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STAFF REPORT

2019 Natural Gas Market Trends and Outlook

Gavin Newsom, Governor

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ABSTRACT

California Energy Commission (CEC) staff produced the *2019 Natural Gas Market Trends and Outlook Report* to support the CEC's *2019 Integrated Energy Policy Report*. Every two years, CEC staff, in consultation with industry experts, examines emerging trends in the natural gas market. An overarching theme of the report is the effect on natural gas from California's recently enacted clean energy targets and decarbonization goals. This report provides updates on key natural gas topics from a national and statewide perspective. These topics include the natural gas price projections, production and supply, pipeline and storage infrastructure, and consumption. To prepare the price forecast, California Energy Commission staff modeled the North American natural gas market and developed cases depicting future natural gas demand and supply trends under a variety of assumptions. The results of this modeling effort serve, in part, as inputs to other modeling work at the California Energy Commission.

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

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In support of the *2019 Integrated Energy Policy Report (IEPR)*, the *Natural Gas Market Trends and Outlook Report* examines emerging trends and uncertainties in the natural gas market. Specifically, the report analyzes trends related to prices, production, demand, and infrastructure for the United States and California. California is undergoing a transition as the state moves away from fossil natural gas to comply with clean energy mandates in the short (1-3 years) and long term (beyond 3 years). While California continues to rely on natural gas as an energy resource, the California Energy Commission will provide the biennial natural gas market outlook on trends and issues that could affect the state.

The California Energy Commission projects future natural gas prices using the North American Market Gas Trade model, which simulates the behavior of natural gas producers in supply basins and natural gas consumers in demand centers throughout the continent. The model includes representations of intrastate and interstate pipelines, liquefied natural gas import and export facilities, and other infrastructure.

Staff developed three "common" cases for the *2019 Integrated Energy Policy Report*: the high demand case (natural gas demand and prices are high), mid-demand case (business-as-usual), and the low demand case (natural gas demand and prices are low). Henry Hub is the location that serves as a central delivery point on the natural gas system near Louisiana's Gulf Coast. Henry Hub is the benchmark for natural gas prices in North America and as the trading location used to price the New York Mercantile Exchange natural gas futures contracts.

The model provides projections of prices and supply of natural gas for California and the continental United States for 2019 through 2030. In the mid demand forecast, the model estimates that the Henry Hub price for 2019 will be $2.66 (2018$) per thousand cubic feet. Prices rise at about 2.37 percent per year between 2019 and 2030 to $3.43 per thousand cubic feet. Statewide, staff estimates the natural gas wholesale border price average to remain below $3.50 per thousand cubic feet through 2030 and below $4.00 per thousand cubic feet through 2050. Furthermore, staff estimates the average natural gas citygate price to remain just below $4.00 through 2030 and below $4.50 per thousand cubic feet through 2050. (A citygate is a point or measuring station at which a distributing gas utility receives gas from a natural gas pipeline company or transmission system. A distributing gas utility, unlike a natural gas pipeline company or transmission system, receives gas to distribute to residential, commercial, and industrial end-users).

Natural gas prices in Southern California have become more volatile in recent years. This volatility is due to multiple factors, including the ongoing pipeline outages and maintenance on Southern California Gas Company's (SoCalGas) backbone system and limited use of the Aliso Canyon natural gas storage field. For more information, please see Chapter 6 of the *2019 Integrated Energy Policy Report*.

Natural Gas Supply and Production

Natural gas reserves have increased in the United States largely because of shale gas development. The Potential Gas Committee (organized by the Colorado School of Mines) compiles estimates of natural gas reserves nationwide. In 2004, the committee estimated total natural gas reserves at 1,311.8 trillion cubic feet. This resource base expanded at an average rate of 7.5 percent per year, and, by 2016, total natural gas reserves reached 3,141.0 trillion cubic feet.

Since 2005, this country's natural gas production has been growing at an annual rate of about 4.1 percent, and since 2009, the United States has been the world's largest producer of natural gas. Since 2011, natural gas production has outpaced natural gas consumption in the United States.

California's in-state natural gas production has declined over the past three decades. In 2017, in-state sources provided about 10 percent of the natural gas consumed in California, while interstate pipeline shipments satisfied the remaining 90 percent. Most of California's out-of-state supply comes from major supply basins in Canada, Texas, New Mexico, Colorado, and Wyoming. Concerns over greenhouse gas emissions associated with these imports led to passage of Assembly Bill 2195 (Chau, Chapter 371, 2018), which calls for the California Air Resources Board to track out-of-state emissions.

In Canada, natural gas production has been growing at a rate of 2.5 percent per year since 2012. Natural gas satisfies one-third of Canada's energy requirements. The growth in natural gas production and Canada's vast natural gas reserves supports the country's exports to the United States.

Mexico has a vast amount of natural gas reserves, yet the development of the country's natural gas resources lags that of the United States and Canada. As a result, over the last five years, Mexico's natural gas production has been falling, and the need for imports are rising. Recent policies of Mexico's president demonstrate a renewed emphasis on developing pipeline infrastructure from the United States to Mexico to increase deliveries of natural gas.

Nationally, the growth in natural gas production that is in excess of domestic demand has resulted in the significant increase in exports of liquefied natural gas (LNG). This growth is expected to continue to meet demand in rapidly growing markets, such as Asia.

Natural Gas Demand

Since 2005, nationwide natural gas demand growth in the residential and commercial sectors has remained flat. Most of the growth originated in the industrial, power generation, and LNG export sectors, while the transportation sector, although growing, only reaches about 0.2 percent of total consumption. The U.S. Energy Information Administration estimates that, by the end of 2017, plant operators had retired about 62 gigawatts of coal-fired generation. Natural gas-fired generation is filling the shortfall, climbing to 35.1 percent of total generation in 2018. The U.S. Energy Information Administration projects that overall growth will continue at an annual rate of about 0.49 percent between 2018 and 2050.

In 2017 and 2018, natural gas was the most consumed fuel or energy source in California. However, while natural gas demand is expected to grow in most of the nation, California will experience a decline because of policies such as Senate Bill 350 (De León, Chapter 547, Statutes of 2015) and Senate Bill 100 (De León, Chapter 310, Statutes of 2018).

Of the state's five end-use sectors—residential, commercial, industrial, transportation, and electric generation—the power generation sector comprises the largest share of natural gas consumption at 45 percent. At 24 percent, the residential sector runs second. Natural gas demand in the residential sector has experienced a slight yet continuous decline since 1990, while demand has been relatively flat in the commercial, industrial, and power generation sectors. In 2018, consumption from the power generation sector slightly increased from 2017.

In 2018, the transportation sector consumption of natural gas represented about 1 percent of the state’s natural gas consumption. Staff expects demand for renewable natural gas (a pipeline quality alternative to fossil natural gas made by capturing and upgrading biomethane from a variety of sources) in this sector to continue to grow throughout the forecast period. The Low Carbon Fuel Standard is a program that seeks to reduce greenhouse gas emissions and other pollutants by decreasing the carbon intensity of California's transportation fuel pool. It also incentivizes the use of low carbon fuels, such as renewable natural gas. According to the U.S. Energy Information Administration, renewable natural gas accounted for about 7 percent of Low Carbon Fuel Standard credits in California during the first three quarters of 2018.

Infrastructure

On a national level, production of natural gas from the Permian Basin of West Texas has been growing rapidly. To address this surge in production, three new interstate pipelines will begin service between 2020 and 2023. Natural gas that flows to western and other markets, including California, could experience upward pressure on prices as new markets emerge for gas from this basin. However, the abundance of natural gas available may lower the risk of higher prices.

Pipeline infrastructure serving California remains largely unchanged over the last two years, and the state expects no expansions. As the state transitions away from natural gas, reliance on an aging existing infrastructure raises concerns. Emergencies, such as the gas leak at Aliso Canyon natural gas storage field in 2015 and ongoing pipeline maintenance issues (discussed in detail in Chapter 9 of the *2019 Integrated Energy*

Policy Report) highlight potential problems. Should the state transition to renewable natural gas or hydrogen (or both) for pipeline injection, pipeline leakage and other potential safety issues would remain.

Underground natural gas storage plays an important role in balancing California's demand requirements with supply availability. This component of the natural gas system is necessary to meet winter demand. It also maintains the daily supply/demand balance and keeps natural gas flowing to customers in the event of temporary disruptions to out-of-state production that is coming into California. These operations ensure reliability since operators withdraw or inject natural gas or both as demand dictates. As a result, about 20 percent of all natural gas consumed each winter comes from underground storage.

In California, Pacific Gas and Electric (PG&E) and Southern California Gas Company (SoCalGas), the state's two major gas utilities, own and operate natural gas storage facilities throughout Northern and Southern California. Four of the state's storage facilities are independently owned.

There is a need to address California's aging natural gas infrastructure and the costs to maintain it as the state transitions toward electrification (all electric) strategies and zero-carbon fuels. The California Energy Commission continues to monitor infrastructure issues for the state's two major gas utilities to assist with energy planning.

CHAPTER 1: Introduction

In support of the *2019 Integrated Energy Policy Report (IEPR)*, the *Natural Gas Market Trends and Outlook Report* examines emerging trends and uncertainties in the natural gas market. In California, natural gas plays an important role for space and water heating, oil refining, industrial processes, cooking, electricity generation, and grid reliability. However, California's goal of transitioning to a zero-carbon electric system under Senate Bill 100 (De León, Chapter 310, Statutes of 2018)[1] — along with building decarbonization,[2] energy efficiency, electric vehicle adoption, the Renewables Portfolio Standard (RPS),[3] and increased use of renewable natural gas (RNG)—sets the stage for the decrease in fossil natural gas use in California.[4] As such, the expectation is that natural gas production and consumption will experience continued decline in the state over the next few decades. During this transition, and while California continues to rely on natural gas as an energy resource, the California Energy Commission (CEC) will provide the biennial natural gas market outlook on trends and issues that could affect the state.

California is decreasing its reliance on natural gas through a combination of market trends and policies that focus on cleaner resources. In the electricity sector, as renewable resource prices have dramatically dropped, renewable generation — including rooftop solar photovoltaic (PV) — has more than doubled from 33 gigawatt-hours (GWh) in 2009 to 77 GWh in 2018.[5] California is also planning to retire aging coastal natural gas-fired power plants that use ocean water for cooling in the near term but may extend the deadline because of reliability concerns. A portion of this capacity will be replaced with imported gas-fired generation, while renewables, energy efficiency, transmission upgrades, and energy storage will largely replace the remainder

1 SB 100 sets a goal that eligible renewable energy resources and zero-carbon resources will supply 100 percent of retail sales of electricity to California customers and 100 percent of electricity procured to serve all state agencies by December 31, 2045.

2 Building decarbonization refers to a strategy to transform buildings from carbon emitters to a clean distributed energy resource.

3 The Renewables Portfolio Standard, also referred to as RPS, is a program that sets continuously escalating renewable energy procurement requirements for California's load serving entities. The generation must be procured from RPS-certified plants and the California Energy Commission verifies RPS claims.

4 There may be industrial uses of natural gas as a chemical feedstock, rather than an energy source, in commercially important organic chemicals or processes for which it may be difficult to find substitutes.

5 CEC, Quarterly Fuels and Energy Reporting.

(see Chapter 6 of the *2019 IEPR* for more details). In addition, California has become the first state to require rooftop solar on new homes under new building standards that went into effect on January 1, 2020.[6]

Building decarbonization is a key strategy for the state's residential and commercial building stock to meet new requirements calling for reductions in GHG emissions from buildings to 40 percent below 1990 levels by January 1, 2030.[7] In July 2019, the City of Berkeley adopted the first building code that disallows gas connections in new buildings.[8] In September 2019, the Menlo Park City Council decided that by "Jan. 1, 2020, heating systems in all new homes and buildings in the city must run on electricity, and all new commercial, office, and industrial buildings, as well as high-rise residences, must rely entirely on electricity."[9]

As the state reduces reliance on fossil natural gas, it must ensure a safe natural gas system while minimizing environmental impacts associated with natural gas infrastructure, including methane leakage. In addition, implementing the most cost-effective uses of RNG and hydrogen — including for transportation — will require research and development. To prepare California for the energy system of the future, the CEC is collaborating with state and federal agencies, utilities, private industry, and other stakeholders to develop:

- Natural gas vehicle technologies and infrastructure.
- Low-carbon fuels such as renewable natural gas and hydrogen.
- Technologies to track and account for methane emissions.
- Technologies that aim to enhance the safety and reduce the environmental impact of the natural gas system.

The CEC's Energy Research and Development Division is also assessing pathways to decarbonizing the energy system, as discussed in Chapter 1 of the *2019 IEPR*. Through the CEC's Electric Program Investment Charge program, the CEC funded a study that evaluates deep decarbonization scenarios in California for 2030 and 2050. Energy and Environmental Economics (E3) published the study in June 2018, which provided results from a model that tested the impact to the grid from 11 long-term energy scenarios that considered a variety of technologies and mitigation strategies.[10] A major focal point of the study is the "high electrification" scenario, which assumes a high rate of

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6 CEC, Title 24 Building Energy Efficiency Standards.

7 Assembly Bill 3232 (Friedman, Chapter 373, Statutes of 2018).

8 The city adopted the new ordinance on July 13, 2019, which becomes effective January 1, 2020. East Bay Times, July 17, 2019, Berkeley Bans Natural Gas in New Buildings.

9 City of Menlo Park, June 18, 2019, Agenda Item D-2, City Manager's Office Staff Report.

10 E3, June 2018, Deep Decarbonization in a High Renewables Future.

electrification in buildings. This scenario predicts a dramatic reduction in natural gas demand at the distribution level yet raises concerns regarding reliability and economic impacts.

A recent report by Gridworks urges the state to initiate an integrated, interagency long-term transition plan for the state's gas system with the goal of minimizing costs and risks for all consumers.[11] Gridworks' report builds on an E3 presentation at a June 2019 CEC staff workshop on natural gas distribution in a low-carbon future. At that workshop, E3 presented 10 potential pathways for the natural gas system as California pursues decarbonization of the electricity system. In October 2019, E3 published these results in a draft report that updated the deep decarbonization scenarios looking out to 2050. The CEC published the final version of the report, *The Challenge of Retail Gas in California's Low Carbon Future*, in April 2020.[12] This study and CEC analysis show the state still using natural gas under all modeled scenarios in 2050 (including the high building electrification scenario). The CEC's Natural Gas Research Program funded this study.

