California Energy Commission

FINAL STAFF REPORT

ESTIMATING NATURAL GAS BURNER TIP PRICES FOR CALIFORNIA AND THE WESTERN UNITED STATES

CALIFORNIA
ENERGY COMMISSION

Edmund G. Brown Jr., Governor

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ABSTRACT

Natural gas burner tip prices, as estimated in this report, attempt to account for the cost to procure and deliver gas to a natural gas-fired electric generator. Burner tip prices include both a commodity and a transportation component. The commodity component is the price of natural gas after production from the well and processing for injection into a nearby utility pipeline. The transportation component is the cost of transporting the gas from the injection point near the production basin to the electric generator for consumption.

Estimated future burner tip prices are used for electricity resource planning. Fuel to run gas-fired turbines is a major portion of the overall cost of operating these generators. These fuel costs therefore affect decisions on the types of electric generation and infrastructure that are built.

The method for estimating burner tip prices uses forecasted annual natural gas commodity prices from the *2013 Natural Gas Issues, Trends, and Outlook Final Staff Report* and transportation rates from interstate, intrastate, and utility level transportation rates. The method first converts annual forecasted natural gas commodity prices to monthly values. Then, the appropriate transportation rate (tariff) is added to account for the price of transportation to the electric generator.

There are some potential uncertainties when estimating burner tip prices. Environmental regulations, changes in supply and demand, and the price of alternative fuels will affect the future commodity price of natural gas. The cost of transporting natural gas may also change based on environmental policies, pipeline infrastructure additions and repairs, and shifts in supply and demand.

Keywords: Natural gas, prices, burner tip, forecasts

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EXECUTIVE SUMMARY

Natural gas burner tip prices are defined as the price paid for natural gas that is burned in a furnace, water heater, natural gas-fired electric generator, or another end use. For this report, burner tip prices are limited to the price paid for natural gas to burn at a gas-fired generator to generate electricity. These burner tip prices include not only the cost of the gas itself (the commodity price), but transportation charges as well. Reliable estimates of burner tip prices, when used to populate electricity production cost models such as PLEXOS®, enable electric system planners to more realistically simulate the dispatch of electric grid resources and, therefore, make informed judgments about future resource plans.

This report presents the California Energy Commission's method for estimating burner tip prices. A transparently documented burner tip price estimation method provides an opportunity for feedback from stakeholders and improvements to the Energy Commission's method over time. This report serves as complete documentation for the associated spreadsheet-based burner tip price model, which is posted with this report on the Energy Commission website. Electricity generation and distribution models, such as the PLEXOS® production cost model and the Cost of Generation model, can use these burner tip prices as reliable inputs. Other agencies, such as the Western Electricity Coordinating Council, may find use in the Energy Commission's methods in their own burner tip price modeling.

This report examines the method and techniques the Energy Commission uses to estimate natural gas burner tip prices for various electricity system planning models. The forecast horizon for these estimates is generally 30 years. This report also examines burner tip price estimation methods employed by other entities, such as the California investor-owned natural gas utilities' *California Gas Report,* the Northwest Power and Conservation Council, and the Western Electricity Coordinating Council. End-use burner tip prices are estimated on a monthly basis by developing and applying monthly seasonal factors derived from historical natural gas commodity price patterns. This annual-to-monthly conversion is described in this report.

The Energy Commission uses both interstate and intrastate natural gas pipeline transportation rate information to estimate the cost of transporting natural gas to natural gas-fired electric generators. Transportation rates will vary depending on customer class and the rate structure for each pipeline or natural gas utility.

Overall, the Energy Commission's burner tip price estimates appear broadly consistent with estimates by other entities. The natural gas commodity price forecasts associated with the Northwest Power and Conservation Council's estimates and the *California Gas Report* burner tip prices use similar assumptions to those of the Energy Commission's natural gas commodity price forecasts. However, the treatment of transportation rates in other estimates of burner tip prices differs. The Energy Commission uses natural gas pipeline and utility pipeline tariffs, while other methods use financial *basis swaps* or historical natural gas regional price differentials. A *basis swap* in natural gas trading locks in the price differential between two price hubs. It is a transaction where one party receives a fixed price for the difference between the price at Henry Hub, Louisiana,[1] and another specified price location, and the other party receives the actual floating price (the true price differential). *Basis swaps* are used mainly to hedge against regional price movements. In theory, the price difference between two market hubs reflects the cost of transportation between the two hubs. Staff chose natural gas pipeline and utility pipeline tariffs because they are publicly available and accessible on pipeline operators' websites.

The Energy Commission's method may need to be revised as the natural gas industry changes with respect to supply, demand, natural gas infrastructure, natural gas procurement strategies (for example, short-term vs. long-term natural gas purchases), environmental policies, and other pertinent factors. This method may be revised should natural gas utilities, pipeline companies, marketers, buyers, or planners provide the Energy Commission with new information on how natural gas is procured and transported. Future work may include running various sensitivities on Energy Commission burner tip price estimates. These sensitivities will include allowing transportation rates to change over time as well as using basis swaps and other methods to estimate transportation costs rather than interstate pipeline tariffs.

1 The Henry Hub, located near Erath, Louisiana, is one of North America's largest natural gas pipeline interchanges; capable of transporting a maximum of 1.8 billion cubic feet per day between ten pipeline systems, or about a quarter of California's total average daily consumption. It is probably the best known of all natural gas trading points on the continent, and is the standard delivery point for the New York Mercantile Exchange natural gas futures contract.

CHAPTER 1
Introduction

Natural gas burner tip prices are defined as the price paid for natural gas that is burned in a furnace, water heater, natural gas-fired electric generator, or other end use.[2] This report is limited to burner tip prices paid for natural gas that is burned in a natural gas-fired electric generator. The natural gas has reached its final destination, and the price of this natural gas includes all transportation charges and commodity costs such as exploration and development costs, gas well completion, production and processing costs, and so forth. Burner tip prices can change because of changes in the commodity cost of natural gas (the price of the gas itself) and changes in the costs to transport natural gas. Fuel costs are a significant component of the variable operating cost of a gas-fired generator. The cost of transportation is the cost of moving natural gas from the basin where it was produced to the burner tip. Natural gas transportation costs are referred to as *transportation rates*, or simply *rates*, in this report. Transportation rates are approved by the Federal Energy Regulatory Commission (FERC) for interstate natural gas pipelines and by the California Public Utilities Commission (CPUC) for intrastate pipelines and natural gas utility distribution pipelines.

This report first examines and documents the Energy Commission's method of estimating burner tip prices; the method has not been previously documented. Examining the Energy Commission's method will also provide opportunities for stakeholders to suggest improvements or changes for more accurate burner tip prices and to account for changes in natural gas industry, such as supply, demand, transportation rates, natural gas procurement strategies, the amount of renewable energy coming onto the electric grid, and environmental policies.

This report also compares the Energy Commission's burner tip price estimation method to the methods of other entities. This comparison will provide insights to how others estimate burner tip prices, as well as provide opportunities to improve upon the Energy Commission method. Comparing burner tip price estimates will show how different assumptions and estimation methods affect results.

There are a variety of ways to estimate burner tip prices. The two main differences between estimation methods are the result of accounting for how natural gas is purchased and how the cost of transportation is represented. Electric generators' purchase and transportation arrangements and terms differ and are confidential; consequently, methods that estimate the prices they pay for natural gas will also differ. Most of the burner tip price estimates examined are roughly in line with the Energy Commission estimates, with relatively minor differences.

Natural gas is important for electricity generation and will continue to be, as natural gas use expands to include backing up intermittent renewable energy. A current set of burner tip

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2 See http://psc.wi.gov/thelibrary/glossary/gasTerms.htm.

price estimates and assumptions will help electricity system planners make informed decisions on which resource mix will best serve load while meeting other criteria, such as environmental policies and reasonable cost to generate electricity.

Report Organization

Chapter 2 describes the Energy Commission's burner tip price estimation method. The treatment of the commodity price of natural gas (the gas itself) and the cost to transport natural gas (transportation rates) are examined. Annual natural gas prices from the *2013 Natural Gas Issues, Trends, and Outlook Final Staff Report*[3] (*2013 Outlook*) are converted to monthly prices to capture some of the seasonal price variations. The transportation rates used are the tariffs posted on the interstate pipeline or gas utility websites. Firm transportation rates, discounted to better reflect the prices electric generators pay, are used instead of interruptible rates.

Chapter 3 looks at burner tip price estimates performed by other agencies, including the Northwest Power and Conservation Council (NWPCC), the state's investor-owned natural gas utilities, and the Western Electricity Coordinating Council (WECC). This chapter discusses the methodologies and results of these other burner tip price estimates, and compares them to the Energy Commission method and price estimates from the *2011 Natural Gas Market Assessment: Outlook* (*2011 Outlook*)[4]. The *2011 Outlook* is used in Chapter 3 instead of the *2013 Outlook* because it is of a vintage more common to the price estimates to which it is compared and, therefore, shares closer agreement on economic growth, natural gas supply, and other key assumptions needed to estimate future prices. These result in closer agreement on prices and their growth rates. Two burner tip price backcasts are also examined and compared to the Energy Commission estimates. A backcast is like a forecast, except that it models results over an historical time horizon; that is, one that begins and ends in the past. One benefit of a backcast is that the results can be compared to actual historical data to test the accuracy of the modeling method.

Chapter 4 discusses the conclusions, lessons learned, and potential future work. This chapter also examines alternative methodologies and assumptions for the Energy

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3 Kennedy, Robert, Silas Bauer, Leon Brathwaite, Peter Puglia, Jorge Gonzales, and Katherine Anderson. 2014. *2013 Natural Gas Issues, Trends, and Outlook Final Staff Report*. California Energy Commission, Electricity Supply Analysis Division. CEC-200-2014-001-SF. The North American Market Gas-Trade Model (NAMGas), developed by Rice University and Energy Commission staff, is a general equilibrium market model used to estimate the annual natural gas price projections in the *2013 Outlook.*

4 Brathwaite, Leon D., Paul Deaver, Robert Kennedy, Ross Miller, Peter Puglia, William Wood. 2011. *2011 Natural Gas Market Assessment: Outlook*. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200-2011-012-SD.

Commission to estimate burner tip prices. Some of these methods may require information from pipeline companies, natural gas utilities, and natural gas-fired generator owners.

This report includes two technical appendices that offer more detailed documentation. Appendix A, Method for Annual-to-Monthly Conversion Factors, discusses the methods used to convert natural gas prices from annual-to-monthly values. Appendix B, Historical Validation of Burner Tip Prices, compares backcasts of Energy Commission burner tip prices with historical burner tip prices provided by energy data vendors.

CHAPTER 2
Energy Commission's Burner Tip Price Estimation Method

Natural gas burner tip prices, as estimated in this report, attempt to account for the cost to procure and deliver natural gas to a natural gas-fired electric generator. Burner tip prices include both a commodity and a transportation component. The commodity component is the price of natural gas after production from the well and processing for injection into a nearby utility pipeline. The transportation component is the cost of transporting the gas from its injection point near the production basin to the electric generator for consumption.

Energy Commission staff has estimated burner tip prices since the early 1990s. The Energy Commission relies on a general equilibrium market model that produces estimates of average annual natural gas commodity price at major hubs throughout North America. These prices required post-processing adders to account for the transportation to move the natural gas to the burner tip. These burner tip price estimates were used by staff as inputs to production cost models to generate electricity prices. This report is the first attempt to formally document the Energy Commission's burner tip price estimation method.

Commodity Component of Burner Tip Price

Because gas-fired generators compete with residential, commercial, industrial, and other sectors for natural gas, the method described in this report for estimating the commodity price of gas accounts for demand from all sectors, as well as natural gas supply, to estimate reliable burner tip prices for gas-fired generators. It could also be based on an annual average price produced from the *2013 Outlook*. To reproduce a backcast of burner tip prices, spot or bidweek prices are used from a published index.[5] For estimating future burner tip prices, *2013 Outlook* forecasted annual prices are used. The *2013 Outlook* prices need to be converted to monthly prices that capture the seasonal fluctuations in gas prices in the winter and summer. The next section discusses this annual-to-monthly conversion.

As with all commodities, natural gas prices usually vary both with the location where the commodity is produced, as well as with the location where it is consumed. Staff therefore built into the burner tip model a representation of the western natural gas supply and pipeline transportation system that supplies the fuel groups of the power plants as represented in the PLEXOS® production cost model representation of the western electric grid. **Table 1** lists these fuel groups and the natural gas price hubs used for each fuel group.

5 Spot and bidweek prices are readily available and account for a large portion of total natural gas procurement.

Burner tip price estimates are provided in regional groups called *fuel groups* developed for the PLEXOS® model. A fuel group can represent a portion of a western state or part of a utility service area. Staff assigned a price hub to each fuel group to reflect where each gas-fired generator purchases its natural gas. Staff reviewed the *2013 Outlook* and Natural Gas Intelligence (https://www.naturalgasintel.com) to determine the appropriate price point for each fuel group. The hub prices used for natural gas commodity price forecasting are from the *2013 Outlook*. Some of the *2013 Outlook* hub prices differ from the *Natural Gas Intelligence* (NGI) prices used for estimating historical burner tip prices. The table identifies a downstream pipeline linking each PLEXOS® fuel group to the NGI price hub, when applicable. The Oregon and Malin fuel groups are not associated with a downstream pipeline, because several pipelines from Canadian and Rocky Mountain gas fields serve the Stanfield and Malin hubs in Oregon, and trading is very liquid at both hubs; plus, they deliver directly to power plants without using additional pipelines. Finally, the Arizona and Southern Nevada PLEXOS® fuel groups, for example, do not cite a downstream pipeline because their proximate liquid natural gas hub is downstream from them at the Southern California border. Plus, pipeline transportation rates to Arizona and Nevada are the same as the California rate; therefore, the Southern California Border average captures the transportation cost to power plants in these two states.

Table 1: Price Hubs and Pipelines for Each PLEXOS Fuel Group

PLEXOS Fuel Group	NGI Price Hub	Downstream Pipeline	*2013 Outlook* Price Hub
Northern Arizona	SoCal Border Avg.		US-AZ Flagstaff
Southern Arizona	SoCal Border Avg.		US-AZ Phoenix
Colorado	Colorado Interstate Gas	Colorado Interstate Gas	US-Kit Carson
Northern Idaho	Kingsgate	Gas Transmission Northwest	Canada-Alberta-Kingsgate
Southern Idaho	Opal	Northwest Pipeline	US-Opal
Montana	Colorado Interstate Gas	Colorado Interstate Gas	US-Montana
Northern Nevada	Malin	Tuscarora Gas Transmission	US-NV Reno
Southern Nevada	Kern Delivery		US-NV Las Vegas
Northern New Mexico	West Texas Regional Average	El Paso North, Transwestern	US-San Juan NM
Southern New Mexico	West Texas Regional Average	El Paso South	US-Permian NM
Oregon	Stanfield		US-GTN Stanfield
Malin	Malin		US-Malin
Utah	Opal	Kern River Gas Transmission	US-Utah
Washington	Northwest Sumas	Northwest Pipeline	US-WA Seattle
Wyoming	Opal	Wyoming Interstate	US-Opal
West Texas	West Texas Regional Average		US-TX West (Waha)
PG&E BB	Malin/Southern Border, PG&E	Redwood/Baja	US-PG&E
PG&E LT	PG&E Citygate	PG&E Local Transmission	US-PG&E
SMUD	Malin/Southern Border, PG&E	Redwood/Baja	US-PG&E
Kern River	SoCal Border Avg.		US-Wheeler Ridge
Mojave	SoCal Border Avg.	Mojave Pipeline	US-Daggett
Coolwater	SoCal Border Avg.	Mojave Pipeline	US-Daggett
SoCalGas	SoCalGas Citygate	SoCalGas Distribution System	US-SoCalGas
Blythe	SoCal Border Avg.		US-Daggett
Southern California Production	SoCal Border Avg.	SoCalGas TLS	US-San Joaquin Valley
TEOR	SoCal Border Avg.	SoCalGas TLS	US-San Joaquin Valley
SDG&E	SoCal Border Avg.	SDG&E TLS	US-SDG&E
Otay Mesa	SoCal Border Avg.	SDG&E TLS	US-SDG&E
Alberta	NOVA/AECO C	TransCanada-Alberta System	Canada-Alberta-AECO
British Columbia	Northwest Sumas		Canada-British Columbia-Sumas
Rosarito		Baja Norte/TGN	Mexico-Baja

Source: NGI, the *2013 Outlook*, and Supply Analysis Office staff.

