California Energy Commission

DRAFT STAFF REPORT

2011 NATURAL GAS MARKET ASSESSMENT: OUTLOOK

In Support of the 2011 Integrated Energy Policy Report

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CALIFORNIA ENERGY COMMISSION

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The natural gas market is part of a worldwide energy commodities market that interacts in complex ways with petroleum, coal, and electricity markets. This report's estimates of future natural gas market activity and prices are based on representations of the interactions of these worldwide energy markets in a computer model. Staff has relied on the experience and expertise of Kenneth B. Medlock III, Ph.D., for both model relationships and input assumptions about key drivers of market activity, especially for activity outside California. Dr. Medlock is the James A. Baker III and Susan G. Baker Fellow in Energy and Resource Economics and Deputy Director of the Energy Forum of James A. Baker III Institute for Public Policy of Rice University in Houston Texas.

Since its *2007 Natural Gas Market Assessment*, the Energy Commission has experienced significant and ongoing reductions in the number of staff members with expertise in natural gas markets, so much so that staff was unable to conduct a model-based natural gas market assessment in support of the *2009 Integrated Energy Policy Report*. With this report, staff has been able to include modeling among its analytic techniques. Staff members acknowledge the direction and support they have received during this long transition from former Executive Director Melissa Jones, Deputy Director Sylvia Bender, and Catherine Elder, M.P.P., Senior Associate Aspen Environmental Group.

Staff also acknowledges the interest, direction, and support it has received from both Chairman Robert Weisenmiller, Ph.D., and Commissioner Carla Peterman of the Energy Commission's Electricity and Natural Gas Committee.

Staff thanks interested parties for their participation at workshops and for comments on staff's workshop materials, presentations, and proposed study design, including Pacific Gas and Electric Company, Sempra Energy Utilities, Western States Petroleum Association, and Southern California Edison Company.

Lastly, the newer members of the natural gas staff gratefully acknowledge the expertise, leadership, and mentoring efforts of both longtime staff members William Wood and Leon D. Brathwaite.

PREFACE

State government has an essential role to ensure that a reliable supply of energy is provided consistent with protection of public health and safety, promotion of the general welfare, maintenance of a sound economy, conservation of resources, and preservation of environmental quality (Public Resources Code Section 25300[b]). To perform this role, state government needs a complete understanding of the operation of energy markets, including electricity, natural gas, petroleum, and alternative energy sources, to enable it to respond to possible shortages, price shocks, oversupplies, or other disruptions (PRC Section 25300(c)). The California Energy Commission's timely reporting, assessment, forecasting, and data collection activities are essential to serve the information and policy development needs of the Governor, the Legislature, public agencies, market participants, and the public (PRC Section 25300[c]).

This staff report describes the methods, assumptions, and results of staff's analysis of plausible future natural gas market conditions using the World Gas Trade Model. A companion staff report, *2011 Natural Gas Market Assessment: Trends*, provides an overview of major natural gas market trends and issues facing the state, including, but not limited to, supply, demand, pricing, reliability, efficiency, and impacts on public health and safety, the economy, resources, and the environment (PRC 25302[a]).

ABSTRACT

The *2011 Natural Gas Market Assessment: Outlook* is produced as part of the California Energy Commission's *2011 Integrated Energy Policy Report*. In this report Energy Commission staff, in collaboration with industry experts from Rice University and elsewhere, has developed future planning cases illustrating natural gas prices and quantities demanded under a variety of assumptions.

Key to this effort is staff's acknowledgement that it is impossible to predict the precise state of the world 6 months or 10 years hence. Instead, staff has produced estimates that are *conditional* on the input assumptions that underlie each case. These cases can be broadly categorized by the kinds of conditions they are meant to capture. The Reference Case presents the future state of the natural gas market under conditions that can best be described as "business as usual." This case posits increasing production from domestic shale reserves and a return to the long-run economic growth path experienced by the United States for the last 20 years. The second set of cases examine national and international drivers that may affect natural gas markets on a large scale and drive national and international natural gas prices and demand either higher or lower than the reference case. The final set of cases examines California-specific drivers that may drive demand for natural gas in California either higher or lower than the reference case assumes.

Keywords: Natural gas, shale, hydraulic fracturing, fracking, supply, demand, infrastructure, trading hub, border price, city gate, price, production, processing, pipelines, liquefied natural gas, LNG, regasification, maximum allowed operating pressure.

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EXECUTIVE SUMMARY

This report's purpose is not to attempt accurate predictions of future natural gas market outcomes, but to provide multiple plausible conditional estimates that explore potential vulnerabilities or opportunities California may face. Making accurate single point forecasts of future gas prices and other market activities is not feasible and may not be particularly useful. This is a necessary consequence of the gas market's high complexity, large menu of competing options for actions, and deep uncertainties about future conditions that are beyond one's control. Nevertheless, it is the aim of this assessment to provide estimates and insights that are useful to California energy and environmental policy-making and implementation.

Worldwide natural gas markets, already linked to petroleum markets, have converged with electricity markets, a fact that multiplies the complexity of interactions among them. Concerns about greenhouse gas emissions press for an even greater role for natural gas in serving transportation demand, either directly or indirectly via electrification. The menu of options available to society for dealing with energy and climate change issues is large and varied, including such seemingly disparate actions as building zero net energy homes to building new nuclear powered generating plants. It is deeply uncertain now what the actual future state of various conditions will be that can significantly affect future natural gas markets (such as future emission reduction policies, future demand for gas-fired electric generation, and so forth). Even experts cannot agree on the future likelihood of such events.

These conditions of high complexity, many options for action, and deep uncertainty argue that market analysts move away from so-called "best guess" or "most likely" forecasts. But, policy- and decision-making still often require making *some* assumptions about future market conditions, even in the face of this great uncertainty. Building and running models to understand better the potential effect of the uncertainties on market outcomes thus can be very useful in helping to advise the decision-making. This necessarily implies that some combination of scenario or sensitivity analysis would be useful, and that is the approach staff took in this assessment. Having multiple plausible *conditional estimates* of the future, which help explore what future natural gas market conditions might be, gives the potential user of such estimates more information about the conditional nature of the estimates to help the user understand the potential consequences of one's own use of a given estimate should the future turn out to be different. Having a better understanding of the uncertainties and their potential consequences can lead to more "robust" decisions — those having satisfactory consequences over a broad range of future conditions that can't be accurately predicted or controlled.

Scope

This natural gas market assessment begins by examining recent trends in demand, supply, infrastructure, and price. The results of this trends analysis will be published as a separate staff report, soon to follow this natural gas market assessment. It will update the current trends analyses staff conducted for the ***2009 Integrated Energy Policy Report***, which can be found at the Energy Commission's website for that proceeding.[1] An analysis of current trends identifies the underlying key drivers of the observed trends. The drivers may include economic, demographic, environmental, regulatory, and policy conditions. The current trends assessment report will also point out identified concerns or controversies that could affect the future states of key drivers, and staff's ability to predict them accurately. This examination of trends helps with understanding what might be plausible ranges of uncertainty for the future states of these key drivers, which guides the assumption changes in the case studies.

How the limitations of estimation techniques and modeling affect the development of this assessment's starting point case, the Reference Case, and the changed cases is discussed in **Chapter 2**, as are the changes to input assumptions made in each case. Understanding the nature of and reasons for the specific input assumption changes is critical to interpreting the model outputs.

Chapter 3 presents the natural gas market modeling results, including volumes of gas demanded, the type and location of gas supply sources being produced, the use of pipeline capacity, and the resulting prices. The model simulates wholesale market activity from wellhead production to the point where gas distribution utilities take control of the gas (at their "citygate") for distribution to customers. More specifically, model results are presented by comparing and drawing insights from the different cases for each of the following areas:

- Price – Prices at major market hubs, such as the one at Henry Hub, are compared over time and across the United States.
- Supply – The quantities of natural gas produced within the United States, the amounts imported, and the amounts from shale deposits are compared.
- Infrastructure – The amount of new pipeline capacity that the model estimates to be built in response to economic conditions is compared.
- Demand – The amount of natural gas consumed by various end-use sectors, including for electric generation is compared.

Chapter 4 describes conditional estimates of gas prices to end users and discusses uncertainties that affect future values these prices may take. Retail distribution of the gas is not included in the model results, nor is the final retail price. This is a "post-processing" activity in which the components of distributions costs are estimated and added to the commodity and transportation costs delivered at the city gate. Just as the wholesale market modeled cases have varied outputs for gas commodity and transportation costs, so too can

1 http://www.energy.ca.gov/2009_energypolicy/notices/2009-05-14_workshop_notice.html.

the significant costs associated with the distribution function vary, depending on what assumptions one makes about the future conditions that affect distribution costs. Uncertainties about aging infrastructure replacement, public safety, environmental mitigation, and climate change policy implementation contribute to the range of variation future end-use gas prices may take.

Chapter 5 briefly identifies the next steps following publishing of this staff draft assessment. Staff refrains from making final conclusions or recommendations based on this draft assessment's assumptions, methods, findings, and initial conclusions. The comments, insights, and recommendations staff receives from stakeholders at the joint ***2011 IEPR*** Committee and Electricity and Natural Gas Committee workshop and in subsequent written comments on this draft and its associated appendices and working papers will be an invaluable addition to what staff has been able to provide to date to advise these deliberations. **Chapter 5** also discusses ongoing pipeline operational safety issues related to the San Bruno incident, since these activities are more current and dynamic than other issues examined in this assessment.

Highlights of Current Trends

Demand Situation

- Over the past decade, U.S. and California residential and commercial demands for gas remain, despite continued population growth.
- Price-responsive industrial sector demand exhibits a generally declining long-term trend, culminating in the current recession-driven downturn.
- Only power generation sector gas demand is increasing, although the recession's effect on electricity demand is also felt in demand for this generation fuel.

Gas Supply Situation

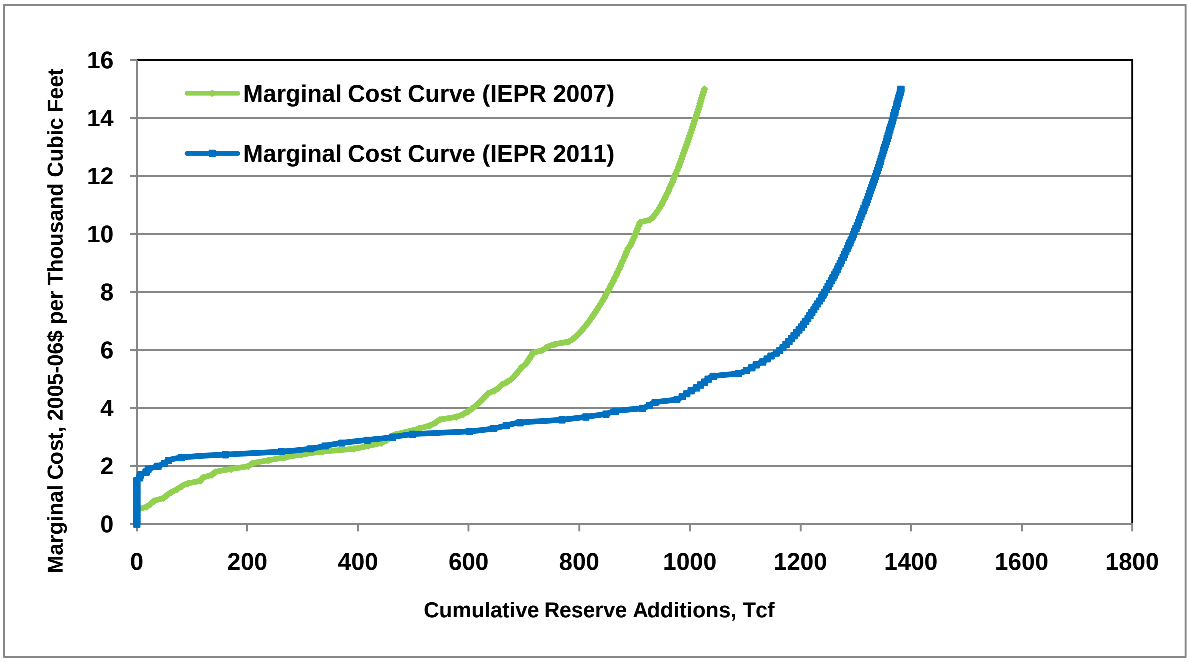
A variety of technological improvements are coming together:

- Three-dimensional and four dimensional seismic exploration surveys improve the knowledge of what's underground, increasing potential reserves.
- Directional horizontal drilling increases access to underground resources, particularly in shale formations, both
  - Improving the productive capability of natural gas-bearing formations.
  - Reducing uncertainty in potential resource estimates.
- Well completion and stimulation activities improve the effectiveness of extraction and lower the cost of producing gas from shale formations.
  - Instead of single-zone well completions, natural gas producers now perforate and stimulate multiple zones.

- The stimulation process, known as hydraulic fracturing, allows greater natural gas flow to the wellbore, sometimes as much as a tenfold increase in intial production.

These improvements are changing the understanding of the underground resource and accessibility to it. **Figure ES-1** compares the current outlook for gas supply costs to the outlook in 2007.

Figure ES-1: Change in Outlook of Gas Supply Costs, 2011 vs. 2007



Source: Rice World Gas Trade Model and California Energy Commission Staff Draft Analysis.

This radically different resource outlook is reversing the future trends predicted in past forecasts, which had foreign supplies outcompeting increasingly expensive domestic supplies on price and being imported to the United States as liquefied natural gas (LNG).

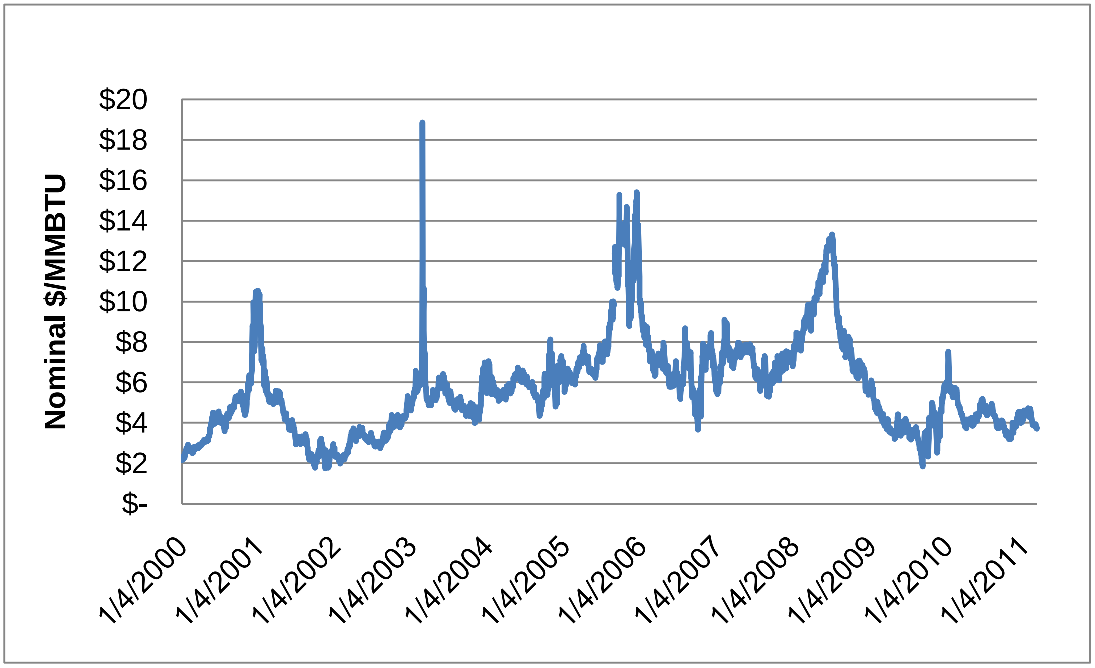
Gas Price Situation

Natural gas is a heavily traded commodities market characterized by inherent volatility. Over just the last decade, natural gas prices spiked several times. (See **Figure ES-2.**) The winter periods of 2000/2001 and 2003/2004 saw prices spike to $10 per million British thermal units (MMBTU) and $18/MMBTU, respectively. Cold weather, which increased demand and put upward pressure on price, triggered these spikes. In September 2005, hurricanes Katrina and Rita caused natural gas production in the Gulf Coast to be shut in. This situation lowered available supply and caused prices to spike over $15/MMBTU.

Since late 2008, natural gas prices have trended lower, in the $4.50 to $5.00 range, and only once in 2009 did prices increase above $6.00. The lower prices following the 2008 price spike can be explained by two factors. The late-2008 economic recession reduced overall demand for natural gas; the industrial and power generation sectors declined more than other sectors. The lower natural gas demand had a negative effect on prices.

Secondly, as described above, large amounts of shale gas are now technically and economically recoverable. This injection of shale gas into the market increased the supply of gas available to consumers and thus helped to lower the price of natural gas. Over the last year (April 2010-April 2011), Henry Hub spot prices have averaged $4.15/MMBTU; this is mainly attributable to slow economic growth and the abundance of shale gas supplies.

Figure ES-2: Henry Hub Daily Spot Market Natural Gas Prices



Source: http://intelligencepress.com.

Are Current Trends a Reliable Guide to the Future?

Might the trends being observed today continue into the future? Can the underlying conditions and resulting prices be expected to persist into the future? Or, might such a view of the future be considered too rosy? Despite the current trends, what other futures might present themselves instead? What future changes to underlying key drivers might occur? Which of these key drivers is most difficult to predict? If a number of futures could be possible, then what range of outcomes might California face, and with what effect on prices, on end users' gas bills, and on the state's progress toward reducing greenhouse gas emissions? Do these ranges of possible outcomes represent vulnerabilities to California, or opportunities? Staff explored these questions by modeling the worldwide natural gas market.

Modeling Analysis

The Business-as-Usual Starting Point: A Reference Case

The basic approach is to start with a "reference case" set of assumptions, then create several "changed cases" by selecting a plausible range of future values for "key" independent variables — those input assumptions expected to significantly affect the results and that, in return, have a significant amount of uncertainty about their actual future states. Consequently, most of the assumptions are the same in all cases. Describing and comparing how the input assumptions vary across the cases are relatively straightforward.

Staff took an econometric modeling approach, with a few exceptions, to building the assumptions for the Reference Case. The approach assumed that past observances are useful predictors of future outcomes. Regression analyses were performed to discover highly predictive explanatory variables and to create equations that link the explanatory variables to historically observed outcomes. The equations were then used as a forecasting tool, a use that presumes that the relationship (between independent and dependent variables) that was observed to hold in the past will continue to hold in the future. Sometimes this approach is referred to a "business-as-usual" approach. The Reference Case generally represents what the commercial agents in the worldwide gas market would do if unconstrained by new policies or prohibitions and not given new incentives. It is not meant to be a "most likely" or "best guess" view of what the actual future will be.

Highlights of Modeling Results

The Reference Case results suggest that the combination of recession-driven weak demand and abundant domestic supply has driven current wholesale market prices significantly below the hurricane-driven highs of a few years ago. These conditions are projected to be temporary as:

- Future demand increases with economic recovery and diminishing opportunities on the production side (drill-it-or-lose-it leasing, profit-rich natural gas liquids, sweet spot plays).
- Prices rise as production marches up the marginal cost supply curve, which has shifted considerably due to the technological innovations described above.
- Even with returning demand, prices could plateau at about $6.00/MMbtu (2010$).

The future also could be much different than the business-as-usual Reference Case suggests.

On the supply side, controversies surround potential public health, safety, and environmental impacts of natural gas production and transportation activities and could result in significantly higher gas production and transportation costs either to avoid or to reduce the impacts. Local drilling embargoes could entirely deny access to significant portions of this growing domestic resource. On the other hand, further technological innovations and improved "best practices" could completely or partially offset these challenges. How these issues will play out cannot be known now, increasing the uncertainty inherent in any assessments of future gas market conditions.

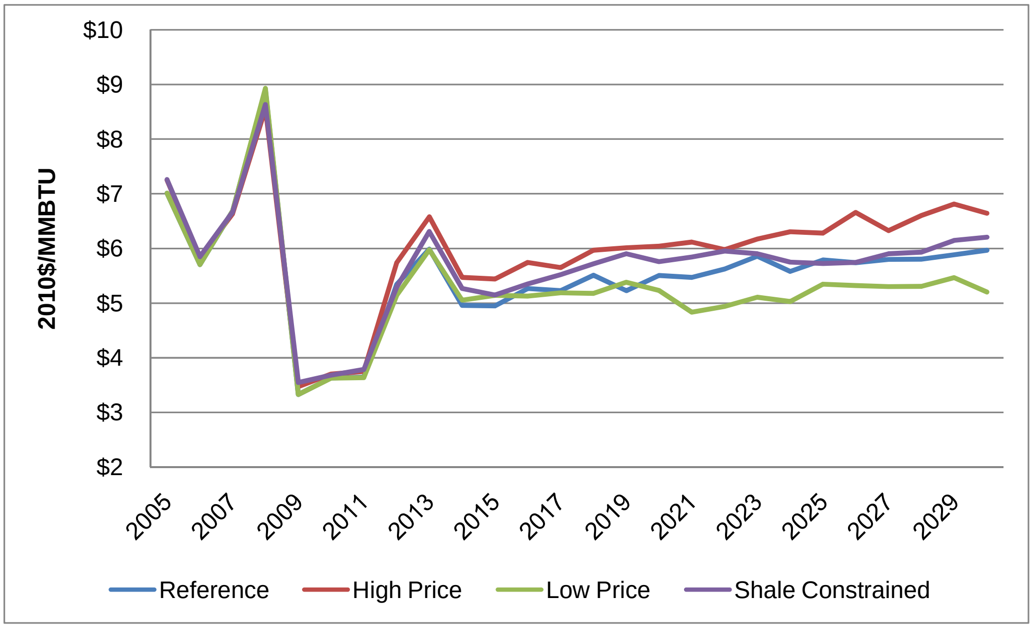
On the demand side, environmental and energy policies that affect electricity generation from any generation fuel type will affect future amount of natural gas combusted by power plants, either because gas-fired generation is already fueling the marginal electricity supply or is among the most cost-competitive generation to build. For example, widespread replacement of coal-fired or nuclear power plants driven by air quality or safety concerns will increase natural gas fuel demand for electric generation, as would significantly increased electric vehicle recharging loads. On the other hand, increased penetration of energy efficiency and conservation programs, non-gas electricity generation by renewable sources, such as geothermal, wind, solar, and biofuels, or increased efficiencies gained by combined heat and power generation, would all act to reduce generation from fossil fuels. But just as with the supply-side drivers, how these issues will play out in the future cannot be known now. The fact of these considerable uncertainties and their potentially significant effect on future natural gas supply and demand (and consequently price) must be expressly taken into account in any assessment of future gas market conditions that is to be useful.

This assessment will provide useful information on potential market outcomes to support policy decisions that require assumptions be made about future gas market activities without accurate predictors. Computer modeling is an analytic tool to help achieve that objective. The assessment employs a study design with multiple scenarios and sensitivities. The reasons or issues on which each case is focused are explained, and descriptions of the assumed future conditions underlying each case are presented. The goal is to better understand the potential vulnerabilities or opportunities that California could face under different future conditions.

Staff constructed three "changed" cases, specifically designed to move national natural gas market prices to levels higher or lower than seen in the Reference Case. Plausible values for the future states of key price drivers that would be expected to achieve that effect were selected. A key term here is "plausible." The conditions underlying each case could plausibly occur; there is no defensible basis for claiming one case is any more likely than another. Staff includes such cases to guard against the risk of one-sided bias. Rather than presenting one conditional estimate that may be too rosy, a number of plausible outlooks are provided, with the differences among their underlying assumptions identified and discussed. This shifts the focus of discussion to gaining a better understanding of the underlying drivers of modeling outcomes, the uncertainties involved in predicting their future states accurately, and the reasons given for having selected the specific input values from the range of other plausible values that might have been selected instead.

Figure ES-3 shows the model's equilibrium condition results for the annual average spot market gas prices at the Henry trading hub for the Reference Case and the three cases designed to move national gas prices: the High Gas Price, the Low Gas Price, and the Constrained Shale Gas cases.

Figure ES-3: Henry Hub Daily Spot Market Natural Gas Prices Across Cases Designed to Move Gas Prices



Source: California Energy Commission Staff Draft Analysis.

Staff constructed two additional "changed" cases, specifically designed to move California natural gas demand to levels higher or lower than seen in the Reference Case. Plausible values for the future states of key demand drivers that would be expected to achieve that effect were selected. In these cases, the focus is on demand-related impacts, such as the potential future total cost of natural gas and GHG emissions from gas combustion. Particular attention was paid to power generation natural gas demand in California. Electric generation gas demand is the end-use sector that is growing rather than declining or remaining level. Due to the variety of energy and environmental policies aimed at influencing both the total amount of electricity consumed and the mix of generating resources (that is, what fraction is supplied by fossil, hydroelectric, nuclear, renewable generators), there is much uncertainty about future gas demand for electric generation, both in California and nationally.

A snapshot description of the assumption differences across the cases, as well as selected model results for 2022, are provided in **Table ES-1**. Selected natural gas costs and emissions metrics "post-processed" from model results are also included in **Table ES-2**.

Table ES-1: Summary of World Gas Trade Model Key Driver Assumptions and Results, 2022

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Case	High CA Gas Demand Case	Low CA Gas Demand Case	Lowered Pressure Case
Results in 2022							
DEMAND							
US Tcf/yr	27.30	25.05	25.92	24.15	25.30	25.06	25.21
US Gas-Fired Electricity Generation Tcf/yr	8.47	9.36	8.75	8.12	8.47	8.38	8.44
CA Tcf/yr	2.19	2.12	2.24	2.10	2.19	2.14	2.18
CA Gas-Fired Electricity Generation Tcf/yr	0.65	0.66	0.66	0.63	0.69	0.62	0.65
SUPPLY							
US Natural Gas Dry Production Tcf/yr	24.78	22.35	25.56	23.47	24.78	24.92	24.75
US Shale Tcf/yr	12.23	8.76	13.59	10.89	12.23	12.34	11.95
US LNG Tcf/yr	1.07	1.84	0.92	1.25	1.07	0.99	1.04
Canadian Imports Tcf/yr	3.48	4.53	3.64	3.04	3.48	3.30	3.28
Exports Tcf/yr	2.5	3.82	2.63	2.1	2.5	2.67	2.35
PIPELINE CAPACITY							
Cumulative New Capacity to CA (TCF) (aggregated from 2010 to 2022)	0.08	0.12	0.06	0.09	0.33	0.10	0.09
Pipeline Utilization; % of total (EPNG+TW+MJ/ GTN/ KRGT/ Ruby)	36.82/68.46/72.87/47.72	34.52/62.07/67.84/48.4	35.11/81.55/70.7/39.04	36.09/59.58/66.77/45.89	36.04/66.89/71.95/47.49	35.95/65.84/70.12/46.80	36.3/89.5/65.1/31.1
PRICES							
Price at Henry Hub ($ 2010)/Mmbtu	5.78	6.156	5.09	6.14	5.8	5.88	5.75
Basis to CA Border at Topock ($2010)/Mmbtu	0.282	0.203	0.325	0.293	0.136	0.251	0.287
Basis to Malin ($2010)/Mmbtu	-0.076	-0.132	-0.033	-0.043	-0.217	-0.091	-0.057
Key Assumptions							
Average Annual GDP Growth Rate	2.7%	3.5%	2.1%	2.7%	2.7%	2.7%	2.7%
Gas Technology Improvement Average Annual Growth Rate	1%	1%	2.50%	1%	1%	1%	1%
Total US Electricity Production (GWh)	4,766,558	4,819,407	4,735,485	4,766,558	4,770,521	4,761,241	4,766,558
US Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	66.8/17.8/5.45/15.37	68.8/17.8/5.4/13.4	65.6/17.8/5.5/16.6	66.8/17.8/5.45/15.37	67.2/17.7/5.5/15.2	66.6/17.8/5.5/15.6	66.8/17.8/5.45/15.37
Total CA Electricity Production (GWh)	238,058	240,698	236,506	238,058	242,021	232,741	238,058
CA Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	44.5/14.5/11.5/29.4	45.0/14.5/11.4/29.1	44.3/14.5/11.6/29.6	44.5/14.5/11.5/29.4	51.6/11.3/11.3/25.8	38.7/14.5/11.8/35.0	44.5/14.5/11.5/29.4
When CA Meets Maximum RPS Target	On Time	On Time	On Time	On Time	2030	On Time[4]	On Time
When Other States Meet Individual Maximum RPS Targets	5 yrs late	15 yrs late	On Time	5 yrs late	5 yrs late	5 yrs late	On Time
Additional US Coal Generation Converts to Natural Gas	0	50 GW	0	0	0	0	0
Constrain/Augment Natural Gas Resources							
US	NY	PA, NY, CO and WY	Upper End of Range	NY	NY	NY	NY
World	IIV enters marker in 2020[2]	IIRV Constrained[1]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]
LNG Exports	Allowed but not imposed	Imposed LNG Exports	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed
Pipeline Capacity Additions (Model feature turned On/Off)	ON	ON	ON	ON	ON	ON	OFF[3]
PG&E Backbone Capacity Reductionm Constraint, Mmcf/d	None	None	None	None	None	None	300 on Baja/200 on Redwood
Additional Environmental Mitigation Cost (2005$/Mcf)	N/A	$0.40/Mcf shale	N/A	$0.40/Mcf shale	N/A	N/A	N/A
	N/A	$0.20/Mcf Conv	N/A	$0.20/Mcf Conv	N/A	N/A	N/A

Source: California Energy Commission Staff Draft Analysis.

[1]Note: IIRV refers to Iran, Iraq, Russia,and Venezuela.

[2]Note: IIV refers to Iran, Iraq, and Venezuela.

[3]Note: Capacity additions off for 2012-2016.

[4]Note: Continues to grow to 40% by 2027 and then stabilizes.

Table ES-2: Rough Estimates of California Power Generation Sector Gas Demand, Gas Costs, Combustion CO_2 Emissions, and Minimum CO_2 Allowance Costs by Case

Selected California Power Generation Sector Results	Reference	High Gas Price	Low Gas Price	Constrained Shale Gas	High CA Gas Demand	Low CA Gas Demand
2017						
Gas Demand (Bcf/Yr)	697	683	694	681	710	685
Combustion CO2e Emissions (Millions Tonnes CO2/Yr)	38.5	37.8	38.4	37.7	39.3	37.9
Gas Costs (Millions 2010 $/Yr)	$4,285	$4,498	$4,293	$4,401	$4,432	$4,208
CO2e Allowance Costs (Millions 2010 $/Yr)	$465	$456	$464	$455	$474	$458
2022						
Gas Demand (Tcf/yr)	651	660	660	627	691	616
Combustion CO2e Emissions (Millions Tonnes CO2/Yr)	36.0	36.5	36.5	34.7	38.2	34.1
Gas Costs (Millions 2010 $/Yr)	$4,310	$4,577	$3,933	$4,390	$4,484	$4,121
CO2e Allowance Costs (Millions 2010 $/Yr)	$555	$563	$563	$535	$589	$525
2030						
Gas Demand (Tcf/yr)	659	687	691	639	797	540
Combustion CO2e Emissions (Millions Tonnes CO2/Yr)	36.4	38.0	38.2	35.4	44.1	29.9
Gas Costs (Millions 2010 $/Yr)	$4,620	$5,303	$4,200	$4,726	$5,399	$3,730
CO2e Allowance Costs (Millions 2010 $/Yr)	$829	$865	$870	$805	$1,003	$680

Source: California Energy Commission Staff Draft Analysis. These are rough estimates.

Computer models will produce accurate predictions of the future only if (1) the real-world relationships represented by the equations do not change over time, and (2) the future values of the independent variables on which the equations act are accurately predicted. Neither condition may be likely to occur. In fact, in the real world, agents can be expected to take actions to ensure that they do not. For example, novel future policy interventions or imposed constraints may alter the real-world relationships represented by the equations (for example, a structural change). Or guesses about the future state of an independent variable that is deeply uncertain may be poor (for example, garbage in, garbage out). These limitations do not make modeling-based analyses useless. The utility of the modeling depends on understanding its inherent limitations, designing the cases appropriately, and interpreting and using the results reflectively.

CHAPTER 1: Introduction

Background

State government has an essential role to ensure that a reliable supply of energy is provided consistent with protection of public health and safety, promotion of the general welfare, maintenance of a sound economy, conservation of resources, and preservation of environmental quality (Public Resources Code Section 25300(b)). To perform this role, state government needs a complete understanding of the operation of energy markets, including electricity, natural gas, petroleum, and alternative energy sources, to enable it to respond to possible shortages, price shocks, oversupplies, or other disruptions (PRC Section 25300[c]). The California Energy Commission's timely reporting, assessment, forecasting, and data collection activities are essential to serve the information and policy development needs of the Governor, the Legislature, public agencies, market participants, and the public (PRC Section 25300[c]).

Purpose of the Natural Gas Market Assessment

This report's purpose is not to attempt accurate predictions of future natural gas market outcomes, but to provide multiple plausible conditional estimates that explore potential vulnerabilities or opportunities California may face. Making accurate single point forecasts of future gas prices and other market activities is not feasible and may not be particularly useful. This is a necessary consequence of the gas market's high complexity, large menu of competing options for actions, and deep uncertainties about future conditions, which are beyond one's control.

Worldwide natural gas markets, already linked to petroleum markets, have converged with electricity markets, a fact that multiplies the complexity of interactions among them. Concerns about greenhouse gas (GHG) emissions press for an even greater role for natural gas in serving transportation demand, either directly or via electrification. The menu of options available to society for dealing with energy and climate change issues is large and varied, including such seemingly disparate actions as building zero net energy homes to building new nuclear powered generating plants. It is deeply uncertain now what will be the actual future state of various conditions that can significantly affect future natural gas markets (such as future emission reduction policies, future demand for gas-fired electric generation, and so forth). Even experts simply cannot agree on their likelihood.

These conditions of high complexity, many options for action, and deep uncertainty argue that market analysts move away from so-called "best guess" or "most likely" forecasts. Then what usefully can be done? Staff thinks it more useful to produce multiple plausible *conditional estimates* of the future to help explore what future natural gas market conditions might be. This approach gives the potential users of such estimates more information about the conditional nature of the estimates to help the users understand the potential consequences of their own use of a given estimate should the future turn out to be different.