Furthermore, the Southern California Edison study Pathway 2045 estimates that a small number of gas generators will still be necessary in the future for grid reliability. The study also asserts that at least 40 percent of the remaining gas in 2045 will need to be low-carbon fuels, such as biomethane or hydrogen.[13]

The CEC tracks key topics and trends related to natural gas infrastructure, including natural gas pipeline flows, storage injections and withdrawals, maintenance events and outages, and regulatory proceedings. The CEC analyzes how these trends affect prices, supply (including in-state production), out-of-state deliveries, and demand (particularly from power plants). In addition to tracking trends, the CEC looks ahead by producing a forecast of natural gas prices at key trading hubs throughout the United States.[14] This report covers these trends in connection with California's recent enactment of SB 100 and other clean energy strategies. The report structure is as follows:

- Chapter 2 discusses price projections developed by the CEC for the North American gas market — referred to as "Henry Hub prices" — as well as natural gas price projections for delivery points into California, including the Malin and Topock hubs.

11 Gridworks, California's Gas System in Transition.

12 CEC, April 2020, The Challenge of Retail Gas in California's Low Carbon Future, prepared by E3.

13 Southern California Edison, "Pathway 2045," November 2019, https://www.edison.com/home/our-perspective/pathway-2045.html.

14 A "natural gas hub" is a central pricing point for natural gas usually at the heart of natural gas infrastructure, such as pipelines and LNG hubs.

- Chapter 3 addresses natural gas resources and production in the United States and the sources for natural gas consumed in California. It provides a status update on natural gas production in Canada and Mexico and discusses the increase in liquefied natural gas (LNG) exports from North America.
- Chapter 4 discusses natural gas demand trends in the United States and trends for the residential, commercial, industrial, and electric generation sectors in California, accounting for the impact from clean energy and decarbonization policies and goals.
- Chapter 5 gives updates on infrastructure and reliability, including the status of interstate and intrastate natural gas pipelines and California storage facilities. It also provides infrastructure updates at the state's two major gas utilities.
- Chapter 6 provides an overview of natural gas issues and outlook for the short and long term. This outlook highlights the most crucial issues that the state must consider when planning for the energy future.
- Appendix A describes the methodologies used in the production cost modeling.

Key findings:

- Natural gas prices are estimated to remain low over the forecast period on a national level. Staff estimates Henry Hub natural gas prices will remain below $4.00 per thousand cubic feet (Mcf) through 2030 and below $5.00/Mcf through 2050.
- Statewide, staff estimates the natural gas wholesale border price average to remain below $3.50/Mcf through 2030 and below $4.00/Mcf through 2050. Furthermore, staff estimates the average natural gas citygate price to remain just below $4.00/Mcf through 2030 and below $4.50/Mcf through 2050.
- California will continue to rely on out-of-state natural gas imports for roughly 85-90 percent of its supply as in-state production continues to decline.
- The transition to cleaner energy sources will result in declining fossil natural gas consumption in California over the next few decades.
- The use of RNG in the transportation sector is likely to grow because of the Low Carbon Fuel Standard (LCFS) and state-funded research and development that promotes the use of RNG in the transportation sector.
- Current estimates of in-state RNG indicate the quantity is not enough to meet emissions reduction goals of 80 percent below 1990 levels by 2050. However, the amount of RNG coming from out of state is increasing because of the financial incentives from the LCFS.
- California will need to address aging natural gas infrastructure and the costs to maintain it as the state transitions toward electrification and zero-carbon resources, such as solar and wind energy.

- The state needs to consider the aging natural gas infrastructure if considering its use for transporting RNG and hydrogen.
- California should initiate a planning process to identify short- and long-term natural gas needs as part of the state's transition to cleaner energy sources.

CHAPTER 2: Natural Gas Price Outlook

California's natural gas system interconnects with a natural gas pipeline network that encompasses the United States, Canada, and Mexico. CEC staff replicates supply, demand, and the transportation of natural gas for the three countries using the North American Market Gas Trade (NAMGas) model. The model simulates the economic behavior of natural gas producers in supply basins and natural gas consumers in demand centers throughout the continent. The model includes representations of intrastate and interstate pipelines, LNG import and export facilities, and other infrastructure.

The NAMGas model assumes that producers, consumers, and natural gas transporters maximize economic utility — suppliers aim to maximize profits, while consumers try to get the lowest price. The interaction of suppliers and consumers produce estimates of the competitive price of natural gas. The model reconstructs the North American natural gas market by modeling the connections of the North American supply basins to intrastate and interstate pipelines, which deliver natural gas to demand centers.

Staff developed three "common" cases for the *2019 IEPR*: the high natural gas demand/low natural gas price case (high demand), business as usual case (mid demand), and the low natural gas demand/high natural gas price case (low demand), using inputs and assumptions, such as increased energy efficiency, renewable generation, and varying amounts of coal-fired electrical generation retirements. In addition, staff updated values for natural gas reserves in the United States.

Staff updated the NAMGas model to include the North American natural gas infrastructure, including new pipeline capacities and new LNG export capacity, while resetting assumptions in the California portion of the model to account for *2019 IEPR* cases. To calibrate the model, staff used actual production and demand data for 2017 and 2018 provided by the CEC Demand Analysis Office, U.S. Energy Information Administration (U.S. EIA), Mexico's Ministry of Energy, and Canada's National Energy Board. The model iterates back and forth among the components to find economic equilibrium at all modeled pricing hubs (nodes) and in all periods. Consequently, the model produces forecasts of natural gas supply, demand, and prices.

Three "Common" Cases: High Demand, Mid Demand, and Low Demand

In developing the three common cases, the NAMGas model incorporated information from the CEC's preliminary *2019 California Energy Demand* forecast of natural gas for the residential, commercial, industrial, and transportation sectors. The NAMGas model also incorporated a forecast of natural gas demand for power plants in the Western

Electricity Coordinating Council (WECC) region.[15] The WECC power generation forecast comes from an electricity dispatch model that uses the PLEXOS software.[16] The natural gas price projections provided in this report reflect September 2019 PLEXOS model outputs. **Appendix A** explains the variables and assumptions for each of the three common cases**.**

Staff also constructed three common residential, commercial, industrial, and transportation natural gas demand cases for North American regions outside California and for natural gas power generation demand outside the WECC region. In these three cases, staff used an econometric model to forecast reference demand for these regions.[17] This econometric model includes factors such as economic growth, an estimate of coal retirements, heating and cooling degree days,[18] and historical demand for natural gas by sector.

Natural Gas Supply Assumptions

Natural gas supply assumptions regarding proved and potential reserves populate the NAMGas model. Two factors distinguish proved reserves from potential reserves: 1) the capital needed for production and 2) the level of certainty of production. Proved reserves consist of all resources with enough geological and engineering information, indicating with reasonable certainty that oil and gas operators can recover such reserves using existing technology under existing economic and operating conditions. Production of proved resources requires the expenditure of operating and maintenance funds.

Potential reserves include all undeveloped natural gas resources. Estimates of potential reserves provide the basis of available natural gas supply in the United States.[19] The

15 The WECC is a nonprofit organization that promotes bulk power system reliability and security in the Western Interconnection, a wide area synchronous grid and one of the two major alternating current power grids in the continental U.S. power transmission grid. WECC extends from Canada to Mexico and includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states between.

16 PLEXOS is an energy market simulation tool that provides real world solutions. The software is a product of Energy Exemplar.

17 An "econometric model" specifies the hypothesized statistical relationship among the various economic quantities pertaining to an economic phenomenon under study. Staff's small "m" model uses variables including economic growth, an estimate of coal retirements, heating and cooling degree days, and historical natural gas demand to build high demand, mid demand, and low demand reference cases for use in the NAMGas model.

18 "Heating degree days" are a measure of how cold the temperature was on a given day or over a period of days. "Cooling degree days" (CDD) measure how hot the temperature was on a given day or over a period of days. Units and Calculators Explained.

19 Potential Gas Committee. December 2016. *Potential Supply of Natural Gas in the United States: Report of the Potential Gas Committee*.

National Energy Board provided estimates of proved and potential resources for Canada, while the Ministry of Energy in Mexico furnished estimates of proved and potential resources for that country.

Potential reserves are geologically known but with decreasing levels of certainty require operating and maintenance costs, as well as the full expenditures of capital for producing these resources that are not required for proved reserves. As total demand for natural gas grows, producers will bring more of these resources on-line, beginning with the lowest-cost resources. Because California imports about 90 percent of its natural gas supply, estimates of potential and proved reserves of natural gas basins in North America are important components of the NAMGas model.

Natural Gas Market Assumptions

As in the past *IEPRs*, staff used two years of historical data to calibrate the model. Specifically, staff incorporated data for 2017 and 2018 for this *IEPR*; however, 2018 was an unusual year due to certain nationwide trends. For example, two of the major supply basins for California (Western Canadian Sedimentary Basin and Permian Basin) experienced negative prices throughout the year. This trend occurred partially because of pipeline constraints, leading to natural gas not fully reaching market centers, as well as record associated gas production in the Permian Basin (located in western Texas and southeastern New Mexico).[20] Regarding the latter, producers are drilling for high-priced oil reserves and are willing to sell the associated gas at a low price or a loss to continue producing oil. As such, dry production in the United States increased from 27.3 trillion cubic feet (Tcf) in 2017 to 30.4 Tcf in 2018. Through June 2019, U.S. natural gas production was 17.5 Tcf, averaging 2.9 Tcf month. If production stays at this level, the United States could produce more than 35 Tcf of natural gas in 2019.[21]

Nationwide demand for natural gas also increased from 27.11 Tcf in 2017 to 29.96 Tcf in 2018. Demand for natural gas in the electric generation and industrial sectors saw the largest gains. In the electric generation sector, natural gas demand increased from 9.25 Tcf in 2017 to 10.63 Tcf in 2018, while in the industrial sector, natural gas demand rose from 7.95 Tcf in 2017 to 8.29 Tcf in 2018.[22]

As natural gas prices have declined because of increased production in the United States, California natural gas utility ratepayers have experienced increased procurement costs. For example, natural gas procurement costs for core customers at PG&E,

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20 "Associated gas production" is a form of natural gas found in deposits of petroleum and dissolved either in the oil or as free gas in the oil reserve.

21 U.S. EIA, Natural Gas Gross Withdrawals and Production.

22 U.S. EIA, Natural Gas Consumption by End Use.

SoCalGas, and San Diego Gas & Electric Company (SDG&E) increased from $2.05 billion in 2016 to $2.47 billion in 2017, a 20 percent increase.[23]

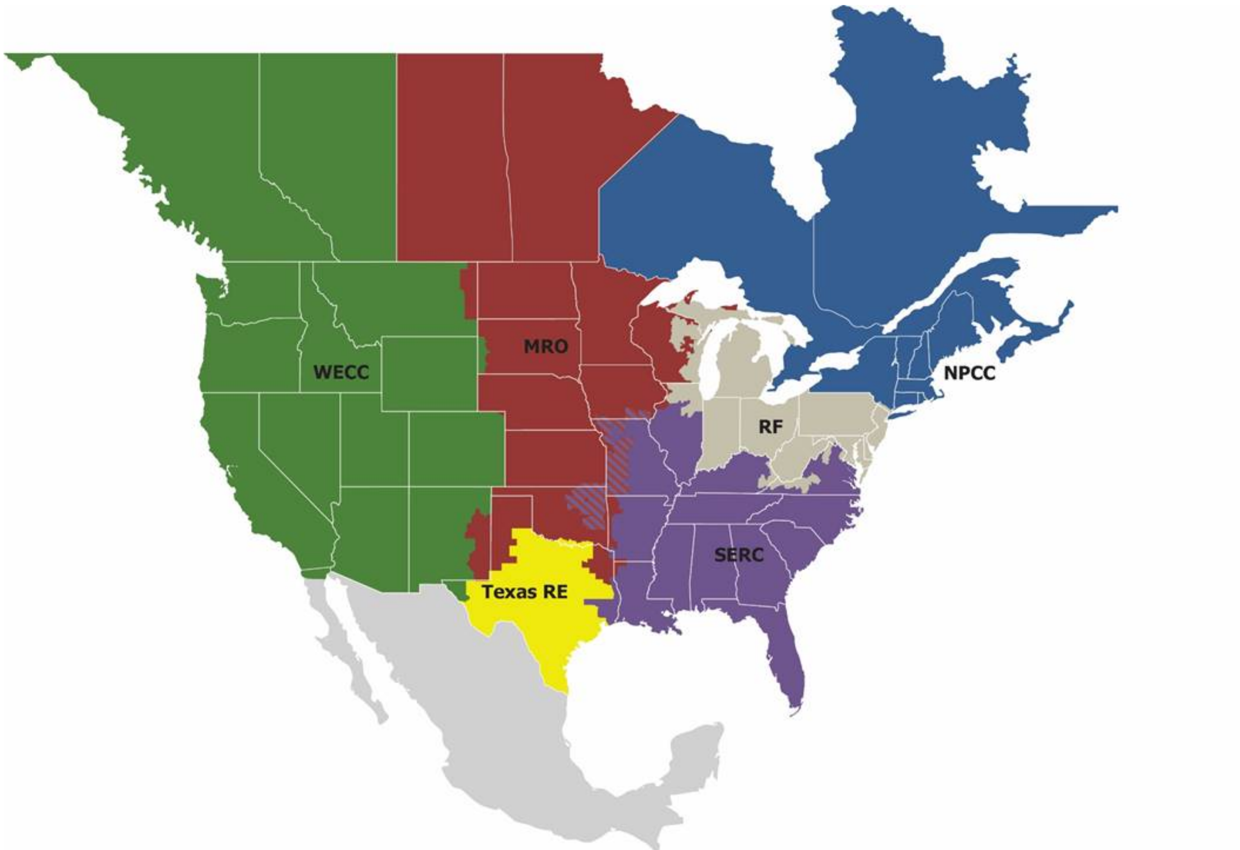
23 CPUC Energy Division. 2018. *2018 California Electric and Gas Utility Cost Report*, p. 45.

California and Western Electric Coordinating Council's Natural Gas Demand From Power Generation

Electricity generation and market competition across the West affect electricity imports and use of natural gas for power generation in California. The CEC considers this effect by simulating electricity production not only within California, but for the entire WECC. **Figure 1** shows WECC and the regional entities across North America that are responsible for compliance monitoring and enforcement of each region's electric system reliability. Power system simulations, conducted using the PLEXOS production cost model,[24] provide estimates of all fuels used for the power generation sector within the WECC region, including natural gas, on an economic basis. Staff's WECC-wide production cost simulation model dataset covers 2019 through 2030 for the three common cases for the *2019 IEPR*. (See Appendix A for specific production cost simulation modeling assumptions).

Figure 1: North American Electric Reliability Areas

24 PLEXOS is a modeling platform owned by Energy Exemplar Ltd. Various models of this type estimate electricity production costs and calculate fuel use, as well as hours of operation by the various generators used to produce electricity.



Source: North American Electric Reliability Corporation (nerc.com).