Converting Annual Prices to Monthly Prices

The Energy Commission used the *2013 Outlook* to provide annual prices. Converting annual prices to monthly prices is a two-step process.[6] First, seasonality needs to be accounted for in creating monthly natural gas prices. In the winter months, for example, natural gas prices tend to increase because space heating load peaks. A seasonal factor must therefore be developed to account for the monthly price variations throughout the year. The seasonal factor is defined as the number that is multiplied by the annual price to get the monthly price for a given month and, therefore, is the ratio of the monthly price to the average annual price. **Table 2** lists the seasonal factors at Henry Hub[7] that staff developed to evaluate seasonal variations between recent 10-, 15-, and 20-year histories. During the 15- and 20-year histories, prices peaked in January at 110 percent of the annual average and dropped to 94 percent of the average annual price in March and September. **Table 2** shows that the seasonal factors change little among the three histories; this similarity indicates that the seasonal variability in natural gas prices has not changed much over the last 20 years. Staff selected the 10-year history from the 2002 – 2011 Henry Hub bidweek gas prices published in NGI to calculate the seasonal factors used in this report because the overall agreement with the historical data is better.[8] Nevertheless, regional weather patterns may change in the future, thereby affecting the seasonal factors going forward.

Table 2: Average Henry Hub Seasonal Factors for 10, 15, and 20 Years

	10 Year	15 Year	20 Year
Jan	1.04	1.10	1.10
Feb	0.97	0.99	0.98
Mar	0.95	0.94	0.94
Apr	0.98	0.97	0.97
May	1.01	1.00	1.00
Jun	1.02	1.01	1.01
Jul	1.04	1.02	1.01
Aug	0.95	0.95	0.94
Sep	0.94	0.94	0.94
Oct	0.98	0.98	0.98
Nov	1.05	1.06	1.06
Dec	1.06	1.05	1.07

Source: NGI and Supply Analysis Office staff.

6 This process is discussed in more detail in Appendix A.

7 The Henry Hub, located near Erath, Louisiana, is one of North America's largest natural gas pipeline interchanges, capable of transporting a maximum of 1.8 billion cubic feet per day between ten pipeline systems, or about a quarter of California's average daily consumption. It is probably the best known of all natural gas trading points on the continent, and is the standard delivery point for the New York Mercantile Exchange natural gas futures contract.

8 NGI bidweek prices are volume-weighted averages of all natural gas transactions surveyed by *NGI* staff; not all market transactions in general. See http://www.naturalgasintel.com/ext/resources/Daily-GPI/NGIMethodology.pdf, p. 5.

The second step in converting annual prices to monthly prices is modeling the year-to-year changes in natural gas prices. For instance, the average annual Henry Hub prices in 2007 and 2008 were $6.86/million British thermal units (MMBtu) and $9.04/MMBtu, respectively, an increase of $2.18/MMBtu. A realistic conversion of these two years' average annual prices to monthly prices cannot show the abrupt $2.18/MMBtu increase from December 2007 to January 2008. A realistic conversion also cannot include applying nothing more than the Henry Hub seasonal factors to these two prices because that part of the conversion method does not account for the $2.18/MMBtu increase from 2007 to 2008, and the resulting discontinuity between 2007 and 2008 seasonally adjusted prices would be unrealistic.

Staff therefore used linear interpolation to model the year-to-year changes in natural gas prices, analyzing two proposed methods: the January-through-December calendar year and the June-through-May year. Even if an annual average natural gas price increases from one year to the next, monthly prices usually both increase and decrease throughout any given year.[9] To develop each method, staff divided each year-to-year change in annual prices by 12—the number of months in a year—and then added to the following year one-twelfth of the difference to the January price for the first method and to the June price for the second method, two- twelfths of the difference to the February price for the first method and to the July price for the second method, and so on, until the year-to-year change in the annual average price is fully accounted for in the first and second method by the following December or May, respectively. Linear interpolation between years simplifies the analysis and fits historical data reasonably well. Staff decided to use the June-through-May year to calculate annual interpolation factors because these yielded prices that better approximated actual Henry Hub prices. The January-through-December year failed to model historical prices as well because of large price changes sometimes occurring between December and January. In contrast, linear interpolation using the June-through-May year smoothes these discontinuities well. The two-step method, therefore, first multiplies the annual average gas price by a seasonal factor and then adds a linear interpolation factor to yield the final price.[10]

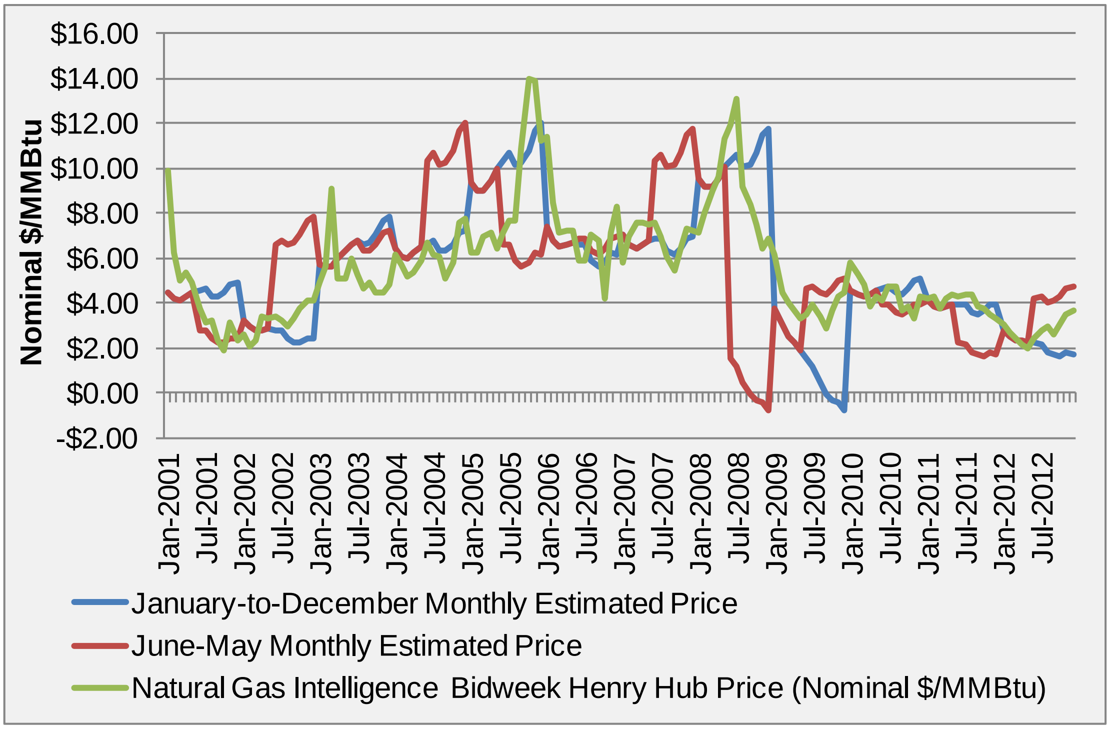
Figure 1 plots 2002 – 2011 natural gas prices estimated by using both the January-through-December and June-through-May years, as well as the seasonal factors, to convert annual natural gas prices to monthly prices. Actual monthly Henry Hub prices are graphed alongside the estimated values. This price graph highlights two key findings about both estimation methods. The first is that both fail to capture the price spikes in the spring of 2003, the fall of 2005, or the summer of 2008, and both price estimates are either flat or

9 For example, Henry Hub prices decreased year over year from 2008 – 2009, although they increased for the first half of 2008 before falling through autumn of that year. See Appendix A for a detailed description of this method.

10 For 2008 prices, the June-through-May year method assumes natural gas prices from the months of June 2008 through May 2009. See Appendix A for a detailed description of the method of converting annual prices to monthly prices.

falling during that period. The second key finding is that the June-through-May year estimates fit the actual data better than the January-through-December year estimates.

Figure 1: 2002 – 2011 Monthly Estimated Henry Hub Prices vs. Actual Prices



Source: NGI and Supply Analysis Office staff analysis.

Caveats and Issues With Natural Gas Prices

Natural gas commodity prices are obtained from forecast modeling, which contains many assumptions about the future state of the world, any of which could prove wrong. Little is known, for example, about the actual natural gas purchase strategies of natural gas-fired generators, because most of this information is confidential. Natural gas-fired electric generators can purchase gas on the spot market through bidweek contracts and multiple-year contracts. Natural gas-fired generators likely will procure a combination of short-term and long-term contracts, as well as bidweek purchases.

A natural gas-fired generator can purchase gas from a border or citygate location (closer to the gas-fired generator) or from a natural gas basin, such as the Permian, San Juan, or the Western Canadian Sedimentary Basin. The Permian basin covers parts of Texas and New Mexico, and the San Juan Basin covers parts of New Mexico, Colorado, Arizona, and Utah. The Western Canadian Sedimentary Basin is in southern British Columbia and Alberta. Most western United States natural gas-fired generators are sited proximate to high-voltage transmission lines or the demand centers whose load they serve, which are usually hundreds of miles from these basins. The decision on where to purchase natural gas will differ for each gas-fired generator and will depend, in part, on the location of the gas-fired generator to natural gas pipelines and the demand profiles of its customers. The Energy Commission burner tip price estimation method assumes that a gas-fired generator will purchase gas from the price hub that is closest to it. The price data used to compare to burner tip backcasts are from NGI and were chosen based on locations relative to gas-fired power plants and natural gas pipelines.

Natural gas-fired generators will generally procure natural gas through a combination of border, citygate, and basin purchases. A gas-fired generator may change how it procures gas based on assumptions about future transportation rates and future *basis differentials*.[11] A literature search revealed no publicly available reports or analyses describing generators' purchasing strategies; therefore, the Energy Commission's approach does not capture this differentiation in natural gas purchasing strategies. There may be pricing hubs more appropriate for a given power plant than what was available. Furthermore, a power plant may purchase gas from multiple price hubs; staff estimations assume only one hub is used.

Many of the same issues affect the estimation of future burner tip prices. The Energy Commission estimation method uses the *2013 Outlook* natural gas price hubs, but there may be other price hubs that better reflect where a power plant purchases gas. Assuming only one price hub is used to buy gas for each power plant fuel group may be incorrect. Some power plant operators may purchase/procure gas in a variety of ways: spot market purchases, monthly bidweek contracts, long-term contracts, and New York Mercantile Exchange (NYMEX) futures contracts. Some long-term natural gas supply contracts can last for 10 years or more. The *2013 Outlook* prices do not capture all of these gas procurement decisions that natural gas power plants face.

Finally, as natural gas market dynamics change, regional production profiles can shift.[12] These production shifts will likely change the relative price differences across different regional natural gas hubs. These relative price shifts can easily make a power plant operator decide to purchase natural gas from a different hub or possibly pay a different price at one hub. In some instances, natural gas may become less available to the market, causing some power plants to shut down, pay higher prices, or find alternative sources of natural gas.

Transportation Component of Burner Tip Prices

The second step in the Energy Commission's method for calculating burner tip prices is adding transportation rates to the commodity price of natural gas. Transportation rates

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11 A *basis differential* is the cash spot price difference between two natural gas price hubs. It is usually defined as the price difference between the Henry Hub spot price and the spot price at another specified price hub.

12 The recent boom in shale gas production in New York and Pennsylvania are good examples of this.

cover the cost of service to transport gas from one location to another, typically from some price hub or purchase location to a customer's burner tip. These rates are based on compressor fuel costs, amortized capital, operating and maintenance costs of the pipeline, customer load profiles, the availability of pipeline capacity, as well as surcharges and other government fees.[13] Pipeline compressors are fueled by gas drawn from the pipeline or by electricity. The fuel costs of these compressors can be included in the transportation rate or assessed as a percentage of that rate. Pipeline operators might also recover their costs from gas shippers with an in-kind payment of additional gas to the operator to cover the gas burned in compressors. In-kind payments also benefit the pipeline operator by transferring the price risk to the shippers.

Transportation Rates Used for Estimating Burner Tip Prices

Staff used both interstate and intrastate transportation rates obtained from each pipeline or natural gas utility website; the most current rates were used. Most rates are those still effective in 2013.[14] During the forecast period (2011 – 2030), staff assumes no real growth in transportation rates; in other words, transportation rates are held constant. Staff then applied discounts to these rates to account for the fact that pipeline operators often offer discounts to ship natural gas on undersubscribed pipelines. Staff used capacity release market prices posted on pipeline operators' bulletin board systems.

The capacity of a proposed new interstate pipeline is largely determined by shippers contracting for firm transportation capacity during the pipeline operator's open season. Most natural gas pipelines offer both firm and interruptible service capacity, with firm transportation usually costing more than interruptible transportation. Interstate pipelines need firm transportation commitments to recover the cost of their services, consistent with FERC pipeline ratemaking rules and the pipeline sponsor's willingness to incur risk for uncommitted capacity. Firm transportation rates consist of a fixed charge to reserve the capacity on the pipeline, plus a volumetric commodity charge that covers the variable operations and maintenance costs per unit of gas transported. The capacity reservation charge for firm capacity service makes up the majority of the full transportation rate. Interruptible service is as-available and is often priced at a maximum rate equal to the *100 percent as-billed* rate for firm service, but pipelines can choose to discount these rates. The *100 percent as-billed* rate is a term that describes conversion of the reservation charge for fixed service to a volumetric basis assuming a 100 percent load factor and adding the smaller, volumetrically calculated portion of the firm rate. However, other terms of firm and interruptible service differ between interstate pipelines, on the one hand, and intrastate

13 *Compressor fuel costs* refer to the amount of natural gas used to run compressors that help transport gas through pipelines. This will be a cost to the entity shipping the gas.

14 Interstate pipeline rates are used to account for the larger natural gas power plants that receive their gas directly off the interstate pipelines, while intrastate rates are used to account for power plants connected to the utility system.

pipelines such as those operated by Pacific Gas and Electric (PG&E), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric Company (SDG&E), on the other hand.

Generator decisions about whether to hold firm or interruptible capacity vary depending on where the generator is located, whether it is utility- or merchant-owned, the projected operating load factor, and risk profile. Within California, generators are served by capacity that is explicitly interruptible when needed to serve core gas customers. Generators may also arrange for gas supplies from a marketer who has also procured firm pipeline capacity and assumes the risks of those costs. The method used in this report to estimate transportation rates therefore relies on assumptions that provide a relatively simple approximation of reality; but in any case, the "noise" in the commodity price estimates is larger than estimates of the transportation rates themselves.

Staff also did not explicitly assume the many municipal surcharges and taxes that are included with many utility transportation rates because they vary by state and municipality, and staff could not establish that these duties had all been identified or which of them generators are liable to pay.[15]

Staff's estimates of natural gas burner tip prices for Northern California (PG&E territory) and Southern California (SoCalGas territory) are provided in **Table 3** and **Table 4,** respectively. In agreement with a comment filed by PG&E on January 9, 2014, staff included in this report tables of all natural gas prices except those that staff obtained from proprietary sources.

Table 3: Estimated Northern California (PG&E) *2013 Outlook* Reference Case Burner Tip Price (Nominal $/MMBtu)

	2014	2015	2016	2017	2018	2019	2020
January	$ 4.89	$ 4.87	$ 5.36	$ 5.34	$ 5.39	$ 5.38	$ 5.53
February	$ 4.64	$ 4.61	$ 5.10	$ 5.06	$ 5.11	$ 5.09	$ 5.23
March	$ 4.56	$ 4.52	$ 5.02	$ 4.96	$ 5.01	$ 4.98	$ 5.14
April	$ 4.70	$ 4.65	$ 5.19	$ 5.11	$ 5.16	$ 5.12	$ 5.29
May	$ 4.85	$ 4.80	$ 5.37	$ 5.27	$ 5.32	$ 5.28	$ 5.45
June	$ 4.68	$ 4.75	$ 5.04	$ 5.14	$ 5.22	$ 5.25	$ 5.35
July	$ 4.75	$ 4.84	$ 5.11	$ 5.22	$ 5.29	$ 5.33	$ 5.43
August	$ 4.42	$ 4.53	$ 4.76	$ 4.86	$ 4.92	$ 4.96	$ 5.06
September	$ 4.37	$ 4.50	$ 4.72	$ 4.81	$ 4.86	$ 4.91	$ 5.01
October	$ 4.53	$ 4.69	$ 4.90	$ 4.99	$ 5.04	$ 5.10	$ 5.21
November	$ 4.87	$ 5.06	$ 5.26	$ 5.36	$ 5.41	$ 5.48	$ 5.60
December	$ 4.92	$ 5.14	$ 5.33	$ 5.42	$ 5.47	$ 5.54	$ 5.67

Source: Supply Analysis Office staff analysis.

15 See http://www.pge.com/tariffs/tm2/pdf/GAS_SCHEDS_G-SUR.pdf, and http://www.socalgas.com/regulatory/tariffs/tm2/pdf/G-MSUR.pdf.