Change in Modeling Approach From *2007 IEPR*

The most significant departure from past practices is the decision not to use estimates of natural gas demand from other Energy Commission staff work in this assessment. Typically, staff's exogenous, or external, input assumptions about demand for natural gas by Californians in the industrial, commercial, residential, and agricultural sectors have come from the Demand Analysis Office demand forecasts. Likewise, the exogenous assumptions about gas demand for electric generation across the Western Interconnection typically have come from Electricity Analysis Office production cost modeling results. Internal timing and modeling capability issues required staff in the Natural Gas Unit to team up with consultants with well-recognized expertise in natural gas markets to conduct this assessment. This assessment was conducted by a joint staff-consultant team, the members of which appear on the title page as authors and consultants. Unless specified otherwise, use of the word "staff" in this report is meant to refer to this team.

Staff assisted Dr. Kenneth Medlock III, Rice University, with the specification of the worldwide gas market model's physical representation of the gas markets with which California most directly interacts (for example, adding a California-focused *topology*, the geographical representation of gas supply and demand areas, or *nodes*, linked by pipelines). In addition, staff assisted Dr. Medlock with specification of the model's representation of certain California energy policy initiatives so California-specific, policy-relevant cases could be created.

Another significant departure from past practice is an increased reliance on econometric modeling to create many of the input assumptions to the natural gas market model. Therefore, this assessment makes use of a mixture of analytic techniques, which are all properly considered "modeling," but which employ a variety of differing "models" and modeling techniques. For example, this assessment relies on an econometric analysis of U.S. state-level historical data for the electric generation sector compiled by the Energy Information Administration performed by Dr. Medlock. **Chapter 2** discusses general issues that arise in the use of models for forecasting and the influence they have on the study design employed in this assessment.

In this cycle, all natural gas market activity is being modeled annually. There is no seasonal, monthly, or daily information either as input or output. Necessarily, the modeling portion of this assessment excludes the operation of natural gas storage infrastructure, which is essentially a seasonal or shorter-term operation. This choice, made necessary by turnover in experienced staff, limits the use of the model to questions usefully addressed by annual modeling. Some annual gas volumes may be expressed as a daily average flow, in cubic feet per day; however, this result is calculated simply by dividing the annual volume in cubic feet per year by 365 days/year. Annual model results may be "post-processed" by applying typical seasonal factors based on past observances to approximate seasonal distributions of the annual model results, but this simple method is not meant as a substitute for seasonal or monthly modeling.

Scope and Organization of Report

This natural gas market assessment begins by examining recent trends in demand, supply, infrastructure, and price. The results of this trends analysis will be published as a separate staff report, soon to follow this natural gas market assessment. It will update the trends analyses staff conducted for the ***2009 IEPR***, which can be found at the Energy Commission's website for that proceeding.[2] An analysis of current trends identifies the underlying key drivers of the observed trends. The drivers may include economic, demographic, environmental, regulatory, and policy conditions. The current trends assessment report will also point out identified concerns or controversies that could affect the future states of key drivers, and the ability to predict them accurately. This examination of trends helps to understand what might be plausible ranges of uncertainty for the future states of these key drivers, which guides the assumption changes in the case studies.

Chapter 2 describes the computer model of the natural gas market built and used in this assessment, how the study design is a product of both the limitations of modeling and the nature of the policy-relevant issues of interest, how issues-related questions direct the cases constructed, and the assumptions underlying each case. The model is a simplified mathematical representation of the complex interactions among world energy markets, focusing on natural gas demand, supply, infrastructure, and price. The algorithms used in the modeling relate the input assumptions made about the future states of many exogenous independent input variables to the dependent output variables, *the results*, which should be interpreted as *conditional* estimates of future market activity. For model results to be "accurate" predictors of the future, not only do the algorithms have to be accurate predictors of future relationships, but so do the assumptions made about the future states of the exogenous independent variables (at least the most significant ones).

This assessment will provide useful information on potential market outcomes to support policy decisions that require assumptions to be made about future gas market activities without accurate predictors. Better understanding the potential effects on market activities of the uncertainties in their key drivers is necessarily an objective of this assessment. Accordingly, the assessment employs a study design with multiple scenarios and sensitivities. The reasons or issues on which each case is focused are explained, and

2 http://www.energy.ca.gov/2009_energypolicy/notices/2009-05-14_workshop_notice.html.

descriptions of the assumed future conditions underlying each case are presented. The goal is to better understand the potential vulnerabilities or opportunities that California could face under different future conditions.

Chapter 3 presents the natural gas market modeling results, including volumes of gas demanded, the type and location of gas supply sources being produced, the flows through pipelines, and the resulting prices. The model simulates wholesale market activity from wellhead production to the point where gas distribution utilities take control of the gas (at their "citygate") for distribution to customers.

The model results are presented by comparing and drawing insights from the different cases for each of the following areas:

- Price – Prices at major market hubs, such as the one at Henry Hub are compared over time and across the United States.
- Supply – The quantities of natural gas produced within the United States, the amounts imported, and the amounts from shale deposits are compared.
- Infrastructure – The amount of new pipeline capacity that the model estimates to be built in response to economic conditions is compared.
- Demand – The amount of natural gas consumed by various end use sectors, including for electric generation is compared.

Chapter 4 describes conditional estimates of gas prices to end users and discusses uncertainties which affect future values these prices may take. Retail distribution of the gas is not included in the model results, nor is the final retail price. This is a "post-processing" activity in which the components of distributions costs are estimated and added to the commodity and transportation costs delivered at the city gate. Just as the wholesale market modeled cases have varied outputs for gas commodity and transportation costs, so too can the significant costs associated with the distribution function vary, depending on what assumptions one makes about the future conditions that affect distribution costs. Uncertainties about aging infrastructure replacement, public safety, environmental mitigation, and climate change policy implementation contribute to the range of variation future end-user gas prices may take.

Chapter 5 suggests a role that the findings in this draft report and staff may play in the Energy Commission's *IEPR* deliberations about current trends and potential future states of the natural gas market. Staff refrains from making final conclusions or recommendations based on this draft assessment's assumptions, methods, findings and initial conclusions. The comments, insights and recommendations we receive from stakeholders at the Joint Committee workshop and in subsequent written comments on this draft and its associated appendices and working papers will be an invaluable addition to what staff has been able to provide to date to inform these deliberations.

CHAPTER 2: Building the Natural Gas Market Model and Case Assumptions

This assessment employs a mixture of different mathematical modeling techniques and different computer models. Staff is committed to conducting the modeling portion of this market assessment as transparently as practicable. This report provides the broadest general explanations of the approach, assumptions, and calculations, as well as highlights in tables and graphs. Appendices provide more detail on modeling inputs, methods, and outputs. Subject to contractual protections of the consultants' intellectual property, staff will also post on the *2011 IEPR* website the detailed results of the gas market modeling for each case, extracted from the proprietary model output files to Microsoft Excel® worksheets.

This chapter focuses on some important general modeling concepts, including inherent limitations of models as accurate predictors of future conditions of complex systems. This limiting fact plays a significant role in the overall study approach staff employed. The chapter describes in general the different models built and used in the assessment. It discusses how the specific design of the analysis both accommodates the limitations of the models and is issues-directed, not model driven, as described later in this chapter. Finally, this chapter describes the specific issues each case is designed to address and describes the key input assumptions for each case. Next is a section focusing on how electricity generation system-related assumptions change across the cases, since uncertainties in key drivers related to electricity system operations and policy also impose significant uncertainties on future gas market activity. Finally, this chapter describes some selected assumptions that remain the same in all cases and that are important key drivers of results in all cases.

General Comments About Building and Using Models

Before describing the specific models staff built and used in this assessment, it is useful to make some general statements about modeling and modeling terms. All models are mathematical simplifications of the real-world phenomena or activities they seek to represent. This basic fact is important to remember when using models to forecast future activities or conditions, especially models representing systems as complex as the natural gas and its related energy markets.

Understanding Important General Modeling Terms

Defining a few basic modeling terms now will help make more understandable the following explanation of how staff built the *models*, and why and how the specific cases were selected. In its simplest form, a model can be described as having equations that specify relationships between variables and operate on input assumptions to produce the output results. The inputs are referred to as *independent variables* — their values come from a source other than the equations that specify the relationships between variables in the model. The outputs are referred to as *dependent variables*—their values are dependent on *both* the value of the independent variables and the relationships in the equations that operate on them to produce the dependent variable results. Since the estimates made about the future state of the independent variables are made outside the model — their estimation process is considered *exogenous* to the model. The other variables are considered *endogenous* to the model, that is, they are specified by the model equations and are calculated by the model.

When using models to predict the future, getting an "accurate" result requires not only having specified accurate equations (meaning they describe well the future relationships between independent and dependent variables), but also having made accurate guesses about what the future state of the independent variables will be. The predictive accuracy of model results may not be important if the model results are used for purposes that have no consequences if the model turns out to be inaccurate. However, elaborate and expensive computer modeling is typically employed to advise decisions that can have significant negative consequences if the future turns out differently than the independent variables and equations assumed in the model "forecasts." A useful way to interpret the results of any model is as a *conditional estimate*. The accuracy of the results is *conditioned* on the accuracy of the model relationships and the assumptions made about independent variables.

Negotiating the Multiple Layers of Modeling

To add to the confusion, many modeling techniques and computer modeling software may be employed all at once in a complex "modeling" effort such as this assessment. For example, analyses that employ a complex computer model — call it ***Model M*** — often use other models (and modeling techniques) — call them ***model m*** — to produce the estimates of the independent variables that serve as inputs to that ***Model M***, the output of which can then be used as an estimate of the independent variables that serve as inputs to yet another model — call it ***model p***. In fact, this is the case with staff's natural gas modeling assessment. Using this simplified framework, "***Model M***" refers to the worldwide natural gas market model, called the World Gas Trade Model (WGTM), built for this assessment using the general computable equilibrium software platform MarketBuilder.[3] And, ***model m***, in this case, is a collection of econometric models and simple spreadsheets staff used to "build assumptions" for ***Model M***.[4] The dependent variable outputs of ***model m*** are staff's estimates of the independent variable inputs to ***Model M***. In a process staff refers to as "post-processing," the dependent variable outputs of ***Model M*** are staff's estimates of the

3 MarketBuilder is a software product of Deloitte LLP MarketPoint Services. For more information about how MarketBuilder works, see http://www.deloitte.com/view/en_US/us/Industries/power-utilities/deloitte-center-for-energy-solutions-power-utilities/marketpoint-home/marketpoint-marketbuilder/76c07c4886549210VgnVCM200000bb42f00aRCRD.htm.

4 An example of "***model m***" is the set of econometric analyses and models staff uses to create the initial "reference quantity" gas demands to input to the WGTM.

independent variable inputs to ***model p***.[5] Many of the issue- or policy-relevant output metrics one hopes to get out of a complex assessment of natural gas market activities require post-processing. In the interest of transparency and so the reader can better understand staff's overall methodology and assumptions, this report attempts to make clear these "***Model M,***" "***model m,***" and "***model p***" distinctions in the following descriptions of this chain of modeling activities.

Applying General Commodity Market Modeling to Natural Gas

The MarketBuilder platform was used to construct staff's general equilibrium model representing the fundamentals of the worldwide natural gas market.[6] MarketBuilder can be used to model commodity supply chains using networks of interrelated "agents" that seek to maximize their profit subject to the constraints assumed in the system. Using this computer platform, the market analyst constructs the geographic representation — the topology — of the commodity market, in this case the worldwide natural gas market, typically specifying more detail for the markets of most interest, usually the local ones. This includes locating the centers of demand for gas, including large gas consumers such as power plants, the interconnecting interstate and intrastate pipelines, liquefied natural gas terminals, and the various supply sources of gas.

Staff's analysis is based on the well-recognized global gas market expertise of consultant Dr. Kenneth Medlock III.[7] Dr. Medlock has used the MarketBuilder platform to construct a model of the worldwide natural gas markets, which he calls the Rice World Gas Trade Model (RWGTM). For this analysis, Dr. Medlock and staff worked closely together to modify his RWGTM for use in the *2011 IEPR* proceeding. The resulting modified model, called simply the WGTM, is the model used in staff's market assessment and described in this report. Staff relied on Dr. Medlock exclusively to specify the topology of gas markets in the United States and the rest of the world, while collaborating with him to specify a more detailed topology for the portion of the gas market with which California directly interacts.

In addition to specifying the geography of the market, the gas market analyst specifies the input assumptions that estimate quantities for the demand for gas, the price elasticities of demand for gas and its competing fuels, the price of competing fuels, the pipeline capacities and transportation costs, the size of the various gas supply resources, and the cost to extract

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5 Examples of "***model p***" and post-processing include the set of spreadsheet models used to calculate end-user gas prices, total costs of natural gas by sector, and GHG emissions from the combustion of natural gas.

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

them (for example, supply cost curves). These assumptions are all developed exogenously to the WGTM itself. They are the independent input variables that the WGTM acts on to produce its output, that is, the WGTM-calculated dependent variables refered to as "results."

Technically, the WGTM performs a dynamic spatial equilibrium linked through time by Hotelling-type optimization of resource extraction. This means that the WGTM takes the initial reference quantity of demand for gas, begins a least-cost selection (within specified constraints) of which supply options to "produce" and with which existing pipelines to "transport" the gas. It then calculates the annual average market price of gas based on the marginal cost of gas supply. Then it calculates the response of the initial demand level to this price to see if demand changes. It also may select, based on rational expectations of current and future conditions, including its endogenous prices, to build new pipelines linking supply to demand, if the market prices over the long term will support the assumed minimum rate of return on investment. The model iterates through this process until an equilibrium state is reached, where demand equals supply at an endogenously determined price. All demand is served that "wants" to be served at that equilibrium price. The resulting prices are best interpreted as conditional estimates of the future annual average prices that would have to be maintained in the market for all of the other results in the model (for example, demand levels, supplies produced, pipelines built and used) to be sustained over time.

The WGTM calculates as output regional prices, regional supplies and demands, inter-regional flows, including transportation capacity expansions. Capacity expansions are determined by the endogenously calculated current and future prices along with exogenous assumptions about capital costs of expansion, operating and maintenance costs of new and existing capacity and revenues resulting from future outputs and prices.

Awareness of Modeling Limitations Help Usefully Frame the Study Design

The preceding general comments about modeling all apply to staff's WGTM modeling. Since all of the underlying assumptions and estimation techniques employed to construct the independent variable inputs to the WGTM are exogenous to the WGTM itself, the resulting values of the dependent variables — the WGTM output — should be interpreted as *conditional estimates* of future market activity. For the WGTM results to be interpreted as *accurate predictors* of what future market activities actually will be, then the estimates of the future states of at least the most significant independent variables (sometimes called the "key drivers" of results) would also have to have been accurately predicted. Such accuracy is not feasible to achieve, given the number of complex interacting key drivers of WGTM results and the deep uncertainties affecting staff's ability to predict accurately their future states. What makes the modeling output conditional is not the kind of modeling employed, but the fact that the real-world activities the model seeks to represent are fundamentally characterized by high complexity, many alternative options for action, and deep uncertainty. These conditions are present in the related electricity and other energy markets as well.

Nevertheless, policy- and decision-making still often require making *some* assumptions about future market conditions, even in the face of this great uncertainty. So, having a better understanding of the uncertainties and their effects can lead to more "robust" decisions — those having satisfactory consequences over a broad range of future conditions staff can't predict or control. Building and running models to understand better the potential impact of the uncertainties on market outcomes thus can be very useful in helping to advise the decision-making. This necessarily implies that some combination of scenario or sensitivity analysis would be useful, and that is the approach staff took in this assessment.

Study Design Is Issues-Oriented

Having acknowledged the need to deal expressly with uncertainties of future market outcomes, the practical limits of time and staff resources require a narrowing of the questions or issues on which to focus the assessment. Staff made initial suggestions about scope and issues on which to focus at workshops in February and April. Stakeholder comments have since provided useful feedback. The issues used to scope the modeling assessment are as follows:

- What potential vulnerabilities to high gas prices might California face in the future?
- What potential opportunities for low gas prices might California enjoy in the future?
- What potential vulnerabilities to higher gas demand in California might the State face in the future?
- What potential opportunities for lower gas demand in California might the State enjoy in the future?
- What potential vulnerabilities for gas system adequacy might California face as pipelines are temporarily removed from service or have their maximum operating pressures reduced while inspections to ensure pipeline safety are conducted, or remedial actions implemented?

Looking at both high and low cases helps guard against the potential consequences of one-sided biases. For example, decisions based on assumptions that future gas prices will be low could have significant negative consequences if gas prices turn out to be high, and vice versa. It depends on the *direct consequences of the specific use* of conditional estimates that turn out to be inaccurate predictors of the future. Generally, it is prudent for the users of any conditional estimate to examine the potential consequences of their use of one estimate for their specific purpose in the event the future turns out to be different from that estimate. This is especially true if the experts providing the estimate have no defensible argument for one estimate being more likely to occur than another. The estimate users' own assessments of the potential regret associated with their use of available alternative estimates may help them choose which estimate is most prudent for them to use, if any. Having done so, their decisions have a better chance of being robust, that is, of performing acceptably over a wide range of possible futures. Gas market analysts can help advise these purpose-specific decision analyses but cannot conduct them, as they require knowledge about the specific uses of the estimates and the details about how consequences play out. For example, the question of what energy efficiency measure is cost-effective is as much about the conditional estimates of cost and performance of the proposed measures themselves as about the cost of the fuel their success may avoid.[8]

Choosing the Starting Point and Changed Cases

The basic approach is to start with a "reference case" set of assumptions, then create several "changed cases" by selecting a plausible range of future values for "key" independent variables — those input assumptions expected to affect significantly the results and that, in return, have a significant amount of uncertainty about their actual future states. Consequently, most of the assumptions are the same in all cases. Describing and comparing how the input assumptions vary across the cases are relatively straightforward. These descriptions are presented later in this chapter.

How did staff decide what cases to construct to specifically address the above issues, and where to start? The concept of a reference case was used, *in the sense of being an initial, well-defined, and well-understood point of reference*. This is neither meant to be a case with a consensus of agreement nor a case judged by anyone to be "expected" or "most likely." (It may serve the function of providing parties a common language with which to argue what futures are expected or most likely.)

Using Econometric Analyses to Build Reference Case Assumptions

Staff took an econometric modeling approach, with a few exceptions, to building the assumptions for the Reference Case. (Note, this description has now moved into the previously discussed realm of "***model m***.") The approach assumed that past observances are useful predictors of future outcomes. Regression analyses were performed to discover highly predictive explanatory variables and to create equations that link the explanatory variables to historically observed outcomes. The equations are then used as a forecasting tool, a use that presumes that the relationship (between independent and dependent variables) that was observed to hold in the past will continue to hold in the future.

8 For a discussion of how a regret analysis can help users of forecasts manage their risks of using forecasts that turn out to be inaccurate, see *Looking Before Leaping: Are Your Utility's Gas Price Forecasts Accurate?* Ken Costello, National Regulatory Research Institute, May 2010. http://www.nrri.org/pubs/gas/NRRI_gas_price_forecasting_may10-08.pdf.

Sometimes this approach is referred to a "business-as-usual" approach. The Reference Case generally represents what the commercial agents in the worldwide gas market would do, if unconstrained by new policies or prohibitions and not given new incentives. It is not meant to be a "most likely" or "best guess" view of what the actual future will be.

Computer models will produce accurate predictions of the future only if (1) the real-world relationships represented by the equations do not change over time, and (2) the future values of the independent variables on which the equations act are accurately predicted. Neither condition may be likely to occur. In fact, in the real world, agents can be expected to take actions to ensure that they do not. For example, novel future policy interventions or imposed constraints may alter the real-world relationships represented by the equations (for example, a structural change). Or guesses about the future state of an independent variable that is deeply uncertain may be poor (for example, garbage in, garbage out). These limitations do not make modeling-based analyses useless. The utility of the modeling depends on understanding its inherent limitations, designing the cases appropriately, and interpreting and using the results reflectively.

Building the Reference Case Assumptions

General Comments on the Reference Case Assumptions

This section only generally describes the effort involved in developing a starting point for modeling the worldwide natural gas market and its associated energy markets. The effort requires specifying worldwide estimates for future states of the following inputs, among others:

- Quantity and location of gas demand by all sectors of the economy
- Quantity, location, and development costs of all natural gas supply sources
- Capacity, location, and cost of all transportation infrastructure, including LNG facilities
- Initial fuel prices and price elasticities
- Economic and demographic conditions

There are simply too many input assumptions to fully describe in this report. More detail on the methods and assumptions employed to build these assumptions is provided in the presentation in **Appendix B** about the development of the Reference Case. Complete Reference Case WGTM outputs are also provided in **Appendix C**. A few selected Reference Case input assumptions, and how they are built, are described immediately below, while others are described further below with respect to how they have been changed by staff in the changed cases. Due to the importance of electric generation as a driver of gas demand,

and the many uncertainties affecting the future mix of power generation sources, a section is included comparing how power generation sector assumptions change across cases.

To improve overall transparency of the modeling methods, as well as its results, this chapter ends with a discussion of some key assumptions that are common to all cases (not changing across cases) but that have significant influence on the results. For example, assumptions about price elasticity of gas demand by sector are important in understanding why the final output (equilibrium) gas demand from the WGTM, which responds to the price of gas in the model, may differ from the reference quantity gas demand assumption[9] initially input to the WGTM. Also described are the method and values used to develop the allocation factors with which the WGTM calculates results at the level of the local gas distribution utility.

Describing Selected Reference Case Assumptions

Dr. Kenneth Medlock III conducted the regression analyses of historical observations of key drivers of activities in the worldwide gas market to develop the econometric equations and to identify the explanatory independent variables used to characterize input assumptions for the general computable equilibrium model (WGTM). The starting point case, which staff refers to as the Reference Case, mostly has assumptions developed by Dr. Medlock. This case represents a future in which commercial activity in the gas market (and related energy markets) proceeds as it generally has done so in the past, with some exceptions or constraints being imposed. As stated, this intended design means that the Reference Case represents more of a "business-as-usual" approach. It's not meant to be an accurate prediction of the future. Few think the future of U.S. and California energy markets will develop without significant structural changes being introduced. Even fewer can accurately predict what those will be.

Key input assumptions for the Reference Case, highlighting those that change in at least one of the changed cases, include the following:

- Average annual growth rate in GDP is 2.7 percent.
- The marginal cost curve for gas supplies reflects year 2011 vintage state of knowledge about the underlying gas resource base and production technologies.
- Average annual rate of "learning" improvement in gas technology is 1 percent.
- Shale gas development in New York is constrained per current moratorium.
- Iran, Iraq, and Venezuela do not enter the market until 2020.

9 The "reference quantity gas demand assumption" is the estimate of gas demand that is input to the WGTM. The assumption itself is the output of the econometric modeling that is used to "build assumptions" about the future states of the WGTM's exogenous independent input variables. Every case has "reference" quantities of gas demand as inputs to its WGTM run. So, this is a completely different use of the same term "reference" than when it is used to refer to the "Reference" Case.

- LNG exports are allowed to occur.[10]
- Pipeline capacity additions are allowed to occur.
- U.S. states' future power generation mix follow current trends based on U.S. EIA state level historical data except renewable generation:
    - California meets its existing Renewables Portfolio Standard (RPS) target on time in 2020.
    - Other states with RPS targets meet their targets five years late.
    - Growth of renewable generation in other states with no RPS targets follows past trends.

Other Reference Case assumptions are discussed below in the context of the changed cases that alter them.

Building the Assumptions for the Changed Cases

Overall Case Structure

Staff created three changed cases to focus on potential vulnerabilities or opportunities potential future gas prices may pose for California. Since California represents only a share of the worldwide gas market, moving the market price for gas tends to take changes to assumptions beyond California's borders. The High Natural Gas Price Case and Low Natural Gas Price Cases were created by changing a variety of international, national, and California-specific assumptions in ways anticipated to move natural gas prices higher and lower than in the Reference Case, respectively. Both demand- and supply-related assumptions were changed. The Constrained Shale Gas Case makes a few gas supply-related assumption changes from the Reference Case, which makes it more of a sensitivity case focused on the uncertainty of shale development going forward. Sometimes this report will refer to these cases collectively as those "focused on price impacts" or designed to "move price." However, natural gas market prices are not the only model results of interest in these cases, as will be shown in **Chapter 3's** discussion of results.

Staff created two changed cases to focus on potential vulnerabilities or opportunities that the potential future demand for gas may pose for the State. Varying levels of demand for gas will have varying consequences to the total cost of gas to Californians and to the amount of GHG emissions from the combustion of the gas consumed. Although the WGTM does not

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10 The phrase "allowed to occur" here means that their occurrence is not prohibited and that whether or not the feature appears in any case is dependent on the model's evaluation of the feature's commercial viability given the endogenous outlook for gas prices (past, present, and future) in that case.

calculate either total gas costs or emissions, staff makes some rough post-processed calculations to estimate them for each case of interest in **Chapter 3**. These cases are the High (and Low) California Gas Demand cases and may be collectively referred to as cases "designed to move California gas demand."

Staff created one additional sensitivity case to examine the potential effect of temporarily reducing the maximum allowable operating pressure on certain PG&E pipelines. This is an attempt to see what effect ongoing inspection or possible mitigation activities related to pipeline safety might have on the annual modeling results in the Reference Case, and how such results may be informative, if at all.

Uncertainties about the potential future resolution of national-level and state-level environmental issues contribute significantly to the assumption building in all cases. Some issues affect the wide-ranging potential public safety and environmental effects of natural gas market activities. Some issues affect the public safety and environmental effects of electricity generation activities, which indirectly but significantly affect the natural gas market, as gas-fired generation experiences a growing role as a marginal supply of electricity. Issues relating to emissions contributing to climate change both directly and indirectly affect gas market activities. All of these, as well as uncertainties about the long-term growth of the economy, had an effect on the case construction.

The sections below first describe the changed cases designed to move national gas market prices higher or lower than in the Reference Case: the High Gas Price, the Low Gas Price and the Constrained Shale Gas cases. Next are described the cases designed to move California's demand for natural gas: the High California Gas Demand and Low California Gas Demand cases. Finally, the Lowered Pressure Case is described, which is designed to examine the implications of what consumers could face if pipeline capacity reductions were to occur for a series of successive annual periods.

High Gas Price Case Description

On the demand side, the economy is growing robustly — coal-fired power plant retirements and slowed renewable generation programs increase natural gas demand for electric generation. On the supply side, some jurisdictions further restrict the development natural gas resources, particularly shale formations. Also, in places where production continues, environmental compliance costs rise as concerns about the safety of hydraulic fracturing continues. As a result, technology development slows, and the rate of *learning improvement* declines.[11] More specifically, the changes made to assumptions in this case include:

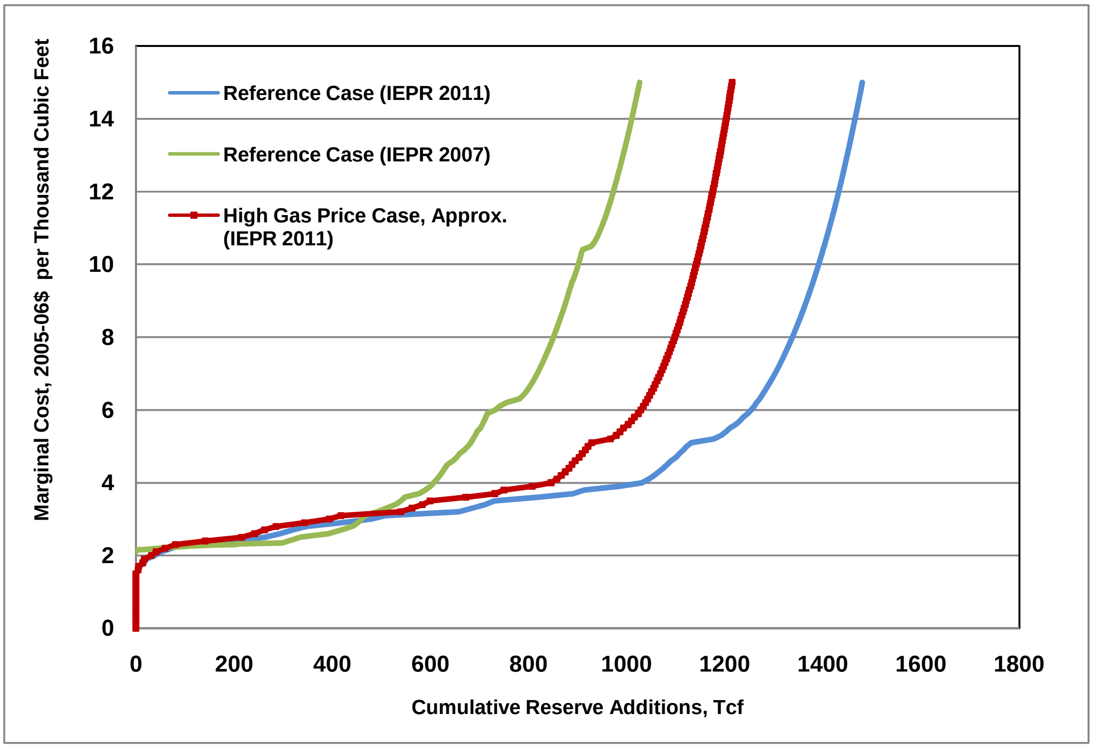
11 Learning improvement is increased productivity achieved through practice, self-perfection, and minor innovations.

- Remove 50,000 megawatts (MW) of coal-fired generation—about 280,000 gigawatthours (GWh) of annual energy production.[12]
- Robust economic performance, with long-term annual economic growth capped at about 3.5 percent.
- Delay RPS implementation so all states with RPS programs , including California, reach their maximum targets 15 years late (extra 10-year delay from the Reference Case's 5-year delay), as states grapple with budgetary concerns and other obstacles, including environmental.
- Robust liquefied natural gas export capability developed and used – Kitimat (Canada, Apache), Sabine Pass (Cheniere), Lake Charles (BG), Freeport, and Cove Point.
- Environmental regulations add $0.40/Mcf to the operations and maintenance cost of developing shale formations and add $0.20/Mcf to conventional resources.
- Remove from development potential shales in particular regions, in particular those in Pennsylvania, New York, Colorado, and Wyoming. This will substantially alter the available gas resource, reestablish a merit order, and alter basis more than price.
- Introduce constraints on natural gas development in Iraq, Iran, Venezuela, and Russia.

Figure 1 shows how the individual assumption changes that affect gas supplies (available resource base, technology improvement) collectively act to shift the marginal supply curve significantly to the left. The Reference Case assumes the 2011 marginal cost curve, while the High Gas Price Case assumes the marginal supply cost curve marked Approximate High Price Case, which is much closer to the supply outlook in 2007, before shale gas reserve additions and production began to skyrocket.

12 This amount was distributed geographically using findings of an analysis by The Brattle Group of the future viability of existing coal-fired power plants under existing and potentially new air pollutant regulations. See *Potential Coal Plant Retirements Under Emerging Environmental Regulations*, Celebi, Graves, Bathla, and Bressan, The Brattle Group, December 8, 2010, www.brattle.com.

Figure 1: Effect on the Natural Gas Marginal Supply Curve of Assumption Changes for the High Gas Price Case



Source: California Energy Commission Staff Draft Analysis.

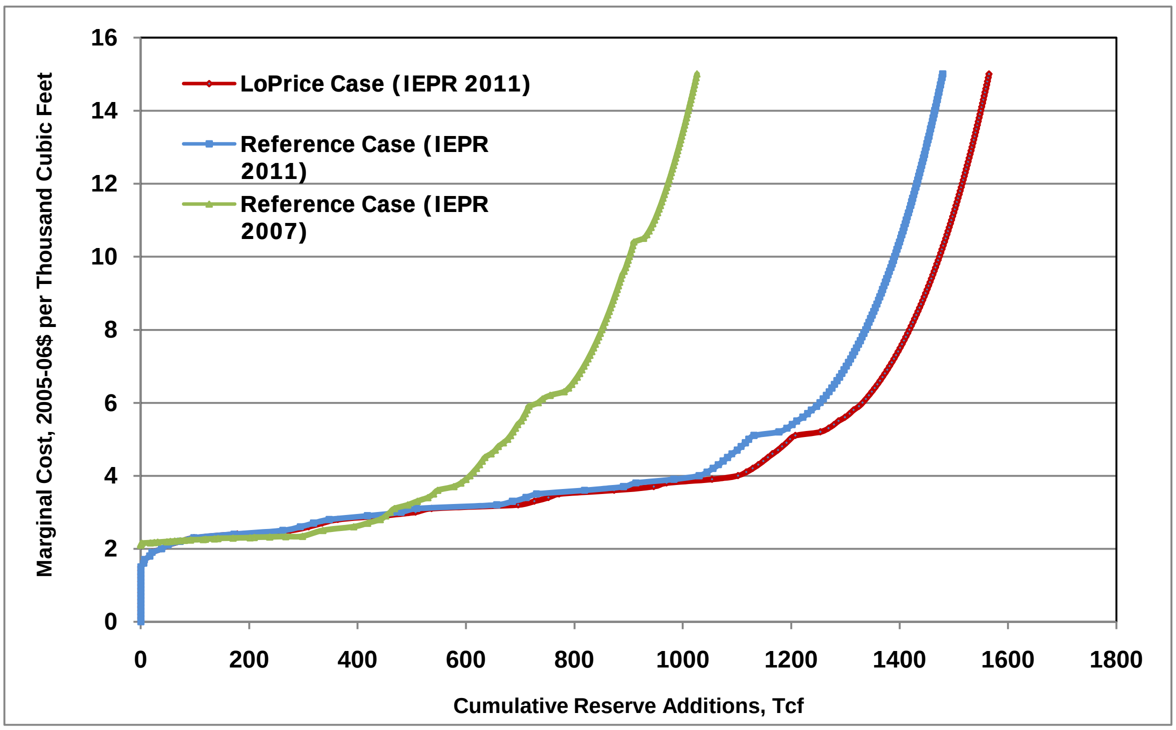
Low Gas Price Case Description

Technology development dominates this scenario. On the demand side, the economy is weak; all states with RPS programs comply on time. On the supply side, environmental concerns decrease as technological developments allow deployment of adequate environmental mitigation without significant overall cost increases; jurisdictions that in the past restricted natural gas development, eased regulations. More specifically, the changes made to assumptions in this case include:

- Economic performance is weak, with long-term annual economic growth capped at about 2.1 percent.
- No LNG exports are allowed, thus keeping North America isolated.
- Average annual rate of learning improvement in gas technology is 2.5 percent.
- Larger resource assessments (increase assessment size to upper range of published data) in the Marcellus, Haynesville, and Western Canadian shales.
- Iran, Iraq, and Venezuela enter the market unimpeded beyond prespecified dates.
- All states with RPS programs meet their maximum targets on time.