The NAMgas model uses the natural gas demand projections from PLEXOS for WECC-wide electricity generation, along with the CEC's forecasted demand for the other natural gas end uses (for example, residential and commercial) inside California, as inputs.[25] The natural gas demand forecast assumptions for the rest of the United States come from applying an econometric analysis state by state to U.S. EIA recorded data by sector. These combined forecasts provide the natural gas demand inputs for the NAMGas model.[26]

The PLEXOS electricity supply and demand assumptions for California reflect the IEPR common cases and current policy mandates, such as the state's Renewables Portfolio Standard (RPS) under Senate Bill 100, retirement of once-through cooling plants,[27, 28]

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25 The NAMGas model simulates the economic behavior of natural gas producers in supply basins and natural gas consumers in demand centers.

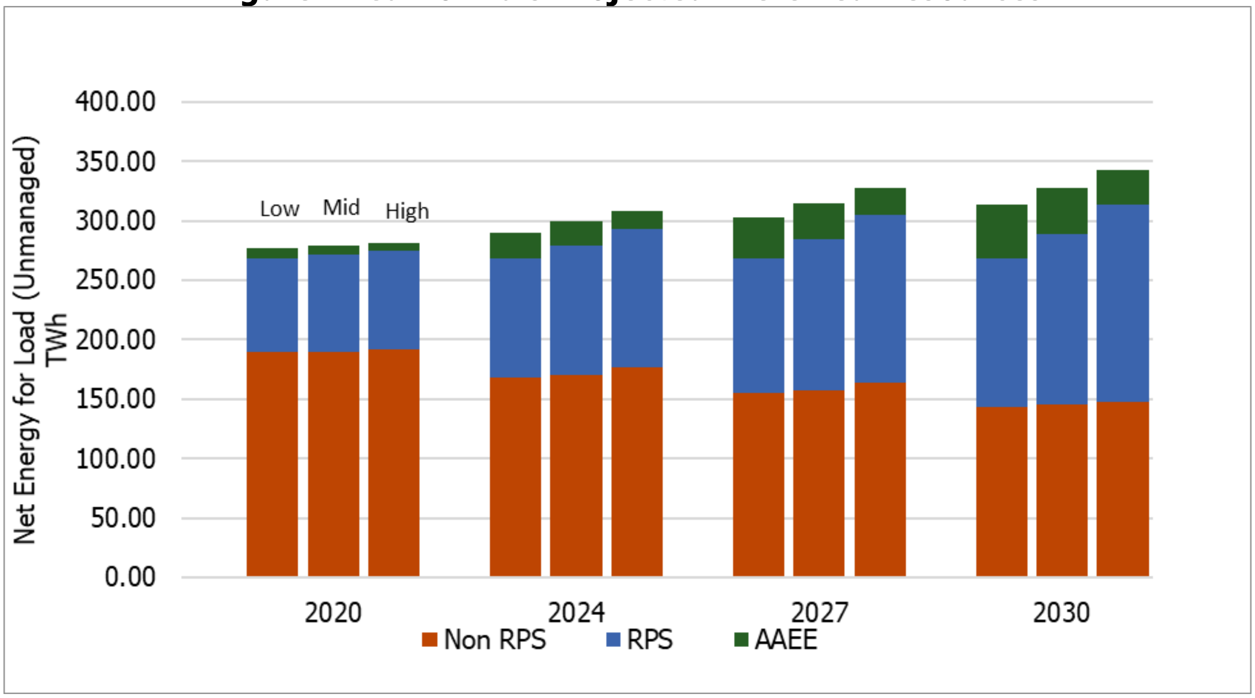
26 NAMGAS solves for demand, supply, and price simultaneously and, as it does so, applies elasticities to come up with final equilibrium demand for all sectors that is different from the demand inputs described in this chapter.

27 Once-through cooling technologies intake ocean water to cool the steam that is used to spin turbines for electricity generation. The technologies allow the steam to be reused, and the ocean water that was

and Senate Bill 350 energy efficiency targets. (See **Appendix A** for specific production cost simulation modeling assumptions).

Figure 2 highlights the growing reliance on renewables and energy efficiency resources to meet the forecast of California's electricity demand', while reducing needs for natural gas, large hydroelectric (hydro), and nuclear energy resources.

Figure 2: California's Projected Preferred Resources



Source: CEC 2019 IEPR Preliminary Demand Projections and 2019 IEPR Draft RPS.

Figure 3 provides PLEXOS simulation results for annual California natural gas demand for electric generation for all three IEPR common cases. A slight increase in statewide gas use for power generation in the mid part of the forecast can be partially attributed to the retirement of both units at the Diablo Canyon nuclear power plant. However, by the end of the forecast period, simulations show a decrease in gas use due to the increased contribution of renewable resources and additional achievable energy efficiency (AAEE) targets for the mid and low demand cases.[29] High demand and lower projections of natural gas prices characterize the high demand case, as well as higher AAEE and behind-the-meter PV. These factors in the high demand case cause an

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used for cooling becomes warmer and is then discharged back into the ocean. The intake and discharge have negative impacts on marine and estuarine environments.

28 In 2010, the State Water Resources Control Board (SWRCB) adopted a policy on the use of coastal and estuarine waters for power plant cooling, OTC, to reduce harmful effects on marine life associated with cooling intake structures.

29 CEC, Demand Analysis Working Group, [AAEE presentation].

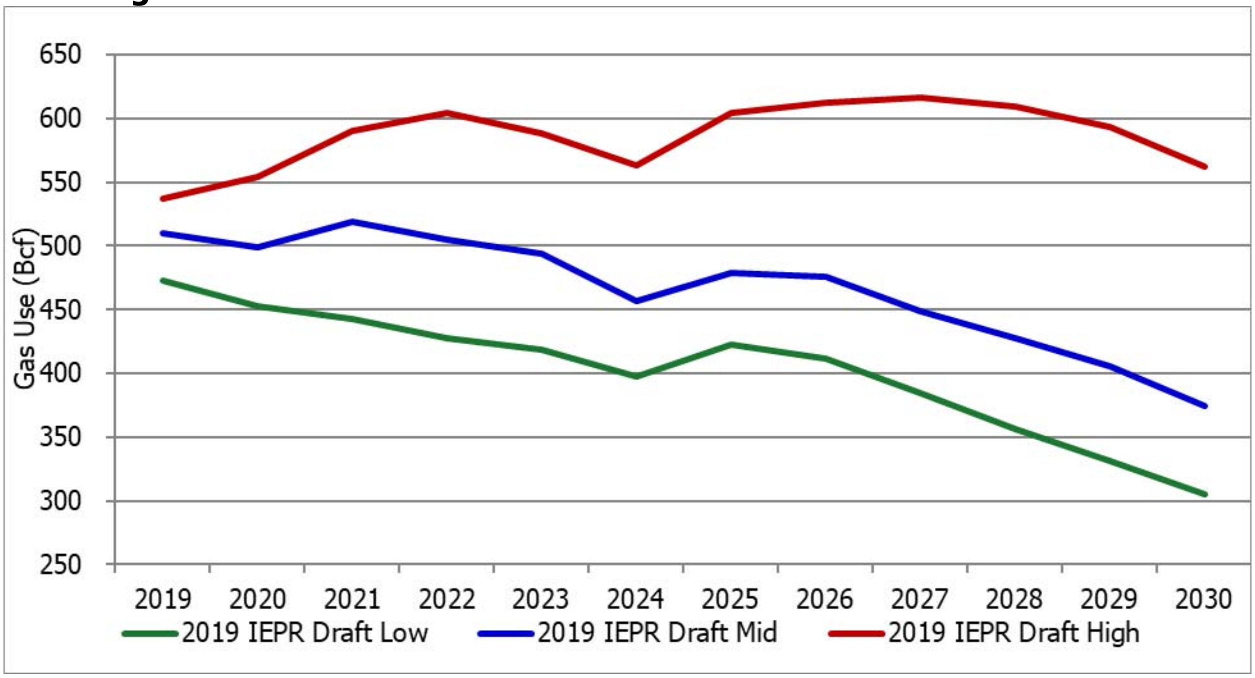
increase in the use of California's existing natural gas generation fleet. This increasing use equates to higher capacity factors for the shrinking natural gas fleet in California. For regions outside California, the increase in capacity factor is primarily due to declining natural gas prices in the high demand case and the declining fleet of coal generators. All common cases use the same coal retirement projections and similar burner-tip coal[30] price projections; however, when comparing the burner-tip natural gas price projections for the common cases, the high demand case natural gas prices are about 40 percent lower than the low demand case in 2030, shown in **Table 1**.[31] Coal price projections are based on the EIA Annual Energy Outlook 2019, which project little to no variation between cases and scenarios.[32]

30 "Burner-tip coal prices," also known as delivered coal prices, refer to the amount a power plant pays for coal to generate electricity. These prices include the commodity price, or mine-mouth price, plus the cost to transport coal from the mine to the power plant. This is comparable to the CEC's natural gas burner-tip prices.

31 "Natural gas burner tip prices" represent the cost of gas for a natural gas-fired electric generator.

32 U.S. EIA, Annual Energy Outlook.

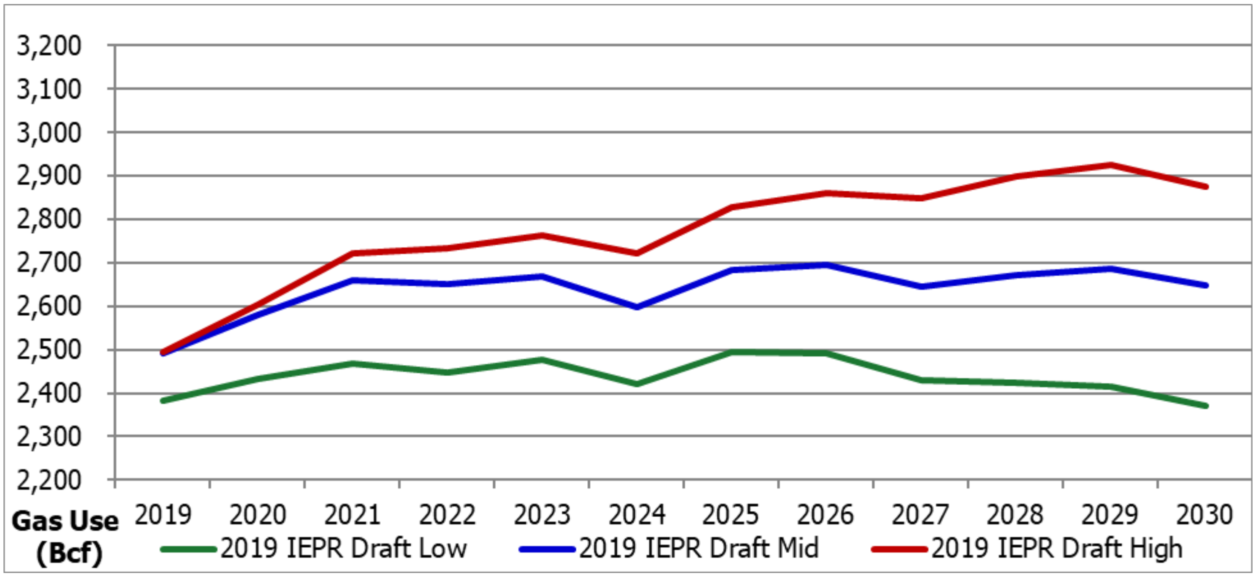
Figure 3: California Annual Natural Gas Use for Power Generation



Source: CEC PLEXOS results, September 10, 2019

Figure 4 provides PLEXOS simulation results for annual WECC-wide natural gas demand for electric generation. For the mid- and high-demand cases, there is an expansion of between 150 and 400 Bcf per year (411 million to 1,096 million cubic feet per day) over the forecast period. The retirement of more than 15 gigawatts (GW) of coal by 2030 in the WECC and the expected partial replacement with gas-fired generation are driving this change. The low demand case projects flat natural gas consumption for electric generation because of lower projected demand as well as high natural gas prices compared to coal prices shown in **Table 1**.

Figure 4: WECC-Wide Annual Natural Gas Use for Power Generation for All Cases



Source: CEC's PLEXOS results, September 10, 2019.

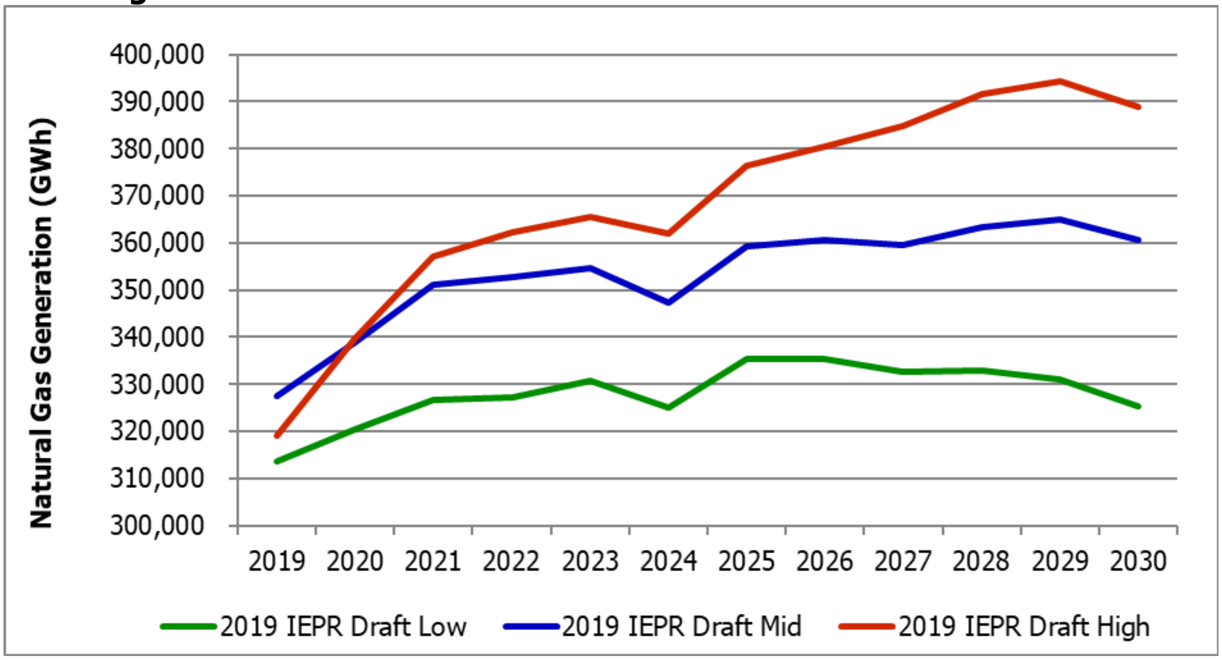
Table 1: Annual Average Coal and Natural Gas Burner-Tip Price Projections

	Burner-Tip Fuel Price (Nominal $/MMBTU)					
	High Demand Case		Mid Demand Case		Low Demand Case	
Year	Coal	Gas	Coal	Gas	Coal	Gas
2019	$1.47	$2.80	$1.51	$3.06	$1.51	$3.30
2020	$1.40	$2.67	$1.42	$3.11	$1.43	$3.51
2021	$1.47	$2.63	$1.49	$3.19	$1.49	$3.65
2022	$1.50	$2.70	$1.52	$3.23	$1.54	$3.69
2023	$1.56	$2.74	$1.58	$3.28	$1.59	$3.75
2024	$1.62	$2.80	$1.62	$3.34	$1.65	$3.84
2025	$1.63	$2.88	$1.62	$3.43	$1.65	$3.95
2026	$1.70	$2.94	$1.70	$3.50	$1.72	$4.04
2027	$1.73	$3.00	$1.72	$3.57	$1.74	$4.13
2028	$1.80	$3.06	$1.80	$3.64	$1.83	$4.23
2029	$1.84	$3.11	$1.84	$3.70	$1.87	$4.33
2030	$1.85	$3.16	$1.85	$3.77	$1.87	$4.41

Source: CEC Burner-Tip Natural Gas Model and U.S. EIA 2019 Annual Energy Outlook.