Table 4: Estimated Southern California (SoCalGas) *2013 Outlook* Reference Case Burner Tip Price (Nominal $/MMBtu)

	2014	2015	2016	2017	2018	2019	2020
January	$ 5.14	$ 5.15	$ 5.64	$ 5.61	$ 5.68	$ 5.65	$ 5.82
February	$ 4.87	$ 4.87	$ 5.36	$ 5.31	$ 5.37	$ 5.34	$ 5.50
March	$ 4.78	$ 4.78	$ 5.27	$ 5.21	$ 5.27	$ 5.23	$ 5.40
April	$ 4.93	$ 4.92	$ 5.45	$ 5.37	$ 5.43	$ 5.38	$ 5.56
May	$ 5.09	$ 5.07	$ 5.64	$ 5.54	$ 5.60	$ 5.55	$ 5.74
June	$ 4.91	$ 5.00	$ 5.30	$ 5.41	$ 5.49	$ 5.52	$ 5.63
July	$ 4.98	$ 5.10	$ 5.38	$ 5.49	$ 5.57	$ 5.61	$ 5.72
August	$ 4.63	$ 4.76	$ 5.00	$ 5.10	$ 5.17	$ 5.21	$ 5.31
September	$ 4.59	$ 4.73	$ 4.95	$ 5.05	$ 5.11	$ 5.16	$ 5.26
October	$ 4.76	$ 4.93	$ 5.15	$ 5.24	$ 5.30	$ 5.36	$ 5.47
November	$ 5.12	$ 5.33	$ 5.54	$ 5.64	$ 5.70	$ 5.77	$ 5.89
December	$ 5.18	$ 5.41	$ 5.61	$ 5.71	$ 5.75	$ 5.83	$ 5.96

Source: Supply Analysis Office staff analysis.

Caveats and Issues With Transportation Rates

Natural gas pipeline transportation rates rise and fall, although generally not uniformly or consistently. Shifting regional production profiles, relative natural gas commodity price differences, and discovery of new resources, such as the Marcellus Shale formation in the eastern United States, can cause transportation rates to change. Pipeline maintenance and replacements, along with environmental regulations compliance, will likely cause rates to rise.[16] Technology advances in pipeline equipment and compressors that reduce the amount of natural gas lost in transport, as well as pipeline infrastructure depreciation, may send rates lower.

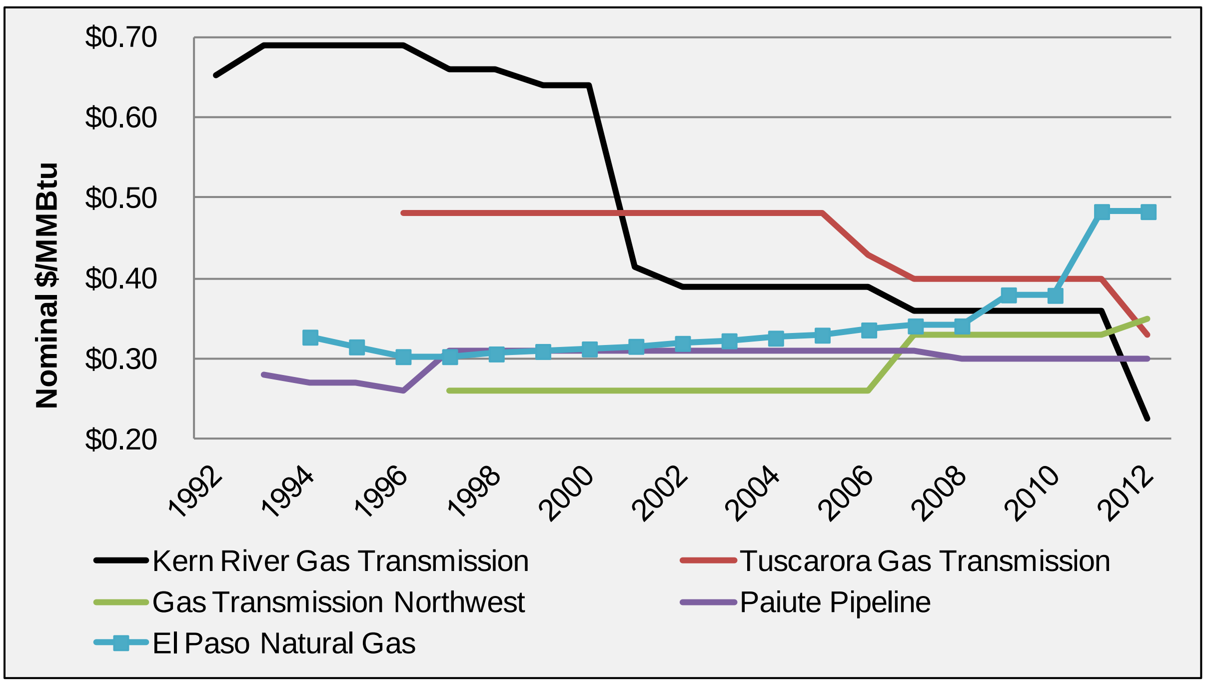
Some fuel groups in the PLEXOS® model represent the receipt of natural gas from more than one pipeline; in these cases, the pipeline rates are added or volume weighted based on gas flows. Staff also assumed that each PLEXOS® fuel group will receive natural gas from the same pipeline(s) for the whole estimation period. In actuality, natural gas power plants may receive gas from different pipelines over time as regional supply areas for natural gas shift or change.

16 See http://www.ingaa.org/File.aspx?id=10757 and http://www.pge.com/myhome/customerservice/energystatus/streetconstruction/gaspipereplacement/index.shtml.

For this analysis, staff assumed there is no real growth in transportation rates during the estimation period (2011 – 2030). Staff discussed using an annual growth rate for transportation rates, but transportation rates normally do not increase/decrease by the same amount each month and year. Staff ultimately decided against adding an annual growth rate but will consider doing so for future work. Trying to forecast when pipelines/utilities will change their rates remains difficult because changes are neither uniform nor consistent.

Figure 2 shows interstate natural gas pipeline transportation rates dating back to the 1990s.[17] Rates on two pipelines decreased over this period, while rates on three increased. California's investor-owned natural gas utility rates exhibit more short-term variations than do interstate natural gas pipeline rates. One reason for this is that rates for the former are regulated by the CPUC and can change multiple times in a single year. Interstate transportation rates are regulated by FERC and generally change much less frequently. Based on historical rate information, staff decided to hold interstate transportation rates constant for the entire estimation period.

Figure 2: Interstate Historical Natural Gas Transportation Rates

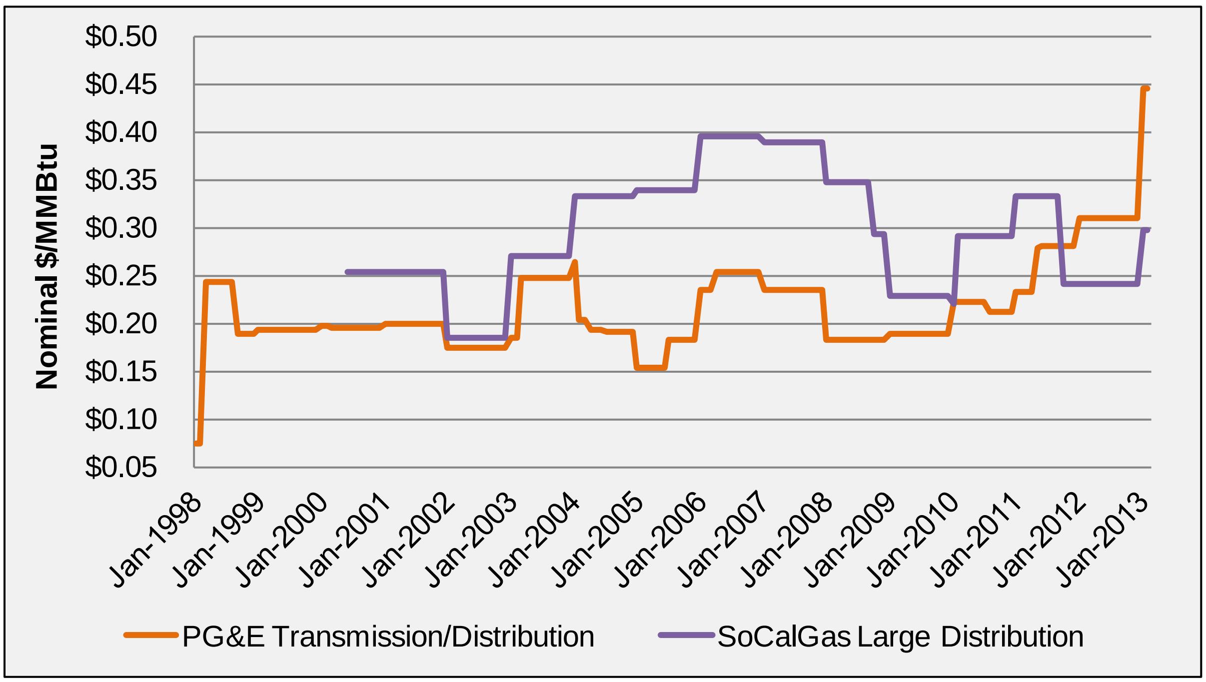


Source: Kern River Gas Transmission, Tuscarora Pipeline, Gas Transmission Northwest, Paiute Pipeline, and El Paso Natural Gas Pipeline tariffs.

17 These rates represent natural gas procured from each basin near the origin of each pipeline to the nearest delivery point to California. Each pipeline will have multiple rates depending on the delivery point.

Figure 3 shows transportation rates for two gas utilities serving California customers from January 1998 through February 2013. Utility transportation rates in California have not shown consistent positive or negative growth over the last 10 years. Transportation rates for California gas utilities are expected to increase, however, because each utility is implementing a pipeline safety enhancement plan. Because the exact rate impacts from the pipeline safety enhancement plan are unknown, the burner tip prices estimated in this report hold utility transportation rates constant.[18]

Figure 3: PG&E and SoCalGas Natural Gas Transportation Rates for Electric Generation, 2000 – 2011



Source: See http://www.pge.com/nots/rates/tariffs/rateinfo.shtml and SoCalGas.

18 The pipeline safety enhancement plans will upgrade natural gas pipelines and infrastructure. See http://www.pgecurrents.com/2011/08/26/pge-files-milestone-plan-to-modernize-improve-safety-of-gas-pipeline-system/ and http://www.socalgas.com/safety/pipeline-safety-enhancement-plan/.

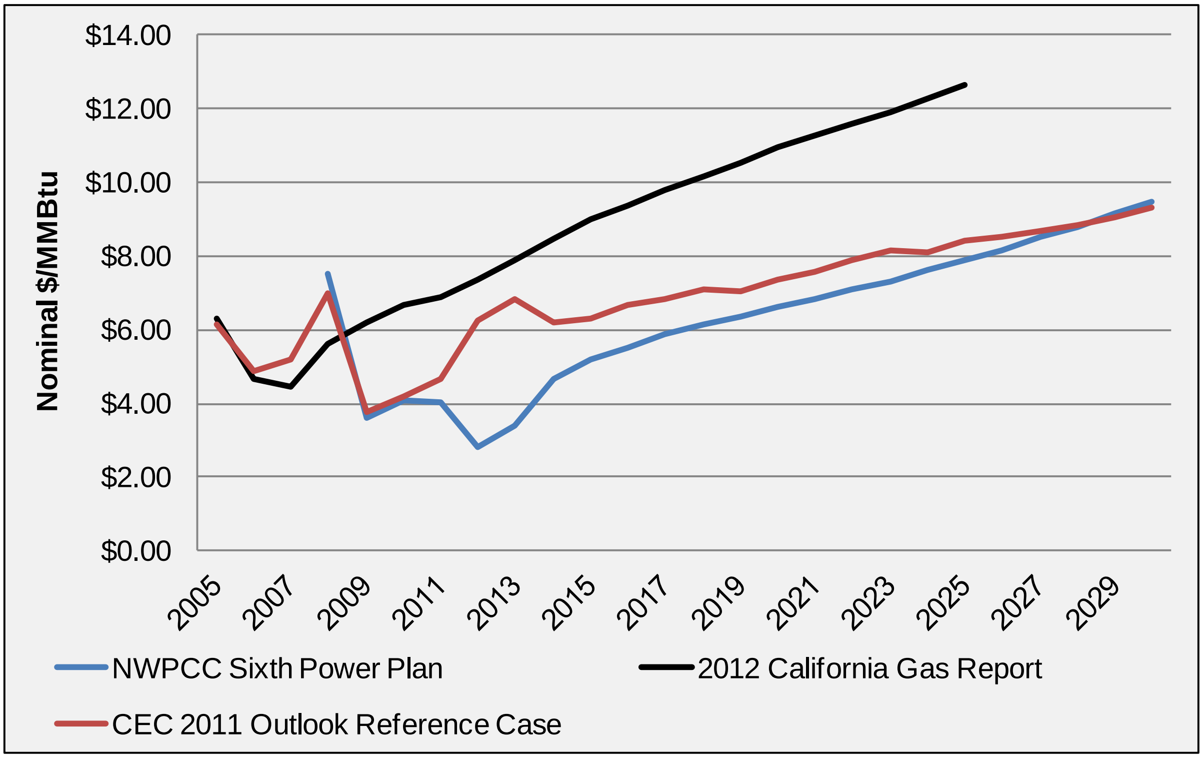
CHAPTER 3
Examination of Other Burner Tip Price Estimates

The NWPCC, WECC, and the California utilities' *California Gas Report* also estimate natural gas burner tip prices. Each method will depend on the purpose and expected use of the burner tip price estimate. This section analyzes the burner tip price estimates and methods of other entities and compares them to the estimates and method used by the Energy Commission. Some burner tip price estimates and methods are not documented completely; thus, it is difficult to directly compare these estimates and methods to those of the Energy Commission. In general, the Energy Commission method has similar assumptions to other burner tip estimation methods, and the estimated burner tip prices are fairly similar. Some methods use public data, while others use confidential or proprietary data. To provide as much of an apples-to-apples comparison as possible in this chapter, staff used prices from the *2011 Outlook* because it shares a vintage and assumptions common to those of the other three estimates as could be acquired. The NWPCC, WECC, and the California utilities' *2012 California Gas Report* price estimates are within a year of publication of the *2011 Outlook* estimates, and all use reference or mid-case assumptions where applicable. This does not imply that the assumptions are identical, but that they do observe similar business-as-usual conditions.

Figure 4 and **Table 5** compare California burner tip price estimates of the Energy Commission's *2011 Outlook* with those of the NWPCC's *Sixth Northwest Conservation and Electric Power Plan*[19] (*Sixth Power Plan*) and the *2012 California Gas Report*. Historical data is used to estimate prices shown in italics, but, due to differences in estimation methods, Energy Commission burner tip prices differ from the other entities' estimates. The price estimates have very similar growth rates beyond 2014, although in the near term (2012 – 2014), the estimates diverge significantly.

19 Northwest Power and Conservation Council. 2010. *Sixth Northwest Conservation and Electric Power Plan*, at http://www.nwcouncil.org/media/6284/SixthPowerPlan.pdf. The NWPCC was established pursuant to the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Public Law 96-501) by the states of Idaho, Montana, Oregon, and Washington. This legislation authorized the NWPCC to serve as a comprehensive planning agency for energy policy and fish and wildlife policy in the Columbia River Basin and to inform the public about energy, fish, and wildlife issues, and to involve the public in decision-making.

Figure 4: A Comparison of Annual California Burner Tip Price Estimates



Source: NWPCC, SoCalGas, and Supply Analysis Office staff analysis.

Natural gas commodity price forecasts can be constructed using both a general equilibrium model and NYMEX futures contract prices. Some natural gas commodity price forecasts combine these two methods. A general equilibrium model analyzes the interactions of supply and demand in the market through mathematical equations and outputs a price when supply and demand are equal.

The burner tip price methods of the NWPCC and WECC have similar assumptions about intrastate transportation rates, plus both assume a small annual growth rate for transportation rates. For interstate transportation rates, most of the other burner tip price estimates staff reviewed use data on financial *basis swaps* or historical regional natural gas price differentials to account for the cost of transportation.[20]

20 A *basis swap* is a transaction where one party receives a fixed price for the price difference between the Henry Hub price and another specified price location, and the other party receives the actual floating price (the true price differential). Basis swaps are used mainly to hedge against regional price movements.

