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Are Natural Gas Flows Responsive to Price Spikes?

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Differences in natural gas prices between pricing centers in California and other locations in the North American network have displayed, in the last few years, values that are difficult to justify in terms of traditional spatial price equilibrium models. Here, we document those extreme values and offer some explanations.

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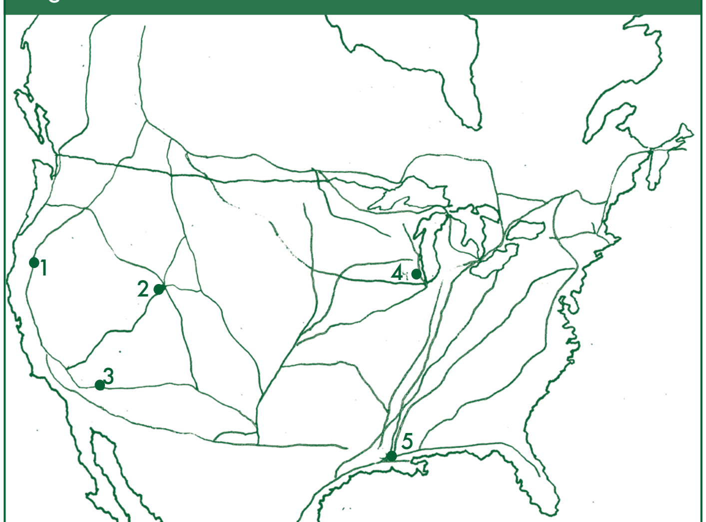
Economics of Sudden Oak Death Control
Alix Peterson Zwane and Jesse Tack

Even though most observers have concentrated on the worldwide increases in the price of energy in the last few years—spot prices of natural gas are now in the range of 6-8 $/MMBtu (million British thermal units), far above the 2-3 $/MMBtu of six or seven years ago—the spatial patterns in the price increases have been interesting in their own right, especially involving natural gas in California relative to elsewhere. Spatial differentials involving California have often been much too large to be justified in terms of transportation costs. Those large differentials have not always been to California's disadvantage. For much of early 2005 (and again in early 2006), price differentials were such that California should have been exporting natural gas, although it continued, of course, to import. Some of the explanation for these oddities can be found in capacity constraints in pipelines, in inventory availability, in changing seasonal needs, and in the pervasiveness of long-term contracts. However, not all price differentials make sense, at least not with the conventional concept of spatial price equilibrium.

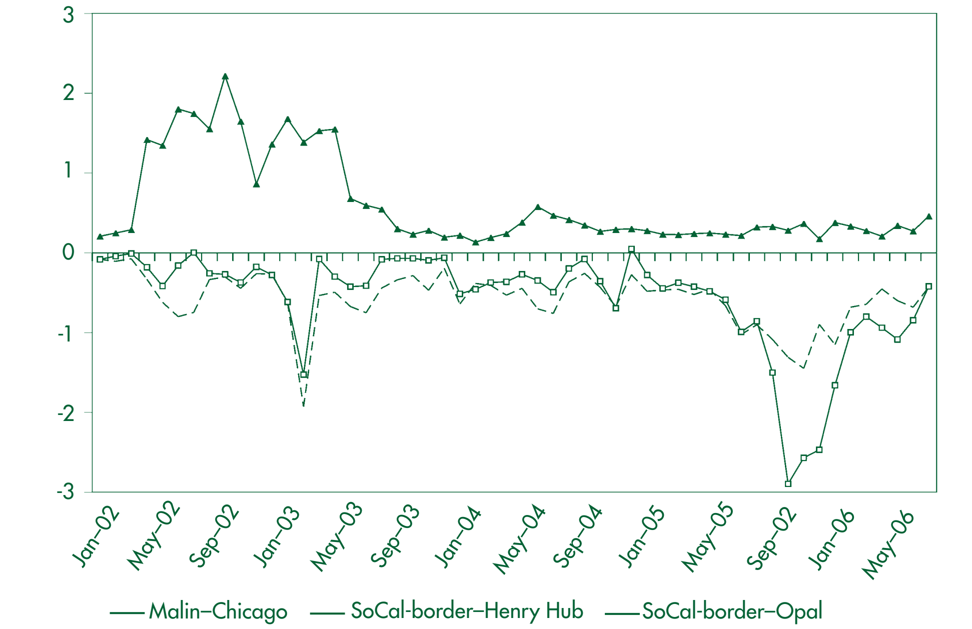
Figure 2 displays the evolution over the last four years of price differences involving locations at the California border and three selected pricing points within the North American network. These points are marked on the map in Figure 1. Opal, which is a gathering hub from producing wells, is representative of the price of gas produced in the Rocky Mountains, much of which flows to California. Whereas the Opal hub has direct connections to California; for the other two, the connections are indirect. Chicago citygate and Henry Hub, which is the crossing point for many pipelines in southern Louisiana, compete with California for gas from Alberta and from the Permian Basin in west Texas respectively. The circumstances behind