Using the simulation results, WECC-wide projections show that natural gas power generation will increase by roughly 10 percent between 2019 and 2030 in the mid-demand case (**Figure 5**). Part of this growth results from the low projected natural gas prices, and part is due to coal plant retirements. Low projected natural gas prices allow natural gas-fired generation to compare favorably to the cost of coal-fired generation in the near term. Longer term, retirements of coal generation (as coal power plants end their useful life and as power purchase agreements expire) drive the growth in natural gas generation.

Figure 5: Western United States Annual Natural Gas Generation

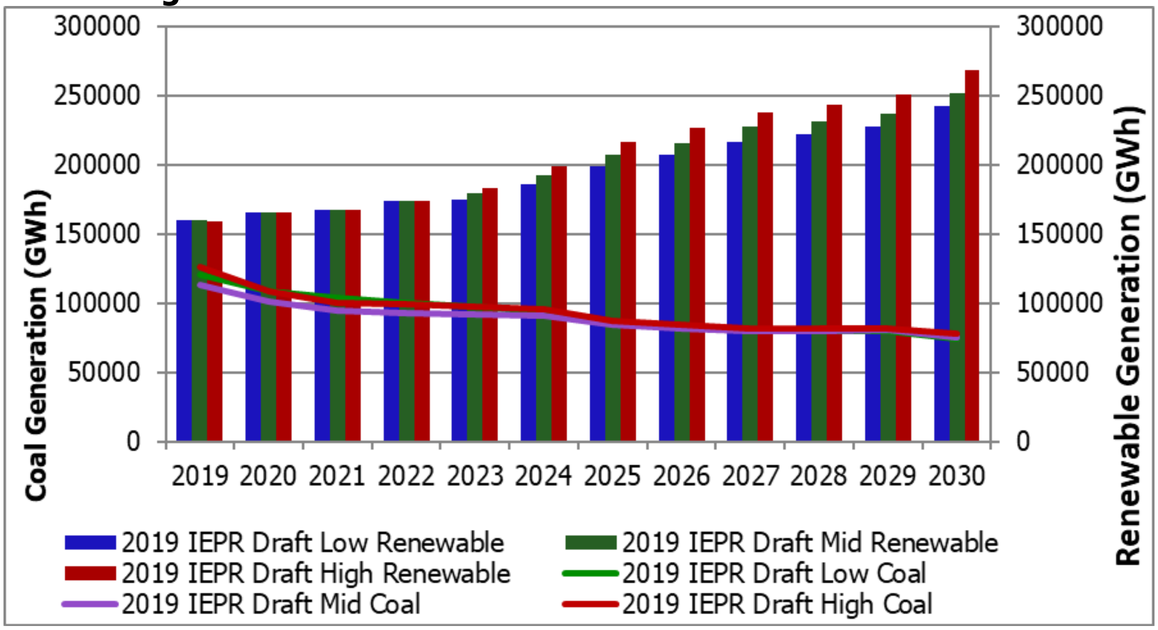


Source: CEC's PLEXOS results, September 10, 2019.

Figure 6 shows that, between 2019 and 2030, WECC-wide coal generation in the different cases will decline by about 38-49 TWh. Many western utilities have indicated plans to replace these aging coal plants with renewables. Alberta, Canada, plans to replace aging coal plants with renewables and natural gas-fired power plants.[33] The graph also shows that, between 2019 and 2030, WECC-wide renewable generation will increase by about 82-109 TWh in the different cases.

33 The AESO 2017 Long-term Outlook describes Alberta's expected electricity demand over the next 20 years, as well as the expected generation capacity needed to meet that demand.

Figure 6: WECC Annual Coal and Renewable Generation



Source: CEC's PLEXOS results, September 10, 2019.

Natural Gas Price Inputs and Assumptions

While the NAMGas model produces price backcasts and forecasts for natural gas hubs throughout North America, the IEPR presents forecasts for only the following: 1) Henry Hub near Erath, Louisiana, 2) Malin, Oregon, and 3) Topock, Arizona.[34] Henry Hub serves as the benchmark for natural gas prices in North America and as the trading location used to price the New York Mercantile Exchange natural gas futures contracts. Malin, Oregon, is the point where gas enters Northern California from Canada and the Rocky Mountains. Topock, Arizona, is the point where gas enters Southern California from the Rocky Mountains, the San Juan Basin (Four Corners region), and the Permian Basin (Western Texas). In addition, the Kern River Gas Transmission pipeline can transport natural gas from the Rocky Mountains to Southern California and Bakersfield via Daggett, California. Natural gas from both the San Juan and Permian Basins may be transported to Topock, Arizona. The NAMGas model focuses on these key hubs given the importance of these hubs in relation to California natural gas supply and reliability.

2019 Model Updates

34 A "backcast" calibrates a model used for forecasting and assesses the ability of the model to produce known results, such as prices in prior years (2014-2016 in the current modeling work). This process should provide results that are close or at the actual prices for 2014, 2015, and 2016.

On April 22, 2019, the CEC held the 2019 IEPR Commissioner Workshop on Preliminary Natural Gas Price Projections and Outlook. Staff provided initial natural gas price results and described the scenarios, inputs, and assumptions used in the modeling. Staff has incorporated four updates to the NAMGas model since the preliminary modeling runs. The changes are as follows:

1. Demand inputs

   The updated demand inputs include the most recent PLEXOS results (from August 2019) for WECC natural gas demand for power generation. Furthermore, staff updated California demand for natural gas in the residential, industrial, commercial, and natural gas for vehicle use sectors using the preliminary natural gas demand forecast posted to the IEPR docket.

2. Historical calibration

   Staff updated the historical calibration as revised data became available. This update lowered the starting prices for the NAMGas model.

3. Natural gas proved supplies

   When the U.S. EIA updated its natural gas proved natural gas resources data, staff included this in the revised runs. Staff revised the supply data upward, which in combination with continued record production levels and associated gas production has lowered the price of natural gas.

4. Price elasticities

   Staff updated the elasticities throughout the model to reflect what is happening in the natural gas market. Staff had updated elasticities for the preliminary model runs, but the additional revisions capture the actual market trends seen today.

Natural Gas Price Findings

The NAMGas model provides projections of prices and supply of natural gas for California and the continental United States for 2019 through 2030.[35] In the mid demand forecast, the model estimates the Henry Hub price for 2019 at $2.66/Mcf (2018 $). Prices rise at about 2.37 percent per year between 2019 and 2030 to $3.42/Mcf. Staff calculated that after accounting for inflation, prices dropped an average of 6.7 percent per year between 2010 through 2016. The development of shale-deposited natural gas accounts for the lowering of real prices.[36]

35 The model provides estimates through 2050. However, staff publishes projections only through 2030. This maintains consistency with the CEC's Demand Analysis Office and all PLEXOS simulations.

36 Inflation-adjusted prices.

Natural gas prices have declined because of increased production in the United States. Statewide, staff expects the natural gas wholesale border price average to remain below $3.50/Mcf through 2030 and below $4.00/Mcf through 2050. Furthermore, staff expects the average natural gas citygate price to remain just below $4.00/Mcf through 2030 and below $4.50/Mcf through 2050.[37]

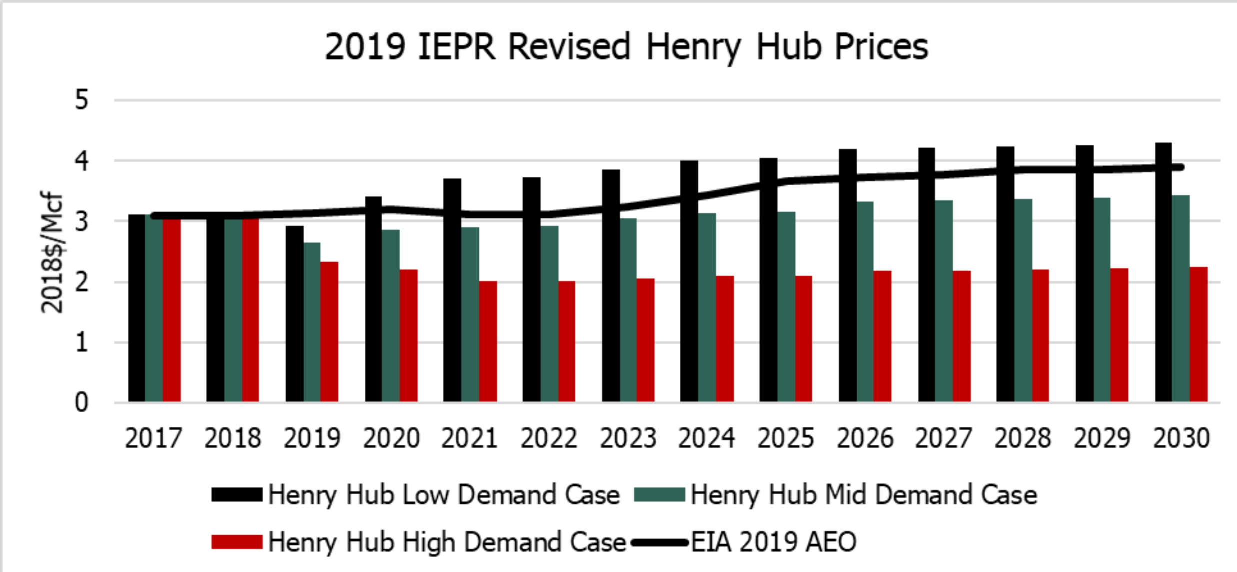
Natural gas prices in Southern California have become more volatile in recent years. This volatility is due to multiple factors, including the ongoing pipeline outages and maintenance on SoCalGas' backbone system and limited use of the Aliso Canyon natural gas storage facility. For more information on these specific infrastructure issues, please see Chapter 6 of the *2019 IEPR*.

Figure 7 shows the forecasted Henry Hub prices for the low-demand, mid-demand, high-demand, and EIA's reference cases. The mid-demand case represents a "business-as-usual" environment. However, the high-demand and low-demand cases use modified assumptions to the mid-demand case that push natural gas demand higher or lower. The high-demand case assumes lower costs for developing proved and potential resources than in the mid-demand case, while the low-demand case assumes higher costs than in the mid-demand case.

Furthermore, the high-demand case assumes larger estimates of available potential resources when compared to the mid-demand case. Similarly, the low-demand case assumes smaller estimates of potential resources. The additional production in the high-demand case will result in lower prices during the forecast period, while the high production costs in the low-demand case will keep prices high.

Figure 7: IEPR Common Cases for Henry Hub Pricing Point (2018$/MCF)

37 Border and citygate prices do not reflect the price that the eventual end-use customer will pay. This is only the commodity price. Other factors such as transportation of the natural gas, profits, policies, and outages affect the end-use price.



Source: CEC and U.S. EIA.

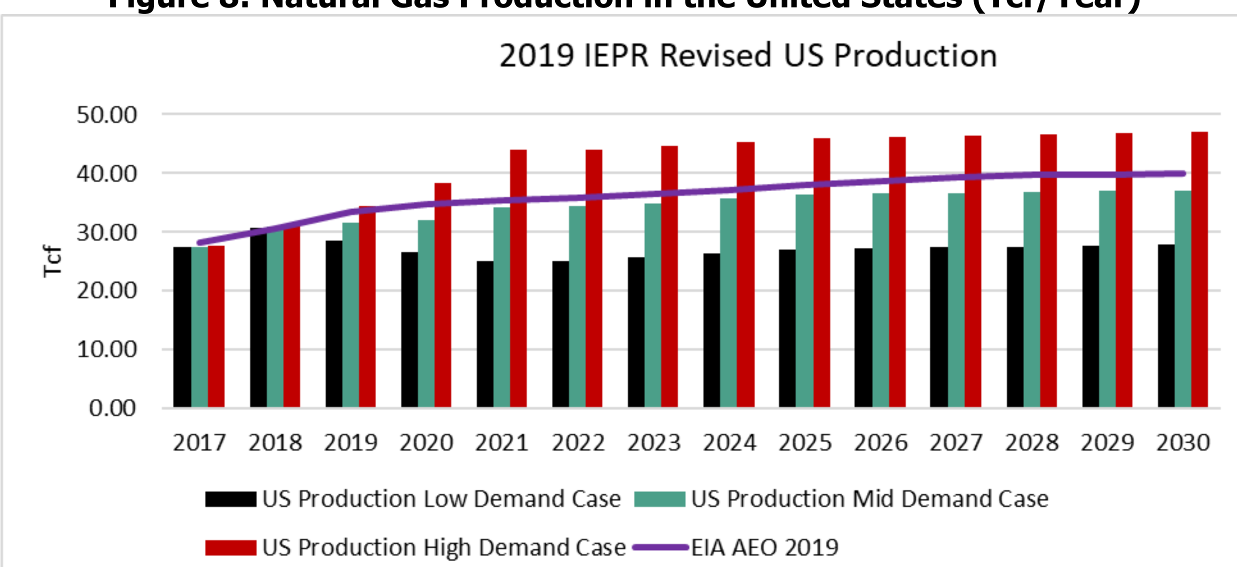
Since the high demand case is also a low-cost case with higher estimates of potential reserves, forecasts show higher production than the mid and low demand cases (

Figure 8). The forecast for U.S. natural gas production in 2030 shows the following for each case:

- High demand: 46 Tcf
- Mid demand: 37 Tcf
- Low demand: 28 Tcf

According to the U.S. EIA, dry natural gas production was 30 Tcf in 2018.