Table 5: A Comparison of California Burner Tip Price Estimates (Nominal $/MMBtu)

Date	NWPCC *Sixth Power Plan*	CEC *2011 Outlook* Reference Case	*2012 California Gas Report*
2005		*$6.12*	
2006		*$4.88*	
2007		*$5.21*	
2008	*$7.51*	$6.97	
2009	$3.58	$3.77	
2010	$4.06	$4.19	$6.31
2011	$4.03	$4.64	$4.64
2012	$2.80	$6.26	$4.46
2013	$3.41	$6.83	$5.60
2014	$4.68	$6.17	$6.17
2015	$5.17	$6.28	$6.68
2016	$5.53	$6.67	$6.90
2017	$5.90	$6.83	$7.38
2018	$6.16	$7.11	$7.91
2019	$6.38	$7.04	$8.45
2020	$6.61	$7.38	$9.00
2021	$6.84	$7.55	$9.39
2022	$7.08	$7.88	$9.78
2023	$7.33	$8.18	$10.17
2024	$7.64	$8.11	$10.55
2025	$7.90	$8.40	$10.94
2026	$8.17	$8.51	$11.26
2027	$8.51	$8.69	$11.59
2028	$8.79	$8.85	$11.93
2029	$9.15	$9.07	$12.28
2030	$9.45	$9.32	$12.64

Source: Northwest Power and Conservation Council (NWPCC), SoCalGas, and Supply Analysis Office staff analysis. Historical data is used to estimate prices shown in italics.

Northwest Power and Conservation Council Burner Tip Price Forecast

The NWPCC developed burner tip price estimates for the *Sixth Power Plan* by first applying the Delphi Method to the forecasting of fuel prices by the NWPCC Natural Gas Advisory

Committee members.[21] Together with the United States Energy Information Administration (U.S. EIA) and other fuel price projections, NWPCC staff use these projections to develop assumptions to populate an econometric spreadsheet model that assumes average United States wellhead prices. These annual prices are converted to monthly prices using historical trends in monthly price movements. The monthly average United States wellhead prices are then converted to Henry Hub prices using historical relationships between the two prices. The Henry Hub prices are converted to regional hub prices using historical basis differentials in econometric equations.[22]

To convert regional natural gas hub prices into burner tip prices, the NWPCC added pipeline transportation rates at each price hub. Pipeline fuel costs and pipeline reservation charges for firm capacity were also added.[23] The prices examined here are from the NWPCC medium case. One of the key assumptions from the medium case—growing shale gas production—puts downward pressure on prices and increases power plant conversions from coal to gas. The medium case also assumes that the United States will have an economic recovery.

Figure 5 shows NWPCC burner tip price estimates for Northern and Southern California. The NWPCC provides burner tip price estimates for both existing and new power plants; the new power plants are assumed to have slightly higher fixed operating costs. For simplicity, an average of these two prices is used. The NWPCC price estimates show a fairly linear 7.4 percent growth rate over the 2012 – 2030 forecast, in addition to a seasonal pattern with increasing volatility over the forecast period.

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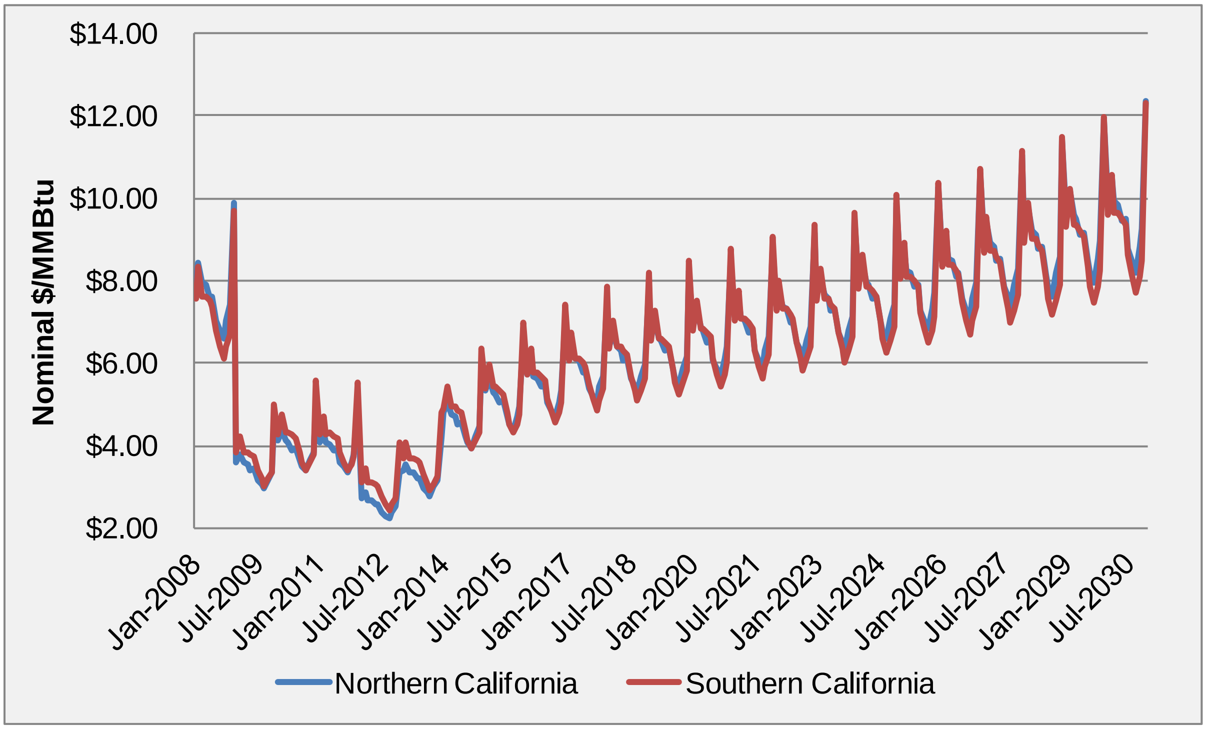
21 See http://www.nwcouncil.org/energy/ngac/home/ for a description of the NWPCC Natural Gas Advisory Committee. See http://www.rand.org/topics/delphi-method.html for a description of the Delphi Method, as originally developed by the RAND Corporation.

22 The regional natural gas price hubs in this forecast include Alberta Energy Company, Sumas, the Rockies, and the San Juan and Permian Basins.

23 For a detailed description of the NWPCC natural gas price forecast model and method, see http://www.nwcouncil.org/media/6293/SixthPowerPlan_Appendix_A.pdf, pp A-5 – A12, A40 – A60.

Figure 5: NWPCC *Sixth Power Plan* Medium Case Burner Tip Price Estimates (2008 – 2030)



Source: See http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Appendix_A.pdf.

Northwest Power and Conservation Council *Sixth Power Plan* Medium Case vs. Energy Commission *2011 Outlook* Reference Case

The NWPCC medium case assumptions differ somewhat from the Energy Commission reference case assumptions, yet burner tip price estimates for each case are quite similar. The NWPCC estimates burner tip prices for Northern and Southern California; therefore, the Energy Commission estimates compare the PG&E and SoCalGas service areas, because these are the closest approximations of Northern and Southern California to the NWPCC geographies. These comparisons are not exact because Northern and Southern California both contain gas-fired generators that are not served by these two utilities; merchant gas-fired generators are an example.

Table 6 contains the prices graphed in **Figure 6** and **Figure 7**, both of which illustrate this comparison. Historical data are used to estimate prices shown in italics. Both of the NWPCC burner tip price estimates show more seasonal volatility than the Energy Commission estimates; furthermore, the seasonal volatility of the NWPCC estimates appear to increase over time while the seasonal volatility of the Energy Commission estimates remains constant. One potential reason for seasonal volatility differences between the two agencies' estimates is that the NWPCC uses historical average United States wellhead prices to account for seasonal variation, while the Energy Commission uses historical Henry Hub prices. The increasing volatility with time is not an actual projection of such price estimates;

it is instead a common artifact of econometric modeling. Energy Commission prices, on the other hand, are estimated using general equilibrium, not econometric, modeling.

The other main difference between the NWPCC and Energy Commission estimates is the price level from 2012 through 2014. The NWPCC estimates show a price dip that goes down to nearly $2/MMBtu, while the Energy Commission estimates show a price bump over the same period that reaches $7.80/MMBtu. These peaks in the Energy Commission estimates are caused by the 2011/2012 interface between modeling historical and forecast assumptions. At this interface, the investment logic and other algorithms of the model begin estimating prices using staff assumptions of future economic recovery and supply curves and begin proving up gas reserves and other results to estimate future prices.[24]

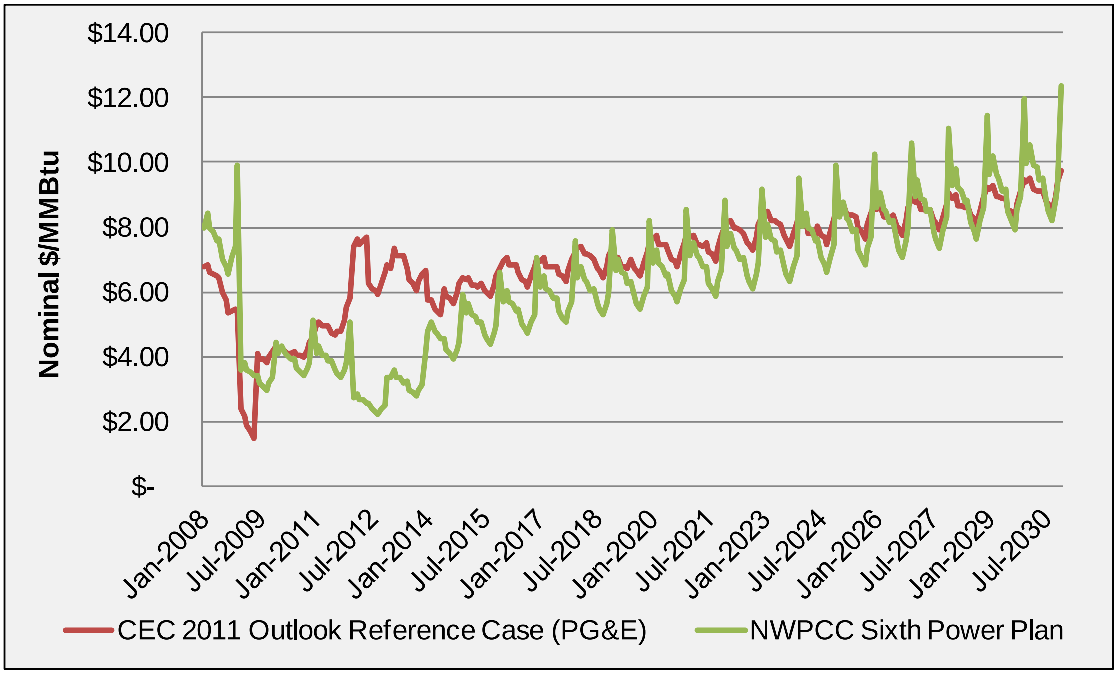
Historical commodity prices for the PG&E and SoCalGas citygate price hubs both average $5.53/MMBtu in the 2011 – 2012 period.[25] Looking at these historical data, actual burner tip prices in 2012 fall in between the Energy Commission and NWPCC estimates, although the NWPCC estimates appear to be a little closer to the historical data. Lastly, the NWPCC estimates better capture the magnitude of the summer 2008 natural gas price spike, perhaps because Energy Commission price estimates are based on market fundamentals such as supply and demand, and regulators agreed that "supply and demand factors alone cannot explain why Henry Hub prices reached $13.32/MMBtu on July 3 and then tumbled to below $6/MMBtu by the end of the year."[26]

24 *2011 Outlook,* pp. 57 – 58.

25 These historical prices are averaged from January 1, 2012, through November 14, 2012.

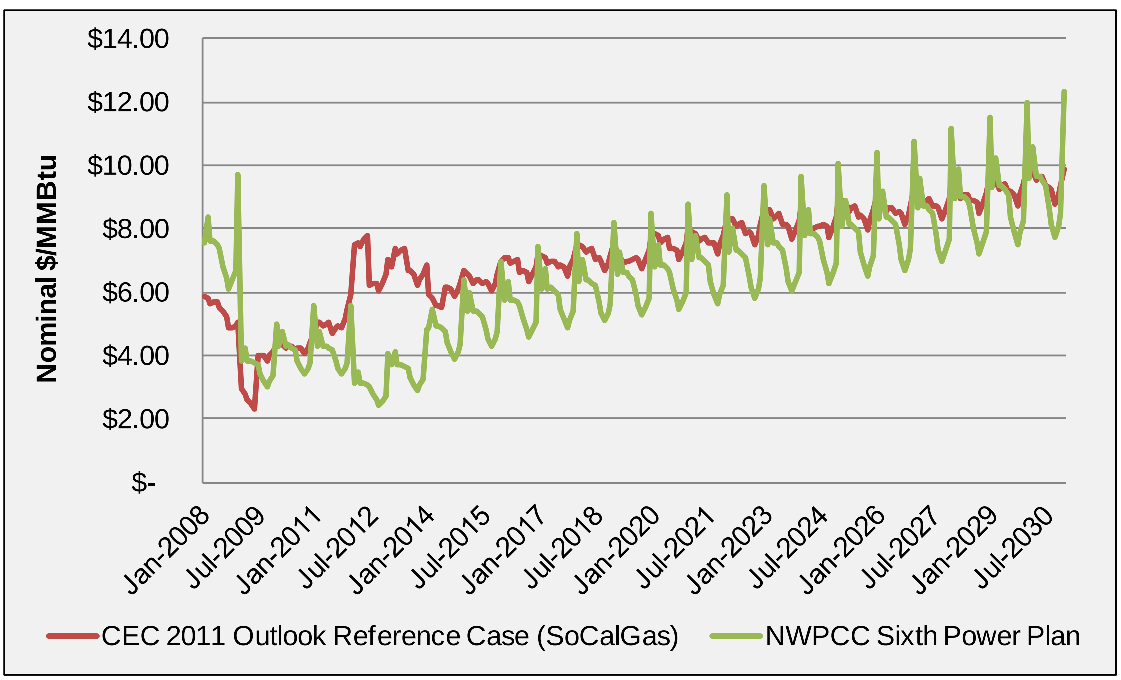
26 FERC (United States Department of Energy). August 2009. *2008 State of the Markets Report*, p. 6.

Figure 6: Northern California Burner Tip Price Estimates, NWPCC vs. Energy Commission



Source: NWPCC and Supply Analysis Office staff analysis.

Figure 7: Southern California Burner Tip Price Estimates, NWPCC vs. Energy Commission



Source: NWPCC and Supply Analysis Office staff analysis.

Table 6: California Burner Tip Price Estimates, NWPCC vs. Energy Commission (Nominal $/MMBtu)

	Northern California		Southern California	
Date	**CEC *2011 Outlook* Reference Case (PG&E)**	**NWPCC *Sixth Power Plan***	**CEC *2011 Outlook* Reference Case (SoCalGas)**	**NWPCC *Sixth Power Plan***
Jan-2008	$6.78	*$7.99*	$5.87	*$7.56*
Jan-2009	$2.39	$3.59	$2.97	$3.82
Jan-2010	$4.24	$4.12	$4.37	$4.29
Jan-2011	$5.00	$4.09	$5.05	$4.26
Jan-2012	$7.43	$2.71	$7.48	$3.10
Jan-2013	$6.70	$3.38	$6.79	$3.68
Jan-2014	$5.74	$4.79	$5.92	$4.90
Jan-2015	$6.37	$5.33	$6.54	$5.38
Jan-2016	$6.95	$5.72	$7.11	$5.72
Jan-2017	$6.97	$6.12	$7.14	$6.08
Jan-2018	$7.32	$6.41	$7.50	$6.35
Jan-2019	$7.01	$6.65	$7.20	$6.56
Jan-2020	$7.64	$6.89	$7.83	$6.79
Jan-2021	$7.68	$7.14	$7.88	$7.02
Jan-2022	$8.13	$7.40	$8.33	$7.25
Jan-2023	$8.41	$7.67	$8.62	$7.50
Jan-2024	$8.07	$8.01	$8.31	$7.80
Jan-2025	$8.60	$8.29	$8.87	$8.06
Jan-2026	$8.56	$8.58	$8.88	$8.33
Jan-2027	$8.78	$8.95	$9.14	$8.66
Jan-2028	$8.90	$9.26	$9.29	$8.94
Jan-2029	$9.17	$9.65	$9.59	$9.29
Jan-2030	$9.39	$9.98	$9.87	$9.58

Source: NWPCC and Supply Analysis Office staff analysis. Historical data is used to estimate prices shown in italics.

California Gas Utilities' *2012 California Gas Report* Burner Tip Price Estimates

The *California Gas Report*, prepared biannually in compliance with CPUC Decision D.95-01-039, estimates natural gas burner tip prices in work papers, which are not published, to prepare forecasts of supply and demand for natural gas. These forecasts and price estimates are then used for modeling electricity generation dispatch. The *2012*

California Gas Report (*2012 CGR*) burner tip price estimates represent usage for cogeneration and other industrial applications, as well as electric generation inside an oil refinery; therefore, these estimates may differ slightly from other burner tip price estimates and assumptions. Electric generation inside an oil refinery may have different usage patterns than electric generation used for other applications, such as meeting baseload demand or meeting peak loads. The following describes SoCalGas burner tip prices and forecast methods for the *2012 California Gas Report Redacted Workpapers*.[27]

For the SoCalGas natural gas commodity price forecast, the *2012 CGR* uses NYMEX Henry Hub futures contracts for the first 18 months of the forecast period and converts these to California border prices (California-Arizona border) using a *basis swap*.[28] After the first 18 months, the *2012 CGR* looks at the average of a number of fundamental price forecasts provided by consultants.