Figure 2 shows how the above individual assumption changes that affect gas supplies (available resource base, technology improvement) collectively act to shift the marginal supply curve to the right. The Reference Case assumes the 2011 marginal cost curve, while the Low Gas Price Case assumes the curve marked Low Price Marginal Cost Curve, which is a significant improvement in gas supply outlook.

Figure 2: Effect on the Natural Gas Marginal Supply Curve of Assumption Changes for the Low Gas Price Case



Source: California Energy Commission Staff Draft Analysis.

Constrained Shale Gas Case Description

In this sensitivity case, environmental concerns, particularly about the treatment and disposal of water used in the hydraulic fracturing process, prompt many jurisdictions to implement additional regulatory requirements on further development of natural gas from shale formations. Regulatory compliance after 2013 adds another $0.40 per thousand cubic feet (Mcf) to the cost of production of shale natural gas and $0.20/Mcf on conventional production (2005$).

Staff's estimation of this additional mitigation cost divided costs into three categories: current level mitigation costs assumed in the Reference Case, additional groundwater protection mitigation, and additional state environmental mitigation taxes or levies.

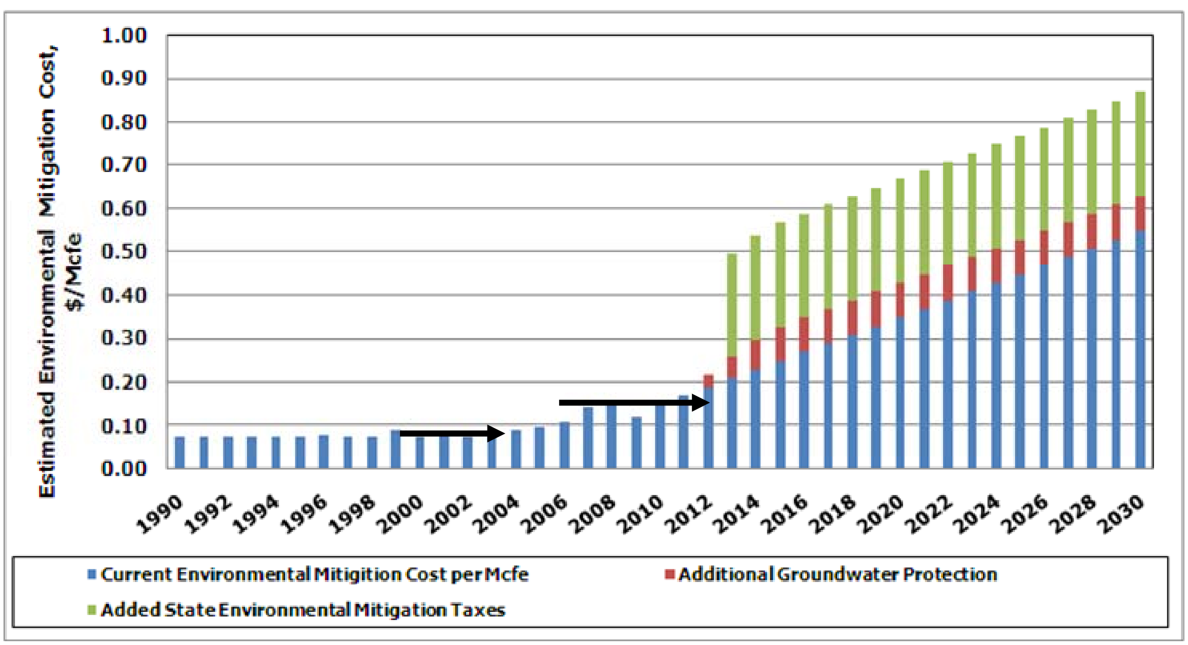
Current Environmental Mitigation Cost: Both the U.S. EIA and the American Petroleum Institute supplied the raw data used in developing the forecasted number for this parameter. In the Reference Case, staff assumed that this category will grow at a nominal annual rate of $0.02/thousand cubic feet equivalent (Mcfe) per year. (The WGTM doesn't expressly assume the projected inflationary increase, since it uses a flat real O&M cost in 2005$.)

Additional Groundwater Protection: Around 2002, mitigation costs started increasing, climbing a total of about $0.08/Mcfe in the succeeding five years. As a result, staff assumes that additional groundwater protection, including water treatment and disposal *and* better cement jobs for aquifer isolation, will result in a similar cost increase.

Added State Environmental Mitigation Taxes/Levies: The Commonwealth of Pennsylvania is considering a mitigation tax of about 4 percent to 8 percent of the wellhead price. If implemented in Pennsylvania, staff assumes other states will follow with similar levies. As a result, for this category, this analysis calculates an approximate mid-value of $0.24/Mcfe, starting in 2013.

Figure 3 demonstrates the total estimated forecasted environmental mitigation cost. Between 2013 and 2030, nominal mitigation cost increases from about $0.50 per Mcfe to about $0.87 per Mcfe. Estimated real cost (2005$), thus, varies between $0.32 per Mcfe and $0.56 per Mcfe, resulting in additional environmental mitigation cost of $0.22 per Mcfe to $0.46 per Mcfe. Since staff intended to bracket the range of uncertainty in natural gas prices and supply, the Constrained Shale Gas Case assumes an *added* mitigation cost of $0.40 per Mcfe (2005$) for shale gas production and, because of the lesser water handling issues, $0.20 per Mcfe (2005$) for conventional gas production.

Figure 3: Estimated Environmental Mitigation Cost, Nominal $/Mcfe



Source: California Energy Commission Staff Draft Analysis.

High California Gas Demand Case Description

Assumption changes in this case are dominated by increased gas-fired generation to replace electricity from the state's two nuclear power plants, which are assumed not to be relicensed, to make up for slowing renewable generation development and to serve increasing electric vehicle charging and natural gas vehicle fueling. More specifically, the changes made to assumptions in this case include:

- Eliminate more than 34,000 GWh of California-located nuclear generation by 2025.
    - San Onofre Nuclear Generating Station Units 2 and 3 are not relicensed and stop generating after 2022.
    - Diablo Canyon Units 1 and 2 are not relicensed and stop generating after 2024 and 2025, respectively.
- Increase California RPS compliance only 1 percent per year through 2029, when 33 percent is reached.
- Double the amount of residential and commercial sector electric vehicle charging that is embedded in the California Energy Commission's adopted *2009 IEPR* demand forecast, adding about 2,400 GWh by 2020 and 4,500 GWh by 2030.
- Add 200 million therms of natural gas transportation demand by 2020 and 400 million therms by 2030 (40-60 million therms currently exist).
- Increase the annual average growth rate of overall California electricity demand by about 0.25 percent (to match the growth rate in High Demand Case of the adopted *2009 IEPR* demand forecast).

Low California Gas Demand Case Description

Assumption changes in this case are dominated by accelerated renewable generation, both central station and distributed facilities, generally displacing gas-fired generation. Since distributed generation reduces electricity sales, on which RPS "percent renewable" obligations are measured, this case has some counterbalancing features. More specifically, the changes made to assumptions in this case include:

- Continue increasing California procurement of RPS-eligible renewable generation by 1 percent of retail sales per year between 2021 (when its 34 percent) and 2027, leveling off at 40 percent in 2027 and beyond.
- Add additional non-RPS-eligible distributed renewable generation, about 6,000 MW by 2030, generating about 8,500 GWh (16 percent annual capacity factor).
- Slow annual average growth rate of overall California electricity demand by 0.15 percent (to match the Low Demand Case of the adopted *2009 IEPR* demand forecast).

Lowered Pipeline Pressure Case Description

This sensitivity case is intended to explore the implications of what consumers could face if pipeline capacity reductions of the assumed magnitudes were to occur for a series of successive annual periods. Since staff's WGTM analysis runs the model in annual mode only, discontinuities or impacts more likely to be seen with seasonal increases and decreases in demand cannot be detected.

To date, certain pipelines on the Pacific Gas and Electric (PG&E) system are operating at lower pressure pending validation of their maximum allowable operating capacity (MAOP). Lowering the pressure on a pipeline has the effect of lowering the maximum operating capacity for the pipeline. The California Public Utilities Commission (CPUC) has ordered that all pipelines for which the gas transmission operators under its jurisdiction (PG&E, Southern California Gas [SoCalGas], San Diego Gas & Electric [SDG&E] and Southwest Gas) do not have "traceable, verifiable and complete" records of MAOP be pressure tested or replaced. These CPUC-jurisdictional gas utilities are launching efforts to review their systems and begin the required testing. Such testing, at times, requires taking lines out of service to perform the test. Should a line segment fail a test, it must be replaced, during which time affected customers would be out of service. In some situations, the gas utilities may choose to replace a segment rather than test it.

The Energy Commission understands that considerable effort is being made to prevent uncontrolled customer outages and minimize curtailments. In particular, the testing schedules attempt to ensure that no lines are out of service during the winter heating season. Several segments identified for testing or replacement are located along PG&E's backbone pipeline that brings gas from PG&E's interconnections with interstate pipelines in Southern California and, therefore, reduce capacity to serve customer load. Furthermore, the testing programs will continue over several years.

Normally the maximum capacity for the Baja Path is 1,140 Mmcf/d. The maximum capacity for the Redwood Path varies depending on the month. The average maximum capacity of the Redwood Path for the year is 2,154 Mmcf/d. The capacity reduction quantities are the results of the Class Location Study Report completed by PG&E in June 30, 2011.[13] The capacity on the Baja Path is currently 680 Mmcf/d. The capacity level on the Baja Path will not go above 680 Mmcf/d until December 31, 2011, while pressure reductions are being implemented. The capacity on the Redwood Path will not rise above 1,800 Mmcf/d until December 31, 2011, while pressure reductions are being implemented. The capacities on the Redwood and Baja Path are subject to further reductions due to maintenance, testing and possible pipeline replacement.

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13 This report can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/49A5D78B-82F7-4224-BBE9-C575D19DB71D/0/63011ClassReport_Final2.pdf.

Accordingly, staff prepared a sensitivity case in the WGTM using Reference Case assumptions except for the following changes:

- The WGTM's function of expanding pipeline capacity is switched off for the years 2012 through 2016, inclusive.
- A portion of northern California's natural gas pipeline capacity is assumed to be unavailable for several years.
  - PG&E's Baja backbone path capacity will be reduced by 300 Mmcf/d from 1,138 Mmcf/d to 838 Mmcf/d for the years 2012 to 2016, inclusive.
  - PG&E's Redwood path capacity will be reduced by 200 Mmcf/d from 2,150 Mmcf/d to 1,950 Mmcf/d for the years 2012 to 2016, inclusive.

At the time of the design of the Lowered Pipeline Pressure Case, the amount of capacity reductions used in the case were what was being implemented on the actual Redwood and Baja pipelines. Since that time, PG&E has further reduced the capacity on both of the interstate back bone pipelines to help facilitate the MAOP testing process. This is why the capacity reductions used in the Lowered Pressure Case and the reductions currently occurring on the actual pipelines (Baja and Redwood) are slightly dissimilar.

Electric Generation Input Assumptions Across Cases

Because electric generation is one of the major drivers of future changes to national and California natural gas demand, this section highlights how the electricity-related assumption changes discussed above ultimately affect the WGTM input assumptions for U.S. and California gas demand for electric generation. **Table 1** and **Table 2** highlight the electric generation resource mix assumed in each case. The power resource mixes are the result of the interactions of the specific judgmental changes staff made to issued-related key drivers of power resource mixes (for example, timing and magnitude of RPS targets, coal-fired power plant retirements.) These power resource mix assumptions are inputs to the econometric analysis, which is exogenous to the WGTM and which calculates the electric generation sector gas demand, which are then input to the WGTM as independent variables.

The regression analysis that examined the relationship between historical trends in electric generation by fuel type and historical gas demand from electric generation yielded an equation that fits the historical data well. But the equation specifies only nuclear, conventional hydroelectric, other renewable (for example, wind, solar, geothermal, and biogas), and fossil fuel types. The form of this equation allowed staff to introduce specific input assumptions about the amount of future renewable, nuclear, hydroelectric, and fossil generation across cases.[14] These issue-relevant changes to inputs require staff judgment

14 The relationship of the four generation fuel types in the model is straightforward: The share of fossil generation is calculated by subtracting the sum of the hydroelectric, nuclear, and renewable

about the plausible range of future values of these key drivers. The reasons for the changes made are discussed above.

Natural gas, petroleum, and coal-fired generation are combined in a single variable, which is input to the econometric equation calculating gas demand by electric generation. The equation estimates how much of the total fossil generation is assigned to each fossil fuel type based on the relative costs of their fuels. A consequence of this approach is that changes in assumptions within the fossil fuel group (for example, retiring 50,000 MW of coal-fired power plants in the High Gas Price Case) are not highlighted in the tables.[15] Nevertheless, the effect is evident in the differences in gas demand for electric generation across the cases.

Table 1 focuses on the cases designed to explore how marketwide future gas prices might change under a variety of plausible future conditions. Therefore, the information highlighted in this table is at a national level. The information for the Reference Case and the Constrained Shale Gas cases are the same for two reasons. First, staff made no electricity demand-related changes to input assumptions between these cases: Changes were just about shale gas supply constraints and costs. Second, being input assumptions to the WGTM, these are the initial "reference quantities" and not the WGTM's final electric generation gas demand, which would be affected by assumptions about price elasticities of demand. U.S. electric generation gas demand most noticeably differs between the High Gas Price Case and the other cases, as this is the case that assumes significant amounts of retiring coal-fired generation, some of which the econometric model replaces with gas-fired generation.

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shares from the total amount of generation. Changing any of these automatically changes the fossil share.

15 It requires some exogenous analysis to show the differences across cases in input assumptions about the different fuel types within the fossil group: gas, petroleum, coal. This could not be completed in time for this draft but will be available in the final draft.

Table 1: Highlights of U.S. Electric Generation-Related Input Assumptions for Cases Focused on Price

	Reference	High Gas Price	Low Gas Price	Constrained Shale Gas
	2017			
Total US Electric Generation (GWh/yr)	4,496,631	4,514,224	4,486,367	4,496,631
Nuclear Share of US Gen (% of Total)	18.5%	18.5%	18.5%	18.5%
Hydroelectric Share	5.8%	5.8%	5.8%	5.8%
Renewable Share	13.5%	12.2%	14.8%	13.5%
Fossil Share	68.0%	69.3%	66.7%	68.0%
US Gas Demand for Electric Generation (Tcf/yr)	8.3733	10.0276	8.1418	8.3733
	2022			
Total US Electric Generation (GWh/yr)	4,766,558	4,819,407	4,735,485	4,766,558
Nuclear Share of US Gen (% of Total)	17.8%	17.8%	17.8%	17.8%
Hydroelectric Share	5.5%	5.4%	5.5%	5.5%
Renewable Share	15.4%	13.4%	16.6%	15.4%
Fossil Share	66.8%	68.8%	65.6%	66.8%
US Gas Demand for Electric Generation (Tcf/yr)	8.9663	11.7262	8.7017	8.9663
	2030			
Total US Electric Generation (GWh/yr)	5,179,648	5,309,049	5,102,910	5,179,648
Nuclear Share of US Gen (% of Total)	16.74	16.7%	16.7%	16.74
Hydroelectric Share	5.0%	4.9%	5.1%	5.0%
Renewable Share	17.0%	14.9%	17.5%	17.0%
Fossil Share	66.3%	68.4%	65.7%	66.3%
US Gas Demand for Electric Generation (Tcf/yr)	9.9367	12.8846	9.6993	9.9367

Source: California Energy Commission Staff Draft Analysis.

Table 2 focuses on the cases designed to explore how California future gas demand might change under a variety of plausible future conditions. Since changes to assumptions that affect demand for electric generation by fuel type were made in both of these cases, the power resource mixes of both differ from that of the Reference Case. Notable differences include the share of generation from nuclear (especially in the High California Gas Demand Case) and from renewable. The change in share for conventional hydroelectric generation changes across cases only because the total generation amount changes across cases. The change in share for fossil generation changes across cases because the total generation amount changes and because nuclear and renewable assumptions are changing with fossil making up the difference.

Table 2: Highlights of California Electric Generation-Related Input Assumptions for Cases Focused on California Gas Demand Impacts

	Reference	High CA Gas Demand	Low CA Gas Demand
		2017	
Total CA Electric Generation (GWh/yr)	223,664	224,925	222,181
Nuclear Share of US Gen (% of Total)	15.1%	15.0%	15.1%
Hydroelectric Share	12.2%	12.2%	12.3%
Renewable Share	25.1%	21.4%	27.6%
Fossil Share	47.6%	51.5%	45.0%
CA Gas Demand for Electric Generation (Tcf/yr)	0.6702	0.7132	0.6375
		2022	
Total CA Electric Generation (GWh/yr)	238,058	242,021	232,741
Nuclear Share of US Gen (% of Total)	14.5%	11.3%	14.5%
Hydroelectric Share	11.5%	11.3%	11.8%
Renewable Share	29.4%	25.8%	35.0%
Fossil Share	44.5%	51.6%	38.7%
CA Gas Demand for Electric Generation (Tcf/yr)	0.6448	0.7237	0.5691
		2030	
Total CA Electric Generation (GWh/yr)	259,909	265,096	251,119
Nuclear Share of US Gen (% of Total)	13.7%	0.0%	13.7%
Hydroelectric Share	10.5%	10.3%	10.9%
Renewable Share	28.7%	33.0%	40.0%
Fossil Share	47.1%	56.7%	35.4%
CA Gas Demand for Electric Generation (Tcf/yr)	0.7467	0.9295	0.5473

Source: California Energy Commission Staff Draft Analysis.

Assumptions All Cases Share With the Reference Case

The following section discusses a few important assumptions that all cases share and have significant effects on the modeling results. Therefore, they are important to understand when interpreting and evaluating model results for all cases.

Price Elasticity of Demand

One of the most important set of assumptions included in the model is the *price elasticity* of demand for each class of natural gas end user. In simple terms, the price elasticity is a measure of how much demand for a product changes for a given change in price, and is usually expressed as a percentage. So a consumer with a price elasticity of -1 for natural gas will reduce the demand for natural gas by 1 percent for each 1 percent increase in natural gas price. This defines how price-responsive people and business are to fluctuations in the market for natural gas.

Price elasticity can result from numerous specific behaviors and responses to price change. The most common reactions to price increases are to cut back on whatever process is consuming the product (for example, adjusting the thermostat in your house to keep your house colder in the winter, thus using less natural gas) or to switch to some other product as a substitute. In "the model," staff does not attempt to identify all of the underlying reasons for price adjustment. Instead, staff has relied on expert judgment and proprietary data to estimate the appropriate price elasticities.

Price elasticities can also vary depending on the time horizon chosen. Short-term price spikes or dips may have different effects than longer-term price levels. In the natural gas sector, economists typically find it necessary to distinguish between short- and long-term price elasticities. This is because participants in the market take different actions depending on what has happened to price in the recent past (this is sometimes called an autoregressive feature in the data).

The WGTM is able to allow for both immediate (one year or less) and longer term (more than one year) response to price. The short-run price elasticities are estimated from national data and shown in **Table 3**. From the same data, an estimate is made of how much participants weight the recent history or prices to determine their longer term choices. This estimate is called the half-life and is shown below. Finally, staff uses the estimates of short-term price elasticity and half-life to calculate long-term price elasticity, also shown in **Table** 3.

Table 3: Price Elasticity of Demand for Gas by Sector, All Cases

	United States			
	Residential	Commercial	Industrial	Power Generation
Price Elasticity (Short-Term)	-0.1475	-0.1218	-0.2201	-0.11860
Half-Life	2.1240	2.6721	3.5360	4.2980
Price Elasticity (Long-Term)	-0.5298	-0.5329	-1.2363	-0.7963

Source: Dr. Kenneth Medlock III, Appendix B.

A more complete explanation of this method, along with the complete estimated gas demand equations are shown in the methodology slides in **Appendix B**. The price elasticity (short run) of natural gas demand in the power generation sector is -0.11860. The price elasticity assumptions shown in staff's April 19, 2011, workshop presentation have changed because the U.S. demand equations now used in the Reference Case have changed since that earlier vintage of the econometric analysis. For example, power generation sector gas demand elasticity had been -0.442 and is now -0.1186.

Part of the reason for updating the econometric demand formulation was improving the statistical methods used to capture time trends within the time series data. There were also improvements to the way the information about hydroelectric, nuclear, and renewable generation, including RPS and other non-RPS-eligible renewable generation (such as distributed renewable generation), were handled.

Allocating Statewide Estimated Gas Demand to Subareas

As described above, a regression analysis of state-level historical gas demand in each sector--residential, commercial, industrial, and electric generation — to derive equations used to project future statewide gas demand for each sector. But the statewide sector-specific gas demands have to be allocated to subareas to correspond to the WGTM gas market topology, which has a substate level of detail linking gas demand to gas supply areas by transpiration facilities.

For states other than California, residential and commercial allocation factors are based on population weights of the defined regions within each state. County populations have been aggregated into regional populations and then used to calculate the region's population share within the state. For industrial and power generation, the weights are based on the location of gas-fired power plants within each state. The method for industry deviates in states such as Texas, where industrial load is particularly large. In Texas, the split of industrial demand is based on analysis of gas-using industry locations. The data sources are the U.S. Census and the Economic Census.

The substate allocation factors for California are calculated by a different method. They are based on historical gas demand by sector and subarea for 2009 reported in the *2010 California Gas Report*.

Table 4 shows the derived allocation factors used in this assessment. Staff's analysis assumes these allocation factors do not change over time in any sector.

Table 4: California Allocation Factors to Assign Statewide Sector-Specific Gas Demand to Geographic Subarea

CA-Central	CA-PG&E	CA-SoCal	
6.21%	32.86%	60.93%	Residential and Commercial
27.56%	30.27%	42.17%	Industrial and Power Generation

Source: California Energy Commission Staff Analysis of *2010 California Gas Report.*

CHAPTER 3: Modeling Results

Chapter 2 describes the role of each case within the overall study design and the assumptions and methods staff employed to construct them. This chapter discusses the highlights of the WGTM results for the cases. The case results are collectively discussed to indicate potential future vulnerabilities or opportunities related to activities in the natural gas and its related energy markets. After a brief description of where to find comprehensive results for each case, the following discussion of case results first focuses on price, then moves to supply, infrastructure, and finally demand-related issues such as cost and GHG emissions.

Staff refrains from making conclusions or recommendations based on this draft assessment's assumptions, methods, findings, and initial conclusions. Staff is still reviewing modeling results from the cases. The comments, insights, and recommendations staff receives from stakeholders at the Joint Committee workshop in September 2011 and in subsequent written comments on this draft and its associated appendices will be invaluable to what staff has been able to provide to date to advise these deliberations.

Detailed Results Available Online

Most of the highlighted results presented in this report are statewide, rather than by individual gas utility area. The exceptions include results about prices and the Lowered Pressure Case, which focused on the PG&E area. The entire set of WGTM results files—one for each case—is available on the Energy Commission's *2011 IEPR* website. Each result file includes complete WGTM results for worldwide, North America, U.S. total and individual states, and California gas utility area, and power plant group area. These result files are in Microsoft Excel worksheet format and include tables of results extracted from the WGTM output files. Staff has created charts of results within these files, which help examine the results. **Appendix C** presents a brief guide to the structure of the worksheets—what is to be found on each "tab."

For easy reference, **Table 5** and **Table 6** provide "snapshots" of key input assumptions and WGTM results for 2022 and 2030. They are provided first as a roadmap to the different case assumptions and results, but being necessarily brief and not designed to tell the whole story, will not be fully clear without the results discussion that follows (or the assumptions discussion that precedes).

Table 5: Summary of WGTM Key Driver Assumptions and Model Results, 2022

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Case	High CA Gas Demand Case	Low CA Gas Demand Case	Lowered Pressure Case
Results in 2022							
DEMAND							
US Tcf/yr	27.30	25.05	25.92	24.15	25.30	25.06	25.21
US Gas-Fired Electricity Generation Tcf/yr	8.47	9.36	8.75	8.12	8.47	8.38	8.44
CA Tcf/yr	2.19	2.12	2.24	2.10	2.19	2.14	2.18
CA Gas-Fired Electricity Generation Tcf/yr	0.65	0.66	0.66	0.63	0.69	0.62	0.65
SUPPLY							
US Natural Gas Dry Production Tcf/yr	24.78	22.35	25.56	23.47	24.78	24.92	24.75
US Shale Tcf/yr	12.23	8.76	13.59	10.89	12.23	12.34	11.95
US LNG Tcf/yr	1.07	1.84	0.92	1.25	1.07	0.99	1.04
Canadian Imports Tcf/yr	3.48	4.53	3.64	3.04	3.48	3.30	3.28
Exports Tcf/yr	2.5	3.82	2.63	2.1	2.5	2.67	2.35
PIPELINE CAPACITY							
Cumulative New Capacity to CA (TCF) (aggregated from 2010 to 2022)	0.08	0.12	0.06	0.09	0.33	0.10	0.09
Pipeline Utilization; % of total (EPNG+TW+MJ/ GTN/ KRGT/ Ruby)	36.82/68.46/72.87/47.72	34.52/62.07/67.84/48.4	35.11/81.55/70.7/39.04	36.09/59.58/66.77/45.89	36.04/66.89/71.95/47.49	35.95/65.84/70.12/46.80	36.3/89.5/65.1/31.1
PRICES							
Price at Henry Hub ($ 2010)/Mmbtu	5.78	6.156	5.09	6.14	5.8	5.88	5.75
Basis to CA Border at Topock ($2010)/Mmbtu	0.282	0.203	0.325	0.293	0.136	0.251	0.287
Basis to Malin ($2010)/Mmbtu	-0.076	-0.132	-0.033	-0.043	-0.217	-0.091	-0.057
Key Assumptions							
Average Annual GDP Growth Rate	2.7%	3.5%	2.1%	2.7%	2.7%	2.7%	2.7%
Gas Technology Improvement Average Annual Growth Rate	1%	1%	2.50%	1%	1%	1%	1%
Total US Electricity Production (GWh)	4,766,558	4,819,407	4,735,485	4,766,558	4,770,521	4,761,241	4,766,558
US Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	66.8/17.8/5.45/15.37	68.8/17.8/5.4/13.4	65.6/17.8/5.5/16.6	66.8/17.8/5.45/15.37	67.2/17.7/5.5/15.2	66.6/17.8/5.5/15.6	66.8/17.8/5.45/15.37
Total CA Electricity Production (GWh)	238,058	240,698	236,506	238,058	242,021	232,741	238,058
CA Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	44.5/14.5/11.5/29.4	45.0/14.5/11.4/29.1	44.3/14.5/11.6/29.6	44.5/14.5/11.5/29.4	51.6/11.3/11.3/25.8	38.7/14.5/11.8/35.0	44.5/14.5/11.5/29.4
When CA Meets Maximum RPS Target	On Time	On Time	On Time	On Time	2030	On Time[4]	On Time
When Other States Meet Individual Maximum RPS Targets	5 yrs late	15 yrs late	On Time	5 yrs late	5 yrs late	5 yrs late	On Time
Additional US Coal Generation Converts to Natural Gas	0	50 GW	0	0	0	0	0
Constrain/Augment Natural Gas Resources							
US	NY	PA, NY, CO and WY	Upper End of Range	NY	NY	NY	NY
World	IIV enters marker in 2020[2]	IIRV Constrained[1]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]
LNG Exports	Allowed but not imposed	Imposed LNG Exports	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed
Pipeline Capacity Additions (Model feature turned On/Off)	ON	ON	ON	ON	ON	ON	OFF[3]
PG&E Backbone Capacity Reductionm Constraint, Mmcf/d	None	None	None	None	None	None	300 on Baja/200 on Redwood
Additional Environmental Mitigation Cost (2005$/Mcf)	N/A	$0.40/Mcf shale	N/A	$0.40/Mcf shale	N/A	N/A	N/A
	N/A	$0.20/Mcf Conv	N/A	$0.20/Mcf Conv	N/A	N/A	N/A

Source: California Energy Commission Staff Draft Analysis.

[1]Note: IIRV refers to Iran, Iraq, Russia, and Venezuela.

[2]Note: IIV refers to Iran, Iraq, and Venezuela.

[3]Note: Capacity additions off for 2012-2016.

[4]Note: Continues to grow to 40% by 2027 and then stabilizes.

Table 6: Summary of WGTM Key Driver Assumptions and Model Results, 2030

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Case	High CA Gas Demand Case	Low CA Gas Demand Case	Lowered Pressure Case
Results in 2030							
DEMAND							
US Tcf/yr	27.58	27.82	29.22	26.81	27.58	27.48	27.79
US Gas-Fired Electricity Generation Tcf/yr	9.47	10.97	9.91	9.23	9.47	9.37	9.54
CA Tcf/yr	2.31	2.25	2.45	2.24	2.31	2.20	2.32
CA Gas-Fired Electricity Generation Tcf/yr	0.66	0.69	0.69	0.64	0.80	0.54	0.66
SUPPLY							
US Natural Gas Dry Production Tcf/yr	25.85	24.18	28.11	25.01	25.85	26.27	26.23
US Shale Tcf/yr	13.44	10.79	16.33	13.05	13.44	13.97	13.89
US LNG Tcf/yr	1.17	1.89	0.99	1.45	1.17	1.12	1.12
Canadian Imports Tcf/yr	4.70	5.24	4.42	3.91	4.70	4.49	4.37
Exports Tcf/yr	2.66	3.65	2.68	2.2	2.66	2.78	2.41
PIPELINE CAPACITY							
Cumulative New Capacity to CA (TCF) (aggregated from 2010 to 2030)	0.19	0.12	0.25	0.16	0.58	0.14	0.23
Pipeline Utilization; % of total (EPNG+TW+MJ/ GTN/ KRGT/ Ruby)	35.8/92.3/66.3/28.3	34.9/80.5/61.0/33.3	37.1/95.1/70.7/30.4	35.5/80.9/64.4/33.6	36.9/95.7/66.9/32.4	34.6/86.5/64.9/29.2	36.3/89.5/65.1/31.1
PRICES							
Price at Henry Hub ($ 2010)/Mmbtu	6.15	6.845	5.36	6.39	6.15	6.04	6.07
Basis to CA Border at Topock ($2010)/Mmbtu	0.282	0.275	0.14	0.42	0.046	0.42	0.32
Basis to Malin ($2010)/Mmbtu	-0.145	-0.129	-0.23	0.004	-0.26	-0.121	-0.08
Key Assumptions							
Average Annual GDP Growth Rate	2.7%	3.5%	2.1%	2.7%	2.7%	2.7%	2.7%
Gas Technology Improvement Average Annual Growth Rate	1%	1%	2.50%	1%	1%	1%	1%
Total US Electricity Production (GWh)	5,179,648	5,309,049	5,102,910	5,179,648	5,184,835	5,170,859	5,179,648
US Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	66.3/16.7/5.0/17.0	68.4/16.7/4.9/14.9	65.7/16.7/5.1/17.5	66.3/16.7/5.0/17.0	66.8/16.0/5.0/17.2	65.8/16.8/5.0/17.5	66.3/16.7/5.0/17.0
Total CA Electricity Production (GWh)	259,909	266,402	256,059	259,909	265,096	251,119	259,909
CA Electricity Resource Mix (% of total from Fossil/Nuclear/Hydro/Renew)	47.1/13.7/10.5/28.7	48.0/13.7/10.3/28.0	46.5/13.7/10.7/29.2	47.1/13.7/10.5/28.7	56.7/0.0/10.3/33.0	35.4/13.7/10.9/40.0	47.1/13.7/10.5/28.7
When CA Meets Maximum RPS Target	On Time	On Time	On Time	On Time	2030	On Time[4]	On Time
When Other States Meet Individual Maximum RPS Targets	5 yrs late	15 yrs late	On Time	5 yrs late	5 yrs late	5 yrs late	On Time
Additional US Coal Generation Converts to Natural Gas	0	50 GW	0	0	0	0	0
Constrain/Augment Natural Gas Resources							
US	NY	PA, NY, CO and WY	Upper End of Range	NY	NY	NY	NY
World	IIV enters marker in 2020[2]	IIRV Constrained[1]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]	IIV enters marker in 2020[2]
LNG Exports	Allowed but not imposed	Imposed LNG Exports	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed	Allowed but not imposed
Pipeline Capacity Additions (Model feature turned On/Off)	ON	ON	ON	ON	ON	ON	OFF[3]
PG&E Backbone Capacity Reduction Constraint, Mmcf/d	None	None	None	None	None	None	300 on Baja/200 on Redwood
Additional Environmental Mitigation Cost (2005$/Mcf)	N/A	$0.40/Mcf shale	N/A	$0.40/Mcf shale	N/A	N/A	N/A
	N/A	$0.20/Mcf Conv	N/A	$0.20/Mcf Conv	N/A	N/A	N/A

Source: California Energy Commission Staff Draft Analysis.

[1]Note: IIRV refers to Iran, Iraq, Russia, and Venezuela.

[2]Note: IIV refers to Iran, Iraq, and Venezuela.

[3]Note: Capacity additions off for 2012-2016.

[4]Note: Continues to grow to 40% by 2027 and then stabilizes.

Price-Related Modeling Results

Future natural gas prices matter to everyone in the market, from the producers who receive them to the consumers who pay them. The uncertainties affecting any attempt to accurately predict future gas prices flows through to producers' predictions of their future revenues and profit as well as to consumers' predictions of their future gas bills. Future gas prices also matter to policy-makers and regulators who have to weigh the potential future tradeoffs that current and proposed policies might produce. An assumption about the future price of natural gas is typically a part of complex analyses that try to balance sometimes competing effects on public health and safety, the environment, and a thriving economy, which requires adequate, reliable and affordable energy supplies. This wide interest in price is why the discussion of results begins with the price-related ones.

The WGTM produces natural gas prices for the Henry Hub, California border locations, and citygate locations inside California. End use prices of natural gas are calculated outside the model and are discussed in **Chapter 4.** Even though they are WGTM results, citygate prices are saved for **Chapter 4** because they are the starting point for many of the end use natural gas price calculations.

The WGTM's input assumptions and outputs about prices are not in current year dollars but in real 2005$. When staff reports a result in real 2010$, the model result has been converted based on historically observed inflation between those years. Most price results in this report are presented in real 2010$. Future inflation expectations would have to be added to increase the real 2010$ results into future year then-current (nominal) dollars to allow results to be compared directly to price or cost estimates made by others, either in nominal dollars or in real dollars other than 2010$. Both real and nominal price results are provided for some outputs in the results worksheets mentioned above. The inflation series, for observed past years and future year estimates, are also included in **Appendix D**.

