Market efficiency, cross hedging and price forecasts: California's natural-gas markets

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Abstract

An extensive North American pipeline grid that physically integrates individual natural-gas markets, in conjunction with economic ties binding the California markets to those at Henry Hub, Louisiana and the New York Mercantile Exchange via an array of financial instruments, suggests that the spot prices at Henry Hub will impact those in California. We verify the suggestion via a partial-adjustment regression model, thus affirming that California traders can exploit the cross-hedging opportunities made available to them via market integration with Henry Hub, and that they can accurately forecast the price they will have to pay to meet future demand based solely on the price of futures at Henry Hub and the price of a California natural-gas basis swaps contract.

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1. Introduction

Natural-gas market reform and deregulation has been an on-going process for almost two decades, resulting in the emergence of wholesale spot markets that span North America [1]. Previous empirical evidence supports the hypothesis of market integration and price convergence across these markets [2-8]. That evidence notwithstanding, *California's* natural-gas price skyrocketed from nearly \$5 per million British thermal units (MMBtu) to over \$50/MMBtu from November to December 2000 [9], a ten-fold increase that far exceeded the contemporaneous rise in spot prices at Henry Hub in Louisiana, the nation's largest natural-gas spot market.

Notwithstanding the pipeline explosion in New Mexico in August 2000 [13], the California natural-gas price spike has been attributed to dysfunction in the state's natural-gas markets that "fed off misconduct, including gas transaction misreporting and wash trading." [10, p. 3]. Since the end of the California energy crisis in June 2001, however, California's natural-gas spot markets have once again been relatively calm. This suggests that the California market dysfunction is an isolated event, at odds with the economic ties that directly bind the California markets to those at Henry Hub, including the futures market operated by the New York Mercantile Exchange (NYMEX), comprise a variety of financial instruments, including swaps, basis contracts, and futures contracts.

As shown in Fig. 1, the physical ties evolving from the pipeline grid both directly and indirectly link the California markets to those throughout North America, including Canada. These economic and physical ties lead us to posit that the California electricity and natural-gas crisis period was an intermediate-term two-pronged aberration from the long-term tendency of those gas markets to behave efficiently, insofar as their spot-price movements are linked to those at Henry Hub. And if the California natural-gas markets are efficient, this opens up the possibility of traders taking advantage of the aforementioned financial instruments in order to inure themselves from the risks that go along with reliance on potentially volatile natural-gas spot markets.

We address these issues simultaneously through a single-equation partial-adjustment regression model that pays due obeisance to a California trader's ability to cross hedge via the Henry Hub futures market. Admittedly simple, the model parsimoniously characterizes the California natural-gas price behavior. A case in point is the energy-crisis issue. Based on the Federal Energy Regulatory Commission's (FERC) 2003 report [10] on price manipulation in the Western markets and the chronology of events detailed by various researchers [8, 11-15], the model incorporates dummy variables to account for each of the prongs, notably, the electricity-crisis period from May 2000 to June 2001, and the natural-gas crisis period from November 2000 to May 2001 and estimates the dollar impact of these crises on the daily spot prices in two California gas markets: PG&E Citygate and SoCal Gas (Topock).[1]

With regard to the market-efficiency and cross-hedging issues, the estimated regression coefficients enable us to infer that, except for the aberrant period identified by the FERC [10] and other researchers [8, 11-15], California's natural-gas spot markets have indeed been efficient, with prices in those markets moving in synch with those at Henry Hub. The inference, in turn, has important implications for traders in two related regards. First, California traders can accurately forecast the price they will have to pay to meet future demand based solely on the futures price at Henry Hub, or in tandem with the price of a California natural-gas basis swaps

[1] One can econometrically identify the crisis periods by solving for the crisis' beginning and ending dates that minimize (maximize) the regression model's sum of squared errors (likelihood function). We did not do so because of (a) the evidence already documented in the extant literature on the California energy crisis; and (b) the unlikely gain in insights from such an econometric exercise. As will be seen in Section 5, our choice of crisis periods yields estimates of the anomalous increases in California natural-gas prices that are close to those found by FERC [10].

contract when such is traded. Second, traders in California's spot markets can cross hedge via the NYMEX futures market for Henry Hub delivery in order to reduce their exposure to the risk entailed in the price volatility common to commodity markets in general.