For the transportation component of the forecast, the *2012 CGR* uses an intrastate transportation rate that is the average of the transmission and distribution-level rates paid by electric generation customers.[29] The transportation rate is assumed to increase each year throughout the forecast period. There is also a greenhouse gas (GHG) price adder added to the commodity price. The GHG adder is included to capture additional costs for refineries/electric generators as a result of new emissions regulations in Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006). The GHG adder for natural gas starts at $0.61/MMBtu in 2012 and increases to $3.42/MMBtu by 2030.

2012 California Gas Report Burner Tip Prices vs. Energy Commission

Table 7 contains the prices graphed in **Figure 8**, which compares the SoCalGas burner tip price estimates from the *2012 CGR* with the Energy Commission burner tip price estimates from the *2011 Outlook* Reference Case. Staff's burner tip price estimates are for gas-fired generators in the SoCalGas service territory, while the *2012 CGR* estimates SoCalGas burner tip prices for industrial applications, cogeneration, and electric generation within oil refineries. Thus, this is not an apples-to-apples comparison. The *2012 CGR* burner tip price estimates are similar to the NWPCC estimates in that there is an initial price drop from 2010 – 2012, followed by a steady increase. Also like the NWPCC estimates is the fact that both estimates in **Figure 8** show a seasonal pattern: Prices are highest in the winter, when space heating peaks and increases natural gas demand. The main difference in the *2012 CGR* estimates and staff's estimates is the slope of the *2012 CGR* price plot. The *2012 CGR* price

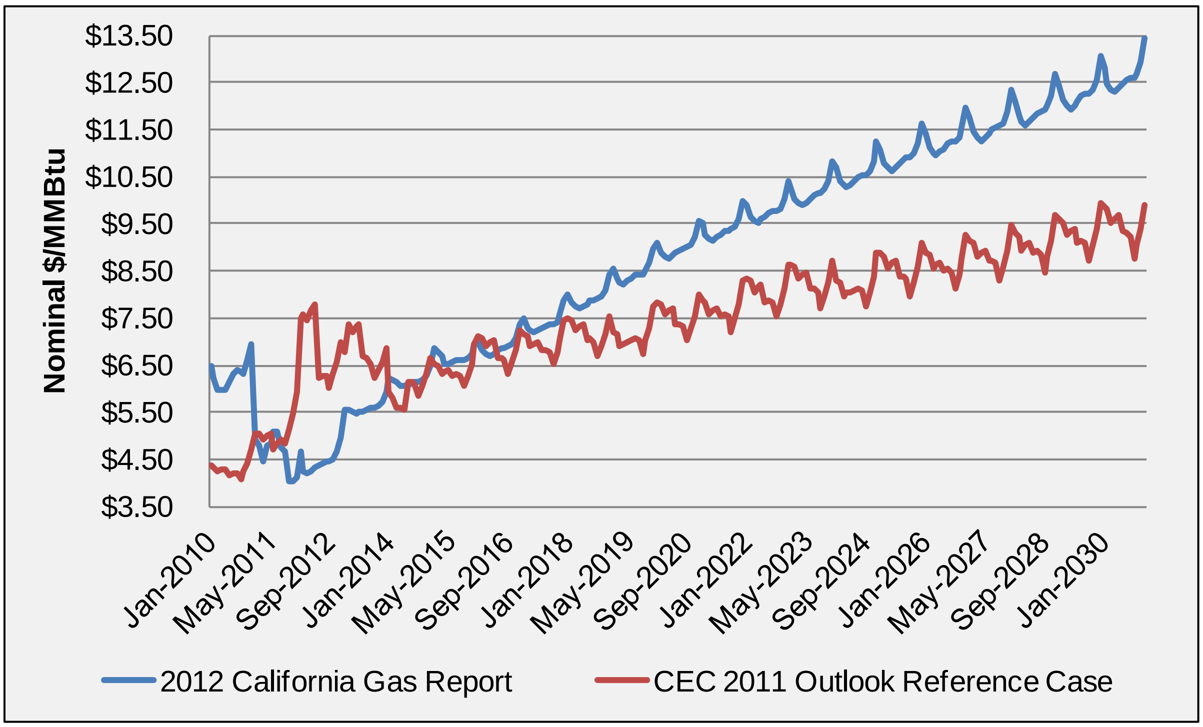
27 *2012 California Gas Report Redacted Workpapers.* See Appendix A of this report and http://www.socalgas.com/regulatory/documents/cgr/REDACTED%20SoCalGas%207%2025%2012.pdf, pp. 249-257. PG&E work papers are not used in this report, because they are not available.

28 For more on *basis swaps*, see http://www.think-energy.net/naturalgas.htm and www.theice.com.

29 *2012 California Gas Report Redacted Workpapers*, p. 195.

plot has a steeper slope (the prices increase at a greater rate); this can be partially explained by the *2012 CGR* adding a GHG price adder to its estimates and increasing the transportation rates over the forecast period (2010 – 2030). Secondly, the *2012 CGR* estimates a dip in 2011 – 2012, which is more consistent with historical natural gas prices than the small bumps the Energy Commission's estimates show over the same period.

Figure 8: SoCalGas Burner Tip Price Estimates:
***2012 California Gas Report* vs. Energy Commission**



Source: SoCalGas and Supply Analysis Office staff analysis.

Table 7: SoCalGas January Burner Tip Price Estimates, *2012 CGR* vs. Energy Commission

Date	*2012 California Gas Report*	CEC *2011 Outlook* Reference Case
Jan-2010	$6.49	$4.37
Jan-2011	$4.93	$5.05
Jan-2012	$4.68	$7.48
Jan-2013	$5.55	$6.79
Jan-2014	$6.22	$5.92
Jan-2015	$6.85	$6.54
Jan-2016	$6.99	$7.11
Jan-2017	$7.48	$7.14
Jan-2018	$8.01	$7.50
Jan-2019	$8.56	$7.20
Jan-2020	$9.12	$7.83
Jan-2021	$9.51	$7.88
Jan-2022	$9.91	$8.33
Jan-2023	$10.30	$8.62
Jan-2024	$10.69	$8.31
Jan-2025	$11.08	$8.87
Jan-2026	$11.40	$8.88
Jan-2027	$11.74	$9.14
Jan-2028	$12.08	$9.29
Jan-2029	$12.43	$9.59
Jan-2030	$12.80	$9.87

Source: SoCalGas and Supply Analysis Office staff analysis.

CHAPTER 4:
Conclusions and Areas for Further Investigation

Conclusions

A burner tip price estimation method that is documented and transparent will allow feedback from stakeholders and the ability to improve the Energy Commission's method over time. Other agencies who use burner tip prices in their modeling, such as the WECC, may find use in the Energy Commission's methods. With adequate documentation and feedback, stakeholders will understand these methods and find confidence in their use.

Staff's burner tip price estimation method uses prices from the *2013 Outlook*, while other methods use data that are publicly available. Publicly available data include Henry Hub commodity prices, NYMEX futures contract prices, and financial basis swap data (for interstate transportation costs). One advantage of using publicly available data is that more stakeholders may be willing to participate, reproduce staff's estimates on their own, and offer suggestions to the method and ideas about potential future work.

The *2013 Outlook* provides natural gas commodity prices for electric generators at 45 hubs across the WECC region; this allows for more options to choose different price hubs for the commodity price portion of the estimates. Another advantage is that the *2013 Outlook* produces price output based on supply and demand fundamentals rather than on NYMEX futures or other financial prices. Financial prices may capture mostly short-term price movements that are not completely based on supply-and-demand relationships. All the methods start with annual prices and convert to monthly values; each method may better capture short-term and seasonal phenomena by using monthly commodity prices instead of annual prices.

The discussion in this report comparing different price estimation methods and the uncertainty over which is better is partly because the actual prices generators pay for natural gas are not publicly disclosed. These prices are specified in contracts for delivery of gas, spot purchases, futures, options, and other hedging instruments whose terms generators and their counterparties conceal from the public. It is also because nobody knows what generators, their suppliers, or anyone else will have to pay years in advance for natural gas. Because market conditions determine prices, analysts have to make assumptions about future conditions to estimate prices. The assumptions about economic growth, natural gas supply, weather, renewable energy policy, and other future conditions used in commodity price forecast modeling almost never turn out to be accurate, so estimates of burner tip prices are really only *conditional* estimates: They have to be interpreted with the assumptions in mind to understand natural gas markets and prices. One key assumption, economic growth, also is a significant factor driving transportation rate growth, but regulations, capital costs, and other factors make estimation of future rates equally uncertain.

Natural gas-fired generation is expected to play an important role in electricity system planning, especially given the integration of a growing portfolio of renewable energy. It will be important to keep staff's burner tip price estimates up-to-date, including the commodity price forecasts and transportation rates. Performing this analysis at least every two years should keep the methods and assumptions updated.

Areas for Further Investigation

Going forward, work could be done to improve the forecasting and estimation method employed by the Energy Commission. The following list of refinements and improvements is by no means exhaustive. It reflects areas where additional information, further refinement, or more analytic resources may lead to improved results.

Align Model With Real-World Practices

First, staff could contact and survey industry stakeholders (natural gas utilities, owners/operators of merchant natural gas-fired generators, and owners/operators of natural gas pipelines) to gain a better understanding of how natural gas is procured and what gas-fired generators pay for natural gas. Determining the amount of long-term, short-term, and other types of natural gas purchases will help reflect more accurately how power plants procure natural gas and how much they pay for the commodity itself. Secondly, different types of natural gas power plants may not purchase natural gas in the same manner. For example, merchant plants may procure natural gas much differently than utility-owned power plants. Peaker power plants may also procure gas differently than baseload power plants. Staff could provide a more detailed analysis with different commodity pricing assumptions for merchant and utility-owned power plants with this information.

Apply the Burner Tip Method to Other Commodity Price Forecasts

For the commodity component of the burner tip price estimates, the Energy Commission uses data from NGI for backcasting and data from the *2013 Outlook* for future prices. The Energy Commission, in the future, could explore other natural gas price data services, such as *Energy Intelligence* (www.energyintel.com), LCI Energy Insight (http://www.lippmanconsulting.com/), *Platt's Gas Daily* (http://www.platts.com/products/gas-daily) or Bentek Energy (http://www.bentekenergy.com/Index.aspx), to gather more natural gas price data. Historical prices from these data services can be used to improve backcast validation of the burner tip method; forecast prices from these data services could be used instead of prices from the *2013 Outlook* for comparison. Changes to the burner tip method itself might be indicated as a result of these comparisons. For example, gas-fired generators purchase their fuel from a variety of natural gas hubs; taking a weighted average of a set of hubs may better represent this fuel cost. Staff could also gather information on long-term natural gas supply contracts and incorporate this gas purchase strategy into its estimates. A gas-fired generator that purchases gas through long-term contracts may pay either more or less than natural gas purchases on the spot market or through monthly bidweek contracts.

Research Variance in Transportation Costs

Staff assumes that all transportation used by gas-fired-generators is paid at a rate discounted from firm capacity, so it is usually in the range of interruptible rates, but with no real growth in those rates. These are necessary simplifying assumptions, given the differences in transportation cost and procurement among natural gas power plant ownership types and the lack of clearly observed patterns in transportation rates. Staff has discussed adding positive or negative growth rates to transportation rates to capture the increase or decline in rates over time. Staff could look at historical transportation rates from various pipelines operators to develop a growth rate. Staff could also use an average of the last three to five years of transportation rates instead of using the most current rate or a longer history, given that the longer history, as shown in this report, demonstrates no apparent positive or negative growth rate. This may help better reflect some of the recent changes in rates. Rates are expected to increase, for example, as a result of the pipeline safety enhancement plans submitted to the CPUC by PG&E and SoCalGas.[30] The rates proposed in the 2015 PG&E gas transmission and storage rate case also imply a significant rate increase. Changes to services resulting from efforts to better harmonize gas transportation with electric generation gas demand or facilities being modified to allow export such as to Mexico could also affect gas transportation rates.

Request Transportation Rate Forecasts

Another option is to contact California utilities and natural gas pipeline operators that supply natural gas into California and western states and ask them to provide transportation rate forecasts. Pipeline operators understand their pipeline system, including maintenance schedules, pipeline upgrades, and replacement needs going forward. Power plants could be surveyed to find out what they pay for transportation, what type of transportation they procure (long-term, firm, interruptible, and so forth), and from which pipeline/pipelines they procure transportation. Staff's method will likely produce more

30 Both PG&E and SoCalGas have submitted to the CPUC pipeline safety enhancement plans that can potentially increase rates to end-use consumers of natural gas. See http://www.pgecurrents.com/2011/08/26/pge-files-milestone-plan-to-modernize-improve-safety-of-gas-pipeline-system/ and http://www.socalgas.com/safety/pipeline-safety-enhancement-plan/.

realistic burner tip price estimates with more accurate assumptions on what power plants pay for natural gas transportation.

Produce Monthly Gas Price Estimates Using the NAMGas Model

Another way to improve the Energy Commission burner tip price estimates is to convert the NAMGas model to a monthly model. Running the NAMGas model monthly eliminates the need to convert annual prices to monthly values; however, staff would need to add explicit modeling of natural gas storage to the NAMGas model. Running the NAMGas model monthly with natural gas storage included will provide staff insights to the seasonal aspects of the natural gas market (including storage injections and withdrawals). The NAMGas model can be run to produce natural gas prices for any period (year, month, week, day, and so forth); smaller time increments, such as days, may be of less use for longer-term forecasting (20 years and more).

Use Scenario Analysis

Scenarios should be included that look at future severe weather events and extended outages of natural gas infrastructure, as well as other scenarios that will affect future natural gas burner tip prices. Running various scenarios helps account for future uncertainty and can provide insights into how unexpected events will impact future burner tip prices. Having an ensemble of burner tip price estimates based on various scenarios will make the Energy Commission's methods and estimates more robust and provide flexibility for electricity system planners who want to consider more than one future scenario.

Acronyms

2011 Outlook	*2011 Natural Gas Market Assessment: Outlook Final Staff Report*
2012 CGR	*2012 California Gas Report*
2013 Outlook	*2013 Natural Gas Issues, Trends and Outlook Final Staff Report*
CPUC	California Public Utilities Commission
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
ICE	Intercontinental Exchange
MMBtu	Million British thermal units
NAMGas model	North American Market Gas-Trade model
NGI	Natural Gas Intelligence
NWPCC	Northwest Power and Conservation Council
NYMEX	New York Mercantile Exchange
PG&E	Pacific Gas and Electric Company
SDG&E	San Diego Gas & Electric Company
SoCalGas	Southern California Gas Company
TEPPC	Transmission Expansion Planning Policy Committee
WECC	Western Electricity Coordinating Council

APPENDIX A: Discussion of Method for Annual-to-Monthly Conversion Factors

There are two components in converting annual natural gas prices to monthly values: a seasonality component and year-to-year interpolation component. Together, both of these components are identified as the annual-to-monthly conversion factor.