Figure 8: Natural Gas Production in the United States (Tcf/Year)



Source: CEC staff

The push to drive production costs lower is allowing producers to operate economically even in a low-price environment. This trend, along with high amounts of associated gas production in the Permian Basin and North Dakota, results in projections of inflation-adjusted natural gas spot prices at Henry Hub (2018$) remaining below $5.00/Mcf until 2050.

The Potential Gas Committee (PGC) is a group of industry experts (organized by the Colorado School of Mines) who compile estimates of natural gas reserves nationwide. Under each biennial assessment of natural gas resources since 2006, the PGC has increased its estimates of potential reserves.[38] The PGC estimated that in 2006, there were 1,321 Tcf of potential natural gas resources.[39] In 2016, its estimate more than doubled to 2,817 Tcf.[40] Much of the increase comes from upward revisions of available natural gas estimates in the Appalachian Mountains.

Resource estimates are a main driver in the model. Prices from the CEC's mid-demand forecast for 2019 through 2030 have declined substantially since the *2011 Natural Gas Market Assessment* because of increased estimates of potential resources and lower production costs (largely due to fracking).[41] In 2011, the CEC forecasted the mid-demand Henry Hub price in 2020 to be $6.25/Mcf. In 2015, this estimate fell to $4.27 for 2020. However, in 2019, the mid-demand Henry Hub 2020 price reached only $2.85/Mcf.

Figure 9 shows the forecasted mid-demand prices (2018 – 2030) for the Henry Hub, Malin, and Topock hubs. Prices at Henry Hub are lower than Malin and Topock in 2019; however, the basis decreases through 2030, with Henry Hub becoming higher than Malin in 2026 and higher than Topock in 2035. This decrease is due to low production costs of natural gas in the Permian, Rockies, San Juan, and Western Canadian sedimentary basins.

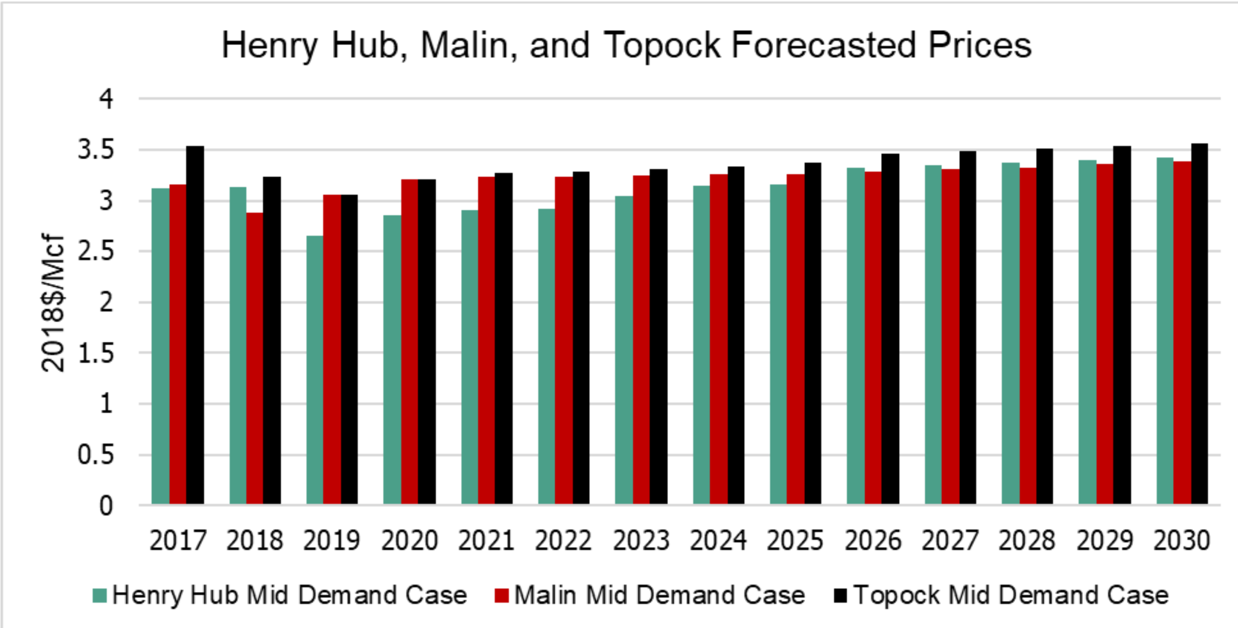
Figure 9: Mid-Demand Case Prices for Henry, Topock, and Malin Hubs (2018$/Mcf)

38 Housed at the Colorado School of Mines (Boulder, Colorado), the Potential Gas Committee assesses the future supply of natural gas in the United States and publishes its assessment every two years.

39 Potential Gas Committee. 2015. *Potential Supply of Natural Gas in the United States*, p. 3.

40 Potential Gas Committee. July 19, 2017. Press Release: "U.S. Potential Gas Committee Reports Record Future Supply of Natural Gas in the U.S."

41 CEC. 2011. Natural Gas Market Assessment.



Source: CEC staff

For California, the model shows the state's natural gas supply not changing from 2018 to 2030. Staff assumed that pipeline capacities for interstate lines that deliver natural gas to California and intrastate lines that deliver gas within the state will not increase over time. Much of California's in-state natural gas production comes from existing resources in the Central Valley, and staff expects that production from those resources will decline.

The forecast shows the percentage of gas received at Malin, Oregon, to remain roughly the same at 39 percent of California's out-of-state supply in 2030, compared to 38 percent in 2016. PG&E's Redwood Path (Lines 400/401), which connects to the Gas Transmission Northwest pipeline and the Ruby pipeline at Malin, Oregon, tends to operate close to capacity. Modeling results indicate that this will continue.

According to the U.S. EIA, pipeline exports to Mexico from the United States increased from 0.499 Tcf in 2011 to 1.38 Tcf in 2016, and the forecast of shipments shows minimal changes. In the mid-demand case, model projections indicate that pipeline exports from the United States to Mexico will hover between 1.5 Tcf to 2.6 Tcf per year through 2030. Several new pipelines are in various stages of construction for exporting natural gas from the United States to Mexico.

The CEC expects that the United States will export increasing amounts of LNG. The modeling shows that the United States is a net exporter of natural gas. While exports will increase, natural gas production is expected to be enough to meet domestic and international demand. Chapter 3 provides more detail on LNG exports.

CHAPTER 3:
Natural Gas Supply and Production

United States

Natural gas reserves have increased in the United States largely because of shale gas development.[42] According to PGC's 2016 estimates, the U.S resource base has expanded at an average rate of 7.5 percent per year since 2004 to 3,141.0 Tcf. At current consumption levels in the United States, this expansion rate translates into a reserve life index of about 125 years.[43]

Since 2005, U.S. natural gas production has been growing at an annual rate of about 4.1 percent, and since 2009, the United States has been the world's largest producer of natural gas.[44] In 2018, production averaged about 83,400 million cubic feet per day (MMcf/d). **Figure 10** displays U.S. dry natural gas[45] (equivalent) production relative to consumption between 2000 and 2018. Since 2011, natural gas production has outpaced natural gas consumption.

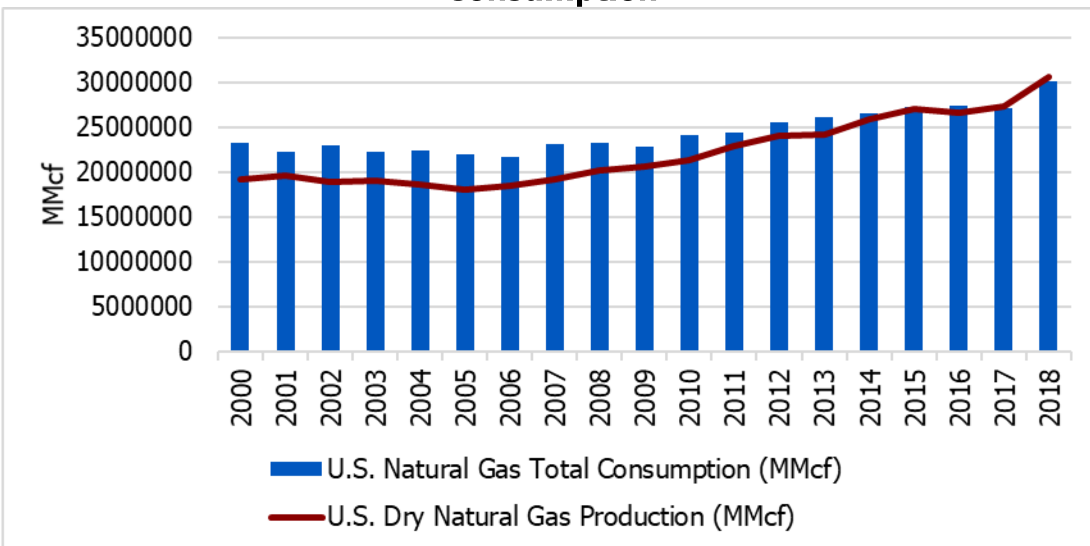
42 The combination of hydraulic fracturing and horizontal drilling in the United States has significantly increased the production of natural gas, particularly from tight oil formations.

43 "Reserve life index" is the total natural gas reserves divided by current consumption. This number represents a broad approximation of the life of natural gas reserves within a jurisdiction and does not include imports or exports of natural gas.

44 U.S. EIA, Today in Energy.

45 Natural gas is processed to remove the nonhydrocarbon gases (for example, water vapor) and hydrocarbon gas liquids, also known as "natural gas liquids." After this separation, the processed natural gas is called "dry" or "pipeline quality." U.S. EIA, Natural Gas Explained.

Figure 10: United States Dry Natural Gas Production and Annual Consumption



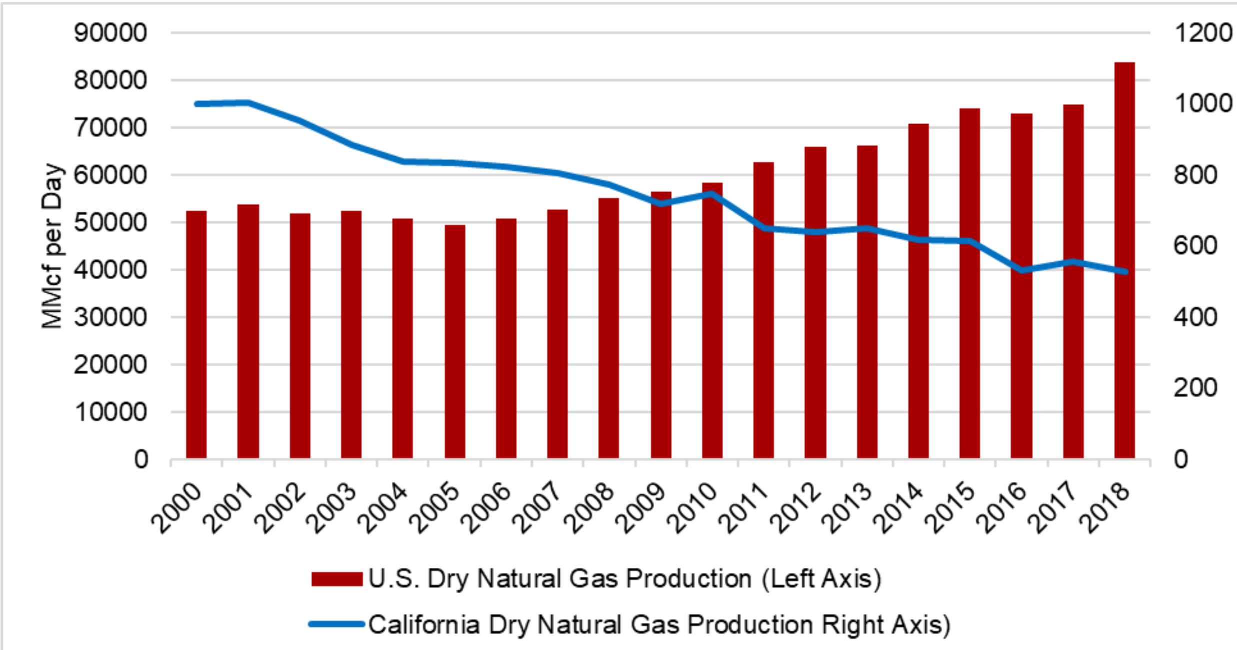
Source: U.S. EIA

In 2018, the production of natural gas from shale formations provided about 66 percent of U.S. natural gas production. This growth has created opportunities for increased U.S. exports by pipeline and LNG shipments, and in 2017, the United States became a net exporter of natural gas. The national natural gas supply-demand balance, as it stands, shows enough supply from U.S. natural gas production, pipeline imports from Canada, and LNG imports to satisfy U.S. domestic consumption/demand, pipeline exports to Mexico, and LNG exports.

California

California's in-state natural gas production, much of which comes from geologic basins in the Central Valley, will continue to decline because of less favorable economics and reservoirs that are less susceptible to increased production via hydraulic fracturing. In 2017, in-state sources provided about 548 MMcfd, or 10 percent, of the natural gas consumed in California, while interstate pipeline shipments satisfied the remaining 90 percent. **Figure 11** shows California's natural gas production compared to the rest of the United States between 2000 and 2018.

Figure 11: California Natural Gas Production Versus the Rest of the United States



Sources: U.S. EIA and California Department of Oil, Gas, and Geothermal Resources (DOGGR).

Most of California's out-of-state supply comes from the Western Canadian Sedimentary Basin (Alberta and British Columbia, Canada), Permian Basin (west Texas and southwestern New Mexico), San Juan Basin (northwestern New Mexico and southwestern Colorado), and Rocky Mountains (Wyoming). Concerns over GHG emissions associated with these imports led to passage of Assembly Bill 2195 (Chau, Chapter 371, Statutes of 2018), which requires the California Air Resources Board (CARB) to establish an out-of-state emissions tracking system.

Starting January 1, 2020, CARB will annually publish the amount of GHG emissions resulting from the loss or release of uncombusted natural gas and emissions from natural gas flares associated with the production, processing, and transporting of natural gas into the state from out-of-state sources.[46]

Canada

The oil and gas industry in Canada has implemented many of the same technological innovations seen in the United States. Since 2012, natural gas production has been growing at a rate of 2.5 percent per year, reaching an average of 16,154 MMcf/d in 2018. In addition, the Canadian Association of Petroleum Producers estimates that the

46 California Legislative Information, Assembly Bill No. 2195.

country has about 1,225 Tcf of natural gas reserves, signaling a reserves life index of about 300 years. Natural gas satisfies one-third of Canada's energy requirements. The growth in natural gas production, along with the size of reserves, supports the country's exports to the United States, which averaged about 7,800 MMcf/d in 2018.