Henry Hub Annual Average Spot Prices

The spot purchase price of natural gas at the Louisiana trading hub called Henry Hub is a nationally important market price benchmark. Currently, natural gas prices at Henry Hub are in the low $4/MMBTU range (in 2010$). Current spot prices of natural gas reflect a large supply from shale natural gas and a slow economy. Much of the natural gas production is occurring on leased land where many gas developers must drill for gas soon or lose their lease. Since demand is low due to the recession, the resulting temporary oversupply situation pushes current market prices down.

What useful information can the modeling results give about future Henry Hub spot market prices? As described in **Chapter 2**, in addition to the "business as usual" Reference Case, staff constructed three other cases to provide information about what gas market prices may be under a variety of plausible future conditions, focusing on key drivers with effects large enough to move price nationally and which have considerable uncertainty: the High Gas Price Case, the Constrained Shale Gas Case, the Low Gas Price Case.

For these four cases, **Figure 4** plots the WGTM results for annual average equilibrium price for spot gas purchases at Henry Hub for 2005 through 2030, in real 2010$ (not increased for inflation). Beginning in approximately 2012, the Reference Case price jumps from the $4/MMBTU range to the $6/MMBTU range. There are a few reasons for this jump. As the economy is assumed to recover and the resulting model demand picks up, the balance between supply and demand is reestablished. Secondly, the most economical (cheapest to produce) shale *plays* are being developed first.[16] As these economical shale areas mature, they will produce less, and the relatively more expensive shale plays will be produced to bring supply to market. Beyond 2015, the price remains fairly flat, growing from about $5/MMBTU to just under the $6/MMBTU by 2030 (in 2010$).

Shale is projected to be the primary source of natural gas for the next 10 years and beyond. If shale gas production is restricted more or has higher environmental compliance costs than assumed in the Reference Case, then staff would expect to see higher natural gas prices as a result. Indeed, the Constrained Shale Gas Case Henry Hub prices results show that. The restrictions and additional environmental costs imposed on this case could be either more or less severe than the assumptions. This is a significant source of uncertainty about future gas prices.

The Henry Hub annual average spot price in the High Gas Price Case reaches $6.00/MMBTU by 2018 (12 years before the Reference Case hits that mark) and by 2030 has somewhat leveled off below $6.80/MMBTU (in 2010$).

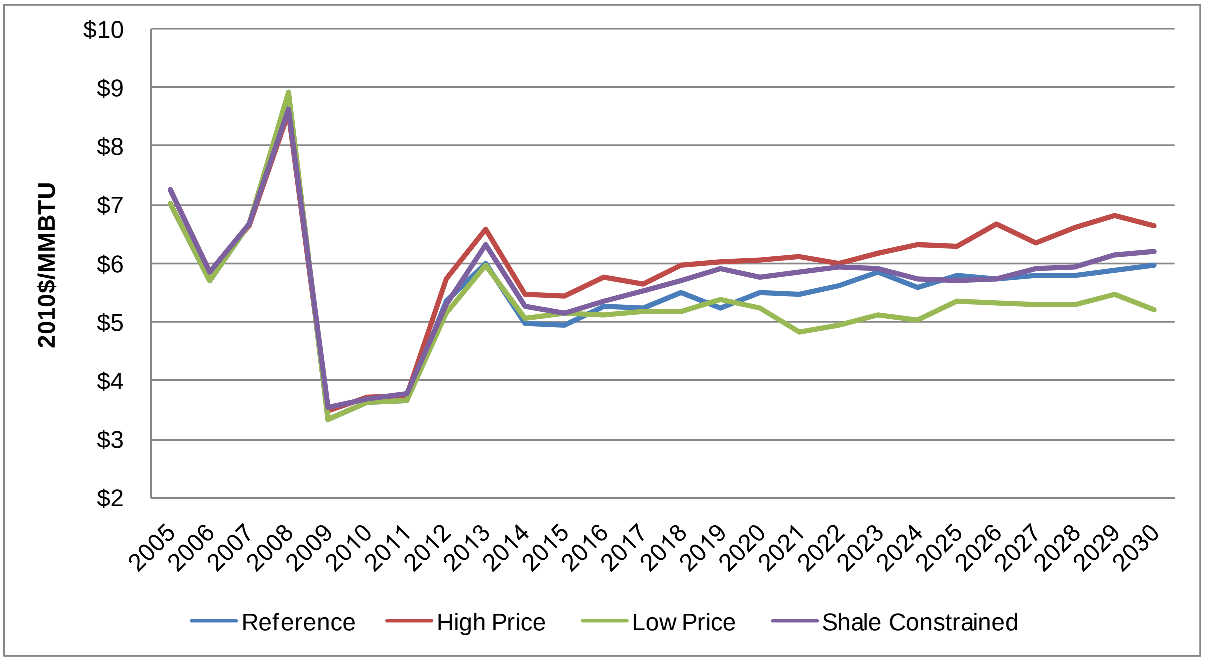
The Low Gas Price case actually yields a Henry Hub gas price slightly higher than the Reference Case in 2019. Surprising results like this may occur because of the timing of investments. Looking past 2019, the Low Price Case's Henry Hub prices hover around $5.00/MMBTU thru 2024, increasing to about $5.30/MMBTU afterward.

Natural gas California border and citygate prices follow the same general trends as the Henry Hub price. Figures of these conditionally estimated prices will be provided in **Chapter 4**. **Figure 4** does not show the price of natural gas for the High and Low California demand cases; prices in these cases do not differ much from the Reference Case and thus do not provide much useful information. California is a relatively small piece of the U.S. natural gas market; it does not have the market power to significantly affect the price of natural gas. However, events outside California can influence the price Californians pay for

16 A shale play is geographic area containing an organic-rich fine-grained sedimentary rock displaying the the following characteristics: Particles are the size of clay or silt, contains high percentage of silica (and sometimes carbonates), is thermally mature, has hydrocarbon-filled porosity and low permeability, is distributed over a large area, and economic production requires fracture stimulation.

natural gas. It is also likely that if the price of natural gas changes at a major market hub outside of California, such as the Henry Hub, the price Californians pay will change as well.

Figure 4: Henry Hub Prices for Selected Cases



Source: California Energy Commission Staff Draft Analysis.

Estimates of future annual average natural gas spot purchase prices at Henry Hub are used by California energy and environmental agencies both to analyze the potential effects of proposed policies and to implement existing policies. For example, when implementing the RPS for investor-owned utilities, the CPUC has directed parties to use a Henry Hub spot gas price forecast as an input to calculating the so-called Market Price Referent (MPR). The MPR is an estimate of the future cost of electricity, assuming the electricity is generated by a gas-fired power plant, California's marginal electricity source. This natural gas-based electricity price has been used as a reasonableness benchmark for the actual prices being bid by renewable generators into the RPS-competitive solicitations for power purchase agreements.

As expectations of future gas prices change over the years, so too has the reasonableness benchmark for renewable generation bid prices. **Figure 5** shows how the CPUC-directed assumptions about future Henry Hub spot gas prices have changed dramatically between 2004 and 2009. Although no MPR was calculated in 2010, the CPUC directed the same method be used to develop a future gas price assumption for analysis conducted in the

Long-Term Procurement Planning (LTPP) proceeding.[17] The 2010 LTPP assumptions for future Henry Hub prices are also shown, as is staff's Reference Case result

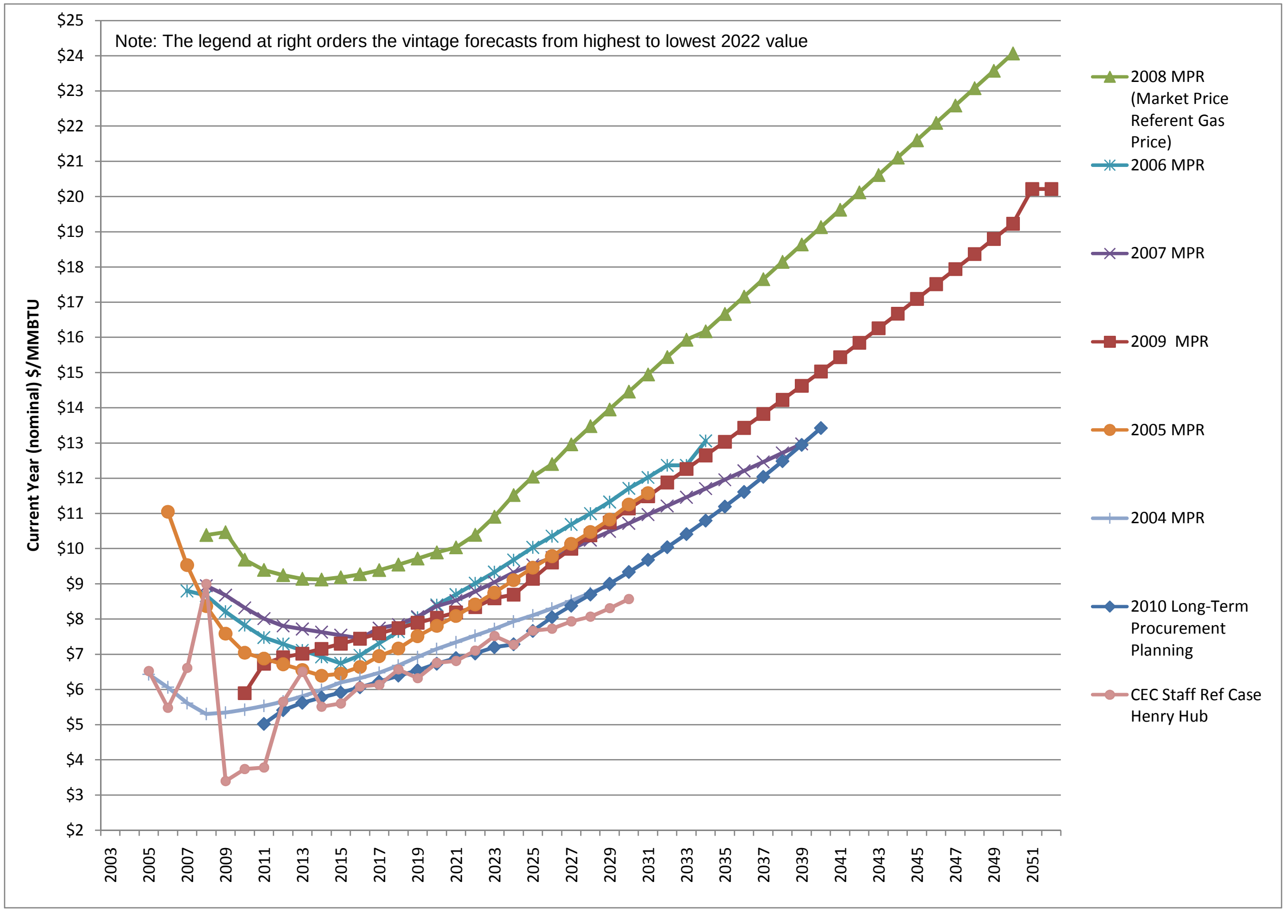
Expectations of future gas prices made between 2004 and 2008 generally increased year over forecast year. After 2008, expectations started going downward year over forecast year as they began to incorporate significant if unexpected events such as the impact of a severe recession on demand and major technological developments in shale gas extraction.

Recent changes to the way the RPS program is implemented may no longer require the MPR benchmark to be calculated. However, it seems inescapable that expectations of future natural gas prices will continue to play some important role in energy and climate change policy analysis and policy program implementation, at least as long as gas-fired generation is the marginal source and a general avoided cost approach is built into the cost-effectiveness analyses of planning studies and new regulation rulemaking, or into the detailed mechanisms employed to implement adopted programs. For example, programs providing incentives for distributed renewable generation and combined heat and power (CHP) facilities by setting fixed feed-in tariffs (or by otherwise establishing price terms of power purchase agreements, which may require reasonableness checks) are likely to incorporate into their programs a then-current expectation of future gas prices.

Whatever the purpose to which a then-current expectation of future gas prices is put, the message of **Figure 5** is clear: Expectations can change quickly and dramatically as the next round of expectations takes into account the events that have just occurred and considers the apparent new trends in motion. The more complex and uncertain the system is about which expectations (assumptions) for the future are being developed, the more careful the user of these expectations (assumptions) must be if acting on them. There are simply limits to how accurate expectations can be.

17 The CPUC's Long-Term Procurement Planning (LTPP) process for investor-owned electric utilities employs a long-term gas price forecast in comparative performance analyses of alternative resource plans, leading to decisions on, among other things, electric capacity and energy and natural gas procurement limits.

Figure 5: Historical Estimates of Annual Average Henry Hub Natural Gas Spot Purchase Price Used as Assumptions in California Energy Regulatory Activities



Sources: Reference Case (Energy Commission Staff Draft Analysis); 2010 LTPP (E3: Energy + Environmental Economics, April 2011 Evaluation Metric Calculator at http://www.cpuc.ca.gov/PUC/energy/Procurement/LTPP/LTPP2010/LTPP_System_Plans.htm ; Market Price Referent (MPR) forecasts (E3: Energy + Environmental Economics, Public Projects website at http://www.ethree.com/public_projects/cpuc3.html).

Using Futures Prices as a Forecast

Using *futures prices* as a forecast has been discussed by many industry stakeholders, including government policy makers; there are pros and cons to using futures prices as a forecast. There is a method known as "blending" where the first few years of futures prices are used, then a fundamental forecast thereafter. One reason for using futures prices is that many people assert that there is no good forecast, so using futures prices will deviate as much as the rest of the market. In theory, futures prices summarize privately available information about the supply and demand of natural gas. There are number of economists who believe that futures natural gas prices make an accurate price forecast. The Lawrence Berkeley National Laboratory performed a study comparing futures natural gas prices to the U.S. EIA's *Short Term Energy Outlook* (*STEO*).[18] Researchers found that the futures prices were closer to spot prices than the *STEO*, which uses an economic model. The time frame examined in this study was up to 24 months in the future. Other analysts compared the U.S. EIA's *2010 Annual Energy Outlook* (*AEO 2010*) reference case projection of Henry Hub gas prices to the NYMEX natural gas futures strip, and find that from 2009 through 2020 both prices are very similar with the NYMEX prices at a slight premium to the AEO forecast.[19]

A futures price is a price set by a number of buyers and sellers that is agreed to today for the purchase of gas to be delivered in the future. However, less than one percent of all natural gas futures contracts are ultimately held for physical delivery.[20] *Forward prices* exist in commodity markets as well as futures prices. There are differences between futures prices and forwards prices, chiefly that forwards are generally private, bilateral (that is, two-party), over-the-counter (meaning nonstandard) contracts; whereas futures contracts are standardized and traded on a public exchange. The fact that so few futures contracts are tied to physical deliveries tells staff that many times these contracts may be used for other purposes such as price hedging. The price paid today for natural gas may be different than it is three months from now. Futures pricing makes use of private knowledge today about what may influence the price in the future. For example, three months from now supply, demand, or government policy situations may change from what they are today. Also, one needs to determine what day to use for a futures contract. For example, a futures contract for delivery of natural gas in March of a given year can be purchased any business day in the preceding February, or the month before that, and so on. Does a forecaster use the 15th

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18 See Wong-Parodi, G. (2005). *Comparing Price Forecast Accuracy of Natural Gas Models and Futures Markets*.

19 See Bolinger, M. & R. Wiser (2010). *Comparison of AEO 2010 Natural Gas Price Forecasts to NYMEX Futures Prices*. Ernest Orlando, Lawrence Berkeley National Laboratory. Retrieved from http://eetd.lbl.gov/ea/emp/reports/53587_memo.pdf.

20 See page 7 of http://www.ngsa.org/assets/Docs/Issues/19a%20-%20US%20Natural%20Gas%20Market%20Transparency%20Study%20by%20Albrecht.pdf.

day of every month, an average of trading days, or some of the trading days during bid week?[21]

Secondly, when using a futures price as a forecast, the forecaster must accept whatever assumptions the traders made, without knowing what those assumptions are. If the purpose of a forecast is to gain insights about the market based on various assumptions made by the forecaster, then futures prices leave the forecaster (and the consumers of the forecast) in the dark, as the assumptions that were made (by the traders) are not knowable.

Another aspect to think about is that most futures transactions take place within the first few years of the tradable horizon for a given contract. There are few buyers and sellers trading futures contracts many years out into the future. But, in fact, Henry Hub Natural Gas Futures are listed for the current year and the next 12 years.[22] If a long-term forecast is the goal, the futures market may not provide a large enough sample size of the market to accurately predict market interactions far into the future. Also, the further out into the future, the more uncertainty surrounds assumptions about the economy, policy decisions, and other factors that affect the price of natural gas. In the short run, the futures price of natural gas may be an adequate forecast, but for terms spanning more than a few years, futures market natural gas prices may not be a good gas price forecast.

Basis Differentials

A basis differential is the difference in the price of natural gas at two different pricing locations. It is a measure of the value of having transportation options available to you that can access the cheapest supplies of natural gas and deliver them for your use. For simplicity, staff assumes a basis differential is the difference from a natural gas pricing point and the Henry Hub pricing point (point of interest minus Henry Hub). **Figure 6** and **Figure 7** represent the basis differentials for Malin and SoCal Border hubs prices relative to Henry Hub. Looking at **Figure 7**, which shows the basis differential between the Malin pricing point and the Henry Hub pricing point, we see that the basis differential shrinks greatly starting in 2010–2011. This means natural gas at the Malin hub is becoming relatively cheaper compared to the Henry Hub. First, the Ruby Pipeline, which brings natural gas to Malin from Wyoming, comes into service in 2011; this creates more gas on gas competition with Henry Hub. The Ruby pipeline gives the Malin location another source to receive gas from. Secondly, with all the shale gas coming to market, staff expects prices of natural gas at various pricing hubs to shift as shale supplies change in different market areas. Also, the REX pipeline, which flows natural gas east from Colorado to Wyoming, played a role in causing California natural gas prices to increase towards Henry Hub prices. In the Low Gas

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21 Bid week refers to the last five business days of a month. During bid week, buyers and sellers arrange for the purchase and sale of natural gas to be delivered throughout the coming month.

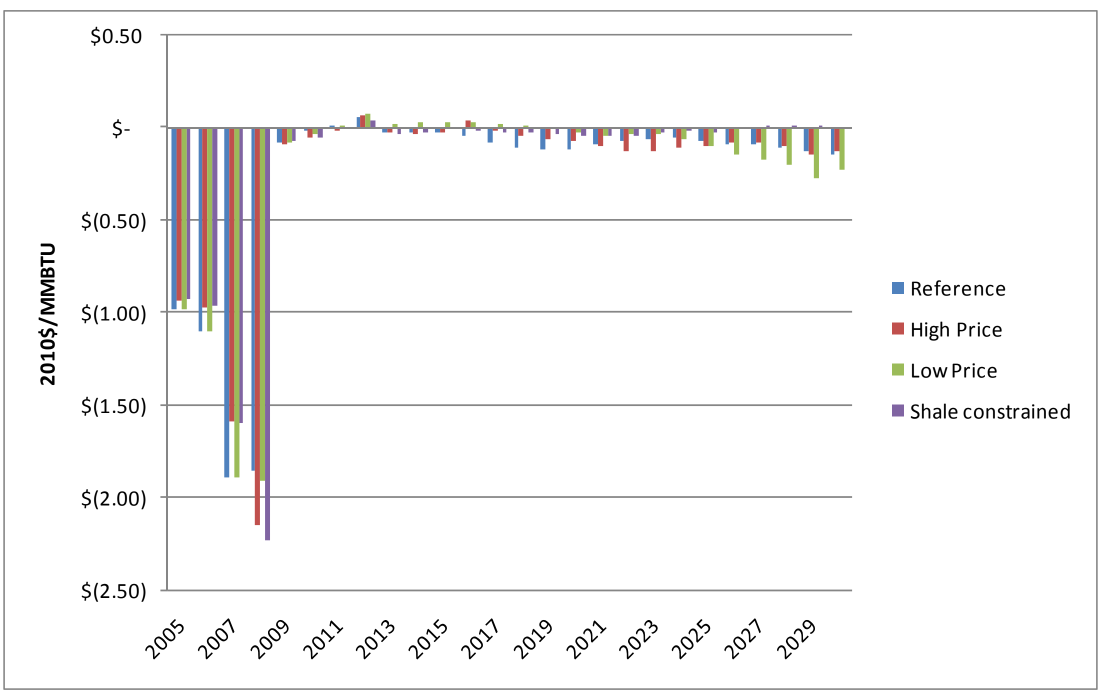
22 See http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_contract_specifications.html, and http://www.cmegroup.com/rulebook/NYMEX/2/220.pdf.

Price Case in **Figure 6**, the basis differential remains larger than the other cases in years 2026 through 2030; this means Henry Hub prices are relatively higher than Malin prices of natural gas. In the Low Gas Price Case, more gas flows through the Ruby pipeline to Malin than in the other cases, which gives Malin more supply options, making its price of natural gas relatively cheaper than Henry Hub.

Figure 7 shows the basis differential between the SoCal Border (Topock) and the Henry Hub. **Figure 7** shows essentially the same story as in **Figure 6**; more shale gas coming to market causes more gas-on-gas competition and changes in shale supply. In **Figure 7**, the Constrained Shale Gas Case, staff's assumption is the cost of producing shale gas becomes $0.20 more expensive than conventional gas; this means there is less shale to meet market demand, and the market demand will be met by more expensive conventional gas sources. Looking at the Constrained Shale Gas Case for 2026 through 2030, staff sees the SoCal Border price of natural gas become more expensive than Henry Hub relative to all the other cases.

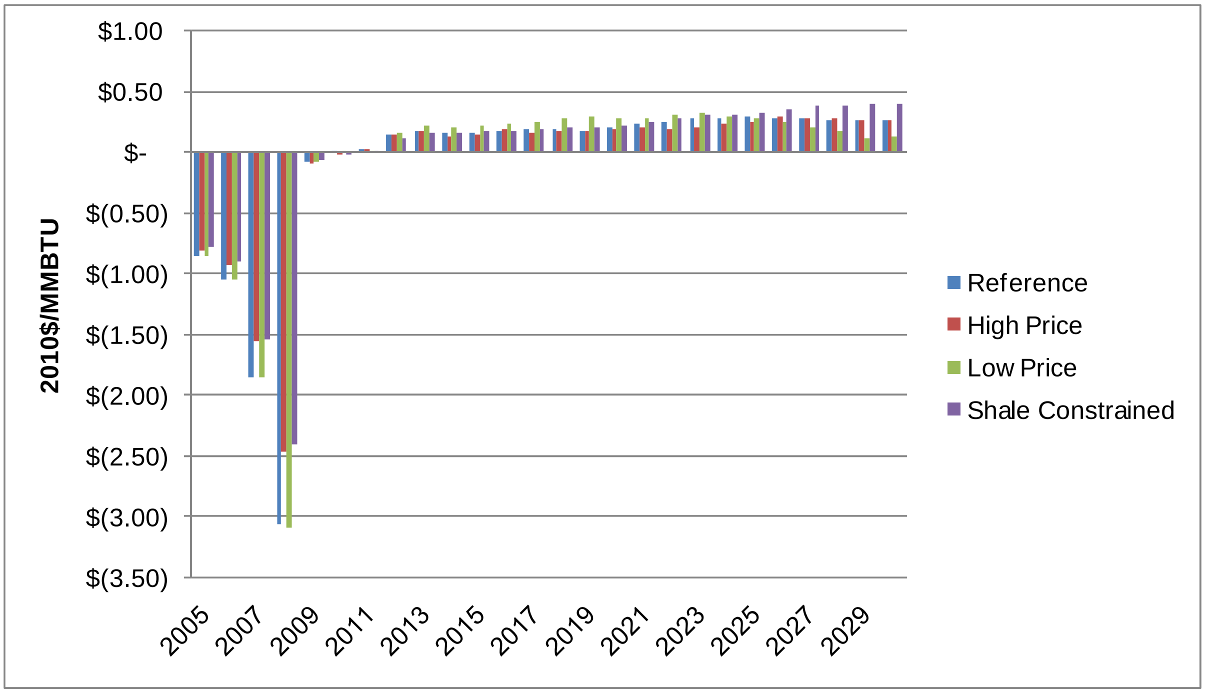
Looking at both **Figure 6** and **Figure 7** SoCal Border (Topock) prices increase more relative to Henry Hub than do Malin prices. This can be explained by the fact that Malin can receive natural gas from the north (Canada) and the south (Gulf Coast), which increases gas-on-gas competition and puts downward pressure on prices of natural gas, whereas Topock has fewer supply options. No basis differentials were computed for citygate price locations because citygate prices of natural gas already have some intrastate pipeline rates included in them, where as Henry Hub prices do not.

Figure 6: Malin Basis Differential to Henry Hub (Malin – Henry Hub)



Source: California Energy Commission Staff Draft Analysis.

Figure 7: SoCal Border (Topock) Basis Differential to Henry Hub (Topock – Henry Hub)



Source: California Energy Commission Staff Draft Analysis.

Although citygate prices are outputs of the WGTM, they are discussed in **Chapter 4**, being the starting point for many end-user gas prices.

Supply-Related Modeling Results

This section highlights selected supply-related modeling results across the cases. **Table 7** and **Table 8** show the annual production volumes for each case for both U.S. gas production from all sources and U.S. gas production from just shale formations, respectively. To further compare the cases, **Figure 8** and **Figure 9** highlight the differences of production in each case from the Reference Case and each other. For selected snapshot years 2020 and 2030, additional tables show how the results for U.S. production, shale production, and California production in selected cases differ from the Reference Case as a percentage.

The discussion in this section focuses on the Reference Case and the changed cases that were designed to move gas market prices: the High and Low Gas Price, and Constrained Shale Gas Cases.

Table 7: U.S. Natural Gas Production Summary, MMcf/d

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Gas Case	High California Demand Case	Low California Demand Case
2005	48,330	48,154	48,330	48,000	48,330	48,330
2006	51,269	50,707	51,269	50,410	51,269	51,269
2007	53,443	53,116	53,443	52,859	53,443	53,443
2008	55,821	55,295	55,821	55,209	55,809	55,823
2009	58,352	57,457	58,354	57,157	58,442	58,346
2010	59,606	58,727	59,581	58,431	59,641	59,586
2011	62,403	61,402	62,444	61,030	62,236	62,331
2012	61,126	58,965	63,060	60,323	61,371	61,684
2013	60,853	56,817	62,574	59,080	60,450	61,856
2014	61,494	55,594	62,618	58,711	60,946	62,630
2015	62,229	55,400	62,505	58,577	61,936	63,186
2016	62,656	55,574	63,124	59,382	62,691	63,569
2017	63,063	56,225	64,300	60,184	63,407	63,998
2018	63,916	57,254	65,336	60,644	63,762	64,772
2019	64,709	57,792	66,318	61,175	64,135	65,469
2020	65,896	58,580	67,437	61,978	65,072	66,508
2021	66,920	59,745	68,906	63,212	65,613	67,360
2022	67,883	61,238	70,029	64,301	66,540	68,283
2023	68,515	62,620	71,019	65,229	67,196	69,104
2024	69,020	63,298	71,907	66,745	68,034	69,929
2025	69,635	63,562	72,329	67,650	69,115	70,076
2026	69,976	64,289	72,573	68,258	68,779	70,626
2027	70,075	65,214	73,036	68,627	68,832	71,260
2028	70,461	65,735	73,934	68,620	69,249	71,274
2029	70,782	65,642	74,919	68,476	69,846	71,267
2030	70,826	66,256	77,020	68,526	70,855	71,976

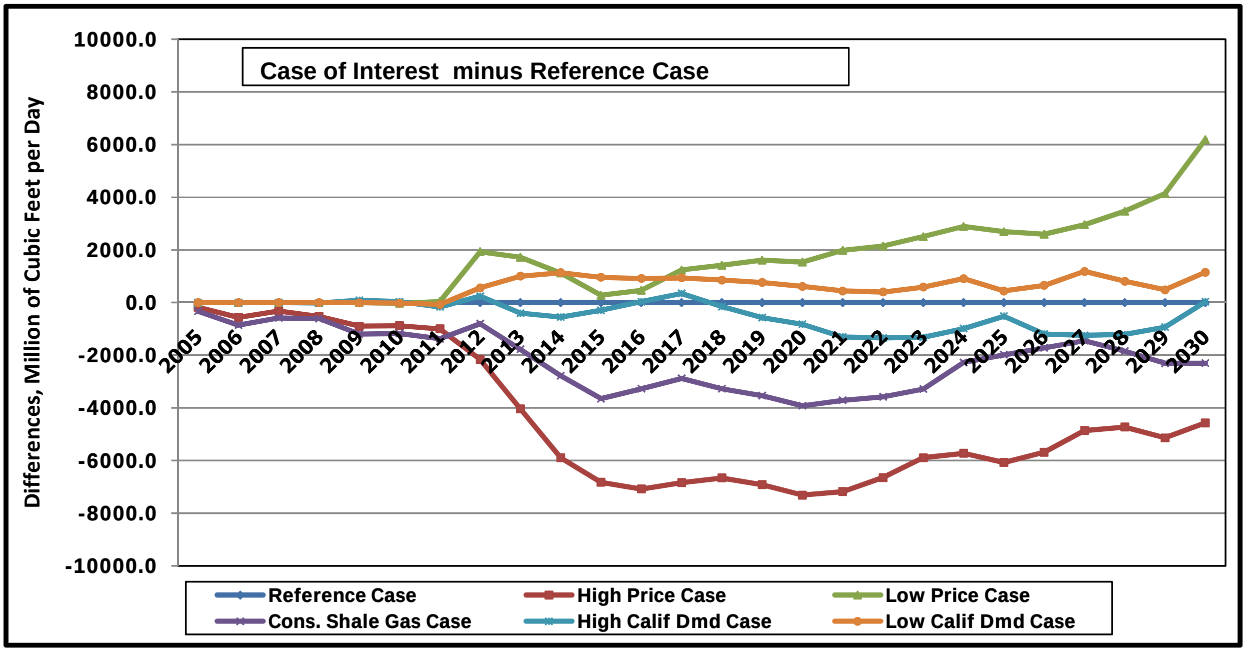
Source: California Energy Commission Staff Draft Analysis.

Table 8: U.S. Shale Gas Production Summary, MMcf/d

	Reference Case	High Gas Price Case	Low Gas Price Case	Constrained Shale Gas Case	High California Demand Case	Low California Demand Case
2005	1,027	1,027	1,027	1,027	1,027	1,027
2006	1,794	1,788	1,794	1,791	1,794	1,794
2007	3,479	3,438	3,479	3,453	3,479	3,479
2008	5,750	5,655	5,750	5,676	5,748	5,750
2009	8,360	8,347	8,360	8,322	8,365	8,360
2010	10,438	10,374	10,434	10,285	10,442	10,435
2011	13,556	13,255	13,610	12,817	13,356	13,490
2012	16,014	13,747	18,496	14,970	16,063	16,442
2013	18,595	14,260	21,671	16,409	17,862	19,446
2014	21,266	14,567	24,476	18,004	20,159	22,233
2015	23,432	15,093	26,316	19,211	22,358	24,136
2016	24,922	15,793	28,147	20,839	24,109	25,385
2017	26,266	16,970	30,089	22,476	25,807	26,612
2018	27,831	18,537	31,696	23,803	27,233	28,098
2019	29,209	19,787	33,074	25,128	28,564	29,415
2020	30,861	21,038	34,465	26,528	30,177	30,999
2021	32,271	22,393	36,030	28,240	31,371	32,407
2022	33,514	24,011	37,237	29,837	32,733	33,799
2023	34,342	25,512	38,295	31,241	33,665	34,824
2024	34,980	26,348	39,266	32,998	34,530	35,672
2025	35,715	26,749	39,820	34,230	35,548	35,948
2026	36,204	27,438	40,160	35,156	35,467	36,521
2027	36,371	28,318	40,669	35,742	35,683	37,106
2028	36,618	28,796	41,655	35,867	36,096	37,295
2029	36,774	28,787	42,665	35,751	36,669	37,531
2030	36,833	29,566	44,748	35,767	37,620	38,276

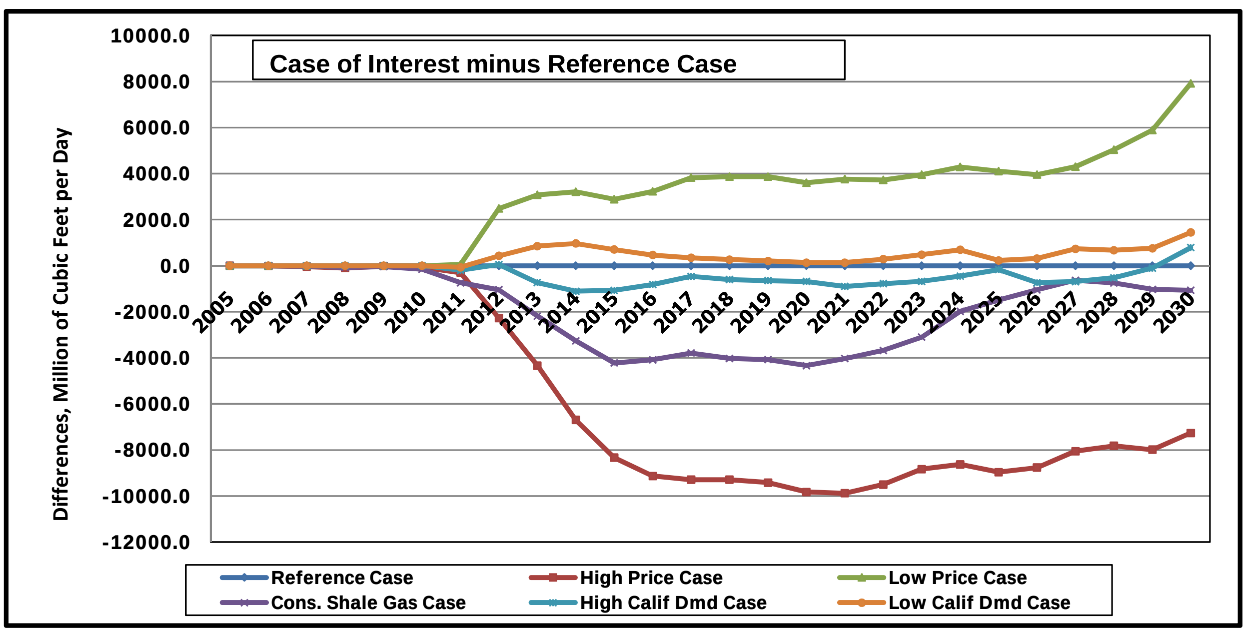
Source: California Energy Commission Staff Draft Analysis.