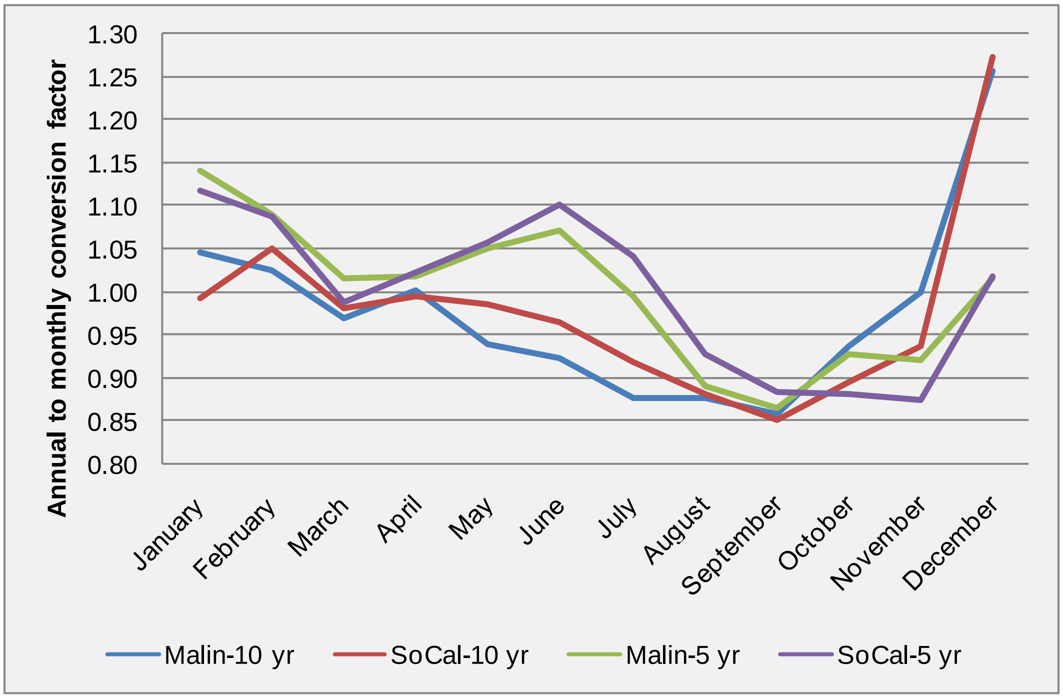
Seasonality

The *2013 Outlook* estimates annual natural gas prices. To obtain a more granular look at the model's natural gas prices, staff converted the annual prices to monthly values. Staff compared historical annual NGI bidweek average and monthly natural gas prices at select pricing points, and calculated a seasonal factor for each month. Staff took averages of these factors over 5, 10, 15, and 20 years using bidweek gas prices NGI surveyed at Henry Hub, Louisiana. As demonstrated in Chapter 2, seasonal factors changed little between histories extending back 10, 15, and 20 years, showing that, in this method of estimating seasonal factors, there is no significant difference between assuming a long price history over a short history. Ultimately, staff decided on the 10-year average (2002–2011) of Henry Hub-derived seasonal factors. Some of the other seasonality factors fit the data better in certain years, but over the whole 1992–2011 period, the 10-year Henry Hub average had the best fit.

Staff also examined seasonal factors based on regional NGI bidweek prices. **Figure A-1** shows the 5- and 10-year average seasonal factors for the Malin and SoCalGas border price points, both located in California.[31] Higher volatility is apparent in these seasonal factors compared to the ones derived from Henry Hub prices, particularly in the winter months. The 5-year seasonal factors do not show the same magnitude of volatility in the winter months; however, they show more volatility in the summer months. In the 5-year seasonal factors, the summer 2008 price spike is a larger percentage of the average seasonal factor than are the 10-year price spikes. Seasonal factors from other regional pricing points were also more volatile than the Henry Hub-derived seasonality factors and showed similar results.

31 The 5-year average is from 2007 – 2011, and the 10-year average is from 2002 – 2011.

Figure A-1: California Annual-to-Monthly Seasonality Factors

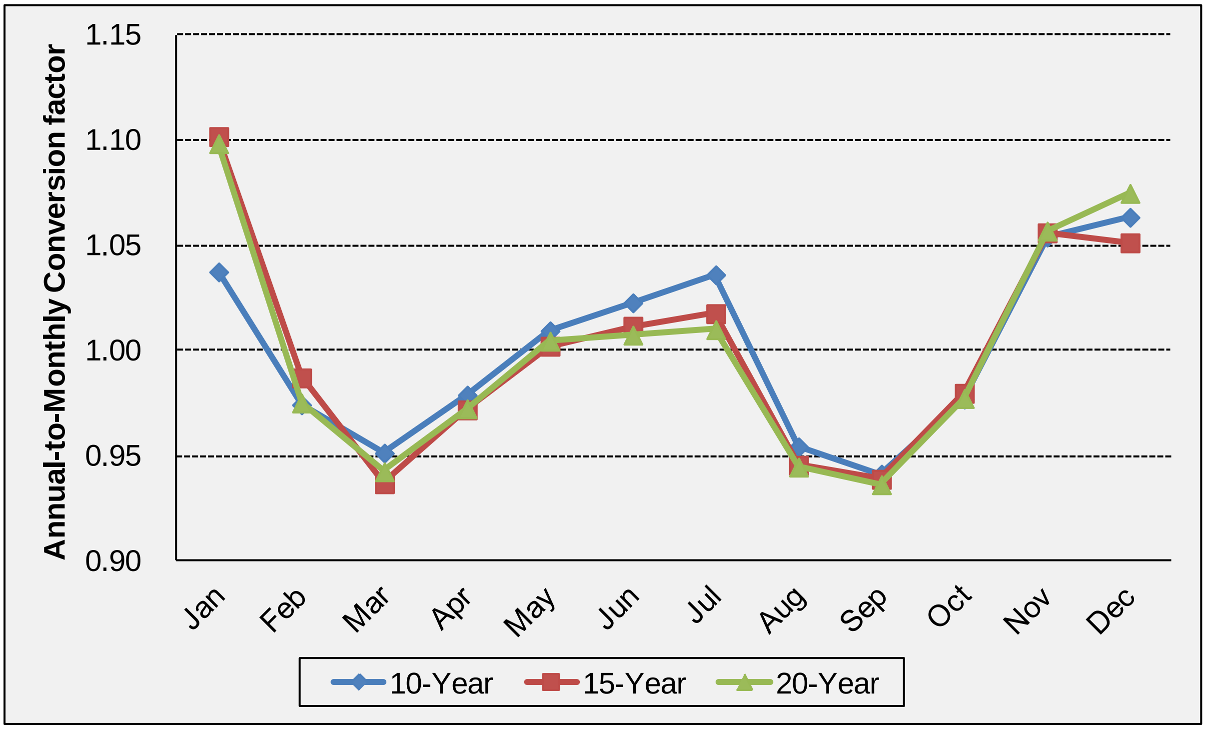


Source: NGI bidweek price data.

The seasonal factor is a number multiplied by the annual natural gas price to get the monthly natural gas price for each calendar month. To obtain the seasonal factor number, staff divided the monthly natural gas price by the annual natural gas price for a given natural gas price hub; in this case, it is the Henry Hub. For instance, if the January seasonal factor is 1.10, then staff multiplied the annual natural gas price by 1.10 to get the January monthly price. This result says that the January monthly price is 10 percent higher than the average annual price.

The formula for the seasonal factor is the monthly gas price divided by the annual gas price for each month. Then, each monthly seasonal factor is averaged over the 10-year time span. Once the January factor for each year was found, the factors were averaged to get one January seasonal factor. All other months are computed the same way. For example, the October monthly factor, 0.98, is the ratio of the 2002 – 2011 average of October monthly gas prices, divided by the 2002 – 2011 average annual gas price. **Figure A-2** illustrates three Henry Hub seasonal factors for each month. All three seasonal factors are very similar and follow a distinct pattern. The seasonal factors spike in the summer and winter months; the winter spike is larger than the summer. These two spikes represent increased natural gas use for both cooling and heating load demand. One reason the Henry Hub seasonal factors are less volatile than the California seasonal factors is that the Henry Hub is a very liquid price hub; this liquidity, and diverse factors that drive its behavior, insulate Henry Hub from some of the price shocks found in other, less liquid, price points.

Figure A-2: Henry Hub Annual-to-Monthly Seasonality Factors



Source: NGI, bidweek price data.

Stakeholders participating in the Western Electricity Coordinating Council/Transmission Expansion Planning Policy Committee (WECC/TEPPC) process from August 2013 until February 2014 recommended that staff replace the monthly price factors at Henry Hub with price factors at five western hubs derived from either (a) the futures strip for each of the five hubs over the 2000 – 2013 time frame, (b) the median price values over the 2000 – 2013 time frame, or (c) the median price values over the 2010 – 2013 time frame.

To test the proposed change to individual hub shapes and determine if there actually was a difference between Henry Hub monthly profiles and those of the five western hubs recommended by WECC, staff performed a statistical test (the Mann-Whitney U test[32]) comparing the historical annual-to-monthly conversion factors of each of five hubs to the same factors at Henry Hub. Using the 95 percent confidence interval as the standard for accepting or rejecting the hypothesis that the monthly factors are the same at each of the hubs, staff calculated p-values shown in **Table A-1**. A p-value below 0.05 would indicate that there is less than 95 percent certainty that the factors at each hub are different than the

32 This is a nonparametric test of two means that does not rely on the assumption that the data tested are normally distributed. The null hypothesis is that the two means tested are the same.

factors at Henry Hub. The values shown in **Table A-1** are all above 0.05; therefore, staff found no defensible basis for replacing the current Henry Hub-based factors of the burner tip model with those recommended by the WECC/TEPPC.

Staff also performed a statistical test (called an F-test) to determine if the price factors had changed in the last three years. The results of the test were that only August showed a statistically significant change in monthly price factors over the last three years, moving from an historical value of 1.1 to 0.92. The late summer period (July-September) showed factors that were nearly significant (with P-values of 0.052 – 0.084). This suggests that staff should continue to monitor and be prepared to update these values in any future revisions of this report.

Table A-1: Mann-Whitney U-Test of Annual-to-Monthly Gas Price Conversion Factors vs. Henry Hub: P-Values

	Northwest Sumas (rmtsumas)	El Paso Permian (wtxepp)	Malin (calm400)	PG&E Citygate (calpgcg)	SoCal Border Average (calsavg)
Jan	0.5727	0.9183	0.8175	0.8777	0.9591
Feb	0.6440	0.8900	0.8770	0.9495	0.9183
Mar	0.8980	0.9180	0.7196	0.7196	0.8777
Apr	0.8777	0.7790	0.8375	0.6444	1.0000
May	0.5215	1.0000	0.8375	0.8777	0.9183
Jun	0.1439	0.8375	0.5050	0.7196	0.6816
Jul	0.0812	0.5050	0.3694	0.5727	0.8175
Aug	0.0578	0.5554	0.3171	0.5727	0.3560
Sep	0.2931	0.7196	1.0000	0.9591	0.8175
Oct	0.3695	0.6816	0.8375	1.0000	0.8770
Nov	0.3975	0.8777	0.5727	0.6081	0.9591
Dec	0.3051	0.9591	0.7976	0.8980	0.9591

Source: Supply Analysis Office staff analysis.

Interpolation

The second component of converting natural gas prices from annual-to-monthly values is interpolation. Moving from one year to the next, staff examined two methods for interpolation. The first method uses a calendar year (January through December), while the second method uses a year that goes from June through May.

The June-through-May year method was chosen after investigating both methods. This method was chosen because the seasonal factor was closest to "1" in June. This helps remedy large price discontinuities from December to January, which occur in some years. Lagging the seasonal calendar by six months better fits the historical data.

In both methods interpolation is assumed to be linear. Staff understands that prices may not always behave like this but makes this simplifying assumption due to lack of any other temporal pattern from history to use. For instance, the annual Henry Hub natural gas price was $6.86 in 2007 and $9.04 in 2008. The price difference between the two years is $2.18. Each month from January through December would have added to it $2.18/12 or $0.18. January would be $6.86+$0.18 = $7.04, February would be $7.04+$0.18 = $7.22, and so on. The December 2007 price, in this example, is $9.04, which is the same as the annual 2008 price. This method works well most of the time.

The following equations fully define both the October seasonal and interpolation calculations to yield the October Estimated June – May Price and provide the logic by which the Energy Commission's burner tip method calculates every other monthly price for the June-through-May year. The first equation identifies the three exogenous variables – the "Average NGI Bidweek Annual Price," the "October Seasonal Factor," and the "October Interpolation Factor for June – May Year" – that yield the final "October Estimated June – May Price." The three subsequent equations define the three exogenous variables identified in the first equation:

(Average NGI Bidweek Annual Price) x (October Seasonal Factor) + (October Interpolation Factor for June – May Year) = (October Estimated June – May Price), where:

(Average NGI Bidweek Annual Price) = 1/12 x (Sum of January – December NGI Bidweek Price);

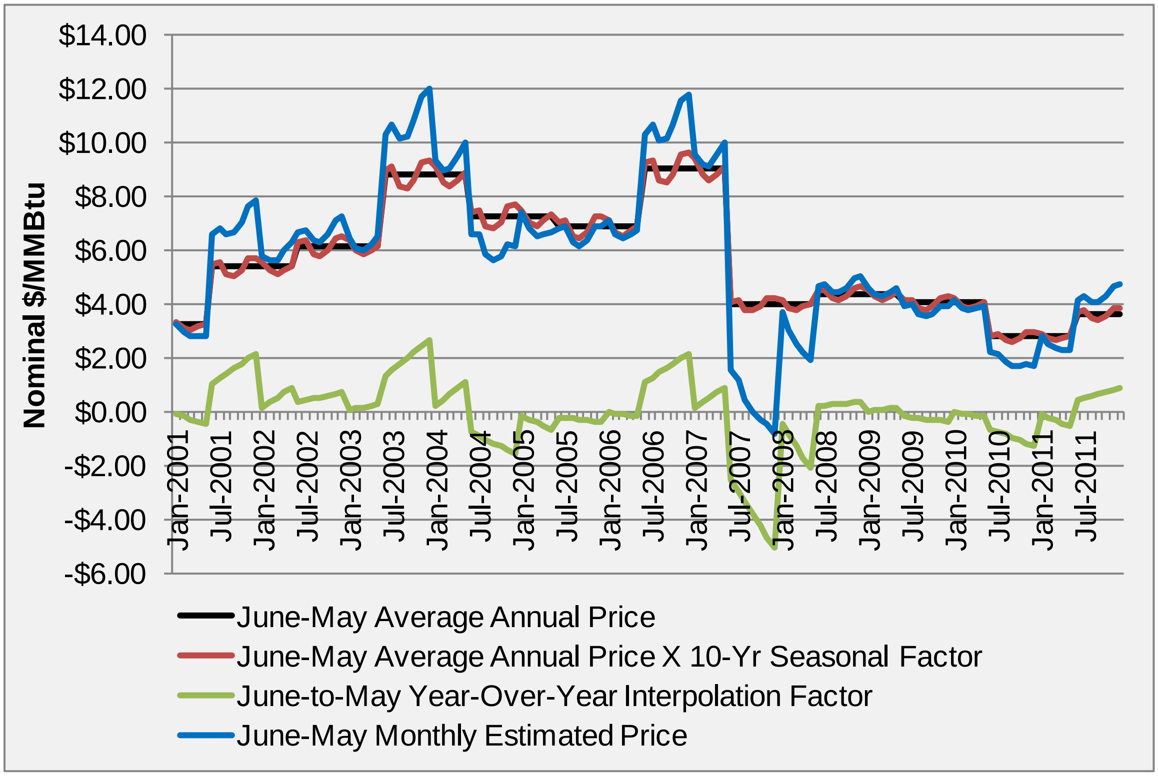
(October Seasonal Factor) = (Average October 2002 – 2011 NGI Bidweek Henry Hub Price)/(Average 2002 – 2011 NGI Bidweek Henry Hub Price);

(October Interpolation Factor for June – May Year) = 1/12 x [(Second-Year Average NGI Bidweek Annual Price) – (First-Year Average NGI Bidweek Annual Price)] x 5.

The factor "5" in the last equation accounts for the fact that October is the fifth month in the June-through-May year.

The following example in **Figure A-3** illustrates the conversion from annual average NGI bidweek gas prices to the monthly estimated price, using the June-through-May year. The black line in the graph is the "June-May Average Annual Price," which is the annual average of the NGI bidweek price. The monthly seasonal factors are multiplied by this price to obtain the "June-May Average Annual Price X Seasonal Factor," which is graphed in red. The "June-May Year-Over-Year Interpolation Factor" is graphed in green. It shows that, for most months, small amounts of less than $1 are added to, or subtracted from, prices to derive the final price. Amounts up to $5 are subtracted in the summer and autumn of 2008 to adjust prices from the 2008 price spike. This is an artifact that would not be replicated using annual price inputs from natural gas forecasting models. These factors are added to the "June-May Average Annual Price X Seasonal Factor" to obtain the final "June-May Monthly Estimated Price" in blue.[33]

Figure A-3: Step-by-Step Calculation of the June-Through-May Estimated Price



Source: NGI bidweek price data and Supply Analysis Office staff analysis.

33 The natural gas commodity price input from the Rice World Gas Trade Model is denominated in 2010 dollars per thousand cubic feet; therefore, this price is converted to nominal dollars per MMBtu by assuming a Moody's Analytics Gross Domestic Product deflator and 1 Mcf = 1.030 MMBtu.

APPENDIX B: Historical Validation of Burner Tip Prices

Western Electricity Coordinating Council 2010 Backcast and Natural Gas Intelligence

WECC staff estimates monthly burner tip prices for each balancing authority[34] in the western states using historical natural gas commodity prices from the Intercontinental Exchange (ICE), as well as price data from the U.S. EIA Form 923.[35] WECC staff performs this backcasting exercise to validate and improve production cost modeling in fulfillment of its mandate to "guide and improve the economic analysis and modeling of the Western Interconnection."[36] The backcast helps calibrate and improve the TEPPC production cost modeling to produce more realistic simulations in its 10-year projections.[37] The WECC method uses historical burner tip prices from the U.S. EIA. Financial data on natural gas commodity prices from the ICE are assumed, and firm transportation rates from pipeline and gas utility websites are used to account for transportation costs when the U.S. EIA data are insufficient. The transportation rates for interstate and intrastate natural gas pipelines are in line with the Energy Commission's transportation rates.

