | | 162,800,000 |

Source: See http://www.arb.ca.gov/cc/capandtrade/auction/auction.htm.

The low and mid energy consumption cases assume identical GHG prices during the first two compliance periods due to a high probability that complementary policies reduce emissions in that time frame. During the third compliance period and beyond, carbon prices in the mid energy consumption scenario were 1.5 times higher than the low energy consumption scenario because staff assumed potential risk for higher demand for allowances as the compliance period ends, the cap tightens, and the economy continues to expand. Staff assumed carbon prices in the high energy consumption scenario would be 3 times higher than the mid energy consumption scenario, but below the containment price, because higher loads and less abatement from complementary policies would raise the demand for available credits. This assumption is supported in the economic analysis done in support of the cap-and-trade regulation.[131]

131 Cap-and-Trade Regulation, Appendix N, page N-13. See: http://www.arb.ca.gov/regact/2010/capandtrade10/capv4appn.pdf.

**Table E-2: Carbon Price (2012 $/Metric Ton)**

| | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Low Energy Consumption Scenario** | 11.69 | 12.33 | 13.04 | 13.75 | 14.52 | 15.39 | 16.32 | 17.33 | 18.43 | 19.59 | 20.83 | 22.16 |
| **Mid Energy Consumption Scenario** | | 12.33 | 13.04 | 13.75 | 14.52 | 15.39 | 16.32 | 26.00 | 27.64 | 29.39 | 31.25 | 33.24 |
| **High Energy Consumption Scenario** | | 36.99 | 39.12 | 41.25 | 43.57 | 46.16 | 48.96 | 52.00 | 55.28 | 58.78 | 62.50 | 66.48 |

Source: Energy Commission staff.