Figure 8: Differences in U.S. Gas Production Across All Cases, MMcf/d



Source: California Energy Commission Staff Draft Analysis.

Figure 9: Differences in U.S. Shale Gas Production Across All Cases, MMcf/d



Source: California Energy Commission Staff Draft Analysis.

In a dynamic market such as the natural gas market, price changes can produce two responses:

- Consumers of natural gas purchase more gas if prices fall or less if prices rise.
- Suppliers of natural gas produce more gas for the marketplace if prices rise or less if prices fall.

All the cases result in some combination of these two responses, as the competing behaviors of economic agents represented in the model translate into a net effect that shows up as the sometimes unexpected, but nevertheless explainable, result.

High Gas Price Case

In the world of higher prices as assumed in the High Gas Price Case, the dominant effect appears to be less natural gas production from suppliers as a result of lower consumer demand. **Figure 8** and **Figure 9** show this is the case for both U.S. production from all sources and production from shale formations as a separate class. Starting in 2010, natural case production falls below the reference case and remains lower than the reference case until 2030. Higher prices push U.S. production 11.1 percent lower in 2020 and 6.5 percent lower in 2030. Total Lower 48 shale production displayed a similar trend. However, in the localized market of California, higher prices stimulated higher natural gas production. California imports about 85 percent of its natural gas requirements and, as a result, a higher price environment stimulated local supply more than it suppressed demand. **Table 9** shows the percentage changes from the reference case.

Table 9: High Gas Price Case Gas Production Compared to Reference Case

	Percentage Change from Reference Case	
	2020	**2030**
U.S. Production	-11.1	-6.5
Shale Production	-31.8	-19.7
California Production	4.5	33.1

Source: California Energy Commission Staff Draft Analysis.

Low Gas Price Case

In the world of lower prices as assumed in the Low Gas Price case, the dominant effect appears to be more natural gas production from suppliers as a result of higher consumer demand. **Figure 8** and **Figure 9** show this is the case for both U.S. production from all sources and production from shale formations as a separate class. Starting in 2010, natural case production exceeds the reference case and remains higher through 2030. Lower prices stimulate natural gas demand which, in turn, causes production to edge higher. **Table 10** shows the percentage changes. U.S. production climbs 2.3 percent higher in 2020 and 8.7 percent higher in 2030. Total Lower 48 shale production and California displayed similar trends, although California's production, by 2030, exhibited the largest impact.

Table 10: Low Price Case Gas Production Compared to Reference Case

	Percentage Change from Reference Case	
	2020	**2030**
U.S. Production	2.3	8.7
Shale Production	11.7	21.5
California Production	6.0	30.6

Source: California Energy Commission Staff Draft Analysis.

Constrained Shale Gas Case

In the world of higher prices that result from the higher costs assumed for shale gas production in this case, the dominant effect appears to be less natural gas production from suppliers as a result of lower consumer demand. However, the response to higher prices of natural gas in the High Gas Price case exceeds that of the Constrained Shale Gas Case, as expected, since the former case resulted in moving gas market prices higher than the latter. Starting in 2010, natural case production falls below the Reference Case and remains lower than until 2030. Higher prices dampen demand, pushing U.S. production lower by 5.9 percent in 2020 and by 3.2 percent in 2030. Total Lower 48 shale production displayed a similar trend. However, in the localized market of California, higher prices, at first, stimulates higher natural gas production. However, by 2030, demand suppression results in lower local production. **Table 11** displays the percentage changes from the Reference Case.

Table 11: Constrained Shale Case Gas Production Compared to Reference Case

	Percentage Change From Reference Case	
	2020	**2030**
U.S. Production	-5.9	-3.2
Shale Production	-14.0	-2.9
California Production	5.8	-5.2

Source: California Energy Commission Staff Draft Analysis.

High and Low California Demand Cases

The changes to Reference Case assumptions which created the High and Low California Gas Demand cases lead to much smaller magnitude shifts in gas production as displayed in **Table 12**.

Table 12: Percentage Change From Reference Case
(Low California Demand and High California Demand)

	Low California Demand		High California Demand	
	2020	**2030**	**2020**	**2030**
U.S. Production	0.9	1.6	-1.3	<0.1
Shale Production	0.4	3.9	-2.2	2.1
California Production	1.1	-4.6	2.3	4.2

Source: California Energy Commission Staff Draft Analysis.

The natural gas market stretches through North America, with pipelines linking regions in the three countries. The North American continent interacts with the rest of the world through "floating pipelines," tankers filled with LNG. Minor demand changes in one region, such as California in these cases, will not affect production in the major producing basins of North America or of the rest of the world. As a result, U.S. natural gas production from all sources, and from shale gas formations as a separate class, exhibited minor shifts when compared to the Reference Case.

Infrastructure-Related Modeling Results

This section discusses highlights of modeling results related to the volumes of natural gas flows between points of interest in the North American gas system, focusing on United States and California in most cases. Flows that cross international boundaries are referred to as exports or imports.[23] Pipeline flows are discussed as well as flows of liquefied natural gas imported or exported by LNG tankers. When exports or imports are discussed, the volumes are the implied gross annual flows in one direction that result from the geographical balancing of supply and demand. Model results also report the usage levels of available pipeline capacity and pipeline capacity additions that the model's capacity expansion function calculates would be economic under the assumed current and future conditions.

Depending on the scale, natural gas flows are generally reported in units of billions or millions of cubic feet per day. As mentioned, this is simply the annual volume divided by 365--an "annual daily averaging" of the model's annual inputs and outputs.

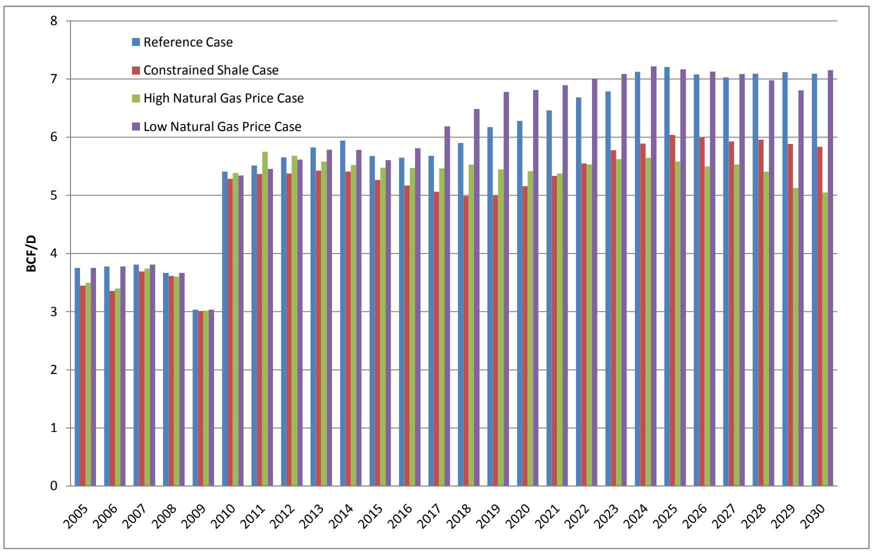
Pipeline Exports

Figure 10 shows the pipeline-transported exports from the United States for the Reference Case and the cases focused on moving gas prices. From 2010 to 2015, levels of pipeline exports across all cases remain relatively close. In the Low Gas Price Case, beginning in

23 The modeler can also refer to flows into or out of any demand or supply "node" (or collection of them) of interest in the model as an import to or export from that node, respectively.

2017, pipeline exports from the United States begin to ramp up higher than in any case. By 2024, export levels in the Reference Case become even with the Low Gas Price Case and remain that way through 2030. The natural gas that is produced in the United States becomes very competitive with markets in Mexico and Canada as prices remain relatively low. Conversely in the High Gas Price Case, the pipeline exports are pushed lower than in any other case because its high gas prices make it a less favorable option for markets in Canada and Mexico. In the Constrained Shale Gas Case, exports are likewise lower than in the Reference Case, but to a lesser extent because this case's assumed higher environmental mitigation costs of gas production affect prices less than the assumptions in the High Gas Price Case.

Figure 10: Pipeline Exports From the United States in Price-Focused Cases (Bcf/d)

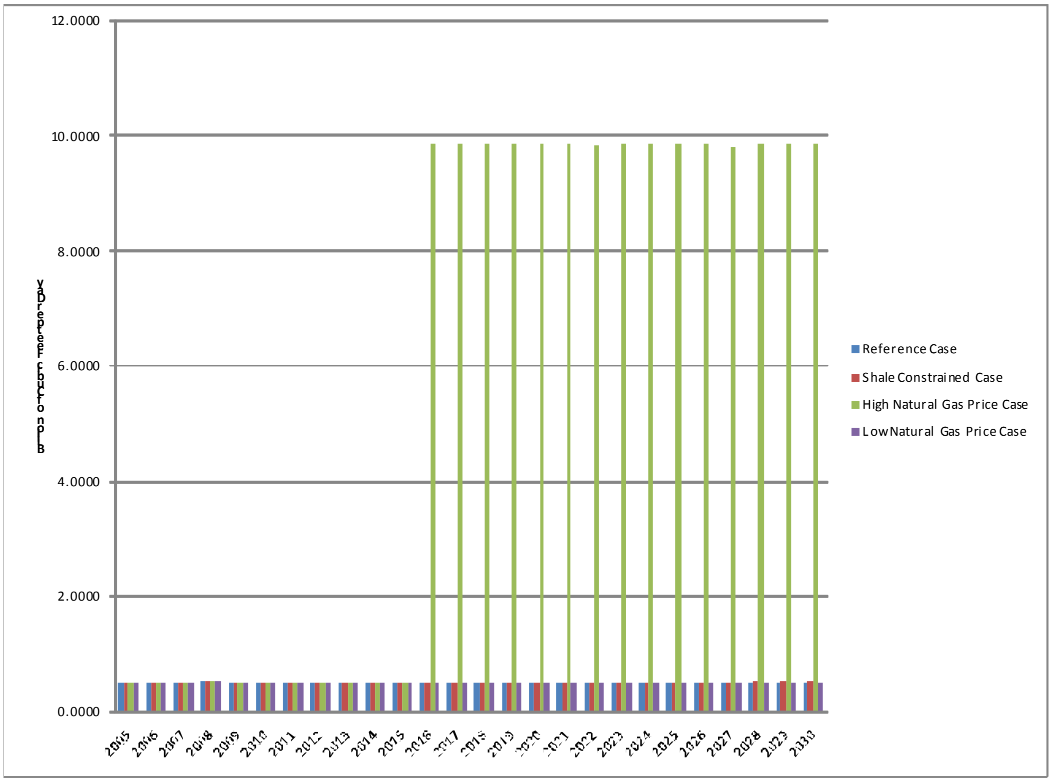


Source: California Energy Commission Staff Draft Analysis.

LNG Exports From the United States

In the High Natural Gas Price Case, LNG exports were imposed as an input assumption through required contracts. The export amount for the High Gas Price Case in **Figure 11** illustrates the input assumption to have roughly 5 Bcf/d of contractual exports from the United States. The intention of having required exports was to help effect higher U.S. natural gas prices for the High Gas Price Case. All of the other cases in **Figure 11** did not have contractual obligations to export LNG and only did so when it became economically feasible. All the other cases for this comparison produced export levels that remained fairly constant at 0.5 Bcf/d through 2030. In none of the cases did the assumed future conditions lead to significant LNG exports being economically competitive.

Figure 11: LNG Exports From United States in Price-Focused Cases (Bcf/d)



Source: California Energy Commission Staff Draft Analysis.

LNG Imports

How imports of LNG to the United States change across the modeled cases is of interest, given that the recent very competitive gas production from domestic shale formations may not have been anticipated by the developers of the LNG infrastructure.

Table 13 shows the volume of LNG imports to the United States in the Reference Case and the changed cases designed to move national gas prices (the Constrained Shale Gas, High Gas Price, and Low Gas Price cases). **Figure 12** simply highlights the differences from the Reference Case among the cases shown in **Table 13**. The High Gas Price Case produces the highest levels of LNG imports when compared to the other cases. Under those prices (driven by higher gross domestic product [GDP], more coal-fired power plant retirements and less renewable generation, constrained development at some shale formations, and higher environmental mitigation costs), foreign gas sources delivered as LNG become more cost-competitive with domestic supplies.

Table 13: LNG Imports to United States in Price-Focused Cases (Bcf/d)

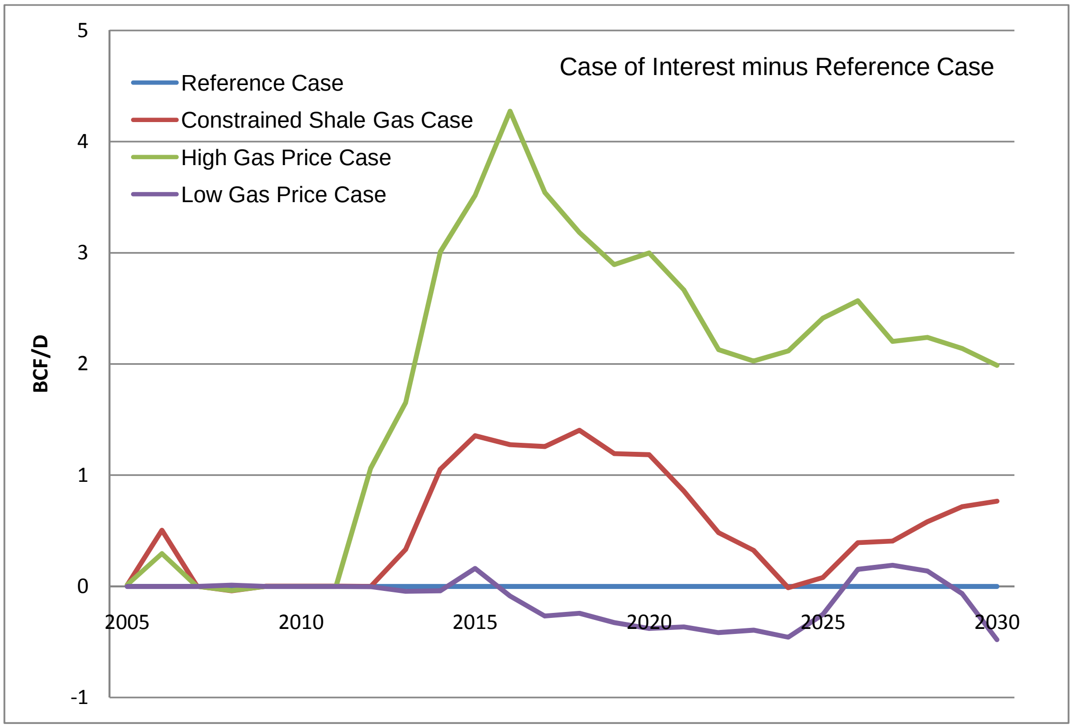
Year	Reference Case	Constrained Shale Gas Case	High Gas Price Case	Low Gas Price Case
2005	5.08	5.09	5.10	5.08
2006	3.35	3.86	3.65	3.35
2007	4.23	4.23	4.22	4.23
2008	2.35	2.31	2.31	2.36
2009	2.48	2.48	2.48	2.48
2010	2.98	2.98	2.98	2.98
2011	2.08	2.08	2.08	2.08
2012	2.94	2.94	4.00	2.94
2013	2.94	3.27	4.59	2.89
2014	3.14	4.20	6.15	3.10
2015	3.24	4.60	6.75	3.40
2016	3.13	4.40	7.40	3.04
2017	3.10	4.35	6.64	2.83
2018	2.94	4.34	6.12	2.69
2019	2.93	4.12	5.82	2.60
2020	2.92	4.10	5.92	2.54
2021	2.87	3.72	5.53	2.50
2022	2.94	3.42	5.07	2.52
2023	2.97	3.29	5.00	2.58
2024	3.03	3.02	5.15	2.57
2025	2.93	3.00	5.34	2.67
2026	2.93	3.32	5.50	3.08
2027	2.94	3.35	5.15	3.13
2028	2.91	3.49	5.15	3.05
2029	3.03	3.74	5.16	2.96
2030	3.22	3.98	5.20	2.74

Source: California Energy Commission Staff Draft Analysis.

Since the Constrained Shale Gas Case shared the same assumptions as the Reference Case except for the higher environmental mitigation costs for domestic gas production, its LNG imports are less than that of the High Gas Price Gas but still higher than in the Reference Case, as expected. The more severe future demand- and supply-side conditions assumed in the High Gas Price Case moved prices more than the assumed increase in mitigation costs of the Constrained Shale Gas Case, which pushed out significantly less LNG imports.

LNG import levels for the Low Gas Price Case are consistently lower than in the Reference Case. Driven by assumed lower GDP and increased renewable generation on the demand side, and on the supply-side by assumed increases in gas resource availability and the rate of gas technology development, and with no additional environmental restrictions on production, the resulting lower prices for domestic supply outcompete LNG imports. With foreign markets paying much higher prices for LNG-delivered gas, under these assumed conditions North America is an even less attractive market.

Figure 12: Difference in LNG Imports to United States Across Price-Focused Cases, (Bcf/d)



Source: California Energy Commission Staff Draft Analysis.

Imports from Canada to the United States

Shown in **Table 14** are U.S. imports of pipeline gas from Canada for the Reference Case and the cases focused on moving gas prices. The differences between these cases and the Reference Case are highlighted in **Figure 13**. Following the same pattern as seen with U.S. imports of other foreign gas supplies via LNG, and for the same reasons, the assumed future conditions in the High Gas Price Case lead to the highest level seen in any case of U.S. imports from Canada. With domestic supplies assumed to be constrained or available at higher cost than in the Reference Case, other sources such as Canadian imports and LNG are increased to make up the difference.

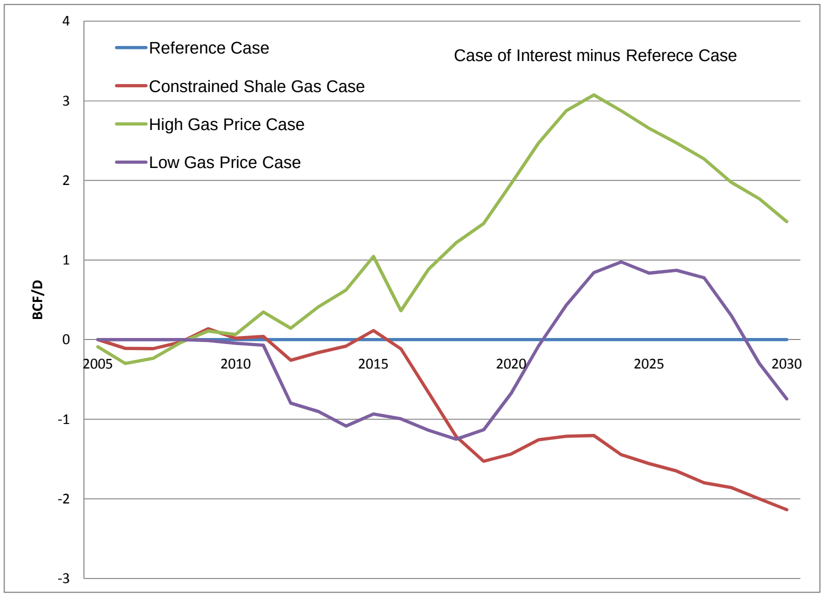
Table 14: U.S. Imports From Canada in Price-Focused Cases (Bcf/d)

Year	Reference Case	Constrained Shale Gas Case	High Gas Price Case	Low Gas Price Case
2005	10.53	10.53	10.44	10.53
2006	10.02	9.91	9.71	10.02
2007	9.71	9.60	9.48	9.71
2008	9.77	9.74	9.73	9.77
2009	8.10	8.24	8.21	8.09
2010	9.37	9.39	9.44	9.33
2011	8.23	8.27	8.58	8.16
2012	8.17	7.91	8.31	7.37
2013	7.88	7.72	8.29	6.98
2014	7.62	7.54	8.24	6.53
2015	7.28	7.40	8.33	6.35
2016	7.62	7.51	7.99	6.63
2017	8.14	7.47	9.02	7.00
2018	8.69	7.47	9.91	7.44
2019	9.18	7.65	10.64	8.05
2020	9.38	7.94	11.33	8.70
2021	9.45	8.20	11.92	9.38
2022	9.53	8.32	12.41	9.96
2023	9.68	8.47	12.75	10.52
2024	10.04	8.60	12.92	11.02
2025	10.52	8.97	13.18	11.36
2026	10.82	9.18	13.30	11.70
2027	11.21	9.41	13.48	11.99
2028	11.82	9.96	13.79	12.11
2029	12.37	10.37	14.14	12.07
2030	12.87	10.74	14.35	12.13

Source: California Energy Commission Staff Draft Analysis.

Natural gas import levels in the Low Gas Price Case start out relatively low and then steadily increase to be greater than the Reference Case in later years. While U.S. domestic natural gas prices are low in this case, the price for natural gas in Canada is low as well in the later years of the model and is able to better compete. However in the last years of the data reflected in **Figure 13**, Canadian import levels in the Reference Case surpass the import levels shown in the Low Gas Price Case.

Figure 13: Difference in U.S. Imports From Canada Across Price-Focused Cases, (Bcf/d)



Source: California Energy Commission Staff Draft Analysis.

The Constrained Shale Gas Case produces the lowest overall levels of Canadian Imports when compared with the other cases in **Figure 13**. For the Constrained Shale Gas Case, it is assumed that environmental restrictions are imposed in shale resource areas in Canada as well as in the United States. With natural gas production from shale in Canada made more expensive, the cost-competitiveness of exporting Canadian shale gas to the United States is reduced in the Constrained Shale Gas Case. The High Gas Price Case also has environmental restrictions on the Canadian shale plays as well. However, LNG exports are imposed in this case beginning in 2016, and increased levels of imports from Canada then become more competitive again.

Pipeline Capacity Additions

Pipeline and other gas transportation capacity expansions are determined within the WGTM by the endogenously calculated current and future prices, along with exogenous assumptions about capital costs of expansion, operating and maintenance costs of new and existing capacity, and revenues resulting from future outputs and prices.

Table 15 shows that the Low Gas Price Case makes the most additions to pipeline capacity when compared with the other cases. The Low Gas Price Case assumes that there are larger resource assessments in the Marcellus, Haynesville, and Western Canadian shales. It also assumes the rate of natural gas technology improvement is higher than in any other case. With lower prices also stimulating demand, flows increase, spurring significant additions to the national pipeline capacity.

Conversely, domestic natural gas supplies were made less cost-competitive with the additional environmental mitigation costs in the Constrained Shale Gas Case. As a result, less pipeline capacity was added when compared to the Reference Case. Finally, the lowest relative amounts of pipeline capacity additions were made in the High Gas Price Case. Requirements for additional pipeline capacity in this case were lessened by price-induced demand reductions and by having supply regions curtailed and bearing additional environmental costs.

Table 15: Pipeline Capacity Additions in Price-Focused Cases

Cumulative Pipeline Capacity Additions (2010-2030)	TCF
Reference Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1889
CA	0.3942
Constrained Shale Gas Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1606
CA	0.3351
High Gas Price Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1166
CA	0.3315
Low Gas Price Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.2479
CA	0.4229

Source: California Energy Commission Staff Draft Analysis.

Table 16: Pipeline Capacity Additions in Demand-Focused Cases

Cumulative Pipeline Capacity Additions (2010-2030)	TCF
Reference Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1889
CA	0.3942
High CA Gas Demand Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.5781
CA	0.5522
Low CA Gas Demand Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1380
CA	0.2679

Source: California Energy Commission Staff Draft Analysis.

As reflected in **Table 16**, the High California Gas Demand Case produced the highest additions to pipeline capacity when compared to the Reference Case and the Low California Gas Demand Case. Most of the capacity additions for this case occurred with interstate pipelines that delivered supplies of natural gas to the California border. The take-away capacity (California intrastate pipelines) additions nearly kept pace with the out-of-state additions. Conversely, the Low Gas Demand Case saw fewer pipeline capacity additions when compared to the Reference Case. For this case, however, take-away capacity additions were greater than the capacity additions that bring natural gas to the borders of California.

Table 17: Pipeline Capacity Additions in Lowered Pressure Case

Cumulative Pipeline Capacity Additions (2010-2030)	TCF
Reference Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.1889
CA	0.3942
Lowered Pressure Case	
Outside CA (Arizona, Oregon, Utah, Wyoming)	0.2254
CA	0.3790

Source: California Energy Commission Staff Draft Analysis.

The ability to add capacity was turned off within the Lowered Pressure Case for 2012 to 2016. However, the ability to add capacity in this Case was turned on after 2016 and the cumulative sum of capacity additions to 2030 is reflected in **Table 17**. The model did make adjustments and compensated for its inability to add capacity between the 2012 and 2016. However most of the additional pipeline compensation occurred with interstate pipelines that serve California. The additions to interstate pipeline capacity in the Lowered Pressure Case are highlighted when compared to the Reference Case.

Pipeline Capacity Utilization Rates

Staff calculates a figure of merit called the *pipeline utilization rate* to indicate how heavily that transportation asset is being used. Each pipeline segment in the model has a known (assumed) maximum annual volume that can flow through it in a year (its annual capacity). As part of its solution, the WGTM calculates the annual volume of gas traveling through each pipeline segment represented in the model. The pipeline utilization rate is the fraction of the model's resulting annual flow compared to its maximum annual flow.

Pipeline utilization rates of WGTM model results followed corresponding trends exhibited for pipeline capacity additions. Selected pipeline utilization rates in the Reference Case and cases focused on moving prices are shown in **Table 18**. Overall, the Low Gas Price Case showed the highest pipeline utilization rates when compared with the other cases. Because California final equilibrium gas demand in the model is higher in this case, and supply is more readily available, most of the pipelines are used at a relatively higher rate.[24] For this case, the low utilization rates on the Ruby pipeline were compensated by increased use on the GTN pipeline.

Table 18: Pipeline Utilization Rates in Price-Focused Cases, 2030 and 2022

Pipeline Utilization Rate (%)	EPNG+TW+MJ (2030)	GTN (2030)	KRGT (2030)	Ruby (2030)
Reference Case	35.80	92.30	66.30	28.30
Constrained Shale Gas Case	35.50	80.90	64.40	33.60
High Gas Price Case	34.90	80.50	61.00	33.30
Low Gas Price Case	37.10	95.10	70.70	30.40
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2022)**	**GTN (2022)**	**KRGT (2022)**	**Ruby (2022)**
Reference Case	36.82	68.46	72.87	47.72
Constrained Shale Gas Case	36.09	59.58	66.77	45.89
High Gas Price Case	34.52	62.07	67.84	48.40
Low Gas Price Case	35.11	81.55	70.70	39.04
Note: EPNG+TW+MJ refers to El Paso, Transwestern and Mojave aggregate pipeline corridor				
Note: GTN and KRGT refer to the Gas Transmission Northwest and Kern River pipeline respectively				

Source: California Energy Commission Staff Draft Analysis.

The Constrained Shale Gas Case and the High Gas Price Case proved to have some of the lowest pipeline utilization rates when compared with the other cases. With higher prices and less domestic natural gas being produced in the Constrained Shale Gas Case, efficient use of the pipeline system decreased. Efficient use of the pipelines is further lessened when the price-induced demand decrease in the High Gas Price Case is factored in.

Table 19 shows selected pipeline utilization rates in the Reference Case and cases focused on moving gas demand in California. Utilization rates along the El Paso aggregate pipeline corridor remained fairly constant through time and across all cases. However, when utilization rates on the GTN pipeline increased, there was a noticeable decrease in usage of both the Kern River and Ruby pipelines across all cases. Overall, the High California Gas Demand Case made the most use of the available pipeline capacity that delivers natural gas to the borders of California. The California Low Gas Demand produced lower pipeline utilization rates when compared to the Reference Case for 2030 and 2022.

24 Some of the input assumption changes made to create the Low Gas Price Case, with the intention of moving national prices lower, reduced the reference quantity gas demand, which are input assumptions to the WGTM, but more so for out-of-state gas demand than for in-state. Facing the lower prices, in-state demand ended up being slightly higher in the changed case than in the Reference Case. Nationally, the opposite occurred.

Table 19: Pipeline Utilization Rates in Demand-Focused Cases, 2030 and 2022

Pipeline Utilization Rate (%)	EPNG+TW+MJ (2030)	GTN (2030)	KRGT (2030)	Ruby (2030)
Reference Case	35.80	92.30	66.30	28.30
High CA Gas Demand Case	36.90	95.70	66.90	32.40
Low CA Gas Demand Case	34.60	86.50	64.90	29.20
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2022)**	**GTN (2022)**	**KRGT (2022)**	**Ruby (2022)**
Reference Case	36.82	68.46	72.87	47.72
High CA Gas Demand Case	36.04	66.89	71.95	47.49
Low CA Gas Demand Case	35.95	65.84	70.12	46.80
Note: EPNG+TW+MJ refers to El Paso, Transwestern and Mojave aggregate pipeline corridor				
Note: GTN and KRGT refer to the Gas Transmission Northwest and Kern River pipeline respectively				

Source: California Energy Commission Staff Draft Analysis.

Pipeline Flows and the Lowered Pressure Case

When comparing the Lowered Pressure Case to the Reference Case, the result that becomes quickly apparent is the redistribution of pipeline flow. The total amount of natural gas being delivered to California between the two cases remains fairly constant for all the years of comparison in **Table 20**. The key difference is the change in flows along the Redwood and Baja Paths. For the Low Pressure Case, maximum capacity on the Redwood and Baja Paths were reduced by 200 Mmcf/d and 300 Mmcf/d, respectively. When compared to the Reference Case, there is increased flow on the Baja Path and decreased flow for the Redwood Path in the Low Pressure Case. There is also noticeably less flow on the GTN pipeline between the two cases for 2012 to 2016. Staff emphasizes that the ability to add more pipeline capacity in California for 2012 to 2016 was turned off for the Low Pressure Case. Because the Baja Pipeline was operating at lower maximum capacity while handling increased flow of natural gas, a larger utilization rate was produced for this pipeline for 2012 to 2016 in the Lowered Pressure Case. Flow on the Redwood Path was slightly reduced while still producing higher utilization rate due to the reduced maximum capacity level used in the Low Pressure Case. Flows on all other major pipelines that serve California remained fairly even when comparing the two cases for 2012 to 2016. **Table 21** shows the corresponding utilization rate comparison between the Reference Case and the Lowered Pressure Case.

Table 20: Lowered Pressure Case Pipeline Flows (Tcf/Year) for Model Years 2012 to 2016

Pipeline Flows Tcf/yr	EPNG+TW+MJ (2012)	GTN (2012)	KRGT (2012)	Ruby (2012)	Baja (2012)	Redwood (2012)
Reference Case	0.89	0.58	0.55	0.00	0.28	0.50
Low Pressure Case	0.88	0.58	0.54	0.00	0.26	0.50
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2013)**	**GTN (2013)**	**KRGT (2013)**	**Ruby (2013)**	**Baja (2013)**	**Redwood (2013)**
Reference Case	0.78	0.48	0.46	0.26	0.14	0.60
Low Pressure Case	0.80	0.44	0.46	0.27	0.15	0.58
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2014)**	**GTN (2014)**	**KRGT (2014)**	**Ruby (2014)**	**Baja (2014)**	**Redwood (2014)**
Reference Case	0.76	0.52	0.45	0.25	0.11	0.63
Low Pressure Case	0.78	0.47	0.46	0.25	0.14	0.58
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2015)**	**GTN (2015)**	**KRGT (2015)**	**Ruby (2015)**	**Baja (2015)**	**Redwood (2015)**
Reference Case	0.75	0.53	0.45	0.25	0.11	0.63
Low Pressure Case	0.79	0.48	0.47	0.24	0.15	0.68
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2016)**	**GTN (2016)**	**KRGT (2016)**	**Ruby (2016)**	**Baja (2016)**	**Redwood (2016)**
Reference Case	0.75	0.55	0.46	0.24	0.11	0.62
Low Pressure Case	0.78	0.49	0.48	0.23	0.16	0.58
Note: EPNG+TW+MJ refers to El Paso, Transwestern and Mojave aggregate pipeline corridor						
Note: GTN and KRGT refer to the Gas Transmission Northwest and Kern River pipeline respectively						

Source: California Energy Commission Staff Draft Analysis.

Table 21: Lowered Pressure Case Pipeline Utilization Rate (Tcf/Year) for Model Years 2012 to 2016

Pipeline Utilization Rate (%)	EPNG+TW+MJ (2012)	GTN (2012)	KRGT (2012)	Ruby (2012)	Baja (2012)	Redwood (2012)
Reference Case	43.30	60.39	83.38	0.00	66.09	63.44
Low Pressure Case	43.23	60.61	82.16	0.00	85.62	69.80
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2013)**	**GTN (2013)**	**KRGT (2013)**	**Ruby (2013)**	**Baja (2013)**	**Redwood (2013)**
Reference Case	38.29	50.25	69.66	58.45	33.41	75.92
Low Pressure Case	38.92	46.16	69.82	61.42	50.00	81.46
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2014)**	**GTN (2014)**	**KRGT (2014)**	**Ruby (2014)**	**Baja (2014)**	**Redwood (2014)**
Reference Case	36.92	54.12	69.21	56.39	26.92	79.87
Low Pressure Case	38.33	48.89	70.43	56.16	46.41	81.18
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2015)**	**GTN (2015)**	**KRGT (2015)**	**Ruby (2015)**	**Baja (2015)**	**Redwood (2015)**
Reference Case	36.67	55.38	68.90	55.94	26.20	80.51
Low Pressure Case	38.39	50.00	71.49	53.88	48.69	95.08
Pipeline Utilization Rate (%)	**EPNG+TW+MJ (2016)**	**GTN (2016)**	**KRGT (2016)**	**Ruby (2016)**	**Baja (2016)**	**Redwood (2016)**
Reference Case	36.43	57.36	69.51	53.65	26.20	78.60
Low Pressure Case	38.33	51.19	73.17	51.37	50.98	81.88
Note: EPNG+TW+MJ refers to El Paso, Transwestern and Mojave aggregate pipeline corridor						
Note: GTN and KRGT refer to the Gas Transmission Northwest and Kern River pipeline respectively						

Source: California Energy Commission Staff Draft Analysis.