Figure B-1 shows estimated burner tip prices for two electricity balancing authorities: the Balancing Authority of Northern California and the Los Angeles Department of Water and Power. This graph illustrates the typical seasonal price trends both generators and all other gas consumers face; these trends are reflected in the other WECC backcasts shown in this report.

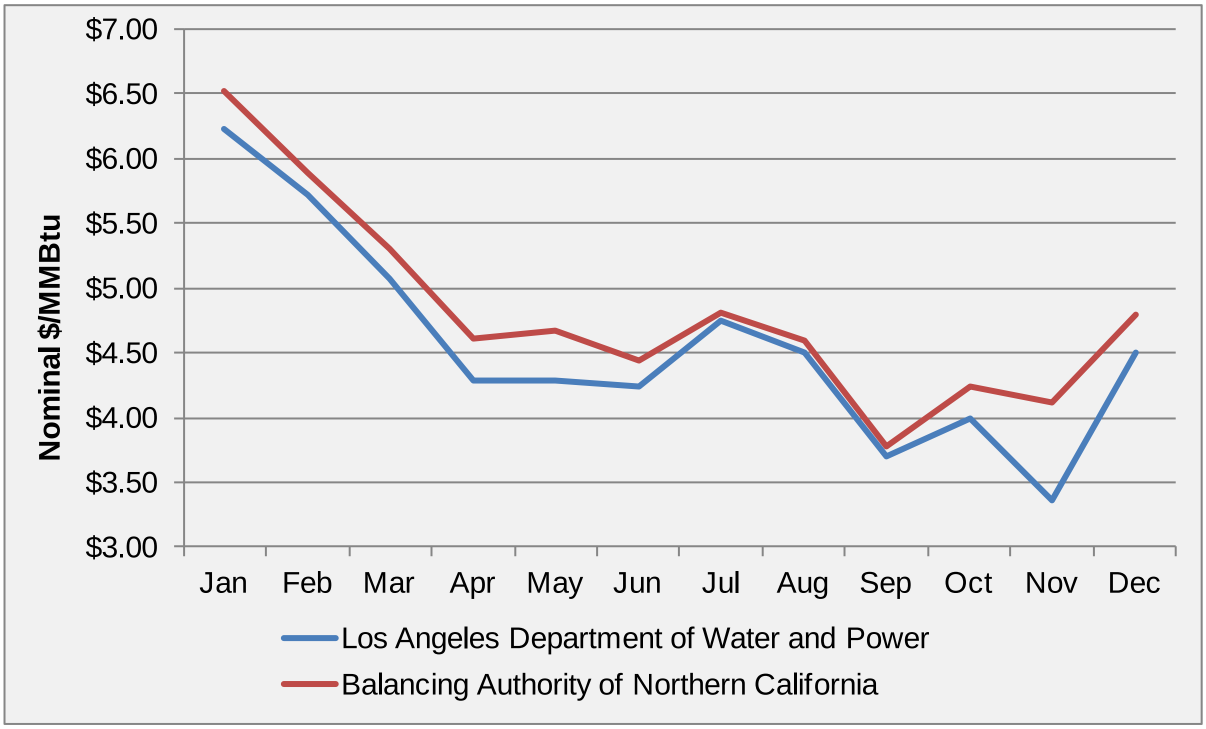
34 A *balancing authority* is an entity that integrates resource plans ahead of time and supports interconnection frequency in real time as well as maintains load-interchange-generation balance within a region. For a list of balancing authorities in the WECC, see http://www.wecc.biz/library/WECC%20Documents/Publications/WECC_BA_Map.pdf.

35 See http://www.eia.gov/electricity/data/eia923/.

36 For more on TEPPC, see http://www.wecc.biz/committees/BOD/TEPPC/default.aspx.

37 Data for this backcast were obtained through EIA-923 forms, which survey power plants for burner tip prices. For more on U.S. EIA Form 923, see http://www.eia.gov/electricity/data/eia923/.

Figure B-1: WECC 2010 Backcast Burner Tip Prices



Source: U.S. EIA Form 923 data reports and www.theice.com natural gas month-ahead and once-through-cooling reports.

Western Electricity Coordinating Council 2010 Backcast vs. Natural Gas Intelligence Bidweek

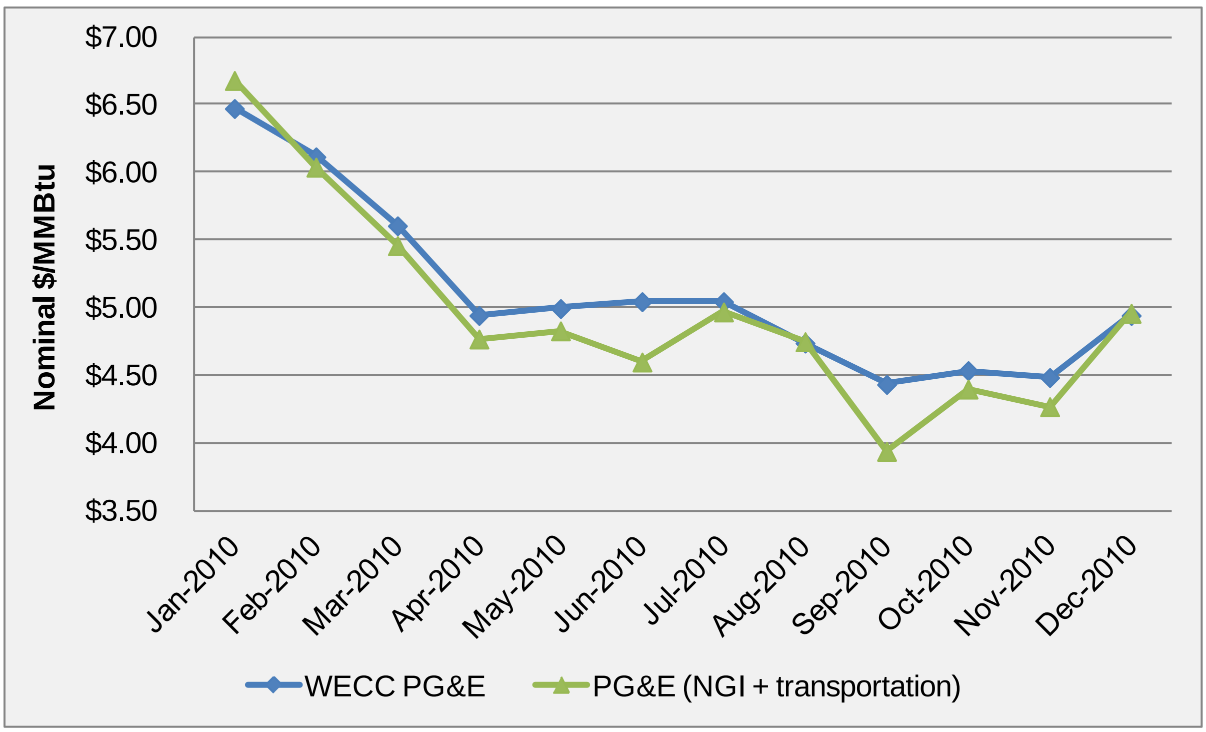
This section compares the WECC backcasts with burner tip price estimates that are the sum of historical bidweek natural gas commodity prices from NGI, plus the applicable transportation rates. The purpose is to validate the WECC backcasts to compare both NGI and WECC backcast prices with burner tip prices estimated by the method documented in this report. The comparison examines burner tip prices in the PG&E, SoCalGas, Northern Nevada, and Southern Nevada regions. NGI monthly bidweek commodity price data are used because this is a comparison of monthly prices; therefore, the annual commodity price output from the *2013 Outlook* is not suitable. The WECC burner tip price estimates are modeled for the electric grid balancing authority for each region; this is not the case for NGI bidweek prices, which are calculated from actual market transactions at each hub. WECC burner tip price estimates are calculated using a method that, net of transportation costs, attempts to simulate bidweek prices relevant to generators in the respective PLEXOS® fuel groups. Staff therefore matched as closely as possible the appropriate balancing authorities to each PLEXOS® fuel group.

The comparisons show the NGI-based estimates are generally a little lower than WECC's estimates. Several factors contribute to the NGI-based prices trending lower than the WECC price estimates. First, the WECC uses both the U.S. EIA Form 923 and month-ahead natural gas prices from the ICE, while the NGI-based estimates use monthly bidweek prices from *Natural Gas Intelligence*. The ICE month-ahead prices are financial prices and, thus, may contain a risk premium, whereas the *Natural Gas Intelligence* prices are physical index prices determined by supply and demand interactions in the market.[38]

The WECC estimates use the same intrastate transportation rate as the NGI-based estimation method. Also, the mapping from balancing authorities to each PLEXOS® fuel group is not perfect; some overlap may occur. All of these factors can contribute to the differences in the natural gas burner tip price estimates examined in this section.

Figure B-2 and **Figure B-3** compare WECC burner tip price backcasts with the NGI-based prices for the PG&E and SoCalGas service areas. Most WECC backcasts for other fuel groups trend closely with, but are also somewhat lower than, the NGI-based price estimates.

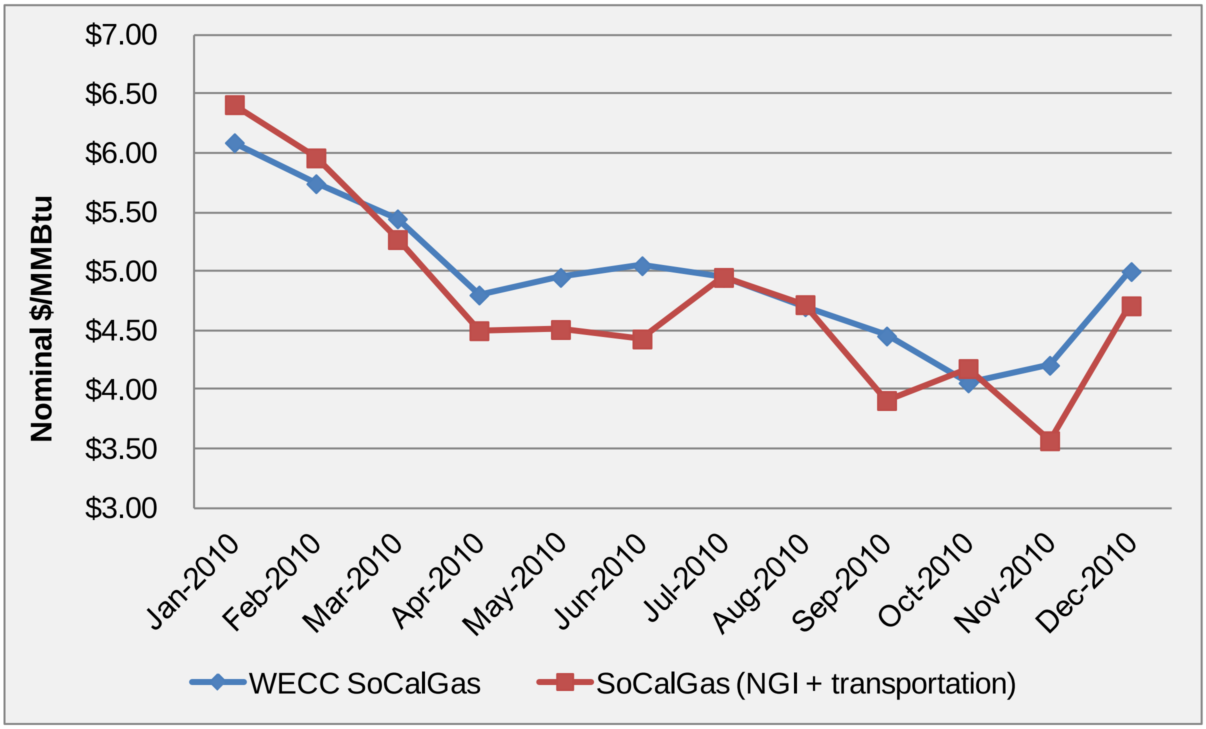
Figure B-2: 2010 WECC and NGI-Based Burner Tip Price Estimates (PG&E)



Source: WECC and Supply Analysis Office staff.

38 A *risk premium* means the extra amount paid to avoid the risk of increasing or volatile natural gas prices.

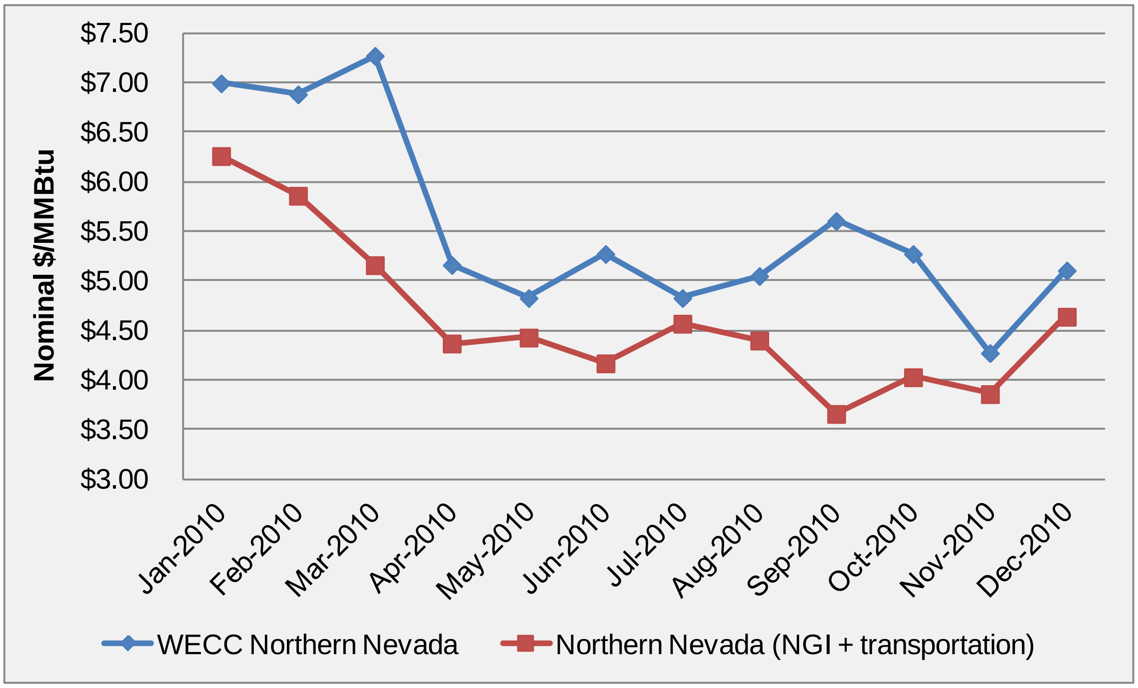
Figure B-3: 2010 WECC and NGI-Based Burner Tip Price Estimates (SoCalGas)



Source: WECC and Supply Analysis Office staff.

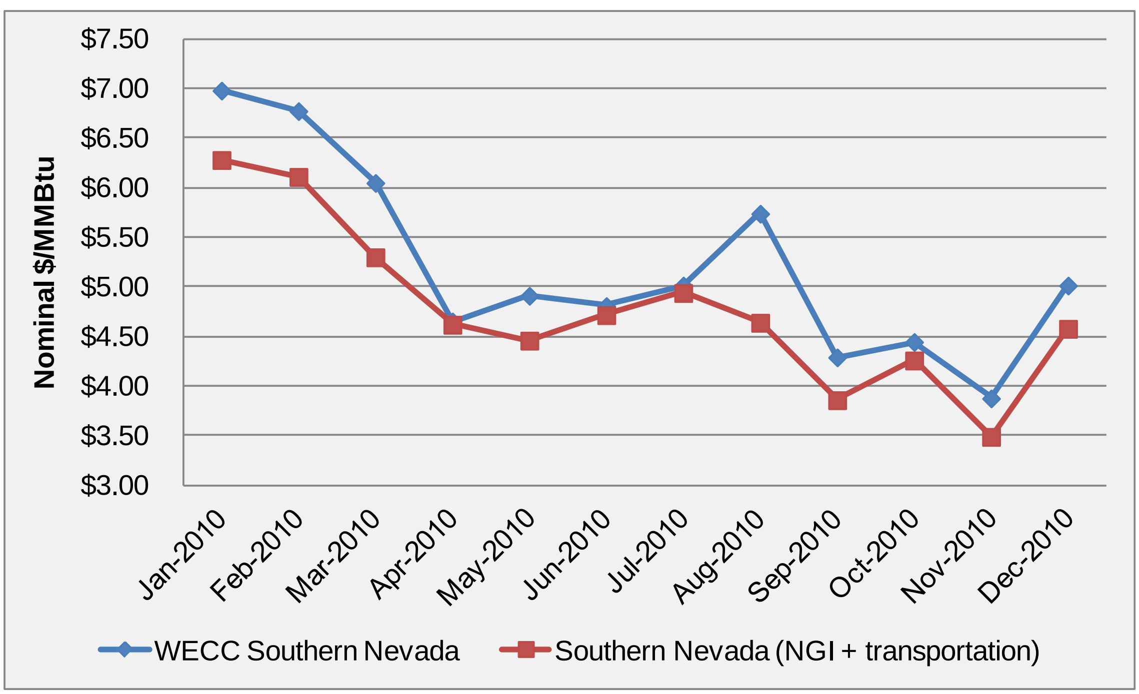
Staff's NGI-based burner tip price estimates for Northern and Southern Nevada fit reasonably well with the WECC backcast; however, the estimates for Southern Nevada appear to have a better fit; see **Figure B-4** and **Figure B-5**.