Figure 1. United States Natural Gas Network and Hubs



1. Malin 2. Opal 3. SoCal-border 4. Chicago Citygate 5. Henry Hub

Figure 2. Selected Natural Gas Price Differentials (January 2002 – June 2006)



each of the three extreme peaks and troughs in Figure 2 are different. We describe each of them and investigate whether flow volumes into California adjusted to these extreme changes in the relative value of gas elsewhere.

Behavior of Spatial Price Differences

From 2002 through 2006, prices were higher at the Southern California border than at Opal, which is consistent with the latter being located in a producing area and California importing gas from there. The large spatial differential observed for this series in 2002 was due to capacity constraints in the Kern River pipe-line—the pipeline that brings Rockies gas to Utah, Nevada, and California. That pipeline's capacity doubled in the spring of 2003 at which point the price difference decreased abruptly: from more than 1.00 $/MMBtu to an average 0.32 $/MMBtu after May 2003.

Does the 0.32 $/MMBtu difference prevailing after May 2003 itself makes sense? According to the published tariff, the variable cost per MMBtu transported in the Kern River pipeline is 0.06 $/MMBtu, much below $0.32. The compressors burn some of the natural gas to push the rest along the pipeline. Thus, in order to calculate the minimum price differential for which transporting gas from the Rockies to California is economical, fuel losses incurred by compressors during transportation must also be included. The percentage loss depends on the number of compressors, which is a function of miles traveled. For gas coming to California, the loss is approximately three percent which, given price levels, amounts to about 0.15 $/MMBtu. Thus, the total variable cost per unit of gas is on the order of 0.21 $/MMBtu, which is slightly below but comparable to the observed post-expansion price differences in Figure 2. After May 2003, the prevailing 0.32 $/MMBtu difference seems to make sense. The pre-expansion differential is therefore the implicit price of the capacity constraint.

Whereas the SoCal border–Opal differential has always been positive, the spatial differentials with respect to consuming centers east of the Rockies have usually been negative, as is the case for the other two series in Figure 2. Chicago competes with California for Canadian gas and is willing to pay higher prices, hence the negative difference. As for the third series in Figure 2, gas produced in the Permian Basin in west Texas can be directed either east or west. Natural gas in California typically trades at a discount relative to the Henry Hub, providing one more indication of the higher willingness to pay for gas in eastern than in western markets.

Prices in California and competing markets east of the producing areas departed considerably on two occasions during this period. First, in February of 2003, spot prices skyrocketed in Northeastern markets due to a cold snap at the end of a colder-than-normal winter in that region. At the New York citygate, for example, the spot price on February 25, 2003 was 25.67 $/MMBtu. However, one week before it had been 10.11 $/MMBtu and one week after it was back down to 9.58 $/MMBtu. Second, Hurricane Katrina had a great and lasting impact on natural gas prices. The Henry Hub price was 9.86 $/MMBtu

Table 1. Trend, Seasonality, and Spikes on the Selected Price Differentials

	Constant	Trend	Season	February 2003	post-Katrina	R-squared
SoCal-border–Opal	**1.097** (4.124)	0.004 (0.740)	**0.321** (2.323)	0.236 (1.059)	–0.030 (–0.361)	0.73
Malin-Chicago Citygate	**–0.249** (–3.176)	**–0.006** (–2.514)	**–0.177** (–3.099)	**–1.603** (–30.711)	**–0.596** (–9.158)	0.72
SoCal-border–Henry Hub	0.018 (0.211)	**–0.014** (–4.915)	–0.103 (–1.175)	**–1.361** (–21.519)	**–1.720** (–8.444)	0.83

Note: t statistics are in parentheses. Coefficients in bold are significant at the 5% level.

the last trading day before the hurricane hit the coast of Louisiana on August 29, 2005 and climbed up to 12.35 $/MMBtu the day after.