Given the WGTM's annual averaging approach, the Lowered Pressure Case should not be viewed as a test for natural gas delivery reliability given reduced capacity levels on the Redwood and Baja pipeline. The Low Pressure Case provides some insight as to how pipeline capacity use is redistributed due the reduced pressure on the Redwood and Baja pipelines. This information could prove useful in the long-term planning of possible pipeline capacity expansions. Daily gas balancing and the ability to inject and release natural gas from storage can play an important role in ensuring the daily reliable delivery of natural gas but are not modeled in the WGTM. An additional analysis is described in Chapter 5 that considers normal degree days as well as "Winter Peak Days" and examines how storage can play an important role in ensuring natural gas delivery. Analyses such as the one found in **Chapter 5** are more useful toward planning for natural gas supply on a daily and seasonal basis.

Demand-Related Results

This section highlights U.S. and California results from the WGTM related to natural gas demand. It first briefly touches on residential, commercial, and industrial demand to later spend more time on results about the electric generation sector gas demand. Activities in the power sector are key drivers of natural gas demand. Most of the cases in this study were designed specifically to examine the potential effects on gas market activities of activities in the power sector, especially as they may be affected in the future by policies or regulations related to public health and safety and the environment. Demand results for all sectors are included in the Excel worksheets described in **Appendix C** and posted on the *2011 IEPR* website.

The section closes with a discussion of a simple post-processing analysis staff conducted to provide some additional demand-related metrics of both general and policy interest. Staff examines the differences across the cases in rough estimates of the total cost of gas combusted by the power sector and the amount of carbon dioxide emissions emitted from that combustion. These are not meant to be definitive absolute cost or emissions estimates for each case; rather they are a rough attempt to translate output metrics about gas volumes into additional policy-relevant metrics, which are directly related to broader public interests.

Residential and Commercial Sectors

U.S. GDP is identical to national income; therefore, as public income changes, spending on commodities such as natural gas changes. The assumption about future growth in U.S. GDP is one of the six most significant factors influencing residential and commercial gas demand. The Reference Case assumption for average annual growth of GDP is 2.7 percent. Two of the cases designed to move gas market prices varied this assumption, while all other cases assumed the Reference Case value. The High Gas Price Case assumed a 3.5 percent annual average GDP growth rate, and the Low Gas Price Case assumed 2.1 percent growth. Although these GDP assumptions were selected to move demand,[25] that was essentially a means to move price. Within the WGTM, the resulting price then acts on price-elastic demand, pushing the final equilibrium-state demand back in the opposite direction. Changes to other input assumptions that were intended to affect price directly also have this interrelationship with demand. These counteracting forces make the magnitude of the outcome, if not the direction, difficult to predict.

The WGTM model's gas demand response in the U.S. and California residential and commercial sectors is shown in **Figure 14**, **Figure 15**, **Figure 16**, and **Figure 17**. As seen in these four figures, the differences between their highest- and lowest-demand cases reach their maxima at the 2030 forecast horizon, and the trends beyond 2014 are all relatively

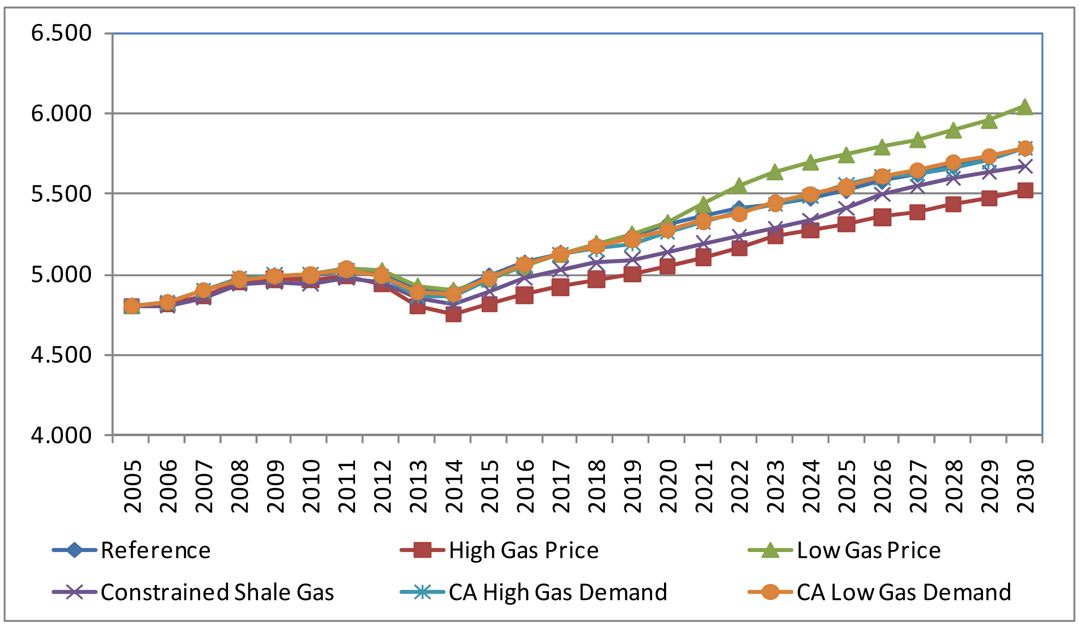
25 Here, demand refers to the reference quantity of demand that is input to the WGTM, but which is the output of the econometric model that uses a GDP assumption as one of its inputs.

linear. The differences in demand between the cases with the highest and the lowest demand in each figure result in a range from 4.2 percent in the U.S. commercial sector (**Figure 16**) to 11.5 percent in the California commercial sector (**Figure 17**). The High California Gas Demand Case is responsible for the California commercial sector having the widest range of differences. Although it has the same 2.7 percent GDP growth rate as the Reference Case, the High California Gas Demand Case specified other assumptions that were designed to drive California gas demand up. Of these assumptions, the three most influential were:

- Removing all electric generation from California's two nuclear plants by 2026.
- Slowing the rate of added new renewable electric generation.
- Increasing California's total electric generation growth rate.

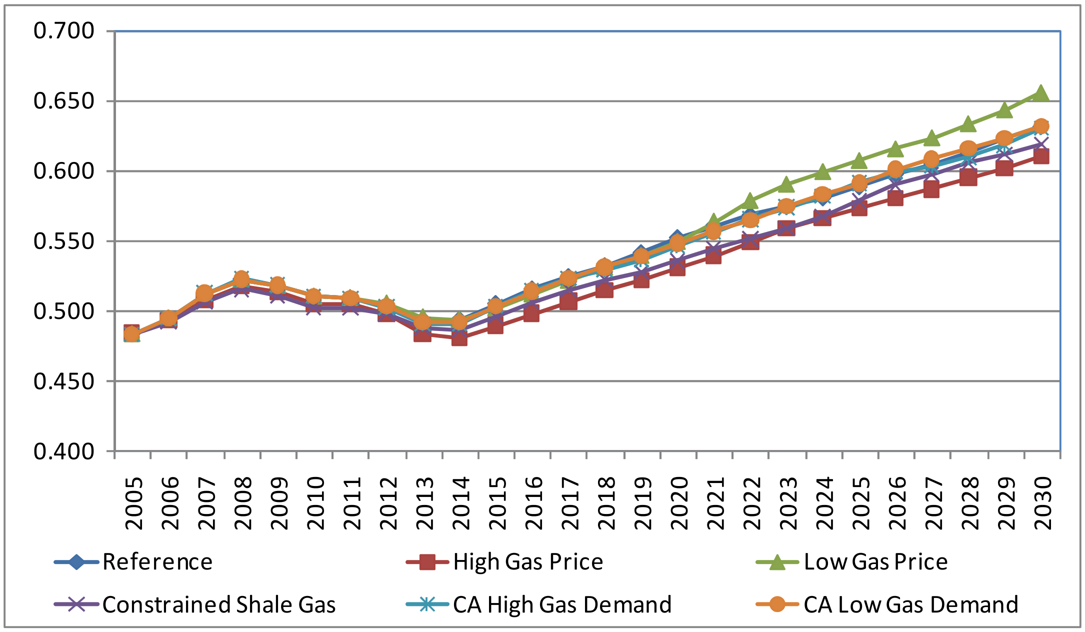
The other five cases, in contrast, trend closely together with the Reference Case, as do all of the U.S. commercial sector results shown in **Figure 16**.

Figure 14: U.S. Residential Gas Demand: Reference Case and Change Cases (Tcf/Year)



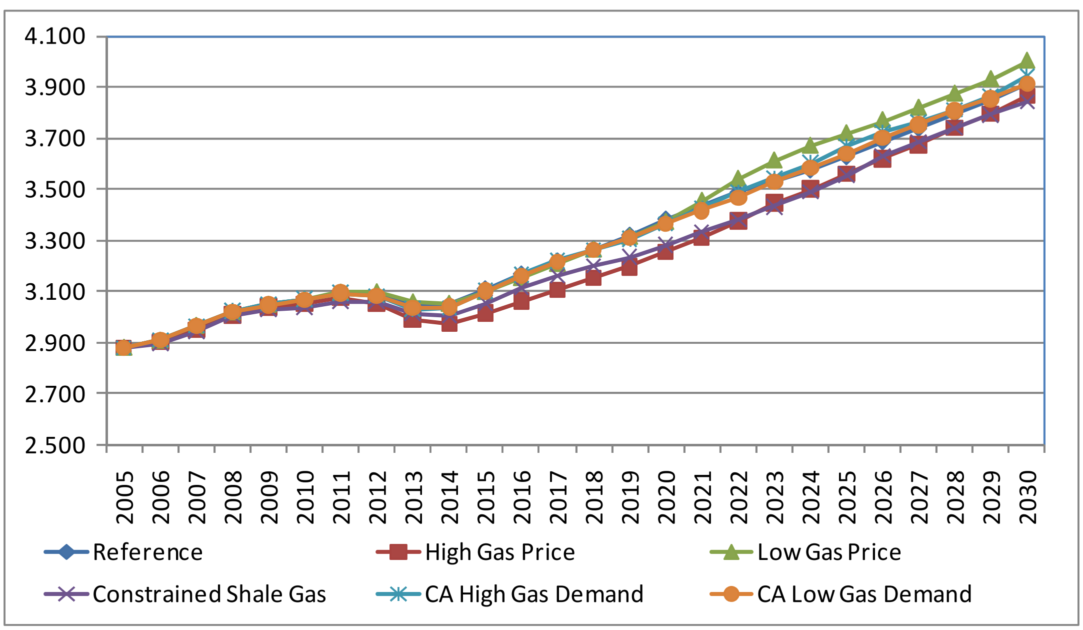
Source: California Energy Commission Staff Draft Analysis.

Figure 15: California Residential Gas Demand — Reference Case and Change Cases (Tcf/Year)



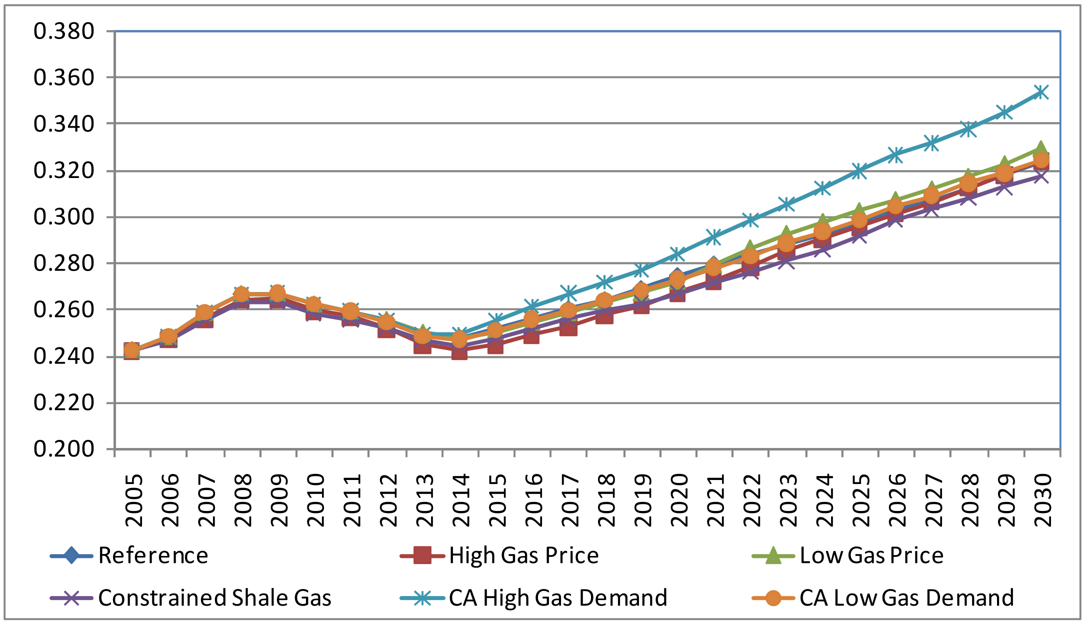
Source: California Energy Commission Staff Draft Analysis.

Figure 16: U.S. Commercial Gas Demand — Reference Case and Change Cases (Tcf/Year)



Source: California Energy Commission Staff Draft Analysis.

Figure 17: California Commercial Gas Demand — Reference Case and Change Cases (Tcf/Year)

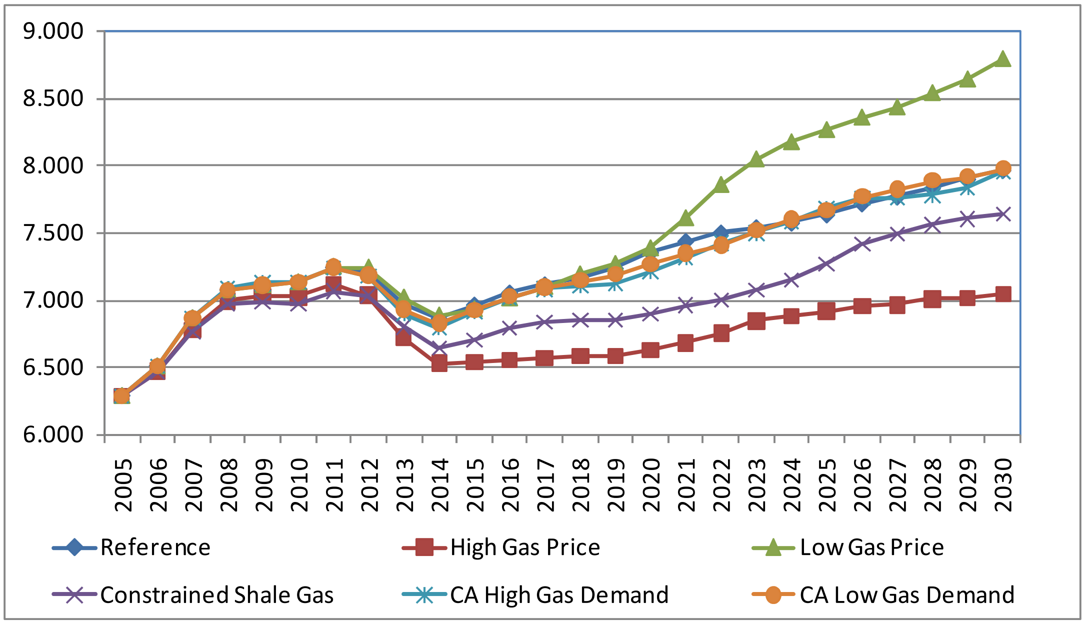


Source: California Energy Commission Staff Draft Analysis.

Industrial Sector Results

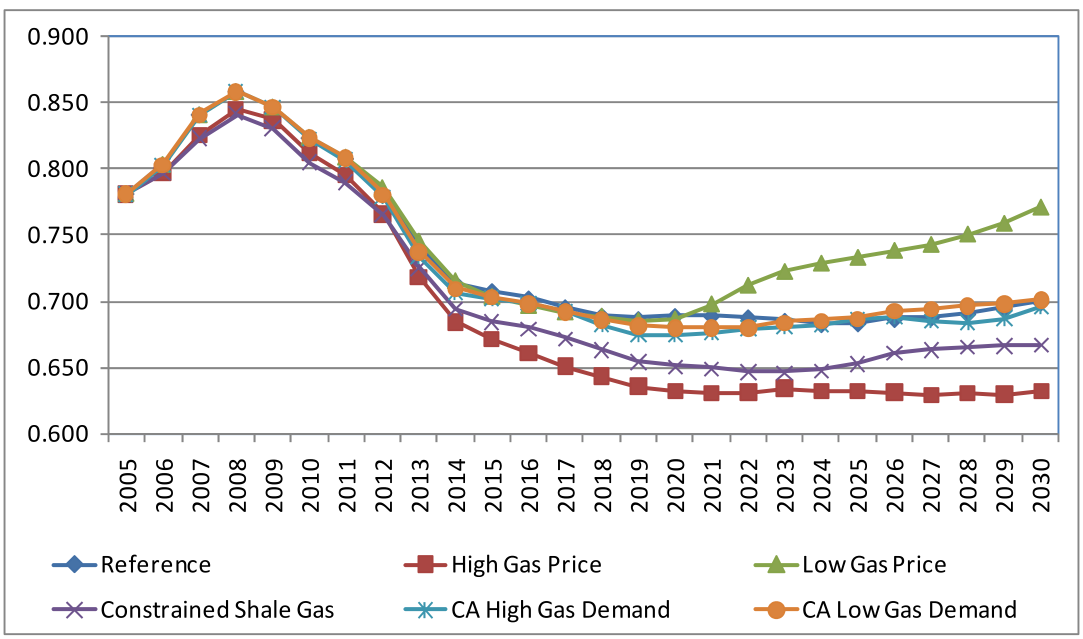
In contrast to the residential and commercial sector results, the U.S. and California industrial sector highest and lowest case results for 2030 differ by 25 and 22 percent, respectively. Another contrast with the other two sectors is the divergence of three of the cases – the Low Gas Price, Constrained Shale, and High Gas Price – from the Reference, High California Demand, and Low California Demand cases, as shown in **Figure 18** and **Figure 19**.

Figure 18: U.S. Industrial Gas Demand: Reference Case and Change Cases (Tcf/Year)



Source: California Energy Commission Staff Draft Analysis.

Figure 19: California Industrial and Enhanced Oil Recovery Gas Demand — Reference Case and Change Cases (Tcf/Year)



Source: California Energy Commission Staff Draft Analysis.

The cases designed to move gas market prices — the Low Gas Price, Constrained Shale, and High Gas Price cases — altered global and national gas supply and electric generation assumptions from the Reference Case and, therefore, had the biggest impact on industrial gas demand. The cases designed to move demand for gas in California — the Low and High California Gas Demand cases — only changed assumptions in this state and none of the global or national gas supply or demand assumptions. The wide divergence in industrial sector demand responses suggests that this sector, which historically has demonstrated a response to gas prices that is more than twice the residential or commercial sector price elasticities, uses switching to cheaper fuels, energy efficiency measures, conservation, or changes to production methods. Two other responses to alter long-run gas demand often available to the industrial sector that are not usually available to the residential and commercial sectors include moving production overseas and increasing capitalization of more energy-efficient industries at the expense of energy-intensive industries. U.S. growth in high-value information technologies with the concomitant decline of steel, automobiles, and other heavy manufacturing is an example of this response.

A final interesting observation is the contrast between U.S. and California industrial gas demand. U.S. industrial gas demand increases after 2014 for all cases, including the High Gas Price Case, which by 2030 increases the North American gas benchmark Henry Hub prices 11.3 percent. The case assumptions achieve this result in part by increasing GDP annual average growth to 3.5 percent, removing 280,000 GWh, or 5.3 percent, of U.S. coal-fired generation, delaying other states' implementation of an RPS by 15 years, constraining LNG imports from major overseas sources, and assuming robust LNG exports. U.S. industrial demand is highest in the Low Gas Price Case and lowest in the High Gas Price case. California industrial sector changed case results show an almost identical pattern of spread around the Reference Case, with the highest gas demand result in the Low Gas Price Case and the lowest gas demand in the High Gas Price Case. The significant contrast is that while all cases show U.S. industrial gas demand recovering after 2014, all cases show California industrial gas demand declining through 2020 and most cases leveling off, with only the Low Gas Price case showing significant growth after 2020.

Power Generation Sector

The principal objectives of California policy makers for the power generation sector are intended to advance the public interest in clean, reliable, efficient, and inexpensive electricity. Environmental and energy efficiency policy initiatives often target the power generation sector and consequently have substantial effects on that sector's gas demand. Two important reasons for why policy makers mark this sector for these policy initiatives is the lower cost of implementation and compliance compared to the other three sectors. Power plants, in contrast to homes, commercial and many industrial businesses, are large facilities whose numbers in any area are small. Therefore, policy makers can more easily identify these facilities and their operators and efficiently collaborate with them on developing regulations that improve energy efficiency or emissions objectives. The second reason policy makers maintain this interest is that the thermal power plant fleet of fossil-fueled generators contributes a significant share of total U.S. emissions: 2,100 million metric tons of CO_2, 5.7 million tons of sulphur dioxide (SO_2), and 4.7 million tons of oxides of nitrogen (NO_x).[26]

Since many of the assumptions about key drivers that varied across the changed cases are focused on the power generation sector, they are not repeated here. It will be helpful for the reader to review the **Chapter 2** descriptions of changed assumptions in each case as well as that chapter's display of results of the econometric modeling that produces the electric generation gas demand input assumptions to the WGTM.[27] In addition, the reader is reminded of the "snapshot" sheets provided at the beginning of **Chapter 3**, which provide a summary of key driver input changes across cases and some selected output values for each case.

Power Sector Natural Gas Demand

The WGTM power sector gas demand results for the United States and for California are shown in **Figure 20** and **Figure 21** for the Reference Case, for the three cases designed to move gas market prices, and for the two cases designed to move California gas demand. Not surprisingly, U.S. power generation gas demand is highest in the High Gas Price Case, which had the most severe input assumption changes affecting the U.S. electric generation mix (**Figure 20**). This case assumed all states with an RPS program suffered an additional 10-year delay in reaching their RPS targets (15 years total, when added to the five-year delay assumed in the Reference Case). In addition, 50,000 MW of coal-fired generating capacity (and 280,000 GWh of electricity generation) were assumed to retire.

California power generation gas demand is highest in the High California Gas Demand Case, in which more than 34,000 GWh of in-state nuclear generation is assumed to shut down after 2025; the RPS does not reach 33 percent until 2029; total electric generation growth is slightly higher than in the Reference Case; and some additional electric vehicle charging is assumed (**Figure 21**). California power generation gas demand is lowest in the Low California Gas Demand Case, in which total electric generation growth is slightly lower than in the Reference Case, 6,000 MW (and 8,500 GWh) of non-RPS-eligible renewable generation is added, and the RPS continues to increase above 33 percent of retail sales by 1 percent per year until leveling off at 40 percent by 2027 and beyond.

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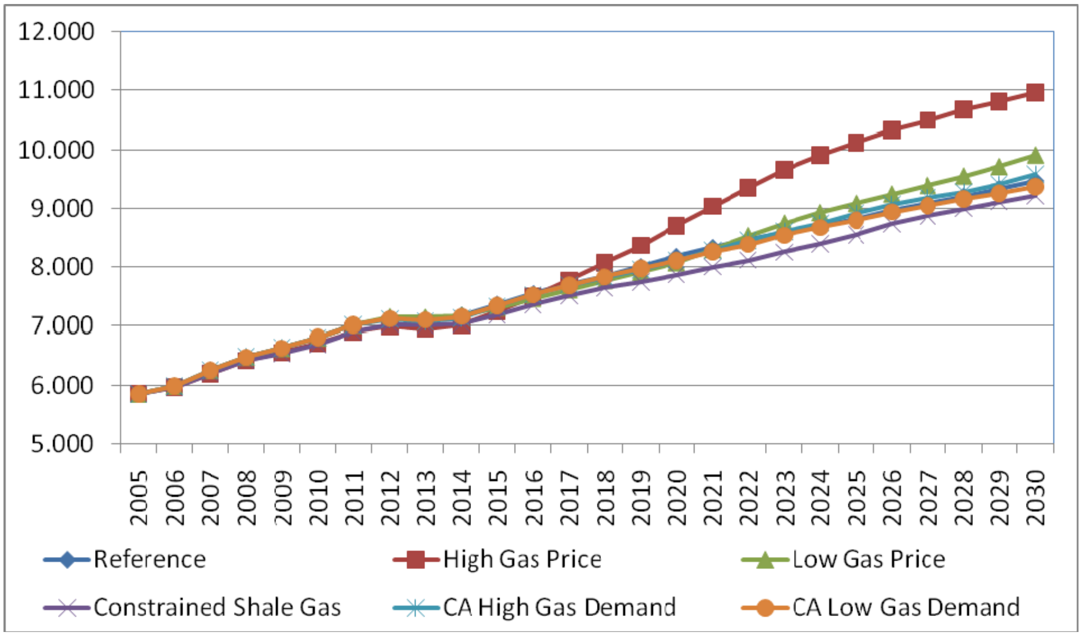
26 Moniz, Ernest J., et. al. Massachusetts Institute of Technology. 2011. *The Future of Natural Gas: An Interdisciplinary MIT Study,* Table 4.2, p. 85.

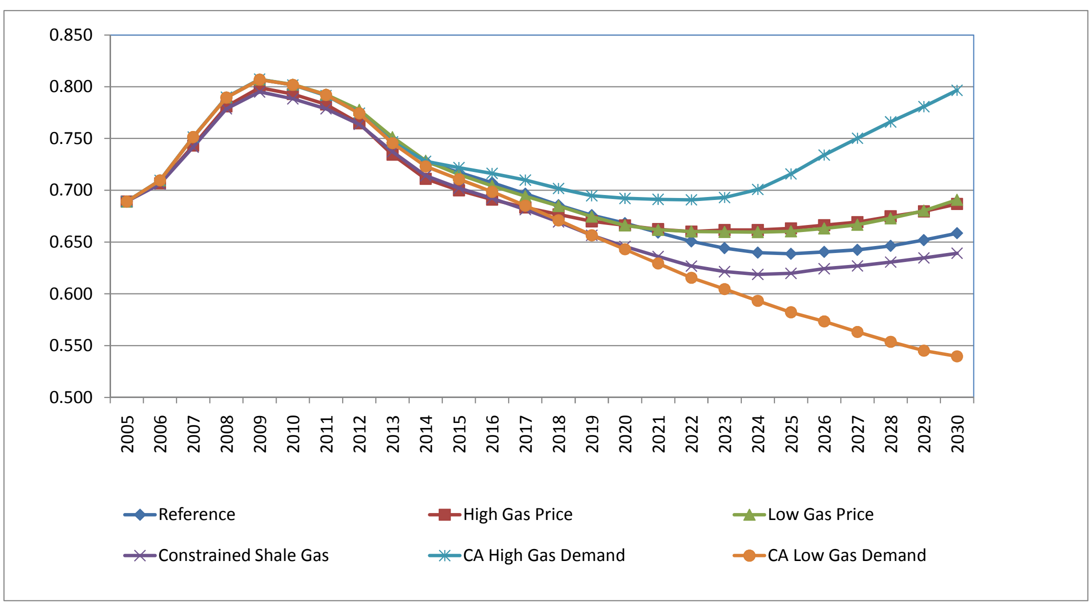
27 This refers to the reference quantities of gas demand for electric generation, which are inputs to the WGTM. The final equilibrium quantities of electric generation gas demand, which output of the WGTM, are presented and discussed in this chapter. Staff makes no direct comparison in this draft report between the reference quantities and final equilibrium quantities, which would show the effects of price elasticities of demand for gas in that sector.

Figure 20: U.S. Power Generation Gas Demand, All Cases, Tcf/Year



Source: California Energy Commission Staff Draft Analysis.

Figure 21: California Power Generation Gas Demand, All Cases, Tcf/Year



Source: California Energy Commission Staff Draft Analysis.

Power Sector Cost and Emission Vulnerabilities

Along with the potential range of electric generation gas demand seen across the cases comes a range of potential vulnerability to the costs and environmental consequences of that gas consumption. Although the same could be done for gas consumption in all end-use sectors, staff roughly estimates three new (that is, exogenous to the WGTM) policy-relevant figures of merit to give power generation gas demand a dimension other than just cubic feet of gas. Calculated from the WGTM output for power sector gas demand, the three estimated metrics are:

- Total cost of natural gas consumed in power generation, in billions of 2010$.
- CO_2 emissions from the combustion of the generating fuel, in metric tons (tonnes).
- Cost of CO_2 allowances required under AB 32 cap and trade program for the combusted fuel, in 2010$.

The focus is on the *differences* among cases rather than the absolute values, since these are rough estimates and only the power sector is included in this post-processing analysis. Staff assumed a weighted-average end-use gas price to generators to apply to the statewide gas demand by generators from the WGTM (**Table 22**). Staff estimates only the emissions from combustion of gas, which are tracked in the WGTM (fugitive methane emissions are not). Staff assumes a CO_2 emission factor for natural gas of 119 lbs CO_2/MMBtu.[28] Staff's assumption for CO_2 cost in **Table 23** is conservatively low, at about the level of the Global Warming Solutions Act (Assembly Bill 32, Núñez, Chapter 488 , Statutes of 2006) cap and trade program "reserve" allowance price established for gas utilities, about $17/tonne (nominal $, in 2020).

Table 22: Volume-Weighted Average of California Gas Utilities' End-Use Price to Electric Generators, 2010$/MMBtu

Power Generators' End Use Prices, 2010$/MMBTU			
Case	**2017**	**2022**	**2030**
Reference	$5.99	$6.45	$6.83
High Gas Price	$6.41	$6.75	$7.52
Low Gas Price	$6.02	$5.80	$5.92
Constrained Shale Gas	$6.29	$6.82	$7.20
High CA Demand	$6.08	$6.32	$6.60
Low CA Demand	$5.98	$6.52	$6.73

Source: California Energy Commission Staff Draft Analysis.

28 (119 lbs CO_2/1 MMBtu)*(0.053977 tonnes/119 lbs)*(1025 Btu/cf)*(1000000 MMcf/Tcf) = tonnes CO_2/year.

Table 23: Carbon Allowance Cost Assumption Using "Reserve" Price

Year	Nominal $/Tonne	2010$/Tonne
2012	$ 10.00	$ 9.74
2013	$ 10.66	$ 10.10
2014	$ 11.36	$ 10.53
2015	$ 12.11	$ 11.01
2016	$ 12.90	$ 11.51
2017	$ 13.75	$ 12.07
2018	$ 14.65	$ 12.66
2019	$ 15.62	$ 13.30
2020	$ 16.64	$ 13.98
2021	$ 17.74	$ 14.68
2022	$ 18.90	$ 15.42
2023	$ 20.15	$ 16.19
2024	$ 21.47	$ 17.00
2025	$ 22.88	$ 17.85
2026	$ 24.39	$ 18.74
2027	$ 25.99	$ 19.67
2028	$ 27.70	$ 20.65
2029	$ 29.52	$ 21.68
2030	$ 31.46	$ 22.76

Source: California Energy Commission Staff Draft Analysis.

Table 24 presents California power generation gas demand and the above-mentioned metrics for the Reference Case, the three cases designed to move gas prices, and the two cases designed to move California gas demand for the snapshot years of 2017, 2022, and 2030.

Focusing on the differences across cases, to get an appreciation for the range that the future cost or emission vulnerability might be, staff shows how the value in each case varies from the Reference Case level for each metric. **Figure 22** shows the differences across cases in California power generation gas demand, in Tcf/yr, from the Reference Case. **Figure 23** shows the total cost of gas combusted in California power generation by case. As seen in **Table 22**, since the price of gas is an output of the WGTM and different in each case, the weighted average cost of gas to electric generators also varies by case. Therefore, the relationship between the amount of gas burned and cost of gas burned is not linear.

Figure 24 shows the annual CO_2 emissions from electric generation across the cases in tonnes/year. This is a linear relationship with the gas demand because staff simply applied a 119 lbs CO_2/MMBtu emission factor. (The shapes of the lines in **Figure 22** and **Figure 24** are essentially the same.) To avoid making apples-to-oranges comparisons, this quantity of emissions is simply that emitted by gas-fired power plants in California as the state-by-state approach of the WGTM maps them. This is not the same as assigning "emissions responsibility" to Californians based on the emissions associated with the power they consume, regardless of the power plant location.

Figure 25 shows the additional cost incurred if all of the CO_2 emissions from the natural gas combusted by power generation in California were obligated to have CO2 allowances for which was paid the minimum reserve price described in the AB 32 cap and trade rulemaking. The minimum reserve price applies to the obligations of gas utilities, beginning in 2015, to have allowances to cover the emissions from the combustion of gas they deliver to their end-use customers smaller than the large industrial and power plant customers who come under the program in 2012. Large industrial facility and power plant owners will likely pay different GHG allowance prices than assumed here. Staff chose the minimum reserve price to represent a lower bound. Readers wanting to estimate additional allowance costs assuming higher emission costs can easily do so as this relationship is also linear.[29]

Staff included the AB 32 GHG allowance cost as a post-processed "adder" to the WGTM price result, not an input to the WGTM's balancing of gas supplies and demand.

Looking at the spread of these post-processed metrics across cases in 2022, staff observes that:

- Low Gas Price Case power generation annual gas costs are $380 million less, while High Gas Price Case generation annual gas costs are $270 million more than the Reference Case
- Low California Gas Demand Case annual CO_2 emissions are 2.0 million tonnes less, while High California Gas Demand Case annual CO_2 emissions are 2.2 million tonnes more than in the Reference Case
- Low California Gas Demand Case annual CO_2 emission allowance costs are $30 million less, while High California Gas Demand Case annual CO_2 emission allowance costs are $34 million more than in the Reference Case.

By 2030, these spreads in cost of gas and tonnes of emissions more than double.

Another caveat to understand is that these rough estimates represent just part of a much larger, complex whole. While showing the incremental cost of gas or emissions from gas-fired generation, these figures are not indicative of a comprehensive tradeoff analysis. For example, the High Gas Price Case does have more gas-fired generation in California and so more gas costs, GHG emissions, and allowance costs than other cases, but this case also has 280,000 GWh less coal-fired generation and the associated GHG emissions, as well as extensive capital costs to replace the coal capacity.