Mexico

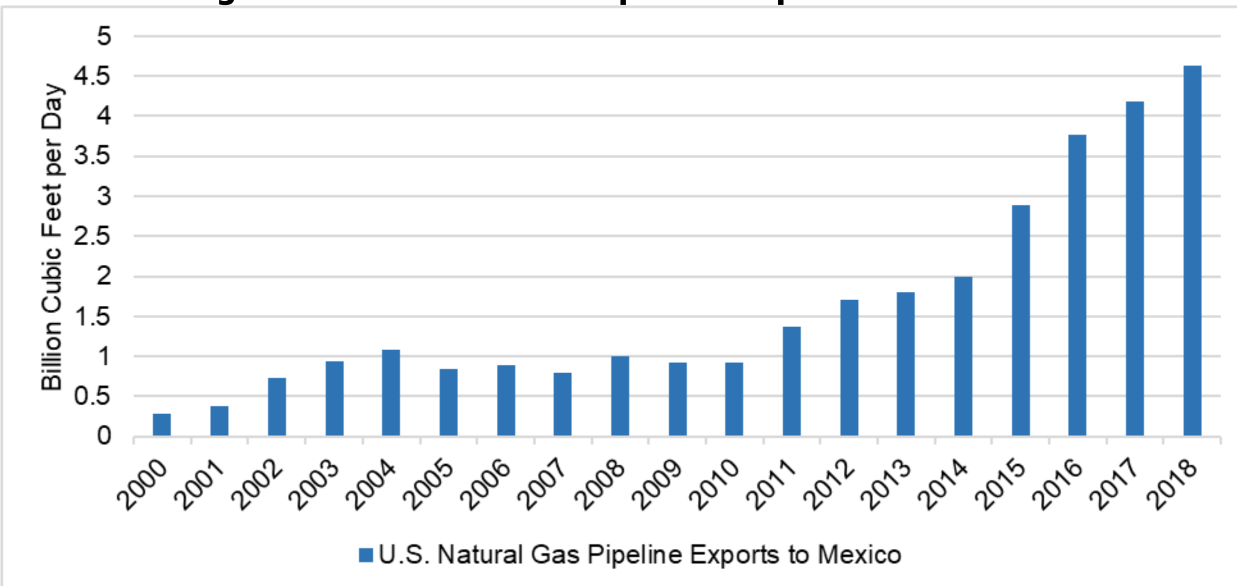
Mexico produced about 4,500 MMcf/d in 2014, but this amount declined to an estimated 3,800 MMcf/d in 2017.[47] The country has a large amount of proved reserves, ranging between 200 and 280 Tcf.[48] Potential reserves exceed 545 Tcf. Yet, the development of the country's natural gas resources lags behind that of the United States and Canada because Mexico has not implemented the technical innovations realized in the rest of North America. As a result, over the last five years, Mexico's natural gas production has been falling, and the need for imports is rising.

In 2010, shipments from the United States to Mexico averaged less than 1 billion cubic feet per day (Bcf/d). Since then, pipeline shipments to Mexico have been expanding at an annualized rate of 22.5 percent as Mexico's natural gas demand has increased for power generation and industrial use. By 2018, shipment volumes exceeded 4.5 Bcf/d. As Mexico imports natural gas from the Permian Basin, increased demand there may reduce the volume of Permian Basin supply available to California. **Figure 12** displays annual pipeline shipments to Mexico between 2000 and 2018.

47 Estimated from U.S. EIA production data.

48 U.S. EIA, Mexico.

Figure 12: United States Pipeline Shipments to Mexico



Source: U.S. EIA

This growing export market has attracted investments in pipeline construction. Since early July 2019, Mexico's President Andrés Manuel López Obrador has been renegotiating contracts for seven natural gas pipeline systems that were in various stages of construction. In late August 2019, he announced a deal that will allow natural gas deliveries to his country to increase.[49] The imports from these pipelines will help Mexico meet its energy demands. Mexico has struggled to meet its energy demand requirements in several sectors, particularly in power generation, and the delays add uncertainty to its markets. More than 75 percent of feedstock in power generation originates from fossil energy (fuel oil and natural gas).

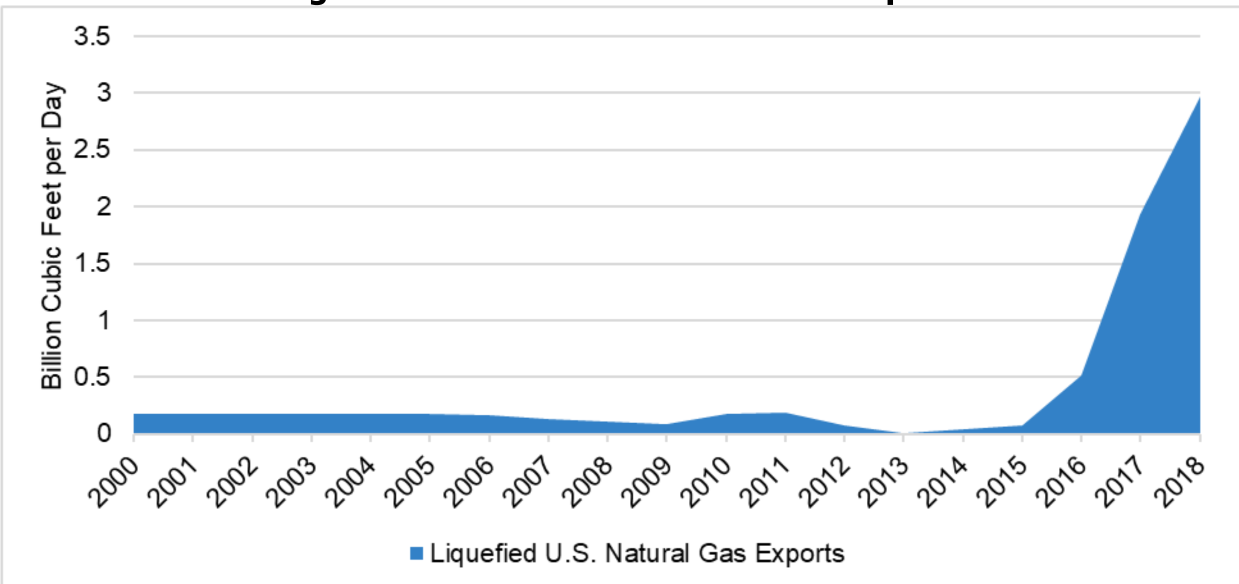
North America LNG Exports

The growth in natural gas production in excess of domestic demand in the United States has resulted in increased exports of LNG. Between 2000 and 2015, U.S. LNG exports averaged about 0.13 Bcf/d. Three new LNG facilities added between 2016 and 2018, brought total export capacity at the end of 2018 to 4.3 Bcf/d, while export volume reached almost 3.0 Bcf/d.[50] **Figure 13** displays the profile of LNG exports between 2000 and 2018.

49 CBC, "Mexico's President Says He's Renegotiated Pipeline Contracts With Canadian and U.S. Companies."

50 Since 2016, Trains 1-5 of the Cheniere/Sabine Pass LNG facility in Sabine, Louisiana; the Dominion-Cove Point LNG facility in Cove Point, Maryland; and Train 1 of the Cheniere-Corpus Christi LNG facility in Corpus Christi, Texas, came on-line.

Figure 13: Total United States LNG Exports



Source: U.S. EIA

Shipments from the Sempra-Cameron LNG facility in Hackberry, Louisiana, began in June 2019. Sempra-Cameron LNG is the fourth new facility to come on-line since 2016, raising U.S. LNG export capacity to about 4.8 Bcf/d.[51] As of 2019, there are more than 110 LNG facilities in the U.S.[52] By the end of 2020, new export facilities should push capacity to almost 9.0 Bcf/d.[53] Further, pipeline projects coming on-line between 2020 and 2022 to deliver natural gas to the Gulf Coast for LNG export will increase California's competition for Permian Basin natural gas.

In addition to the newly constructed LNG export facilities on the Gulf Coast and Atlantic Ocean, there are proposals to construct facilities in Oregon; Baja California, Mexico; and British Columbia, Canada, to serve markets in Asia and the Pacific. If these proposed facilities export gas upon completion, they would compete with California for natural gas supplies, as they would receive gas from the same supply basins that serve California.

In early 2020, the Federal Energy Regulatory Commission (FERC) expects to decide on the application for the proposed 1.08 Bcf/d Jordan Cove LNG export facility in Coos Bay, Oregon.[54] The project includes a 229-mile feeder pipeline that will bring natural gas

51 The Cameron LNG project is in southwest Louisiana.

52 FERC, LNG.

53 U.S. EIA's Database of Liquefaction Facilities.

54 FERC, Draft Environmental Impact Statement.

from the Ruby and Gas Transmission Northwest pipelines in Malin, Oregon, to Coos Bay. Malin is located adjacent to the California border, and the Pacific Gas and Electric (PG&E) Redwood Path (Lines 400/401) connects to the Ruby and Gas Transmission Northwest pipelines there. The public comment period for FERC's draft environmental impact statement ended in July 2019.

In March 2019, Sempra announced that it received authorizations to export U.S.-produced natural gas to its Energía Costa Azul (Costa Azul) LNG facility near Ensenada. In addition, Sempra can reexport LNG from Costa Azul to countries that do not have a free-trade agreement with the United States. Adjacent to the existing Costa Azul import terminal, Sempra plans to construct a three-train export center in two phases that will serve natural gas demand in Mexico and Asia.[55] Development of the Costa Azul LNG export project is contingent upon obtaining binding customer commitments, permits (including additional export authorization from the Mexican and U.S. governments), financing, incentives and other factors, and reaching a final investment decision.

According to Natural Resources Canada, there are 13 proposed export terminals in British Columbia ranging in capacity from 0.3 Bcf/d to 4.3 Bcf/d.[56] These 13 proposed facilities have been issued export licenses.

55 An "LNG train" is an LNG plant liquefaction and purification facility, where clean feed gas is cooled using refrigerants. The liquefaction plant may consist of several parallel units arranged in a sequential manner, which is why they are called "LNG trains."

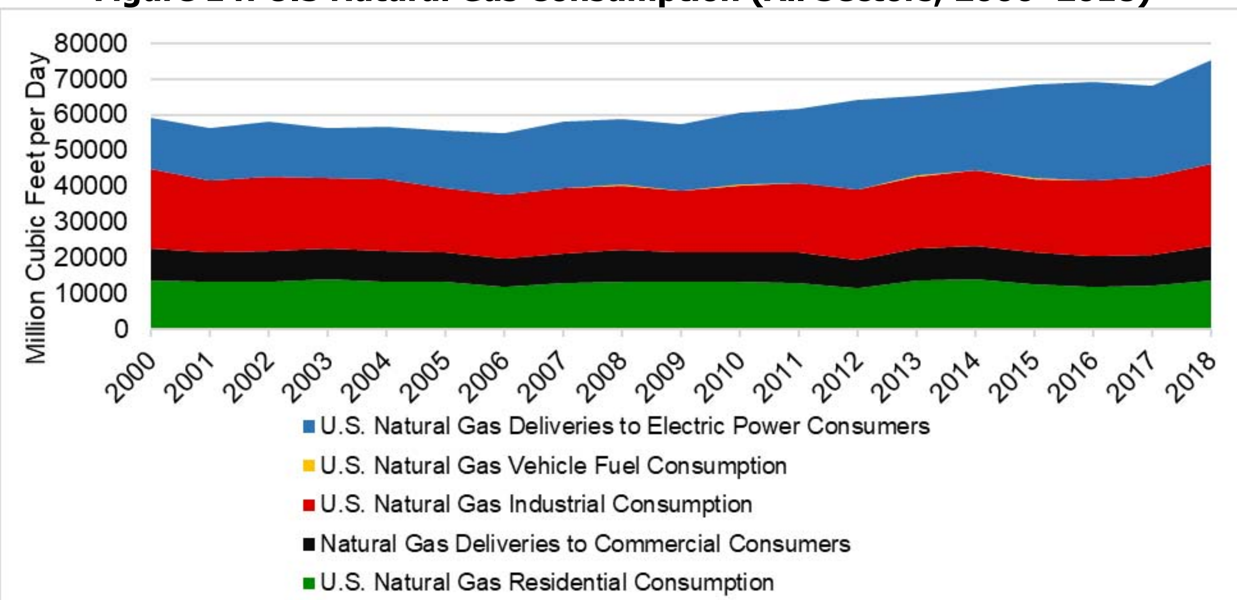
56 Canadian LNG Projects.

CHAPTER 4:
Natural Gas Demand

United States

In 2018, the five demand sectors of the United States consumed 27.4 Tcf (or an average of 75,087 MMcf/d).[57] Since 2005, consumption in the residential and commercial sectors has remained flat; most of the growth in demand originated in the industrial and power generation sectors. The share of natural gas usage in the transportation sector, while growing, reached only about 0.2 percent of total U.S. consumption. **Figure 14** shows U.S. natural gas consumption, segregated by sector, between 2000 and 2018.

Figure 14: U.S Natural Gas Consumption (All Sectors, 2000–2018)



Source: U.S. EIA

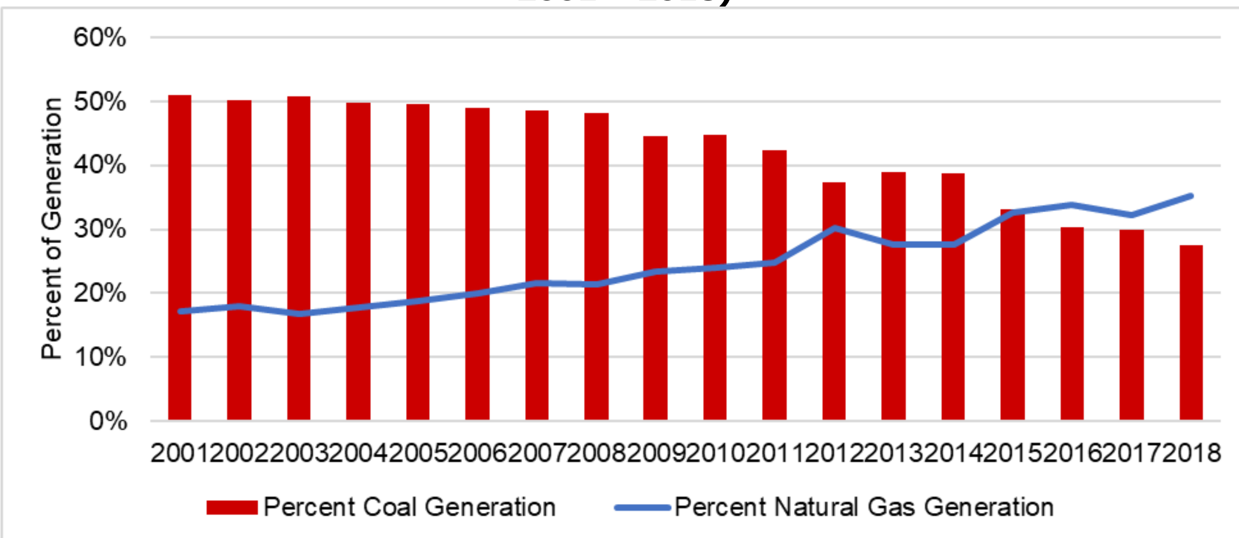
Demand for natural gas in the United States has been growing at an annualized rate of 2.3 percent since 2005. The U.S. EIA projects that overall growth will continue at a rate of about 0.49 percent between 2018 and 2050. The growth in natural gas production and the lower-than-average prices seen in the last few years support the expanded use of natural gas, particularly in the industrial and power generation sectors.