The 25 percent increase at the Henry Hub brought about by Katrina rippled throughout the country and became amplified on eastern markets and muffled in western markets. For instance, the New York and Boston citygates experienced 33 percent and 32 percent price increases, respectively. On the other hand, prices increased by 17 percent at Opal and by 15 percent at the Southern California border. As shown in Figure 2, the price difference between Henry Hub and California pricing points fell dramatically and took long to recover. The Malin–Chicago difference also experienced a plunge, although it was smaller in magnitude.

Spatial Prices and Flows of Natural Gas

Given the magnitude of the price differences in February 2003 and late 2005, economic models of spatial price equilibrium would surely predict a reversal in flow. In practice, the flexibility of flow patterns will depend on the number of arbitrage paths in the network and the portfolio of market services available to customers.

The North American natural gas pipeline and storage network is highly developed, with over 70 trading points and almost 400 underground storage facilities spread throughout the United States and Canada. The New York Mercantile Exchange (NYMEX) offers an actively traded natural gas futures contract which calls for delivery at the Henry Hub. As liquidity in spot and futures markets increased over the last decade, the extent to which long-term contracts are used for purchasing natural gas has decreased. A large proportion of natural gas purchases and transportation decisions are taken during the last five business days of each month—the so-called bidweek—for gas flowing the following month. Subsequent adjustments to the monthly commitments can be made through additional transactions in the daily spot market. Every producing region has alternative destinations to which it can send its gas and every market center can obtain its gas from alternative sources. Thus, producers and buyers can arbitrage spatial price differentials to the extent that capacity limits and institutions permit.

To assess if actual molecules of natural gas are flowing toward the areas in which they are most highly valued at each moment in time, we examine spatial price differentials and flow patterns focusing on events that triggered acute price spikes during the period of analysis, namely January 2002- June 2006. Table 1 emphasizes trends and seasonal factors in the price differences. The negative gaps between Malin and Chicago, and between SoCal-border and the Henry Hub, have widened over the period of analysis. No statistically significant seasonality can be found in the SoCal-border–Henry Hub differential. For the other two series, however, relative prices shift from the injection season to the winter months. The price difference between Malin and Chicago decreases by 0.17 $/MMBtu during the injection season, while the difference between SoCal-border and Opal increases by 0.32 $/MMBtu during that same period. By a relative seasonality argument, we should expect Canadian flows to the West Coast to be relatively smaller during the injection season than during the winter months and Rockies flows to California to be relatively higher during the summer.

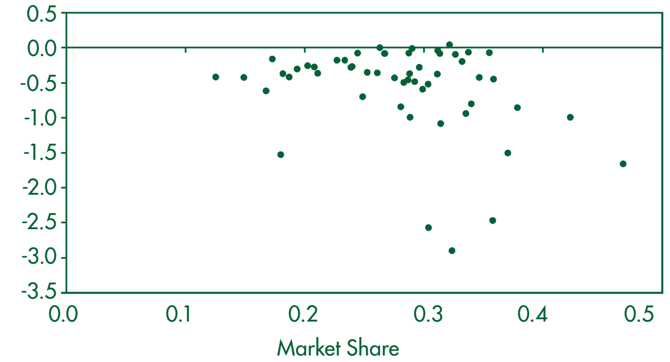
The magnitude, trend, and seasonal factors of market-share series representative of the competition between eastern and western market centers for each of the producing regions serving California are summarized in Table 2. These regressions also control for the effects of the cold spell in the winter of 2003, the abrupt change in prices triggered by Hurricane Katrina and, in the regressions involving to the Rockies, for the Kern River pipeline expansion.