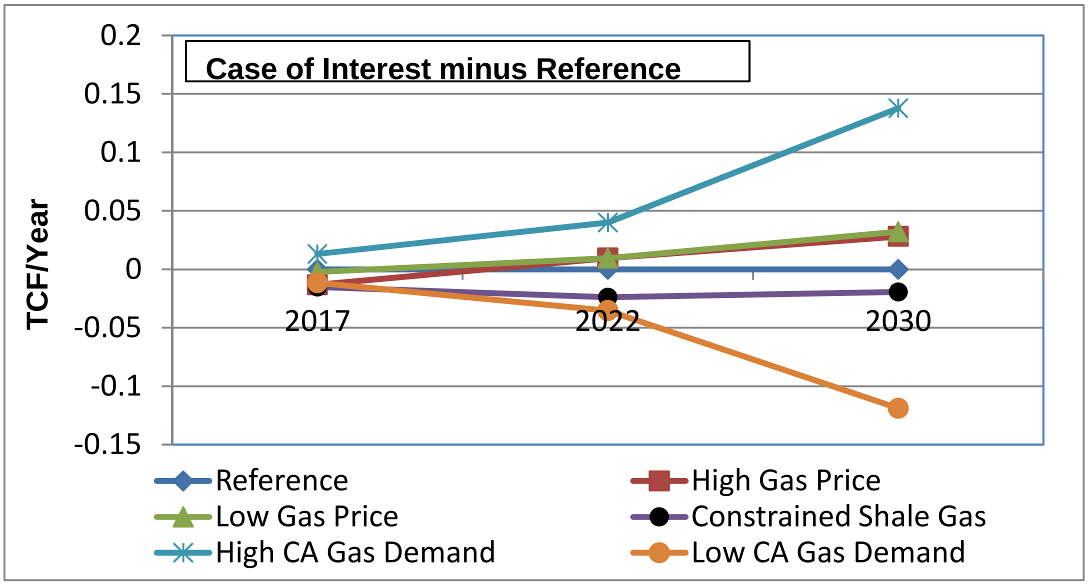
29 What allowance prices actually will be is not linear, just the estimate of the total allowance cost at any assumed allowance price.

Table 24: Rough Estimates of California Power Generation Sector Gas Demand, Gas Costs, Combustion CO_2 Emissions, and Minimum CO_2 Allowance Costs by Case

Selected California Power Generation Sector Results	Reference	High Gas Price	Low Gas Price	Constrained Shale Gas	High CA Gas Demand	Low CA Gas Demand
	2017					
Gas Demand (Bcf/Yr)	697	683	694	681	710	685
Combustion CO2e Emissions (Millions Tonnes CO2/Yr)	38.5	37.8	38.4	37.7	39.3	37.9
Gas Costs (Millions 2010 $/Yr)	$4,285	$4,498	$4,293	$4,401	$4,432	$4,208
CO2e Allowance Costs (Millions 2010 $/Yr)	$465	$456	$464	$455	$474	$458
	2022					
Gas Demand (Tcf/yr)	651	660	660	627	691	616
Combustion CO2e Emissions (Millions Tonnes CO2/Yr)	36.0	36.5	36.5	34.7	38.2	34.1
Gas Costs (Millions 2010 $/Yr)	$4,310	$4,577	$3,933	$4,390	$4,484	$4,121
CO2e Allowance Costs (Millions 2010 $/Yr)	$555	$563	$563	$535	$589	$525
	2030					
Gas Demand (Tcf/yr)	659	687	691	639	797	540
Combustion CO2e Emissions (Millions Tonnes CO2/Yr)	36.4	38.0	38.2	35.4	44.1	29.9
Gas Costs (Millions 2010 $/Yr)	$4,620	$5,303	$4,200	$4,726	$5,399	$3,730
CO2e Allowance Costs (Millions 2010 $/Yr)	$829	$865	$870	$805	$1,003	$680

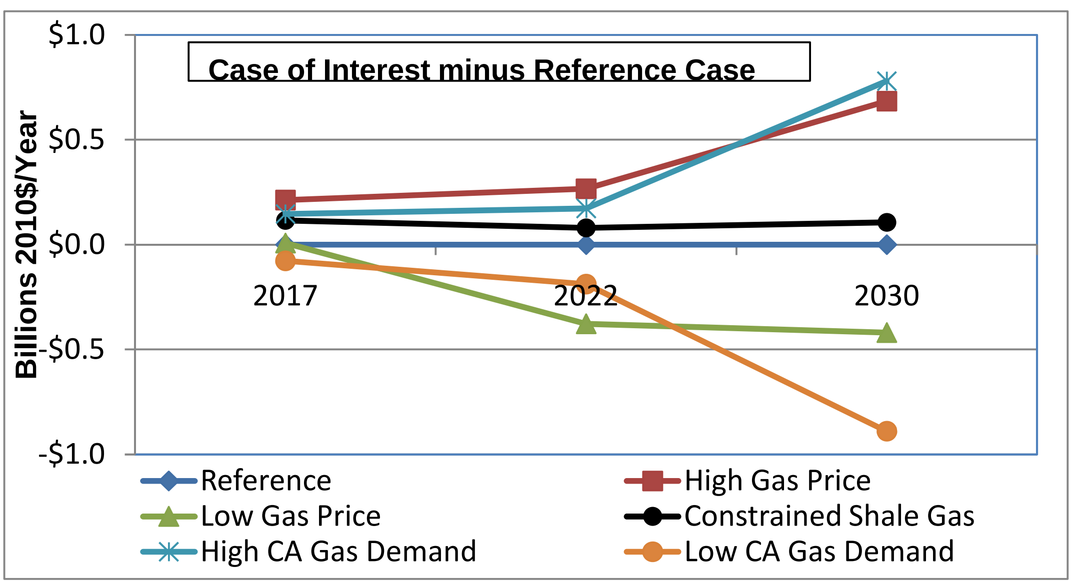
Source: California Energy Commission Staff Draft Analysis.

Figure 22: Differences in California Power Generation Annual Gas Demand Across All Cases



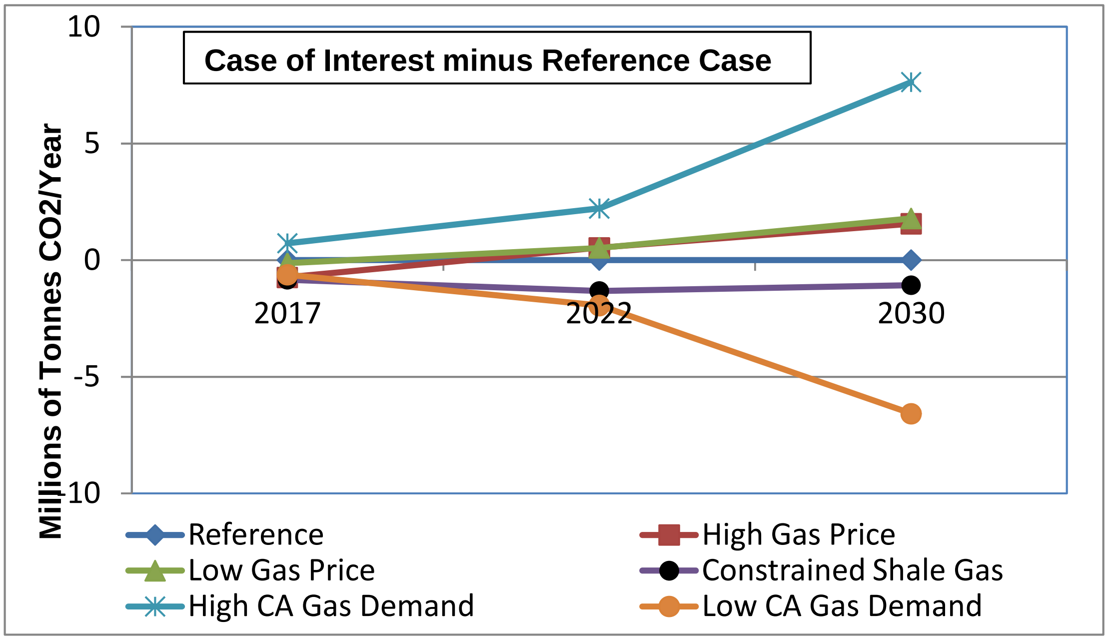
Source: California Energy Commission Staff Draft Analysis.

Figure 23: Differences in Estimated California Power Generation Annual Gas Costs Across All Cases



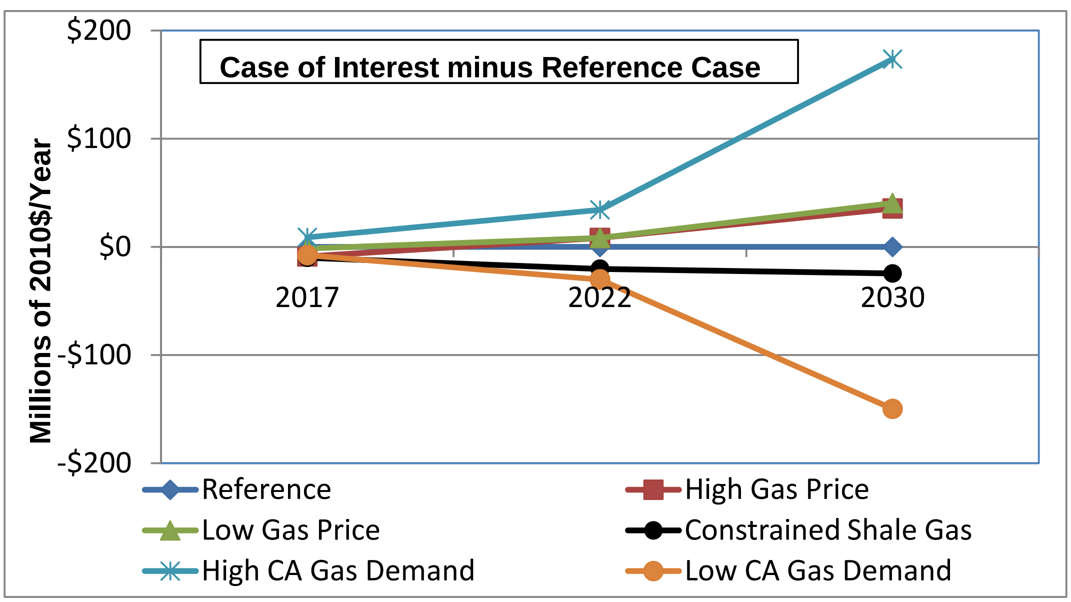
Source: California Energy Commission Staff Draft Analysis.

Figure 24: Differences in Estimated California Power Generation Annual CO_2 Emissions From Combustion Across All Cases



Source: California Energy Commission Staff Draft Analysis.

Figure 25: Differences in Estimated California Power Generation Annual Emission Allowance Costs Across All Cases



Source: California Energy Commission Staff Draft Analysis.

Reflecting on the Modeling Results

As expected, the modeling results directly reflect the assumptions staff made in each case about the future states of key drivers of natural gas market activities. Plausible alternative assumptions about future underlying conditions can significantly move national gas prices away from the level in the Reference Case.[30]

- The additional operating costs staff assumed for groundwater protection and environmental mitigation for gas extraction activities increased Henry Hub spot market prices in the Constrained Shale Gas Case about **4 percent above** the Reference Case prices.[31]
- To these additional environmental mitigation costs, the High Gas Price Case further constrained the development of gas from some shale formations, increased annual GDP growth from 2.7 to 3.5 percent, delayed RPS implementation across the nation by 10 years, and removed 50,000 MW of coal-fired generation, which collectively increased Henry Hub spot market prices by about **10 percent above** the Reference Case prices.
- In the other direction, the Low Gas Price Case assumptions of lowered annual growth in GDP (2.1 instead of 2.7 percent), higher U.S. and Canadian shale gas resource assessments, higher average annual gas technology learning improvement, relaxed market entry constraints for Iran, Iraq, and Venezuela, and accelerated national RPS compliance collectively lowered Henry Hub spot market prices by about 6 **percent below** the Reference Case prices.

Plausible alternative assumptions about future underlying conditions can also significantly move California gas demand away from the level in the Reference Case.

- The loss of SONGS and Diablo Canyon nuclear generation, a delay in RPS implementation, additional electric vehicle charging and natural gas veicles, and a slight increase in annual average growth in electrical demand (perhaps from reduced energy efficiency savings) increased California gas demand in the High California Gas Demand Case by about **21 percent above** the Reference Case demand.

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30 Staff has not attempted to "bookmark" the *widest* plausible range of input assumptions or model outcomes by specifying the *highest* and *lowest* plausible cases. To do that would require further elicitation of the judgment of experts in the various fields of activity affecting the underlying conditions. Even with this extra effort, experts may still be unable to agree on direction, magnitude, or likelihood of future specific conditions.

31 The average of the annual percentage differences between Constrained Shale Gas Case and Reference Case Henry Hub prices over the period 2012 to 2030 is 3.75 percent. The percentage differences between a changed case and the Reference Case shown in this section are all computed similarly.

- In the other direction, an increase in California RPS compliance to 40 percent by 2027, an additional 8,500 Gwh of renewable distributed generation by 2030, and a slightly slower annual average growth in electrical demand (perhaps from increased energy efficiency savings) decreased California gas demand in the Low California Gas Demand Cases by about **18 percent below** the Reference Case demand.

Having identified key drivers of natural gas market outcomes of widespread interest, such as prices, it is prudent to continue to monitor activities that affect these indicators. Doing so could conceivably reduce some uncertainty about their potential future states. Future economic conditions, the state of knowledge about the extent and economics of natural gas resources, progress of environmental, public safety, or energy policies directly or indirectly affecting coal-fired, nuclear, and renewable generation resources, regulations affecting access to natural gas resources, innovations in the technology of natural gas exploration, drilling and production, international gas market developments, nuclear power plant relicensing and safety proceedings, and electric and natural gas vehicle transportation initiatives are all activities that staff will continue to monitor when assessing the natural gas market and making conditional estimates of future market outcomes.

The future states of the identified key drivers of gas prices are both beyond California's control and difficult to predict accurately. There are risks inherent in using any conditional estimate of future gas prices for planning or policy decisions. Ideally, these risks should be understood and managed in the decision-making process. Understanding the risks begins with understanding the effects on gas prices of uncertainties about the future states of their underlying drivers. Having a plausible range of estimates that clearly relate the input variables (future underlying conditions) to the results (market outcomes) is important to building this understanding. Decision-making processes that use a gas price estimate typically include estimates of other key factors, about which there is also uncertainty. The uncertainties in these estimates also contribute to the risks inherent in the decision-making. Ideally, the risk management assessment of the potential consequences of the decision would estimate a range of consequences of acting on the presumption that one estimate (of gas prices and all other factors that are uncertain and are key drivers of the consequences) will happen when it turns out that a different value than the presumed estimate actually occurs. With some understanding of the risks inherent in using the conditional estimates for a particular decision, the decision-maker can judge how tolerable the risks seem, or modify the decision or policy to include mechanisms that work to directly reduce the risks.

CHAPTER 4: End-Use Gas Prices

Much of the nation's natural gas is delivered directly to large-volume end users, such as power plants and industrial facilities, by *interstate or intrastate transmission pipeline companies*. Residential and commercial consumers have their gas delivered by their *local distribution company's* network of lower pressure and smaller diameter *distribution pipelines* and *laterals*. The transmission pipeline companies deliver gas to the local distribution companies at their various *city gate* locations, where ownership of the gas transfers and the *local distribution function* is deemed to begin. Because of these differences in the way gas is delivered to end users in different sectors, the cost of delivery differs across sectors, and so, too, do the prices required to recover those costs. The more expensive-to-serve sectors pay higher prices, reflecting their higher costs of delivery. Residential customers pay the most for gas delivery, followed by commercial, industrial, and electric generation customers, respectively.

As described in **Chapter 2**, the WGTM estimates the commodity prices and interstate and intrastate transportation rates of delivering natural gas to the California border or to local distribution company city gate locations. The additional costs incurred by the distribution company to deliver the gas to its end users are estimated exogenously to the WGTM. For power plant and large industrial gas consumers served directly by interstate or intrastate transmission pipeline companies, staff begins with the WGTM's border price (rather than the citygate price) and adds exogenously estimated delivery costs.

Staff describes the various components of delivery costs by sector in this chapter as well as gives an explanation of the method of estimating end use delivery costs. Just as there is uncertainty about the future states for the key drivers of commodity prices and interstate transportation costs, there is uncertainty about the future states for the key drivers of delivery costs. The last section discusses some of the contributors to these uncertainties and provides some rough estimates of what effects they could have on future natural gas end-use prices.

This chapter focuses on methods, issues, and uncertainties related to future end-use pricing, but does not provide price estimates for all of the gas distribution companies or all of the modeled cases. To illustrate the general discussion, staff uses only PG&E-related examples. However, staff did estimate each distribution company's end-user gas prices under all modeled cases. These estimates are available in Microsoft Excel worksheets on the IEPR website at: http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/xls_results/.

In this chapter staff uses the terms *end-use price* and *end-use rates* somewhat interchangeably. Where the discussion refers to CPUC or other regulatory proceedings that establish specific transportation rates, then the term "rates" is used. Where the discussion refers to the combined total of all costs, including the gas commodity cost as well as transmission and distribution costs, then the term "price" is used.

Utility Cost to Operate the Distribution System

Table 25 illustrates the cost allocation associated with operating and maintaining a local distribution utility's distribution system. This table uses data from 2001 and is for SoCalGas. These numbers should be taken as an illustrative example of what goes into utility distribution costs and rates. These percentages may differ across utilities and be different in 2011.

Table 25: Local Distribution Utility System Cost Categories

Function	Percentage
Storage	5%
Transmission	4%
Distribution	14%
Customer Accounts	10%
Service and Information	5%
Administration	26%
Taxes	17%
Depreciation	19%
Total	100%

Source: 2001 SoCalGas Annual Report to the CPUC, pgs 317-325.

Utility transportation costs, often called "*the margin*" or utility "*fixed costs*," refer to all the costs associated with operating and maintaining the utility distribution system. They do not include the cost to purchase and deliver the natural gas to California.

The margin includes expenditures associated with operation, maintenance, administration, taxes, and depreciation. Operational and maintenance costs are incurred for storage, transmission, and distribution. These costs are applied to cover engineering, record keeping, compressor and pipeline maintenance, compressor fuel, and controlling the flow of natural gas from supply sources to the end user.

Such things as meter reading, maintaining customer records, and collection expenses are included in Customer Accounts. Service and Information charges cover the expenses for customer assistance. Administration covers general salaries, office expenses, outside services and consulting, employee pensions, injuries, and so forth. The utilities are subject to local, state, and federal taxes. Finally, depreciation covers the aging of the utility system.

Method for Estimating End-Use Gas Prices

Staff estimated end-use natural gas prices for PG&E, SoCalGas, and SDG&E. For each utility, local transmission and distribution costs were added to the citygate price to obtain the end-use price. End-use prices are estimated for the residential, commercial, industrial, and power generation sectors. The data used to estimate the transmission and distribution costs comes from the CPUC's Biennial Cost Allocation Proceeding (BCAP) decision for each utility.

PG&E End-Use Prices

Staff used the partial settlement in the 2009 BCAP's Appendix to calculate end-use natural gas prices for PG&E.[32] For residential transportation rates, the non-CARE (California Alternatives Rates for Energy program) residential rate was used.[33] For commercial transportation rates, a volume-weighted average of small and large commercial customers was calculated. Industrial end-use transportation rates were calculated using a volume-weighted average of backbone-, transmission-, and distribution-level industrial customer service. For electric generation, the backbone-level transportation service rate was used.

SoCalGas End-Use Prices

The 2009 BCAP[34] was used to calculate end-use natural gas prices for SoCalGas. For residential customers, the residential transportation rate was used. For the commercial customer transportation rate, the core commercial and industrial rate was used. The industrial end-use transportation rate is computed as the volume-weighted average of transmission- and distribution-level service for noncore commercial and industrial consumers. The electric generation end-use transportation rate is calculated as the volume-weighted average of transmission- and distribution-level electric generation customers. Staff's calculations are different for SoCalGas than for PG&E as the BCAP for each utility has a different level of detail.

SDG&E End-Use Prices

Information from the SoCalGas 2009 BCAP was used to calculate end-use natural gas prices for SDG&E. The end-use transportation rates for SDG&E were computed using data from

32 See Table K and Table L at https://www.pge.com/regulation/BCAP-PGE-2009/CPUC/Draft-Decisions/2010/BCAP-PGE-2009_CPUC_Draft-Dec_20100623-01Atch01.pdf for the BCAP Appendix 1.

33 California Alternative Rates for Energy (CARE) rates apply to low-income customers.

34 See Table 1 at http://www.socalgas.com/regulatory/documents/a-08-02-001/application_2008_0204.pdf for SoCalGas' BCAP.

rate tables in the 2009 SoCalGas BCAP.[35] These rates were calculated using the same method as for SoCalGas as the rate tables for both these utilities have the same amount of detail.

The following examples look at just PG&E. Other California utilities may have somewhat different natural gas commodity and transportation costs. These examples are intended to show the magnitudes of different transportation cost components and how different model scenarios affect end-use prices of natural gas.

Figure 26 plots the PG&E Citygate price for the Reference Case and the changed cases designed to move national gas market prices. This price plot should not be taken as the absolute high and low limits on natural gas prices, but rather a plausible range of what annual average equilibrium prices of natural gas could be given staff's assumptions for each case. From 2021 through 2030, the High Price Case is, on average, 10 percent higher than the Reference Case price, and the Low Price Case is, on average, 10 percent lower than the Reference Case price.

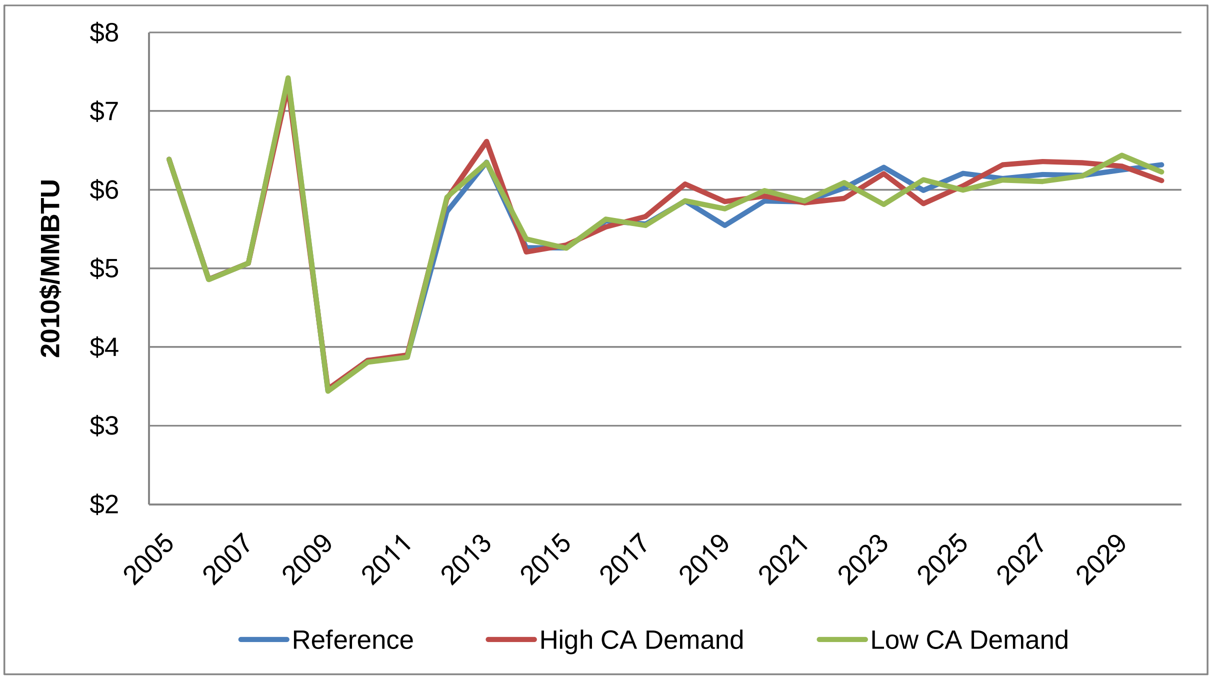
Figure 26: PG&E Citygate Prices Across Price-Focused Cases

Source: Energy Commission Staff Draft Analysis.

35 See http://www.socalgas.com/regulatory/documents/a-08-02-001/LRMC-NCORateTables.pdf page 6, Table 1.

Figure 27 shows how natural gas prices at PG&E Cityate are affected by the higher and lower levels of California gas demand in the modeled cases designed to move demand in California. The changes in California natural gas demand have a negligible effect on prices at the citygate. The price of natural gas at the Henry Hub shows the same story. California is a relatively small piece of the U.S. natural gas market and thus does not have a lot of market power to affect prices. The natural gas prices for SoCalGas Citygate and SDG&E Citygate are similar across these cases.

Figure 27: PG&E Citygate Price Across California Demand-Focused Cases



Source: Energy Commission Staff Draft Analysis.

Citygate and End-Use Prices

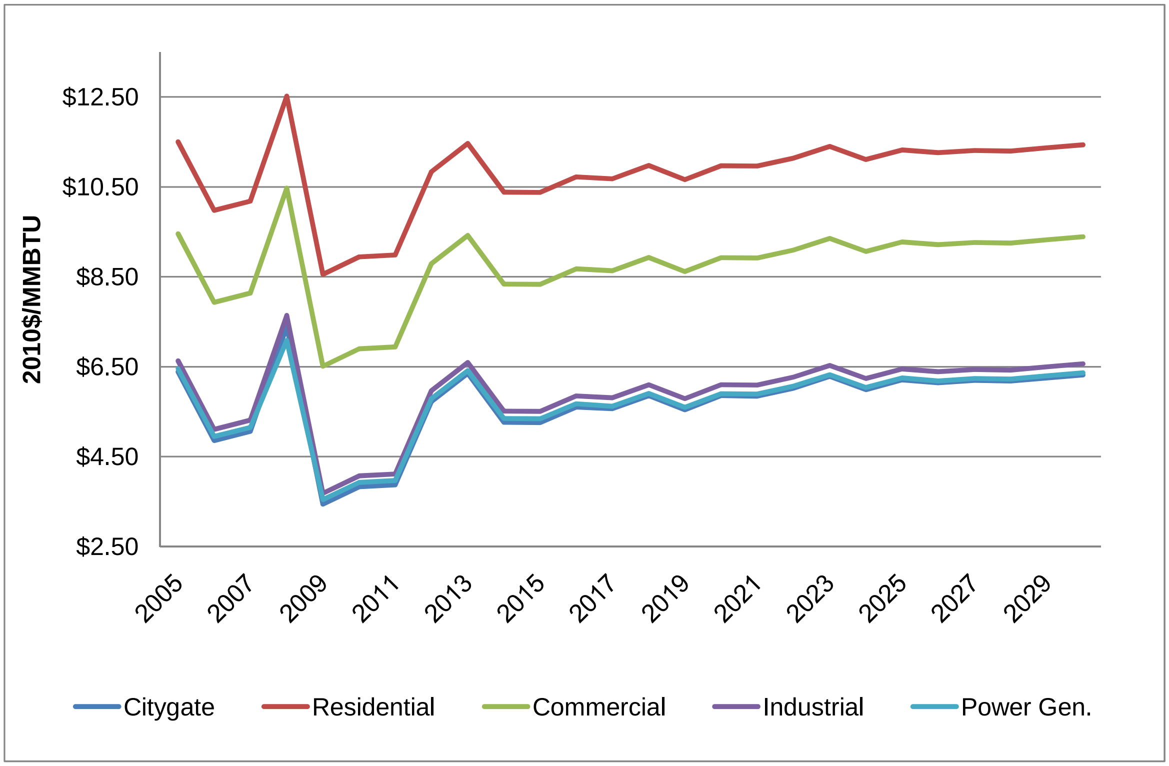
Figure 28 highlights the differences in delivery costs across customer classes by showing the Reference Case PG&E Citygate price and its associated estimates of residential, commercial, industrial, and electric generation end-use prices. No other cases are shown because transportation costs are held constant among cases.[36] In addition, the end-use transportation rates are held constant over time.[37] Residential customers pay for metering infrastructure,

36 This is a simplifying assumption. In reality, differences in market activities included in the WGTM modeling could lead to downstream differences in transportation service and costs.

37 This is another simplifying assumption. It implies that future transportation rates increase at the rate of inflation. Significant new investment in transportation facilities, such as pipeline or compressor replacements, could cause transportation rates to increase in real terms.

administration, and other services that some of the other end use customers do not. From 2005 through 2030, on average, the residential transportation (distribution) rates make up 48 percent of the total end-use price, while the commercial transportation makes up 36 percent. Industrial and electric generation customers are generally larger end use customers and their transportation charges make up a very small portion of their total end-use natural gas price.

Figure 28: PG&E Citygate and End Use Prices, Reference Case



Source: Energy Commission Staff Draft Analysis.

Table 26 shows the Reference Case estimates of PG&E total end-use prices and transportation components by sector. The data for this table was taken from the 2010 PG&E BCAP.[38] For distribution- and transmission-level service, the PG&E Citygate price was used, while for backbone-level service, the California border price was used. A volume-weighted average border price was used as there are border locations at Malin, Oregon, and Topock,

38 See Table L and Table K at https://www.pge.com/regulation/BCAP-PGE-2009/CPUC/Draft-Decisions/2010/BCAP-PGE-2009_CPUC_Draft-Dec_20100623-01Atch01.pdf.

Arizona. The weighting for the average border price was based on natural gas flows into California from each location. Only end users who receive their natural gas from a border location have to pay a backbone rate; citygate price locations already include the backbone rate in their prices.

Rsidential customers pay the most for transportation services, as seen in **Table 26**; in this example transportation makes up more than 50 percent of the total end-use price of natural gas. Residential end-use customers pay more for transportation (distribution) services because there are more meters to monitor and service, as well as more administrative costs. This table also indicates that transportation rates vary widely across customer classes. The prices in **Table 26** are a snapshot of 2010; staff made no projections of transportation rates going forward.

Table 26: 2010 PG&E End-Use Prices and Transportation Rates, Reference Case

Customer Class	Gas Commodity Cost in 2010 (2010$)	Transmission/Distribution Rate ($/Dth)	Backbone Rate ($/Dth)	**Total Transportation Rate ($/Dth)	Total End User Price ($/Dth)
Residential NON-CARE rate -citygate	$3.83	$5.12	N/A	**$5.12**	$8.95
Commercial					
Small Commercial - citygate	$3.83	$3.26	N/A	$3.26	$7.09
Large Commercial - citygate	$3.83	$1.04	N/A	$1.04	$4.87
Volume weighted average commercial rate	**$3.83**		N/A	**$3.07**	**$6.90**
Industrial					
Distribution - Industrial - citygate	$3.83	$1.04	N/A	$1.04	$4.87
Transmission - Industrial - citygate	$3.83	$0.10	N/A	$0.10	$3.93
Backbone - Industrial - border*	$3.63	$0.04	$0.294	$0.34	$3.97
Volume weighted average Industrial rate	**$3.83**		N/A	**$0.89**	**$4.72**
Electric Generation					
Electric Generation - Distribution and transmission - citygate	$3.83	$0.06	N/A	$0.06	$3.89
Electric Generation - Backbone - border*	$3.63	$0.06	$0.294	$0.35	$3.98
Electric Generation- volume weighted average rate	**$3.75**		N/A	**$0.18**	**$3.93**
* Border prices are a volume weighted average price of Topock and Malin					
** Total transportation is the sum of backbone, transmission, and distribution					
Rates and Volumes for weighting from: Table K, proposed rates, July 1, 2010	https://www.pge.com/regulation/BCAP-PGE-2009/CPUC/Draft-Decisions/2010/BCAP-PGE-2009_CPUC_Draft-Dec_20100623-01Atch01.pdf				
Backbone Rates From Gas Accord V: Appendix A, Table A-1	http://www.pge.com/pipeline/library/regulatory/gasaccord5/ga5settlement.pdf				
Note: the 2010 gas commodity cost was used for this example					

Source: Energy Commission Staff Draft Analysis.

Uncertainties About Key Variables

As discussed, gas delivery costs are very significant components of total gas prices for residential and commercial customers. Staff's estimates of end-use gas prices relied on sources of information that did not attempt to assess what future costs of the transportation component could be. A number of current issues suggest that future significant capital investments in transportation infrastructure or increases in operating expenses could occur. Both the scope and magnitude of these potential future transportation cost increases are characterized by considerable uncertainty. Staff made rough estimates of the potential effect on future transportation cost components of end-use gas prices of the following contingencies:

- Capital investments for pipeline inspection, repair, or replacement in response to public safety concerns about pipeline integrity or environmental contamination
- Continuation of the Puplic Purpose Program surcharge
- Costs of CO_2 allowance obligations on local distribution companies required by the cap and trade program of AB 32.

A brief discussion about each subject follows, and a rough estimate of impact is made.

Increased Captal or Operating Expenses Associated With Public Safety or Environmental Concerns

As discussed in **Chapters 3** and **4**, concerns about the integrity of the natural gas pipeline system have been raised by the circumstances surrounding the September 2010 gas pipeline explosion in San Bruno. The ongoing inspection program could reveal the need for significant capital investments in pipeline repair or replacement.

Another factor that may lead to changes in the transportation rates of end-use consumers is the U.S. EPA's proposed rulemaking that would limit the amount of polychlorinated biphenlys (PCBs) allowed in natural gas pipelines and compressors. Reducing the amount of PCBs allowed in natural gas pipelines and compressors may require cleaning or replacing pipelines and compressors; the costs for this would ultimately be paid by ratepayers. The Interstate Natural Gas Association of America (INGAA) estimates that the total cost to the U.S. to comply with the U.S. EPA's rule on PCBs would range from $33 billion to $466 billion (nominal) in 2020.[39] These costs are not insignificant.

When pipelines or compressors are replaced or repaired, the cost will generally, but not always or totally, fall to ratepayers. Staff computed a rough estimate of how much more ratepayers might pay to recover $500 million and $1 billion in capital costs for pipeline replacements. This calculation looks at the PG&E system and assumes: The costs of the new

39 See http://www.ingaa.org/File.aspx?id=10757 page 21.

pipelines is spread over 20 years, the PG&E system has 2,200 MMcfd of flowing supply, the utility receives a 10 percent rate of return, and lastly that costs are spread evenly to each end-use demand sector. **Table 27** and **Table 28** illustrate this calculation.

Table 27: Transportation Rate Increase With $500 Million in New Pipeline Costs

	Current Rate	Increase	Total	Percent Change
Residential	$5.48	$0.22	$5.80	4%
Industrial	$1.52	$0.06	$1.58	4%
Electricity Generation	$0.55	$0.02	$0.57	4%

Source: Energy Commission Staff Draft Analysis.

Table 28: Transportation Rate Increase With $1 Billion in New Pipeline Costs

	Current Rate	Increase	Total	Percent Change
Residential	$5.48	$0.44	$6.02	8%
Industrial	$1.52	$0.12	$1.64	8%
Electricity Generation	$0.55	$0.04	$0.59	8%

Source: Energy Commission Staff Draft Analysis.