The shift from coal-fired generation to natural gas is an ongoing trend outside California that accounts for the increased demand in the power generation sector. Low natural

57 U.S. EIA, Natural Gas Monthly.

gas prices and environmental regulations are transforming generation preferences. Coal-fired power plants are facing retirement, are undergoing retrofits, or may need to invest in expensive additional retrofits to comply with regulations. In 2005, coal-fired generation accounted for almost 50 percent of total generation and in 2018 accounted for only about 27 percent. **Figure 15** displays the share of total generation by fuel type (coal and natural gas).

Figure 15: Share of Total Generation by Fuel Type (Coal and Natural Gas, 2001 – 2018)



Source: U.S. EIA

According to the U.S. EIA, between 2010 and the first quarter of 2019, U.S. power companies announced the retirement of more than 546 coal-fired power units, totaling about 102 GW of generating capacity.[58] Plant owners intend to retire another 17 GW of coal-fired capacity by 2025. Natural gas-fired generation is filling the shortfall, climbing to 35.1 percent of total generation in 2018.

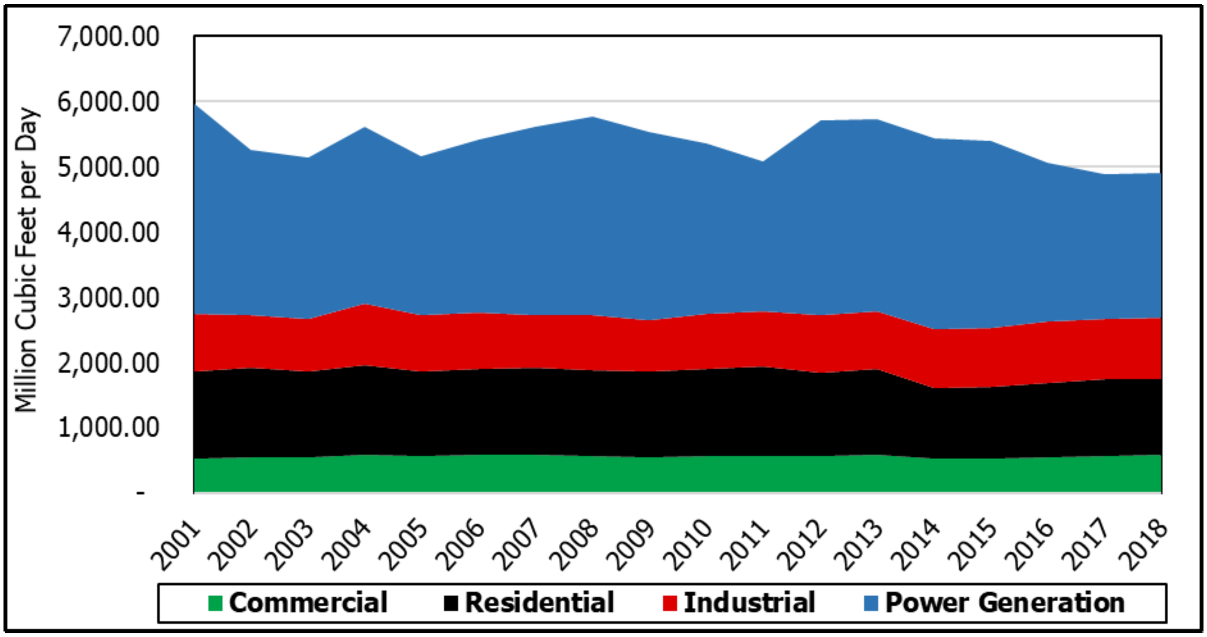
California

While natural gas demand is growing in most of the United States, California expects a decline because of state policies such as Senate Bill 350 (De León, Chapter 547, Statutes of 2015) and Senate Bill 100. (See Chapter 5 of the *2019 IEPR* for more discussion of SB 100.) Clean energy strategies, including the RPS, energy efficiency standards, and carbon neutrality, will reduce residential and commercial demand for fossil natural gas. In 2017 and 2018, natural gas was the most consumed fuel or energy source in California, according to the CEC. California's five end-use sectors—residential, commercial, industrial, transportation, and electric generation—consumed 1,799,292

58 U.S. EIA, Today in Energy.

MMcf (4,930 MMcf/d average) of natural gas in 2018. **Figure 16** displays California natural gas consumption for the four major consuming sectors between 2001 and 2018. Transportation is excluded.[59]

Figure 16: California Natural Gas Consumption (All Sectors, 2000 – 2018)



Source: CEC staff

The power generation sector comprises the largest share of the state's natural gas consumption at 45 percent. At 24 percent, the residential sector runs second. **Figure 17** below breaks down the percentage use by the four major consuming sectors.[60]

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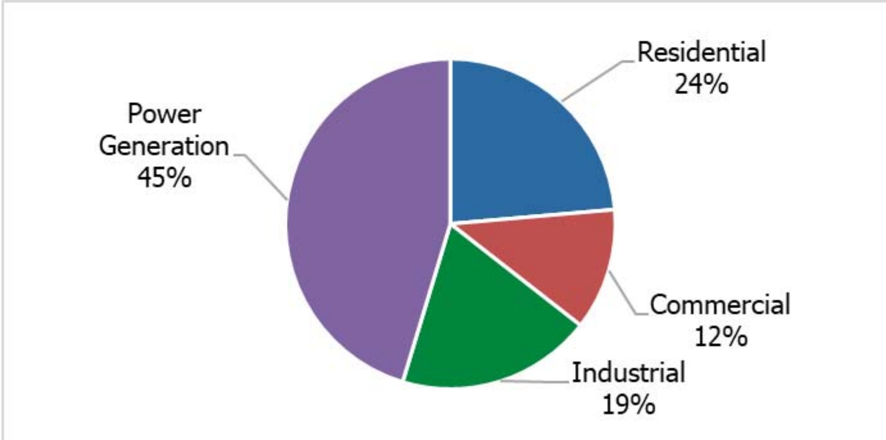
59 Transportation consumption is so small that it does not show on the graph.

60 Based on CEC data.

Figure 17: Percentage Usage of Natural Gas by Sector in California (2018)



Source: CEC staff

Natural gas demand in the residential sector has experienced a slight yet continuous decline since 1990, while demand has been relatively flat in the commercial, industrial, and power generation sectors.[61] In 2018, the power generation sector in California consumed 813,238 MMcf of natural gas.

Staff expects demand for RNG in the transportation sector to continue to grow throughout the forecast period (2030). The LCFS, which is part of the Global Warming Solutions Act of 2006 (AB 32), aims to reduce transportation carbon intensity by 20 percent by 2030. CARB revised the LCFS, effective January 4, 2019, making RNG a viable alternative to gasoline or diesel.[62] RNG has a carbon intensity lower than the new CARB target, which means the fuel will generate LCFS credits that can be used by regulated parties to offset LCFS deficits.[63] According to the U.S. EIA, RNG accounted for about 7 percent of LCFS credits in California during the first three quarters of 2018.[64] RNG is commonly used in heavy-duty commercial fleets. In 2018, the transportation sector consumption of natural gas totaled 19,819 MMcf, representing about 1 percent of the state's natural gas consumption. The CEC-funded study *Deep Decarbonization in a High Renewables Future* identifies a "high-biofuel" transportation scenario as "high risk" due to concerns about the long-term availability and sustainability of growing crops for

61 CEC, *2017 IEPR*, Chapter 8, page 225.

62 CARB, Low Carbon Fuel Standard Program.

63 According to the U.S. EIA, carbon intensity is defined as the amount of carbon by weight emitted per unit of energy consumed. A common measure of carbon intensity is weight of carbon per British thermal unit (Btu) of energy.

64 U.S. EIA.

biofuels. The availability of RNG could constrain the use of this fuel on a large scale; however, RNG imports from out-of-state are increasing because of the LCFS.

At a CEC IEPR Preliminary Natural Gas Price Forecast workshop on April 22, 2019, Jonathan Bromson with the California Public Utilities Commission presented an overview on the agency's RNG and hydrogen program. With regards to RNG, Mr. Bromson stated, "It is too early to tell how much RNG will be introduced and when into the California supply" but highlighted RNG benefits, including how "… reducing waste gas from flaring directly into the atmosphere, and instead putting it to beneficial use via pipeline injection for use in electric and transportation sectors, moves the state towards the short-lived climate pollutant reduction goals."[65]

Over the last decade, there has been a large influx of renewable generation on California's electricity system. As a result, the amount of generation from natural gas plants has decreased by roughly 22 percent, from 117 GWh in 2018 to 91 GWh in 2019. Renewable generation, including rooftop solar, has more than doubled, from 33 GWh in 2009 to 77 GWh in 2018. In terms of installed capacity, the change is even more dramatic. During the last decade, installed renewable capacity in the state more than tripled, from 9,313 MW in 2009 to 32,313 MW in 2018.

Between 2009 and 2018, California retired more than 6,600 MW of natural gas power plants using once through cooling (OTC).[66] While the state expects to retire another almost 9,000 MW by the end of 2020, the CPUC recommended as part of proceeding R.16-02-007 to extend the deadline because of system reliability concerns.[67] For more information, please see Chapter 6 of the *2019 IEPR*, which discusses Southern California reliability issues.

Over the last decade, natural gas installed capacity has declined. Natural gas generation has typically been the swing generation used to make up for loss of hydroelectric resources during droughts. In recent years, renewable generation has begun to serve that purpose. For more information, please see Chapter 1 of the *2019 IEPR*.

65 Transcript from the April 22, 2019, IEPR workshop on Preliminary Natural Gas Price Forecast and Outlook.

66 "Once-through cooling" refers to the use of coastal water sources for the cooling of power plants, which has detrimental impacts on marine life and estuarine ecosystems. In 2010, the State Water Control Board established a policy to eliminate once-through cooling at power plants by 2020.

67 On June 20, 2019, the CPUC issued a ruling in its integrated resource plan Proceeding R.16-02-007 identifying potential system capacity shortfalls beginning in 2021 because of tightening of the bilateral resource adequacy market. The CPUC ruling identified three simultaneous approaches to meet system needs, one of these being extension of OTC compliance deadlines. Chapter 6 provides more details.

CHAPTER 5: Natural Gas Infrastructure and Reliability

United States

Production of natural gas from the Permian Basin of West Texas has been growing, and some industry observers expect production will double by 2025. However, the pipeline transmission infrastructure needed to move natural gas from this basin is lagging the surge in production. Three pipelines, at differing stages of planning and construction, are attempting to close the gap. Each gas transmission line will transport about 2.0 Bcf/d from the Permian Basin to the Texas Gulf Coast and will serve mostly the LNG export market. These pipelines, expected to begin service between 2020 and 2023, will add competition for natural gas coming from the Permian Basin. Natural gas that flows to western and other markets, including California, could experience upward pressure on prices as new markets emerge for gas from this basin. However, the abundance of natural gas now available may reduce the risk of higher prices.

California

Pipeline infrastructure serving California remains largely unchanged over the last two years. The CEC anticipates no expansions, but Questar Southern Trails (a small pipeline with a capacity of 300 Bcf) discontinued service to California in 2019 because of economic considerations. The CEC expects that this closure will have little or no effect on California's natural gas supply, as deliveries on Southern Trails into California had dropped significantly — from 1,791 MMcf in 2017 to 7.4 MMcf in June 2019, when the pipeline service ended. This delivery amount was small, and other pipelines can meet this demand.

At this time, no new natural gas pipelines or storage facilities are planned for California. As such, the state's reliance on an existing infrastructure that is aging is cause for concern. The San Bruno pipeline explosion in 2010, the gas leak at the Aliso Canyon natural gas storage facility in 2015, and ongoing pipeline maintenance issues highlight the potential problems.

Should the state transition to RNG or hydrogen (or both) for pipeline injection, pipeline leakage and other potential safety issues would remain. The LCFS is resulting in increased out-of-state RNG imports due to the financial incentive that is not available in other states. The LCFS could increase the amount of RNG available for transportation and other uses. At this time, however, research shows that in-state supply of RNG is somewhat limited and that the transportation sector is the primary user. The University of California, Davis, estimated 93 billion Bcf/year of RNG potential in 2013—enough to meet about 4.5 percent of an average day's demand in California.[68] In addition, *Deep Decarbonization in a High Renewables Future* states that there is an insufficient amount of RNG in California to meet long-term demand for low carbon fuels in buildings and industries without widespread electrification.[69] It is uncertain how much of a role RNG will play in power generation but California should give this issue more attention as part of the state's long-term planning process. The *2021 IEPR* will reevaluate RNG potential, as recommended in Chapter 9 of the *2017 IEPR*.

Underground natural gas storage plays an important role in balancing California's demand requirements with supply availability. This component of the natural gas system is necessary to meet winter demand. It also maintains the daily supply/demand balance and keeps natural gas flowing to customers in the event of temporary disruptions in production. These operations ensure reliability since operators withdraw or inject natural gas or both as demand dictates. As a result, about 20 percent of all natural gas consumed each winter comes from underground storage.

In California, the working gas capacity of natural gas storage facilities connected to the systems of PG&E and Southern California Gas Company (SoCalGas) totals 376 Bcf.[70] Natural gas storage facilities (including independently owned) that are interconnected to PG&E's natural gas system have a working gas capacity of 238 Bcf.[71] SoCalGas operates four storage fields that interconnect with its transmission system and have a working gas capacity totaling 138 Bcf. In 2018, the U.S. EIA reported that operators injected 149,116 MMcf into California's storage facilities and withdrew 201,291 MMcf.

There is a need to address California's aging natural gas infrastructure and the costs to maintain it as the state transitions toward electrification and zero-carbon fuels in the electricity system. The CEC continues to monitor infrastructure issues occurring with the state's two major gas utilities—SoCalGas and PG&E—to inform energy planning efforts in the short and long terms. Below are updates on new or existing infrastructure issues for both utilities.