The constant in the regressions presented in Table 2 can be interpreted as the baseload market share that deliveries on westbound versus eastbound pipelines represent for each of the producing regions. Market shares on Canadian gas imports by states on the Pacific Coast versus the Midwest are similar and have remained stable over the period considered. However, a much larger proportion of gas exports from the Rockies and the Permian Basin goes to eastern rather than western

Table 2. Trend, Seasonality, and Effect of Price Spikes on Selected Market Shares

	Constant	Trend	Season	February 2003	post-Katrina	R-squared
Canada–West	**0.1817**	–0.0003	**–0.0150**	**–0.0649**	–0.0156	0.27
	(22.543)	(–1.388)	(–2.181)	(–9.350)	(–1.474)	
Canada–Chicago	**0.2073**	0.0002	**0.0116**	**0.0284**	**0.0079**	0.26
	(38.488)	(1.522)	(2.359)	(5.821)	(2.051)	
Rockies–West	**0.2537**	**–0.0015**	**0.0262**	–0.0106	0.0059	0.89
	(23.729)	(3.911)	(3.023)	(–1.197)	(0.784)	
Rockies–East	**0.4359**	0.0008	**0.0289**	0.0013	**–0.0208**	0.55
	(43.792)	(1.811)	(3.302)	(0.164)	(–2.205)	
Permian–West	**0.2338**	**0.0025**	**–0.0380**	**–0.0868**	–0.0330	0.52
	(9.269)	(4.374)	(–2.442)	(–4.601)	(1.466)	
Permian–East	**0.5408**	**–0.0032**	**0.0806**	**0.0871**	–0.0076	0.66
	(18.616)	(–4.539)	(4.919)	(4.139)	(–0.350)	

Figure 3. Share of Permian Exports Going West versus West–East Price Differential



states. The western market share has trended upwards for Permian gas but downwards for gas from the Rockies.

Seasonality in market shares is strong and consistent with what spatial price equilibrium models would predict given the seasonality in price differences presented in Table 1. Deliveries of Canadian gas to the western states, and to California in particular, decrease during the injection season as the premium that eastern markets are willing to pay over California is higher at that time of year. For Rockies gas, the seasonal shift is positive in both the eastern and western directions implying that the remainder (namely northbound exports) go down during the summer months. For Permian gas, even though no statistically significant seasonality appears in the price difference, the share of gas flowing toward eastern markets increases during the summer months.

The short-lived price spike observed in February 2003 had a larger effect on flows than the sustained increase in the East–West difference that followed Hurricane Katrina. In February 2003, western market shares in Canadian and Permian exports decreased by six and eight percentage points, respectively, relative to what would be normal at that time of the year. However, no statistically significant effects are observed for westbound flows in the September–December 2005 period despite the significant widening of the gap in California versus Chicago and Henry Hub prices. The different reaction of markets to these two events is puzzling, at least at first glance.

A combination of magnitude and timing of price increases can provide some explanation. All months in the winter of 2003 had been colder than normal, prompting large withdrawals from storage. So when temperatures plunged at the end of February, not much gas was left near the market centers where heating demand was peaking. Thus, all the adjustments had to come through reallocation of pipeline flows. The average daily flow received in California from Canada during the week of February 24–28, 2003 was 38 percent lower than the average daily flow in that path for the whole winter. Meanwhile, the average daily deliveries from the TransCanada pipeline into the Northeast were 67 percent higher than the average for the whole winter. Also, the price increases observed on those days in February 2003 were much larger than those observed in the aftermath of Hurricane Katrina. The hurricane hit near the end of the injection season when all storage facilities were close to full. Apparently, the magnitude of the spatial differences—given the inventory situation—was not enough to trigger a large redirection of flows.

Figure 3 shows, at most, a weak relationship between western bound flows from the Permian Basin and a price difference—SoCal-border minus Henry Hub. This differential is representative of relative competition between market centers located east and west of the Permian Basin. To analyze price responsiveness of flows toward California, we estimated elasticities of the corresponding residual supply curves that California faces for Canadian, Rockies, and Permian gas. According to that analysis, flows toward California are inelastic (that is, unresponsive) to changes in the relevant spot price difference beyond seasonal changes, reflecting the strength of demand in the California market versus competing locations.

In sum, the effect on California of a weather shock elsewhere, such as a hurricane or a cold snap, depends very much on where in the continent-wide network it happens and when. The fact that only a small portion of total natural gas flows is traded in the daily spot market, paired with inflexible end-use demand levels, limits the ability to modify flow decisions in response to short-lived spatial arbitrage opportunities. Pipeline capacity constraints and requirements to maintain operating pressure are additional factors to explain the resistance to move away from planned flows. Also, the possibility of injecting or withdrawing gas weakens the link between prices and flows. When storage cannot be used as a buffer (which happened in February 2003) observed behavior shows that it is feasible to reallocate large volumes on short notice, but only with substantial changes in price.

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