A rough estimate of the compliance cost to California ratepayers of complying with the U.S. EPA's PCB rule can be calculated as in **Table 28**. Using the low estimate compliance cost of $33 billion, and taking 10 percent of this cost (the population in California is roughly 10 percent of the U.S. population) yields an estimated California cost of $3.3 billion. If the cost in California to replace or upgrade pipelines and compressors is $3.3 billion, and assuming every $1 billion spent on pipeline replacements equals an 8 percent increase in rates to all customer classes, a 26.4 percent increase in transportation rates would be expected. The costs in **Table 28** are for 2010 while the costs from the INGAA study are for 2020. This is just a rough estimate to show the potential magnitude that a policy like this could have on natural gas transportation rates.

Public Purpose Program Surcharge

The Public Purpose Program (PPP) surcharge is collected to fund specific low-income, energy efficiency, conservation, and public interest energy research.[40] Since this surcharge is a component of the natural gas distribution rate for nonelectric generation end-use sectors for each California utility, the fate of this surcharge can affect those gas customers' prices.

40 For more on the PPP surcharge see http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-PPPS.pdf.

There are a number of bills in the the California State Legislature potentially affecting this program. Assembly Bill 723 (Bradford, Statues of 2011) would extend a portion of the PPP surcharge through 2020.[41] If the bill does not pass, end-use gas transportation rates would likely become lower.

Table 29 shows the total transportation rates and PPP rate components for PG&E in its July 2010 proposed rates.[42] These transportation rates differ slightly from staff's end- use estimates because of rounding and how each demand sector is classified. All rates in **Table** 29 are in nominal $/MMBTU. **Table 29** indicates that the PPP surcharge makes up a substantial portion of the total transportation rate; in this example, 87 percent of the total transportation rate for backbone level industrial end use customers. This example illustrates the relative magnitudes of the natural gas PPP surcharges for different customer classes; the PPP surcharge may change from year to year.

Table 29: Public Purpose Program Surcharge

Customer Class	PPP Surcharge	Total Transportation Rate	PPP Percent of Total Transportation Rate
Residential Non-CARE	$0.65	$5.730	11%
Small Commercial Non-CARE	$0.44	$3.870	11%
Large Commercial	$0.69	$1.920	36%
Industrial - Distribution	$0.38	$1.460	26%
Industrial - Transmission	$0.33	$0.570	58%
Industrial - Backbone	$0.33	$0.380	87%
Electric Generation - Transmission	N/A	$0.059	N/A
Electric Generation - Backbone	N/A	$0.059	N/A

Source: https://www.pge.com/regulation/BCAP-PGE-2009/Testimony/PGE/2009/BCAP-PGE-2009_Test_PGE_20090529-01.pdf Table 5-A.

Cost of GHG Emission Allowance Obligation of AB 32 Cap and Trade Program

Another potential driver of natural gas end-use price is AB 32 carbon allowance costs. Starting in 2015, deliverers of natural gas not already covered by the cap and trade program will need to have CO_2 allowances to cover their emissions. This obligation will fall to local gas distribution companies. The allowance costs will, at least partly, be passed on to residential and commercial gas consumers. There are uncertainties in these carbon allowance costs such as how many allowances will be allocated for free rather than auctioned, how the bidding in the auctions will work, how the money collected from the

41 See http://info.sen.ca.gov/pub/11-12/bill/asm/ab_0701-0750/ab_723_cfa_20110624_094903_sen_comm.html for more on AB 723.

42 https://www.pge.com/regulation/BCAP-PGE-2009/Testimony/PGE/2009/BCAP-PGE-2009_Test_PGE_20090529-01.pdf Table 5-A.

allowances will be used, and at what price the allowances will trade. These uncertainties can greatly affect the cost of carbon allowances.

The Brattle Group found, in its study of AB 32's potential effects on small businesses, that carbon allowance costs could increase natural gas prices by $1.50–$3.00 per Dekatherm or 12 percent to 25 percent in 2020.[43] Staff calculated carbon allowance costs to get a ballpark estimate of how carbon allowance costs could affect natural gas prices. This calculation assumes the minimum (reserve) allowance price and that 50 percent of the allowances are free and 50 percent are auctioned. The emission factor assumed for all sectors is 5.31E-08 Million metric tons per million Btu ($MMTCO_2e$)/MMBtu. This is equivalent to 119 lbs CO_2/MMBtu, the value commonly used within the Energy Commission's Electricity Analysis Office [44]. These prices are an estimate of what commercial and residential customers pay on top of their natural gas rates. Due to the inherent uncertainties in the carbon allowances, their cost could end up higher or lower than what has been estimated. **Table 30** summarizes the carbon allowance cost calculation performed by staff. All the prices in **Table 30** are in real terms, and adding the minimum carbon allowance cost to the Reference Case PG&E Citygate prices yields an increase of between 5 percent and 10 percent.

43 See http://www.ucsusa.org/assets/documents/global_warming/AB-32-and-CA-small-business-report.pdf.

44 See http://www.epa.gov/cpd/pdf/brochure.pdf.

Table 30: Estimated Reserve Minimum Carbon Allowance Cost

Year	2010 $/Dth	PG&E Citygate 2010$/MMBTU	PG&E Citygate With Allowance Cost Added	Percent Increase to Citygate Price
2012	$0.26	$5.72	$5.98	5%
2013	$0.27	$6.35	$6.62	4%
2014	$0.28	$5.27	$5.55	5%
2015	$0.29	$5.26	$5.55	6%
2016	$0.31	$5.60	$5.91	5%
2017	$0.32	$5.57	$5.89	6%
2018	$0.34	$5.86	$6.19	6%
2019	$0.35	$5.54	$5.90	6%
2020	$0.37	$5.86	$6.23	6%
2021	$0.39	$5.85	$6.24	7%
2022	$0.41	$6.02	$6.43	7%
2023	$0.43	$6.29	$6.72	7%
2024	$0.45	$5.99	$6.44	8%
2025	$0.47	$6.21	$6.68	8%
2026	$0.50	$6.14	$6.64	8%
2027	$0.52	$6.20	$6.72	8%
2028	$0.55	$6.18	$6.73	9%
2029	$0.58	$6.25	$6.83	9%
2030	$0.61	$6.32	$6.92	10%

Source: Energy Commission Staff Draft Analysis.

CHAPTER 5: Next Steps and Ongoing Analysis

This chapter describes staff's suggested next steps for seeking stakeholder comments on staff's work and insights from the work of others. Subsequently, staff will produce a final version of this report.

Since it is an ongoing issue, staff discusses in this chapter an analysis conducted on the pipeline system pressure-related issues associated with the San Bruno incident. This analysis is separate from the previously discussed WGTM Lowered Pressure Case.

Finalizing Staff's Natural Gas Market Assessment

Any assessment of the current and possible future state of a market as large and complex as the natural gas market is daunting. It is also a necessary precursor to making informed decisions on a whole range of energy-related policies. The deliberative process resulting in this report included opportunities for reflection and input by stakeholders.

- In February 2011, staff participated in a workshop to discuss the economic and demographic assumptions that became part of the inputs to the model.
- In April 2011, staff presented case outlines that became the foundation for the forward-looking portion of this report.

This report is another key milestone in maintaining the transparency and validity of the analytical process. The next milestone will be feedback from stakeholders on how the results of this analysis can best be used. Staff has worked to produce estimates of future prices and quantities that are specifically meant to be "useful" and relevant for policy makers.

Following the publication of this report, a workshop will be held in September to present the results and solicit stakeholder feedback. The key to making these estimates useful is connecting the results as presented in this draft report to the ways in which they might be best used. For this effort, staff seeks the input of stakeholders in three critical areas:

- What additional relevant insights do stakeholders draw from the information presented in this report?
- How might the range of natural gas prices affect California's current energy policies, and how might those policies need to be changed to avoid possible negative outcomes?
- What issues or questions do stakeholders believe need to be explored more fully in the near future?

After the workshop, staff will review and consider stakeholder comments. Staff is open to a wide range of possible inputs from stakeholders. However, it may not be possible to explore every analytical question within the time limit of the *2011 IEPR*. Therefore, staff reserves the option of continuing analysis related to the questions and insights raised by stakeholders after the final revision to this report for subsequent *IEPR* cycles (especially in response to bullet number three).

A final report will be issued by the end of 2011, utilizing the full range of information and insights gathered throughout this process and proposing policy insights, choices, and recommendations for both decision-makers and stakeholders. Staff will carefully consider all stakeholder feedback during the finalization of this report.

Updating Potential Impacts of San Bruno Incident

On September 9, 2010, a 30-inch-diameter, high pressure natural gas transmission pipeline exploded under a neighborhood street in San Bruno, California. The explosion of Line 132, owned by PG&E, killed 8 people and destroyed 37 homes. The CPUC and the National Transportation Safety Board (NTSB) both launched investigations into the explosion.

Among the early findings by the NTSB was a longitudinal seam on a segment of Line 132 failed, while PG&E had indicated that the segment was seamless. As a result, the NTSB encouraged and the CPUC ordered PG&E to begin searching for “traceable, verifiable and complete” records to confirm the features and maximum allowable operating pressure (MAOP) of its pipelines in “High Consequence Areas” (HCAs). The CPUC also ordered PG&E to reduce operating pressures on lines of similar vintage and characteristics to Line 132 located in HCAs by 20 percent below the maximum allowable operating pressure (MAOP). Subsequent additional pressure reductions have either been ordered by the CPUC or implemented voluntarily by PG&E on additional lines, some in conjunction with hydrostatic testing that PG&E is conducting this year on 152 miles of pipeline for which it could not find records to validate MAOP.

In June, the CPUC issued an order as part of Order Instituting Rulemaking (OIR)11-02-019 into new pipeline safety rules, directing PG&E, SoCalGas, San Diego Gas & Electric (SDG&E) and Southwest Gas to pressure test or replace all pipelines, not just those in HCAs, for which the operators do not have “traceable, verifiable and complete” records of MAOP. This testing is expected to take several years. Until that testing is complete, operating pressures may be reduced to a level 20 percent below MAOP.

On June 30, PG&E released the results of a “Class Location Study.” The Class Location Study found that several of PG&E’s pipelines were misclassified. The classifications are used to help set MAOP based on the pipeline segment’s proximity to homes and businesses. To immediately remedy the misclassifications, PG&E reduced operating pressures on several additional pipeline segments.

There are several potential impacts to customers from the lower operating pressures and testing. First, reducing operating pressure in a pipeline effectively reduces the amount of natural gas that can be delivered through that pipeline in a given period. To the extent that lower pressures are below the pressures needed to support deliveries under PG&E’s

original temperature design criteria, customer curtailments can result. To date, PG&E has reported no curtailments to customers as a result of reducing the MAOP by 20 percent on some of its pipelines. However, in an October 2010 letter to the CPUC, PG&E identified conditions, including conditions warmer than those known as a "Cold Winter Day," under which service to customers on the San Francisco peninsula could be affected.[45] Cold Winter Day conditions are defined by PG&E to occur once every two years. In that letter, PG&E also identified steps it could implement in terms of operations or the addition of cross-ties between certain lines that would reduce the probability of potential curtailments. PG&E has not yet released an update of this analysis for winter 2011–2012, but the CPUC has confirmed to staff that the steps it identified last winter were implemented.

In addition, the lower pressures reduce PG&E's daily operating flexibility. This flexibility is embodied in what PG&E calls "pipeline system inventory." The inventory defines a range of minimum and maximum amounts of natural gas that PG&E needs to or can hold in the pipeline system without affecting service. Normally that range is 600 MMcf per day and provides an operational cushion to absorb imbalances between customer deliveries and actual daily usage. When inventory gets close to the minimum or maximum levels, PG&E issues an "operational flow order" (OFO) directing its customers to better balance their deliveries into the system with their usage. Normally a high inventory OFO occurs when too many customers have delivered more gas into the system than they have used or injected into storage; conversely, a low inventory OFO occurs when customers use more gas than they delivered into the system or withdrew from storage. Customers were allowed to be out of balance in the opposite direction of the OFO since using excess gas when the system is overpressured, for example, would help reduce the high pressure causing the OFO.

With the additional pressure reductions necessitated by the findings of the Class Location Study, PG&E's 600 MMcf per day permissible inventory swing has become only 200 MMcf per day. PG&E has therefore, since around July 1, been issuing high and low inventory OFOs simultaneously, on the same day. These simultaneous daily OFOs mean that customers must match their deliveries of gas into the PG&E system on both the high and low sides of their daily usage. This situation is likely to prevail until PG&E is able to complete changes to the affected pipeline segments that would allow PG&E to return those segments to their prior MAOP. In the meantime, staff is monitoring for market effects of the tighter balancing.

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45 The letter, from PG&E's Brian Cherry to CPUC Executive Director Paul Clanon, can be found at: http://www.cpuc.ca.gov/NR/rdonlyres/6A94E6D5-7DE1-40EE-9461-ADC116A17707/0/Oct25PGEResponsetoCPUC.pdf

Second, hydrostatic testing means taking the segment of line being tested out of service. Testing typically takes several days. If the test causes the pipeline to fail, then it must be replaced, during which time the segment remains out of service. It appears that for most of the segments being tested in 2011, PG&E has the ability to reroute natural gas to continue service to nearby customers. Certain very large customers, such as gas-fired electricity generating plants, take service directly from high pressure transmission pipelines. The Energy Commission is aware that service to certain power plants may be affected, and staff is working with its sister agencies to provide information and contingency planning support to address potential outages.

Third, the flow reduction due to lower operating pressures (on what is known as the "backbone" portion of PG&E's transmission system) amounts to a loss in flow capability of about 500 MMcf/d. In summer months, this capacity is often used to help fill underground gas storage. Gas in storage is essential to meeting California's winter month gas requirements. Staff's analysis to date leads to the encouraging conclusion that PG&E should be able to inject into storage most, if not all, of the gas it needs to protect service to core customers even with the reduced operating pressures and lower gas flows.

Fourth, staff looked at whether the reduction in lower backbone transmission availability could affect the state's ability to meet all natural gas demand. As a first cut, staff assessed capacity available to serve monthly average daily demand under normal weather conditions in what is known as a *gas balance analysis*. This involved taking PG&E's projection of annual demand in a normal year (obtained from the *2010 California Gas Report*) and spreading it across months using annual to monthly spread factors calculated from a series of recorded monthly demands. Using six years of recorded monthly demand, staff calculated a factor that describes demand in each month on the PG&E system as a percentage of average annual demand. These demands are an imperfect proxy for PG&E demand forecasted by month in a normal weather condition year. Using this monthly demand spread, and projected backbone capacity availability as posted on PG&E's Pipe Ranger, the analysis suggests that PG&E's natural gas capacity reserve margin could be pushed to very close to zero in December and January.

Looking at average daily demand in a month can be misleading without realizing that, as demand swings up and down around that average day, PG&E has the flexibility to withdraw much more gas from storage on a given day that it cannot sustain for every day over a month or over a winter. For example, the analysis assumed average daily withdrawals of 350 MMcf/d in December, but on a specific cold day PG&E can withdraw upwards of 1,100 MMcf/d. In addition, noncore customers should be able to withdraw some amount of gas from third-party storage that PG&E can accept into its local transmission system rather than into its backbone system and a small piece of any difference might be absorbed in pipeline system inventory. This assumes, however, that noncore customers fill their storage. Noncore customers did not fully fill their storage inventories during summer and fall 2000, which contributed to natural gas price impacts that winter as the electricity crisis unfolded. As customers prepare for winter 2011-2012, noncore customers would be prudent to use available backbone capacity to inject as much gas as possible into storage.

Table 31: PG&E High Demand Day Gas Requirements and Sources

MMcf/d	Dec 8 2009 Recorded	Dec 9 2009 Recorded	Winter Peak Day Forecast from 2010 California Gas Report/1
Demand			
Core	2,840	2,926	2850
Industrial	677	692	420
Electric Generation	551	528	1000
Off-System	27	68	0
Total	4,095	4,214	4,270
Capacity & Supply			
Redwood	901	809	1,800/2
Baja	1,031	1,051	733
Silverado (CA Production)	120	120	130
PG&E Storage	1,344	1,228	1,100
Independent Storage	699	1,006	507
Total	4,095	4,214	4,270

Source: Compilation of data reported on PG&E Pipe Ranger, *California Gas Report*, and staff analysis.

1 The capacity and supply data shown are Energy Commission staff projections, updated for PG&E notices on its Pipe Ranger web site. See http://www.pge.com/pipeline/operations/pipeline_maintenance/foghorn.shtml.

2 Ruby Pipeline feeds into the Redwood path. PG&E has noted in previous *California Gas Reports* that under very cold conditions it often sees a diminution in supply delivered to the California border. Achieving deliveries of 1800 MMcf/d on a cold day seems reasonable given the new supply offered from Ruby.

Staff then looked at what would happen under colder conditions, including under "Winter Peak Day" (WPD) conditions, to assess the effect of pressure reductions on natural gas service. PG&E projects demand under WPD conditions of 4,270 MMcf/d and notes in the *2010 California Gas Report* that WPD conditions have a recurrence probability of 1-in-35 years. The capability to serve WPD demand and a comparison to two cold days with demand close to WPD from December 2009 are shown in **Table 31**. Larger than average day withdrawals from storage by PG&E were required to meet demand on these days. Note also that on the two cold days in 2009, noncore customers chose to pull gas from storage and used that gas in lieu of out-of-state supplies delivered via backbone capacity. In looking at the WPD, staff assumed that customers would make full use of available backbone capacity and that PG&E would withdraw 1,100 MMcf/d of gas from storage – 1,100 MMcf/d is intentionally smaller than what PG&E withdrew on the cold days shown from 2009, leaving a small contingency margin. Making full use of backbone capacity constrained by the pressure reduction means that some gas must come from independent storage to serve all demand. The importance of filling not only PG&E storage, but independent storage, to make up for the constrained backbone capacity on days colder than average conditions occur is clear. Customers who have access to those independent storage facilities would be prudent to use available backbone capacity to inject gas this fall and to include in their winter 2011–2012 contingency planning an expectation that they may need to use their stored gas for reliability purposes.

List of Acronyms

Acronyms	Proper Name
AEO 2010	*2010 Annual Energy Outlook*
ANPR	Advance Notice of Proposed Rulemaking
BCAP	Biennial Cost Allocation Proceeding
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
CARE	California Alternate Rates for Energy
CCGT	Combined cycle gas turbine
CFR	Code of Federal Regulations
CFTC	Commodities Futures Trading Commission
CH_4	Methane
CHP	Combined heat and power
CMP	Compliance Monitoring Program
CO_2	Carbon monoxide
COMEX	Commodity Exchange
CPUC	California Public Utilities Commission
Dth	Decatherms
EOR	Enhanced oil recovery
EPNG	El Paso Natural Gas
ERCOT	Electricity Reliability Council of Texas
F&D	Finding and development cost
FERC	Federal Energy Regulatory Commission
FTA	Free Trade Agreement
GDP	Gross domestic product
GhG	Greenhouse gas
GTN	TransCanada Gas Transmission Northwest
GWh	Gigawatt hours
HCAs	High Consequence Areas
ICE	Intercontinental Exchange
IECA	Industrial Energy Consumers of America
INGAA	Interstate Natural Gas Association
LIPP	Long-Term Procurement Proceeding
LNG	Liquefied natural gas
MAOP	Maximum Allowable Operating Pressure
Mcf	Thousands of cubic feet
MCFe	Thousand cubic feet equivalent
MIT	Massachusetts Institute of Technology
$MMTCO_{2E}$	Million metric tons carbon dioxide equivalent
MMcf/d	Million cubic feet per day
MPR	Market Price Referent
MW	Megawatts
N_2O	Nitrous cxide
NERC	North American Electric Reliability Council
NTSB	National Transportation Safety Board
NYMEX	New York Mercantile Exchange
OFO	Operational Flow Order

Acronyms	Proper Name
OIR	Order Instituting Rulemaking
PCB	Polychlorinated biphenyl
PG&E	Pacific Gas and Electric
PHMSA	Pipeline and Hazardous Material Safety Administration
PPP	Public Purpose Program
REX	Rocky Mountain Express Pipeline
RFO	Residual fuel oil
RPS	Renewables Portfolio Standard
RWGTN	Rice World Gas Trade Model
SDG&E	San Diego Gas & Electric
SO_2	Sulphur dioxide
SoCalGas	Southern California Gas Company
STEO	*Short-Term Energy Outlook*
Tcf	Trillion cubic feet
Tcf/yr	Trillion cubic feet per year
Thm	Therm
TSCA	Toxic Substances Control Act
U.K. NBP	United Kingdom National Balancing Point
U.S.	United States
U.S. DOE	U.S. Department of Energy
U.S. DOT	U.S. Department of Transportation
U.S. EPA	U.S. Environmental Protection Agency
USD	U.S. dollar
USEIA	U.S. Energy Information Administration
USGS	U.S. Geological Survey
WTI	West Texas Intermediate
WSGR	Worldwide Shale Gas Resources

APPENDIX A: Glossary of Terms

Adsorbed Gas: Methane molecules attached to organic material contained within solid matter.
Backbone Transmission System: The system used to transport gas from a utility's interconnection with interstate pipelines, other local distribution companies, and the California gas fields to a utility's local transmission and distribution system.
Border Price: This is a price at the border of a state; it represents the place where gas goes from an interstate pipeline to an intrastate pipelines. The border location is not always exactly on the border of a state, but is normally very close to it.
Carbon Footprint: The total set of greenhouse gas emissions caused directly and indirectly by an individual, organization, event, or product.
Casing: Pipe set with cement in the hole in the earth.
Combined Cycle Gas Turbine: An assembly of engines that convert heat into mechanical energy, which in turn usually drives electrical generators. The principle is that the exhaust of one heat engine is used as the heat source for another, increasing the system's overall efficiency.
Citygate Price: The price paid by a natural gas utility when it receives natural gas from a transmission pipeline. "Citygate" is used because the transmission pipeline often connects to the distribution system that supplies a city.
Coal-bed Methane (CBM): Natural gas extracted from coal deposits.
Drilling: The process of boring a hole in the earth to find and remove subsurface fluids such as, oil and natural gas.
Environmental Impact: Adverse effect upon natural ambient conditions.
Formation: A bed or rock deposit composed, in whole, of substantially the same kind of rock; also called reservoir or pool.
Futures Market (natural gas): A trade center for quoting natural gas prices on contracts for the delivery of a specified quantity of a natural gas at a specified time and place in the future. Natural gas futures start from the next calendar month and can go up through 36 months into the future. For example, on October 2, 1998, trading occurs in all months from November 1998 through October 2001.
Groundwater: Water in the earth's subsurface used for human activities, including drinking.
Henry Hub: Located in Southern Louisiana, is a key natural gas pricing point in the Lower 48.
Horizontal Well: A hole at first drilled vertically and then horizontally for a significant distance (500 feet or more).
Hydraulic Fracturing: The forcing into a formation of a proppant-laden liquid under high pressure to crack open the formation, thus creating passages for oil and natural gas to flow through and into the wellbore. Also known as "fracking" or "fraking."

Local Transmission System: The term "local transmission system" includes the pipeline used to accept gas from the backbone transmission system and transport it to the distribution system.
Manipulation: Any planned operation, transaction, or practice that causes or maintains an "artificial price." The Commodities Futures Trade Commission (CFTC) defines artificial price as a price higher or lower than it would have been if it reflected the forces of supply and demand.
Net Present Value: The process of finding the current-date value of a stream of future periodic cash-flows. Present value of revenues minus present value of costs gives the net present value.
New York Mercantile Exchange (NYMEX): The world's largest physical commodity futures exchange. Trading is conducted through two divisions: the NYMEX Division, which is home to the energy, platinum and palladium markets, and the Commodity Exchange (COMEX) Division, where metals like gold, silver, and copper and the FTSE 100 index options are traded. The NYMEX uses an outcry trading system during the day and an electronic trading system after hours.
Original Gas-in-Place: The total initial volume (both recoverable and non-recoverable) of oil and/or natural gas in-place in a rock formation.
Permeability: The ability of a fluid (such as oil or natural gas) to flow within the interconnected pore network of a porous medium (such as a rock formation).
Porosity: The condition of a rock formation by which it contains many pores that can store hydrocarbons.
Production Decline Profile: A chart demonstrating the depletion of a producing well.
Proppant: A granular substance (sand grains, walnut shells, or other material) carried in suspension by a fracturing fluid that keep the cracks in the shale formation open after the well operator retrieves the fracturing fluid.
Recoverable Reserves: The unproduced but recoverable oil and/or natural gas in-place in a formation.
Rig Count: The number of drilling rigs actively punching holes in the earth.
Shale: A fine-grained sedimentary rock whose original constituents were clay minerals or mud.
Shale Gas: Natural gas produced from shale formations.
Shale play: A geographic area containing an organic-rich fine-grained sedimentary rock with the following characteristics: Particles are the size of clay or silt, contains high percentage of silica (and sometimes carbonates), is thermally mature, has hydrocarbon-filled porosity and low permeability, is distributed over a large area, and economic production requires fracture stimulation.
Spot Market (natural gas): A market in which natural gas is bought and sold for immediate or very near-term delivery, usually for a period of 30 days or less. The transaction does not imply a continuing agreement between the buyers. A spot market is more likely to develop at a location with numerous pipeline interconnects, thus allowing for a large number of buyers and sellers. The Henry Hub in Southern Louisiana is the best known spot market for natural gas.

Spot Price (natural gas): The price for a one-time open market transaction for near-term delivery for a specific quantity of natural gas at a specific location where the natural gas is purchased at current market rates.
Stimulation: The process of using methods and practices to make a well more productive.
Tight Gas: Natural gas from very low permeability rock formations.
Unconventional Production: Natural gas from tight formations or from coal deposits or from shale formations.
Well Completion: The activities and methods necessary to prepare a well for the production of oil and natural gas.
Well: A hole in the earth caused by the process of drilling.
Wellbore: The hole made by drilling. It may be cased, for example, pipe set by cement within the hole.
Wellhead Price: The value at the mouth of the gas well. In general, the wellhead price is considered to be the sales price obtainable from a third party in an arm's length transaction (no transportation or processing costs are included). Posted prices, requested prices, or prices as defined by lease agreements, contracts, or tax regulations should be used where applicable.

APPENDIX B: Development of the Reference Case From the Rice World Gas Trade Model

This appendix is Dr. Ken Medlock's Microsoft PowerPoint® presentation saved as an Adobe PDF® file. The PDF file is posted on the Energy Commission website at this link:

http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/Appendix_B/

APPENDIX C: Guide to World Gas Trade Model Results for All Study Cases

This appendix is a guide to the structure of the Microsoft Excel files that contain the WGTM results for each of the study cases: Reference, High U.S. Gas Price, Low U.S. Gas Price, Constrained Shale Gas, High California Gas Demand, Low California Gas Demand, and Lowered Pressure cases. **Table C-1** explains the nomenclature used in the model result files. Each of the Excel files contains results from a particular case, each divided into 19 sheets, and each presenting a different aspect of the model output. Two versions of the Excel worksheets--xls and xlsx—are provided. The files are posted at: http://www.energy.ca.gov/2011_energypolicy/documents/2011-09-27_workshop/xls_results/

Table C-1: Explanation of Nomenclature in Model Results

Spreadsheet Tab Name	Explanation of Sheet	Sample Name Within Sheet	Remarks
CHARTS	This sheet contains two graphs: U.S. Demand Totals and California Demand Total.		Graphs contain no names that required further explanation.
U.S._Dmd_Total	This sheet contains actual historical data and the model results for U.S. Natural Gas Demand.	Sheet lists natural gas demand by state.	
Calif_Dmd_Total	This sheet contains actual historical data and the model results for California Natural Gas Demand.	**D: U.S.-CA PG&E (Ind):** This name conveys that this demand is in the U.S., in California, and in PG&E's service territory. Further, the information represents the industrial demand in the specified jurisdiction.	All represented demands in the WGTM begin with D: • Res represents residential • Comm represents Commercial • Ind represents Industrial • Pwr represents Power Generation.

Spreadsheet Tab Name	Explanation of Sheet	Sample Name Within Sheet	Remarks
Calif_Dmd_PGE	This sheet contains actual historical data and the model results for Natural Gas Demand the Pacific Gas and Electric service territory.	Similar to the above.	
Calif_Dmd_SoCal	This sheet contains actual historical data and the model results for Natural Gas Demand the SoCal service territory.	Similar to the above with the information now tailored to the SoCal service territory.	
Calif_Dmd_SDGE	This sheet contains actual historical data and the model results for Natural Gas Demand the San Diego Gas and Electric service territory.	Similar to the above with the information now tailored to the San Diego Gas and Electric service territory.	
US_Dmd_PGen	This sheet contains actual historical data and the model results for U.S. Power Generation Natural Gas Demand.	**D: US-PA Pittsburgh (Pwr):** This name conveys that this demand is in the U.S., in Pittsburgh, Pennsylvania. Further, the information represents the Power Generation demand in the specified jurisdiction. **(1)**	
WECC(US-CAN)_Dmd_PGen	This sheet contains actual historical data and the model results for Western Energy Coordinating Council for U.S. and Canada Natural Gas Demand.	Similar to the above with the information now tailored to the WECC states in both Canada and the U.S.	Only whole states in the U.S. represented in the totals.
WECC(US)_Dmd_PGen	This sheet contains actual historical data and the model results for Western Energy Coordinating Council for U.S. Natural Gas Demand.	Similar to the above with the information now tailored to the WECC states in the U.S.	Only whole states in the U.S. represented in the totals.
US_Prod_Total	This sheet contains actual historical data and the model results for U.S. Natural Gas Production.	Sheet lists natural gas production by state.	

Spreadsheet Tab Name	Explanation of Sheet	Sample Name Within Sheet	Remarks
US_Prod_Shale	This sheet contains actual historical data and the model results for US Shale Natural Gas Production.	**S: US-Gulf Coast-Texas RRC 4 (Eagle Ford T1) Shale YTF:** This name conveys that this supply resource is in the US, in the Gulf Coast, in Texas Railroad Commission District 4, and in the Eagle Ford producing basin. Further, the information represents production from a shale formation. YTF stands for Yet To Find, which means that this supply resource is a potential resource.	All represented supply resources in the WGTM begin with S: GTK means Growth to Known. This represents the reserve appreciation.
Calif_Prod_Total	This sheet contains actual historical data and the model results for California Natural Gas Production.	Similar to the above with the information now tailored to California. **(2)**	
Calif_Supply_Total	This sheet contains model results for California Natural Gas Supply and Demand.	**P: US-Kern (UT to CA):** This name conveys that this pipeline is in the US, and is named Kern (River), with this leg travelling from Utah to California.	All represented pipelines or pipeline corridors in the WGTM begin with P:
Can_Prod_Total	This sheet contains actual historical data and the model results for Canada Natural Gas Production.	Similar to (2) above with the information now tailored to Canada.	
Can_Imports	This sheet contains actual historical data and the model results for US imports of Natural Gas from Canada.	**Hub: Canada-British Columbia-Sumas:** This name conveys that this hub is in Canada, in British Columbia, and is located at Sumas.	Hubs represent locations into which pipelines are connected and out of which natural gas flows, also along pipelines.

Spreadsheet Tab Name	Explanation of Sheet	Sample Name Within Sheet	Remarks
LNG_Imports	This sheet contains actual historical data and the model results for U.S. imports of Liquefied Natural Gas.	**Proc: LNG Regas-US (Cove Point) (Contract):** This name conveys that this LNG re-gasification processing facility is located in the U.S. and at Cove Point. Further, this represents the contracted flows.	**Proc:** Can represent a LNG re-gasification facility or a liquefaction facility or a wellhead processing facility.
CA_Dmd_PGen	This sheet contains actual historical data and the model results for California Natural Gas Demand for Power Generation.	Similar to (1) above with the information now tailored to California.	
Calif_RefDmd	This sheet contains model input reference demands for Power Generation and other sectors in California.	Similar to above	
HubPrices	This sheet contains Natural Gas prices for selected pricing hubs in the U.S.	**Hub: US-Malin:** This name conveys that this hub is in the U.S. and located at Malin, Oregon.	

APPENDIX D: GDP Deflator Series

Table D-1: GDP Deflator Series

Year	1977=1	2005=1	2007=1	2010=1
1970	64.42	24.32	22.88	21.98
1971	67.64	25.53	24.02	23.08
1972	70.55	26.63	25.06	24.07
1973	74.47	28.11	26.45	25.41
1974	81.23	30.66	28.85	27.71
1975	88.90	33.56	31.57	30.33
1976	94.01	35.49	33.39	32.07
1977	100.00	37.75	35.51	34.12
1978	107.02	40.40	38.01	36.51
1979	115.92	43.76	41.17	39.55
1980	126.49	47.75	44.92	43.15
1981	138.34	52.23	49.13	47.20
1982	146.78	55.41	52.13	50.08
1983	152.59	57.60	54.19	52.06
1984	158.32	59.77	56.23	54.01
1985	163.11	61.58	57.93	55.65
1986	166.71	62.94	59.21	56.88
1987	171.55	64.76	60.93	58.53
1988	177.45	66.99	63.02	60.54
1989	184.15	69.52	65.40	62.82
1990	191.25	72.20	67.92	65.25
1991	198.03	74.76	70.33	67.56
1992	202.73	76.53	72.00	69.16
1993	207.21	78.22	73.59	70.69
1994	211.57	79.87	75.14	72.18
1995	215.98	81.54	76.71	73.69
1996	220.09	83.09	78.17	75.09
1997	223.98	84.56	79.55	76.41
1998	226.51	85.51	80.45	77.28
1999	229.84	86.77	81.63	78.41
2000	234.82	88.65	83.40	80.11
2001	240.12	90.65	85.28	81.92
2002	244.01	92.12	86.66	83.25
2003	249.27	94.10	88.53	85.04
2004	256.34	96.77	91.04	87.45
2005	264.89	100.00	94.08	90.37
2006	273.52	103.26	97.14	93.32
2007	281.57	106.30	100.00	96.06
2008	287.72	108.62	102.19	98.16
2009	290.36	109.61	103.12	99.06
2010	293.11	110.65	104.10	100.00
2011	295.41	111.52	104.91	100.78
2012	301.05	113.65	106.92	102.71
2013	309.23	116.74	109.82	105.50
2014	316.14	119.35	112.28	107.86
2015	322.32	121.68	114.47	109.96
2016	328.45	123.99	116.65	112.06
2017	334.02	126.09	118.63	113.95
2018	339.13	128.03	120.44	115.70
2019	344.12	129.91	122.21	117.40
2020	349.07	131.78	123.97	119.09
2021	354.14	133.69	125.77	120.82
2022	359.34	135.65	127.62	122.59

Source: California Energy Commission Staff 2011 Preliminary California Energy Demand (CED) Forecast.