Sempra/SoCalGas

Southern California has been the focus of major electric reliability concerns, starting with the unexpected retirement of Southern California Edison's (SCE's) San Onofre Nuclear Generating Station Units 2 and 3 in 2013, years ahead of schedule. At the same

68 Catherine Elder, *Effects on California of Winding Down Natural Gas*.

69 E3, *Deep Decarbonization in a High Renewables Future*.

70 PG&E, in its 2018 gas transmission and storage rate case, has asked the CPUC for permission to retire and decommission two of these plants.

71 Independently owned storage fields include Lodi Gas Storage, Wild Goose Storage, Central Valley Storage, and Gill Ranch Storage.

time, several natural gas-fired power plants along the Southern California coast have closed. The phaseout of OTC plants will close additional plants, although the timing is uncertain given recent CPUC concerns with the impact of closures on electricity reliability. In addition, SoCalGas historically used the Aliso Canyon natural gas storage field, which has been operating under constrained conditions, to balance gas supply and demand throughout the year and meet peak heating demand in winter. These events, coupled with the multiyear outages of natural gas pipelines 235-2, 4000, and 3000 on the SoCalGas system, are tightening the region's energy supply. For details and updates on pipeline maintenance and related issues in Southern California, see Chapter 6 of the *2019 IEPR*.

In the 2017 IEPR, the CEC reported on a pending application from SoCalGas and San Diego Gas & Electric Company (SDG&E) seeking permission from the CPUC to build a new 47-mile pipeline, Line 3602, to replace the aging Line 1600 in San Diego County.[72] SoCalGas and SDG&E argued that the new line and derating of Line 1600 would provide a measure of redundancy, additional safety, and reliability for gas service into San Diego. Opponents to the project cited concerns over the path of the pipeline through neighborhoods and regional parklands. The CPUC rejected the application on June 21, 2018, because the company had not shown why it needed to increase gas pipeline capacity.[73] However, on February 6, 2020, the CPUC gave approval to SoCalGas to begin a four-year project to repair and upgrade a 50-mile segment of the pipeline. This plan is a hybrid of the previous submittal from SDG&E and SoCalGas and entails replacing 37 miles of the line in the more urban and suburban areas and pressure-testing segments in the remaining 13 miles in areas that are more rural.[74]

PG&E

While storage has played an important role in PG&E's gas balancing requirements, the utility has introduced a new storage strategy that reduces its role in managing seasonal prices for core customers. PG&E owns three natural gas storage facilities in California — McDonald Island (Sacramento-San Juaquin River Delta), Los Medanos (Contra Costa County), and Pleasant Creek (Yolo County). PG&E also owns 25 percent of the Gill Ranch Storage LLC facility (near Fresno, California). PG&E's largest facility, McDonald Island, has an operating capacity of 82 Bcf. Pleasant Creek and Los Medanos are considerably smaller, with operating capacities of 2.0 and 17.9 Bcf, respectively. In addition to Gill Ranch Storage, PG&E's system is connected to three independently

72 The new pipeline would have transported natural gas from the existing Rainbow Metering Station at the Riverside/San Diego County line, south to the Marine Corps Air Station Miramar in San Diego.

73 California Public Utilities Commission, December 4, 2018.

74 *The San Diego Union Tribune*, https://www.sandiegouniontribune.com/business/energy-green/story/2020-02-06/line-1600-decision-by-the-cpuc.

owned storage facilities in Northern California—Wild Goose Storage, Central Valley Gas Storage, and Lodi Gas Storage.

As part of its 2019 Gas Transmission and Storage Rate Case (A. 17-11-009), PG&E proposes to change its storage asset holdings to help decrease long-term costs.[75] Reasons for the change include increased maintenance costs under the Geologic Energy Management Division (CalGEM),[76] CalGEM's new safety regulations (effective October 2018), the abundance of natural gas, lower seasonal price differences, and a decline in natural gas use in California. PG&E also has a robust natural gas backbone pipeline system (primarily composed of Lines 300, 400, and 401) that stretches from the California-Arizona border in Topock, Arizona, to the California-Oregon border in Malin, Oregon.

In addition to storage, PG&E can use linepack within its backbone system as a form of storage.[77]

In the rate case, PGE&E proposed ceasing operations at its Los Medanos and Pleasant Creek gas storage facilities by the end of 2021. On September 12, 2019, the CPUC issued a decision approving PG&E’s plant to sell Pleasant Creek, if it submits a plan for obtaining sales offers. As for Los Medanos, PG&E must perform a reliability study before selling, showing it can provide reliable gas storage and transmission service without a facility.

75 Chapter 11, [Natural Gas Storage Strategy](#).

76 CalGEM was formerly known as the Division of Oil, Gas, and Geothermal Resources, or DOGGR.

77 “Linepack” refers to the volume of gas that can be stored in a pipeline. Gas can be injected at a receipt point on a pipeline (or pipeline segment), increasing the pressure in the line, and can be removed later at a delivery point, lowering the pressure in the line.

ACRONYMS

Acronym	Proper Name
AAEE	additional achievable energy efficiency
AB	Assembly Bill
Bcf	billion cubic feet
CARB	California Air Resources Board
CHP	combined heat and power
CPUC	California Public Utilities Commission
DOGGR	Division of Oil, Gas, & Geothermal Resources
CEC	California Energy Commission
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GW	gigawatt
GWh	gigawatt-hours
IEPR	*Integrated Energy Policy Report*
LNG	liquefied natural gas
LCFS	low carbon fuel standard
MMBtu	million British thermal units
MMcf	million cubic feet
NAMGas	North American Market Gas-Trade Model
OTC	once-through cooling
PG&E	Pacific Gas and Electric Company
PV	photovoltaic
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company

Acronym	Proper Name
SoCalGas	Southern California Gas Company
Tcf	trillion cubic feet
U.S.	United States
U.S. EIA	United States Energy Information Administration
WECC	Western Electricity Coordinating Council

APPENDIX A
Production Modeling Methodologies

There are several assumptions made to align with other energy agency planning exercises. This section discusses assumptions in which analyses show that the results are sensitive to changes. CEC staff's WECC-wide production simulation model dataset covers 2019 through 2030 for the three common cases for the *2019 IEPR*. **Table A-1** summarizes these cases.

Table A-1: IEPR Common Cases

Common Case	CED 2019 Preliminary Load Forecast	Natural Gas Price	Energy Efficiency* 2018 IEPR Update	RPS Target
High Energy Consumption	High	Low	Low AAEE	60% by 2030
Mid Energy Consumption	Mid	Mid	Mid AAEE	60% by 2030
Low Energy Consumption	Low	High	High AAEE	60% by 2030

* Adjusted for committed component of AAEE

Source: CEC staff

Hourly Net Export Constraint

Staff imposed an hourly net export constraint of 4,000 MW in all IEPR common cases. The CPUC's Proposed Input and Assumptions: 2019-2020 Integrated Resource Planning dated October 2019 assumes a staggered constraint starting at 2,000 MW in 2020 growing to 5,000 MW by 2030. Staff used 4,000 MW for all years and all common cases since the IEPR simulations are statewide, while the CPUC assumptions are for the California Independent System Operator's area only. This constraint allows the production cost model to curtail zero-cost renewable power as opposed to exporting all excess renewable energy. Renewable energy resources in certain hours experience excess loads and are transmission constrained. The renewable curtailments are about 1,000 GWh by 2030 for the mid- and low-demand cases, while the high-demand case peaks above 4,500 in 2030. The mid-demand case generally has the lowest amount of renewable curtailment, while the low- and high-demand cases consistently incur the higher amount of renewable curtailments. The low-demand case projects the highest amount of renewable curtailment due to the higher in-state versus out-of-state RPS compared to the mid- and high-demand cases (See **Figure A-1**).

Figure A-1: Annual Renewable Curtailments by Case

Source: California Energy Commission, PLEXOS results September 10, 2019

Table A-2: Percentage of RPS Portfolio Located In-State by Case

In-State RPS Ratio	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Low Demand	80%	77%	72%	68%	67%	69%	71%	71%	73%	75%	75%
Mid Demand	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
High Demand	77%	73%	67%	65%	65%	65%	65%	65%	65%	65%	65%

Source: CEC staff estimate

Hydro Generation Forecast

For all three IEPR common cases, staff used the hydroelectric generation forecasting technique that began with the 2015 IEPR to develop monthly generation profiles for all hydro plants in the WECC. This technique uses WECC-wide hydroelectric generation data from the U.S. EIA covering a shorter and more recent period.[78] This method reflects the overall trend of reduced hydroelectric generation due to persistent or semipersistent drought conditions in the western United States, as well as changes in hydroelectric operations due to federal and state regulations concerning water releases for flood protection, agricultural needs, and fish populations.

Before 2015, staff used the hydroelectric generation data from 1991 to the most recent year for which a complete set of data was available (in this case, 2017). Staff uses hydroelectric generation data from 2003 to 2017 to calculate the average monthly generation by hydroelectric plant. (U.S. EIA datasets for 2018 were not complete at the time of simulation runs.) Staff used this monthly average for all years of the simulation horizon for all hydroelectric plants in the U.S. portion of the WECC.

Because of a lack of available data, staff did not update the Canadian hydroelectric generation forecast for Alberta and British Columbia (B.C.); however, information posted on the BC Hydro, Columbia Power, and Fortis B.C. websites are consistent with PLEXOS results for B.C.'s annual hydro generation amounts.

Resource Assumptions Outside California

The existing power system resources, known future retirements, and other WECC state/province policies serve as the foundation and guideposts when determining the future resource portfolio. Since California depends on imported energy to meet demand, resources and policies of surrounding states directly affect California over the forecast period. The modeling assumes other states will achieve more aggressive renewable energy targets. Simulations include state regulations governing the operation

78 See U.S. EIA's website.

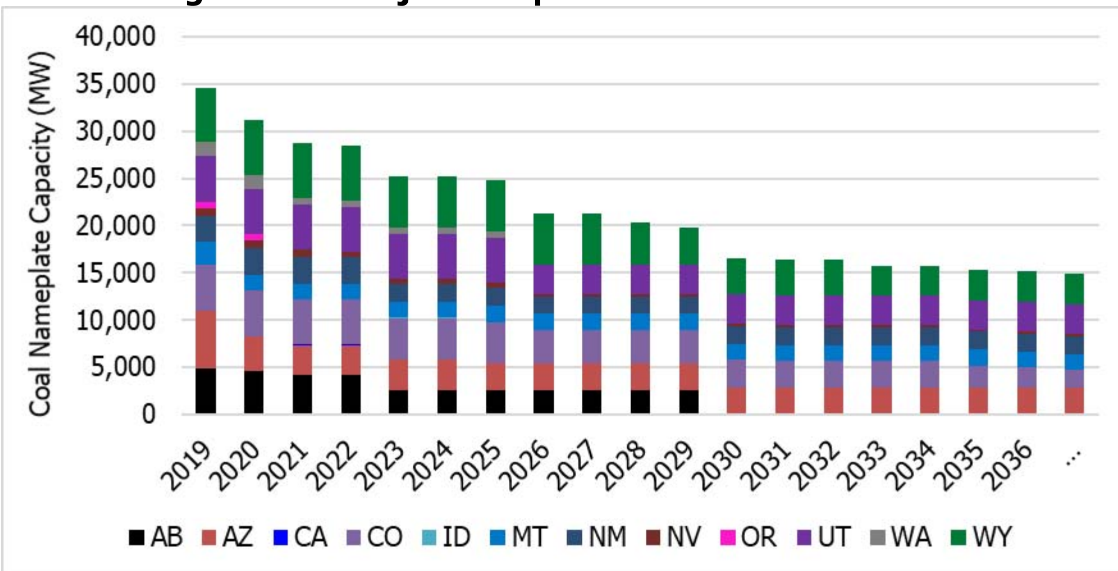
of existing system resources and development of future resources (as of January 1, 2019). When possible, simulations also include existing utility and county/citywide goals but do not include proposed state regulations or company/corporation pledges or goals.

WECC Coal Generation Assumptions

Simulations include announced and confirmed coal generation retirements. Environmental policies may accelerate some retirements. For example, units in Alberta must cease coal firing by 2030, but many have plans to convert to natural gas in the early 2020s. Also included are proposed retirement by the generation owner with tentative announced retirement dates.

By 2030, simulations include assumptions that about 15 GW of coal retirements will occur in the WECC. **Figure A-2** shows the annual decline in MWs resulting from coal retirements in the WECC states. This decline is about 45 percent of the total coal operating capacity today. These assumptions are identical in all IEPR common cases.

Figure A-2: Projected Operational WECC Coal Units



Source: Northwest Power Planning Council 2021, Existing Policy Assumptions, August 20, 2019

WECC Renewable Energy Assumptions

Table A-3 lays out state-by-state renewable energy build-out targets assumed in this modeling cycle for the IEPR common cases.

Table A-3: WECC-wide RPS Targets by State for IEPR Common Cases

Low-Demand Annual RPS Targets (GWh)				
State	**2020**	**2024**	**2027**	**2030**
Arizona	4,713	6,925	7,717	8,110
California	79,018	100,127	112,924	124,877
Colorado	9,334	9,146	9,031	8,934
Montana	1,130	1,153	1,174	1,197
Nevada	6,998	7,181	8,341	8,544
New Mexico	3,378	3,649	3,876	4,126
Oregon	8,782	9,590	13,016	16,086
Utah	3,968	5,792	6,798	7,596
Washington	11,408	11,502	11,613	11,762
Total	128,729	155,065	174,489	191,233

Mid-Demand Annual RPS Targets (GWh)				
State	**2020**	**2024**	**2027**	**2030**
Arizona	4,767	7,070	7,911	8,338
California	81,289	108,080	126,408	143,701
Colorado	9,365	9,270	9,199	9,134
Montana	1,147	1,182	1,210	1,238
Nevada	7,101	7,362	8,596	8,832
New Mexico	3,428	3,741	3,994	4,265
Oregon	8,912	9,832	13,415	16,628
Utah	4,026	5,938	7,006	7,852
Washington	11,576	11,792	11,969	12,159
Total	131,611	164,269	189,708	212,148

High-Demand Annual RPS Targets (GWh)				
State	**2020**	**2024**	**2027**	**2030**
Arizona	4,810	7,188	8,103	8,585
California	83,932	116,560	140,670	164,948
Colorado	9,519	9,485	9,480	9,456
Montana	1,152	1,196	1,232	1,267
Nevada	7,130	7,445	8,752	9,039
New Mexico	3,442	3,783	4,067	4,365
Oregon	8,949	9,943	13,658	17,018
Utah	4,043	6,005	7,133	8,036
Washington	11,624	11,925	12,186	12,444
Total	134,601	173,530	205,280	235,158

Source: CEC staff