Figure B-4: 2010 WECC and NGI-Based Burner Tip Price Estimates (Northern Nevada)



Source: WECC and Supply Analysis Office staff.

Figure B-5: 2010 WECC and NGI-Based Burner Tip Price Estimates (Southern Nevada)



Source: WECC and Supply Analysis Office staff analysis.

Table B-1: WECC 2010 Burner Tip Price Estimates (Nominal $/MMBtu)

Month	LADWP	BANC	PG&E	SoCalGas	N. Nevada	S. Nevada
Jan	$6.23	$6.52	$6.47	$6.09	$6.99	$6.98
Feb	$5.71	$5.88	$6.12	$5.74	$6.88	$6.77
Mar	$5.06	$5.30	$5.61	$5.44	$7.27	$6.05
Apr	$4.29	$4.61	$4.94	$4.80	$5.16	$4.65
May	$4.29	$4.67	$4.99	$4.95	$4.83	$4.91
Jun	$4.24	$4.44	$5.05	$5.05	$5.27	$4.81
Jul	$4.74	$4.81	$5.05	$4.95	$4.83	$5.01
Aug	$4.50	$4.59	$4.74	$4.70	$5.05	$5.74
Sep	$3.70	$3.78	$4.43	$4.45	$5.61	$4.29
Oct	$3.99	$4.24	$4.54	$4.06	$5.27	$4.45
Nov	$3.36	$4.12	$4.49	$4.21	$4.27	$3.88
Dec	$4.50	$4.80	$4.94	$5.00	$5.11	$5.01

Source: WECC and Supply Analysis Office staff analysis.

Energy Commission Backcast vs. Ventyx Velocity Suite and Natural Gas Intelligence

Staff compared historical burner tip prices from Ventyx to its own burner tip price estimates because the Ventyx survey method yields historical prices that serve as a reasonable benchmark for evaluating the Energy Commission burner tip price estimation method and results. Ventyx historical burner tip prices are compiled from EIA Form 923.[39] Staff aggregated the Ventyx power plant-level data into subregions of the WECC, such as Northern and Southern California, and Northern and Southern Nevada, which best approximate the Energy Commission burner tip topography. An additional estimation method is included that uses historical bidweek natural gas prices coupled with the transportation rates used in staff's burner tip price estimates; this additional method is compared to the Ventyx historical prices and staff's estimated burner tip prices. Because the burner tip prices from Ventyx are compiled from surveys of individual power plants, Energy Commission staff computed natural gas volume-weighted averages to derive similar prices for California, Arizona, and Nevada. **Table B-2** lists the number of power plants by region used to calculate the volume-weighted prices.

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39 These historical prices are available to paid subscribers to the Ventyx Energy Velocity Suite. The quality of this data is subject to the survey method used by EIA for the EIA Form 923.

Table B-2: Power Plant Census in California, Arizona, and Nevada

Region	Census
Northern California	176
Southern California	173
Northern Nevada	6
Southern Nevada	17
Northern Arizona	4
Southern Arizona	28

Source: U.S. EIA Form 923 and Supply Analysis Office staff analysis.

The results of the backcast comparisons are mixed but quite similar for all three states, as shown in **Table B-3**.

Table B-3: Backcast of Burner Tip Prices, Ventyx vs. Energy Commission (Nominal $/MMBtu)

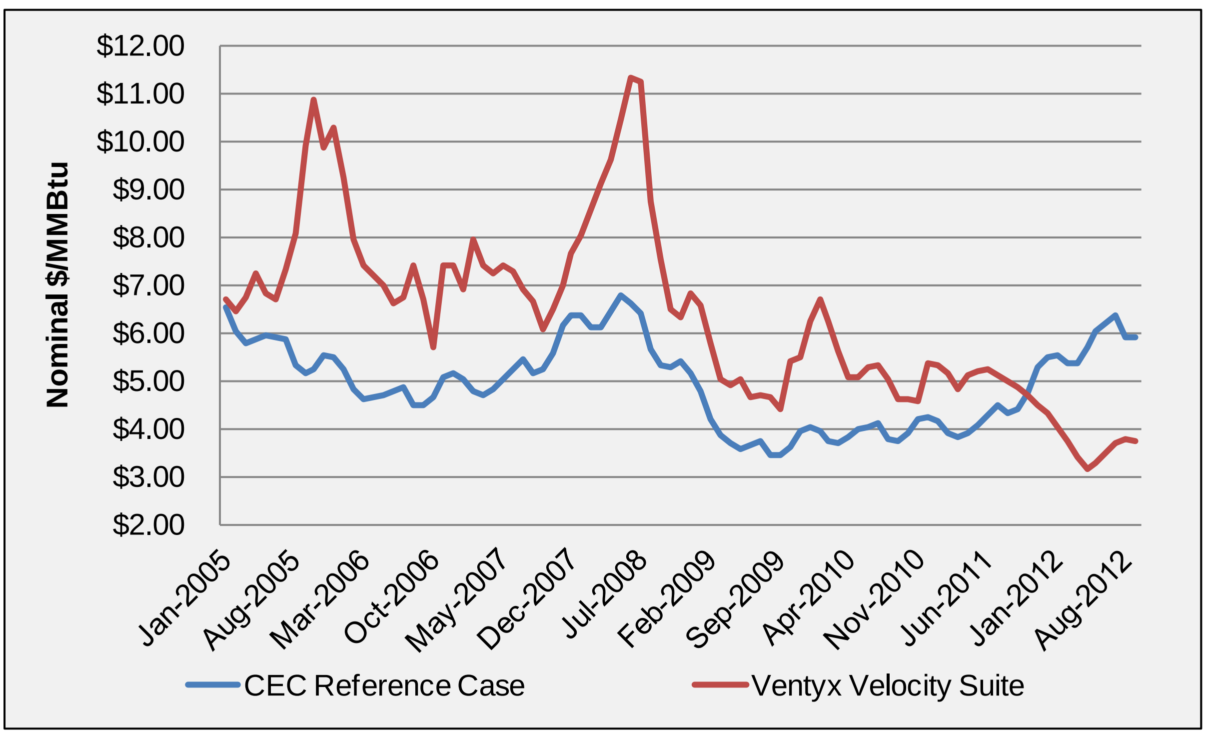
Date	California		Arizona		Nevada		Northern California		Southern California	
	CEC	Ventyx	CEC	Ventyx	CEC	Ventyx	CEC	Ventyx	CEC	Ventyx
Jan-2005	$6.53	$6.70	$5.78	$5.68	$6.24	$6.97	$6.42	$6.64	$6.65	$6.77
Jan-2006	$5.25	$9.23	$4.56	$9.23	$4.97	$9.28	$5.13	$9.19	$5.36	$9.27
Jan-2007	$5.04	$6.91	$4.33	$7.09	$4.77	$6.64	$4.93	$6.87	$5.15	$6.98
Jan-2008	$6.38	$8.02	$5.10	$8.24	$6.08	$7.74	$6.71	$7.99	$6.05	$8.06
Jan-2009	$4.77	$6.56	$3.85	$6.49	$4.50	$7.47	$4.87	$6.67	$4.67	$6.43
Jan-2010	$3.95	$6.72	$3.34	$7.41	$3.68	$7.53	$3.83	$6.74	$4.07	$6.69
Jan-2011	$4.14	$5.33	$3.51	$5.65	$3.87	$5.67	$4.02	$5.31	$4.26	$5.36
Jan-2012	$5.53	$4.04	$4.64	$3.65	$5.22	$3.96	$5.41	$4.03	$5.64	$4.04

Source: Ventyx Velocity Suite and Supply Analysis Office staff analysis.

For California, Arizona, and Nevada, staff's burner tip price estimates are consistently lower than the Ventyx historical prices, but all three show similar trends in their historical burner tip prices. However, other than the 2005 price spike resulting from hurricanes Katrina and Rita, and the 2008 price spikes, both of which could not be predicted years in advance, and the last year of the backcast, staff's burner tip price estimates fit reasonably well with Ventyx historical prices. Beginning in 2012, staff's price estimates increase, while the Ventyx history shows prices decreasing.

Figure B-6 illustrates these findings for California. These differences are to be expected because the *2013 Outlook*, which provides the commodity prices used in the Energy Commission burner tip model, relies for its price estimates on the NAMGas, a long-run model that estimates average annual prices; it is not designed to predict short-term price movements based on unexpected weather events, pipeline shutdowns, or other unpredictable short-term phenomena. These and other differences are also due to the fact that all forecast models simplify actual market behavior, including the abstraction of variables from the markets they simulate. For example, one gas price is estimated for all electric generators in a given region and year, but this is an abstraction of the reality, which is that their prices will vary, and their gas costs are based on purchases on contract, on different markets, and through other means where the prices vary. Abstraction of variables is one type of simplification that all models, including the NAMGas model, must observe. Computer-based models do not have the power to estimate gas prices, supply or demand with the temporal, geographic, economic, and other aggregations that are found in real markets. However, staff expects to populate and run the NAMGas model on a monthly time frame to incorporate more short-term factors, such as weather-driven demand, supply shocks, and natural gas storage. This initiative will provide more realistic, yet still far from perfect, simulation of gas markets.

Figure B-6: Backcast of California Natural Gas Burner Tip Prices

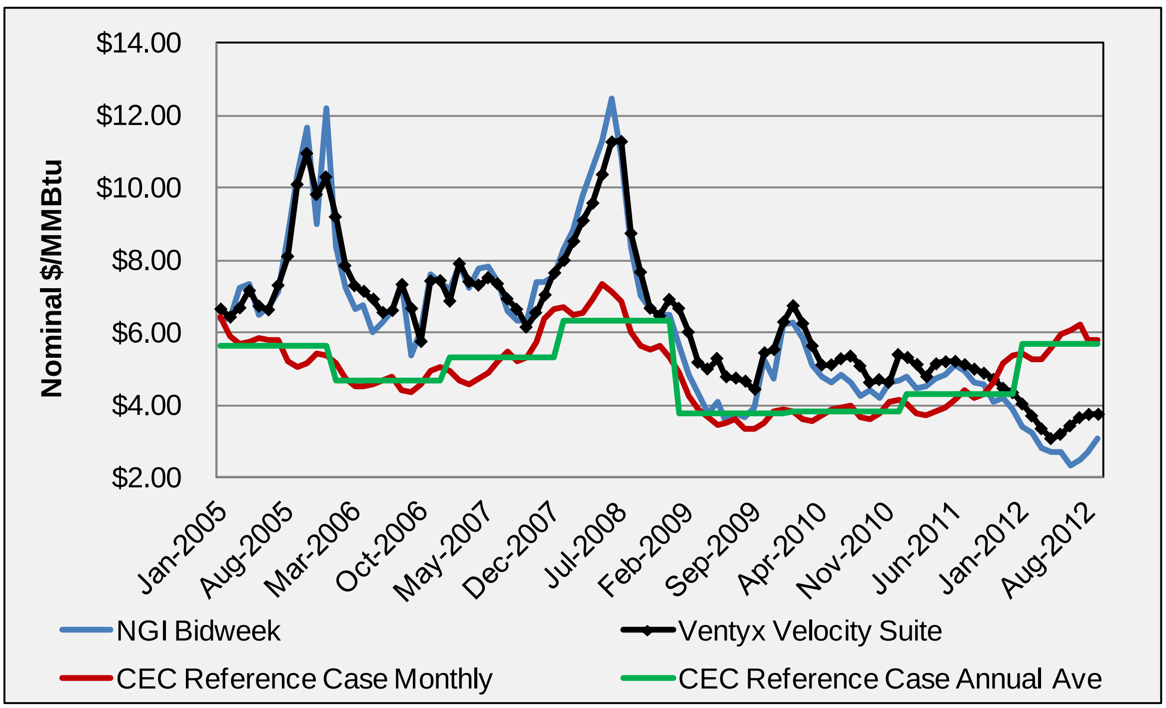


Source: Ventyx Velocity Suite and Supply Analysis Office staff analysis.

Because staff's price estimates showed some difference from the Ventyx historical prices, staff added to the comparison burner tip price estimates that use historical bidweek prices to represent the commodity price of natural gas and the same transportation rates that staff used in its burner tip price estimates. Historical bidweek prices come from *Natural Gas Intelligence*. Bidweek prices are used as a reasonable assumption for how most natural gas is procured, even though a lot of gas is procured on the daily spot market, on contract, or through other arrangements. For Northern California, the PG&E citygate price was used, while for Southern California, the SoCal Border price was used. Staff may make similar comparisons in the future with other subregions in the WECC.

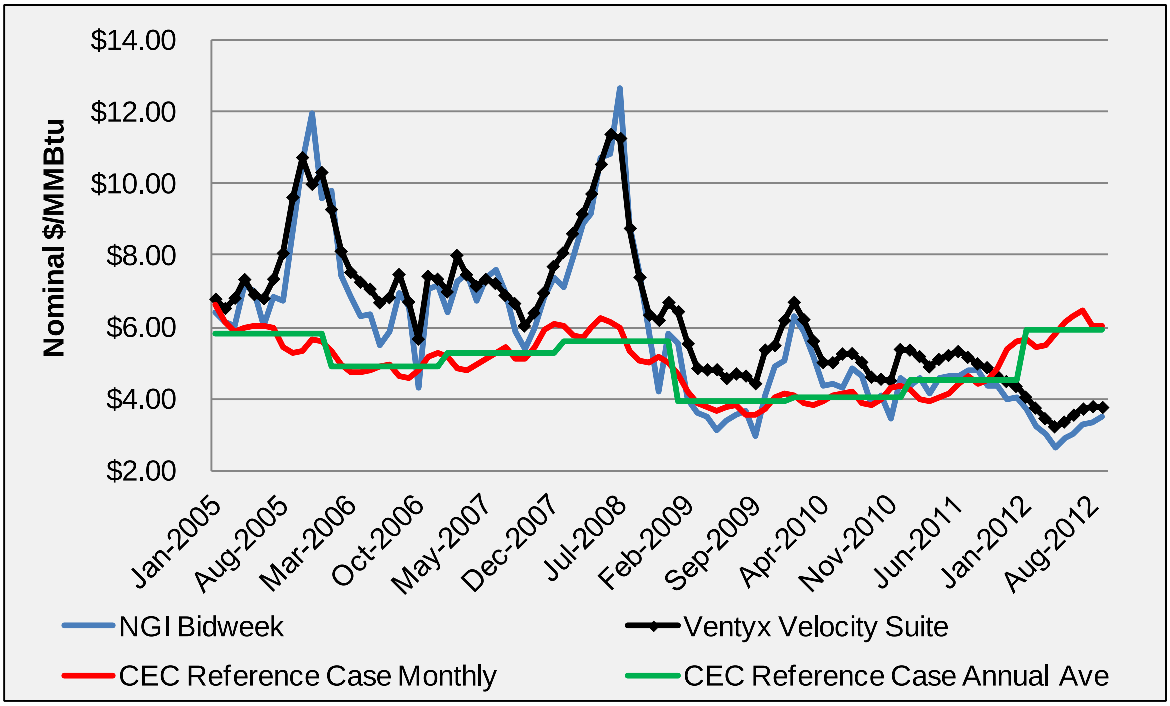
As expected, the burner tip price estimates using the bidweek commodity prices fit acceptably with the Ventyx historical burner tip prices. **Figure B-7** and **Figure B-8** illustrate these findings. These results are similar for Arizona and Nevada as well. **Figure B-7** and **Figure B-8** both suggest that the bidweek price is a good approximation of how much gas-fired generators pay for the commodity portion of the burner tip natural gas price.

Figure B-7: Northern California Burner Tip Prices, Ventyx vs. Energy Commission



Source: Ventyx Velocity Suite and Supply Analysis Office staff analysis.

Figure B-8: Southern California Burner Tip Prices, Ventyx vs. Energy Commission



Source: Ventyx Velocity Suite and Supply Analysis Office staff analysis.