2. Modeling considerations

Natural-gas traders are concerned with both the current spot price, P, at which they may have to acquire gas and the price they will pay to meet demand at some future time t, P_t. They may, however, have the option of locking in the latter price through the purchase of one or more fixed-price forward contracts. NYMEX, for example, has been offering monthly natural-gas futures contracts since April 1990, with the future currently extending as far as a 72-month time horizon. Moreover, in addition to being able to purchase natural-gas futures for delivery in an external market such as Henry Hub at a fixed price of P_{F} per MMBtu, NYMEX also offers to traders buying gas in local markets such as PG&E Citygate or SoCal Gas natural-gas swaps contracts at a price of P_{SF}. In this case, the trader has a perfect forecast of the time-t price:

$$P_{\mathrm{F}t} = P_{\mathrm{SF}} + P_{\mathrm{F}}. \tag{1}$$

To determine whether the trader will actually be willing to pay that price at time t, consider a spot-price regression that relates the spot price for a local delivery location without forward/futures trading, such as PG&E Citygate, and the spot price $P_{\mathrm{E}t}$ in an external market with forward/futures trading, such as Henry Hub:

$$P_t = \alpha + \beta P_{\mathrm{E}t} + \varepsilon_t. \tag{2}$$

Here, α and β are coefficients to be estimated, and ε_t is a random-error term with the usual normality properties, including zero mean and finite and constant variance $\sigma^2 > 0$.

Buyers can cross-hedge their costs per MMBtu by going to the external market, buying β MMBtu of forward gas at the fixed price of P_F, taking delivery at future time t, and then selling β MMBtu in that external market at the market's spot price of P_{Et}. The buyer thus earns a profit of $\beta(P_{Et} – P_F)$. The buyer that pays P_t in the local spot market therefore has a *net* cost per MMBtu of $P_t - \beta(P_{Et} – P_F) = \alpha + \beta P_{Et} + \varepsilon – \beta(P_{Et} – P_F) = \alpha + \beta P_F + \varepsilon.$ The net-cost variance is the $\sigma^2 > 0$ that cannot be reduced by cross hedging.

If $P_{Ft} < \alpha + \beta P_F$, the buyer's expected profit per MMBtu is $(\alpha - P_{SF}) + (\beta - 1)P_F$. The buyer earns that profit by purchasing basis swap contracts at a cost of P_{SF} and external-market futures at a price of P_F, and selling natural-gas forward to another trader at a price of $\alpha + \beta P_F$. Conversely, if $P_{Ft} > \alpha + \beta P_F$, a trader can cross-hedge the local-market spot price and sell both basis swap contracts and Henry Hub futures contracts so as to earn an expected positive profit of $(P_{SF} - \alpha) + (1 - \beta)P_F$ per MMBtu. Since a positive expected profit cannot persist in a market with active spot and futures trading, in order for Eq. (2) to hold it must be true that $\alpha = P_{SF}$ and $\beta = 1$, in which case Eq. (1) provides a perfect natural-gas price forecast.

The estimates of α and β, denoted by a and b, are obtained through a partial-adjustment model that is a variation on a theme explicated in detail in [16, 17]. Using the present notation, that model permits one to infer a and b from the parameter estimates of Eq. (3):[2]

$$P_t = \theta + \gamma P_{Et} + \phi P_{t-1} + \mu_t. \tag{3}$$

[2] Eq.(3) is a linear specification as implied by the law of one price and the economic reality that traders' cross-hedging strategies are based upon the prices in the separate markets rather than upon the logarithms of those prices. The linear specification thus allows for a straightforward test of the market-efficiency hypothesis of $\alpha = 0$ and $\beta = 1$ under negligible transportation costs. That being said, we acknowledge that others (e.g. [7]) have explored the market-integration issue through a log-linear specification, albeit not with our hedging perspective. In recognition of that alternative, we also estimated the regression models reported in Section 4 in log-linear form. At least in terms of the signs of the parameter estimates and their statistical significance, as well as corresponding tests on the residuals, there was nothing to distinguish the linear and the log-linear specifications.

Here, $\theta = \alpha\,\lambda$, $\gamma = \beta\,\lambda$, $\phi = (1 - \lambda)$, and $\mu_t = \lambda\varepsilon_t$; where $0 \leq \lambda \leq 1$ measures the extent to which daily prices adjust to an unobservable long-run equilibrium price for that day, with $\lambda = 0$ implying a complete lack of adjustment and $\lambda = 1$ implying instantaneous adjustment.

When μ_t has the familiar white-noise properties that we would like to ascribe to a random-error term, using ordinary least squares (OLS) to estimate Eq. (3) will yield unbiased and precise coefficient estimates so long as the random errors, μ_t, are not serially correlated. To allow for the possibility of serial correlation in which the random-error term follows a k^{th}-order autoregressive process, AR(k), we set $\mu_t = \Sigma_j\rho_j\mu_{t-j} + \omega_t$, where ω_t is white noise (with the desired normality properties) and $j = 1,\ldots, k$ [18, Chapter 10]. We then substitute $\mu_t = \Sigma_j\rho_j\mu_{t-j} + \omega_t$ into Eq. (3) and estimate it using the maximum likelihood (ML) procedure, thus avoiding any potential bias caused by the possible correlation between P_{t-1} and μ_t.

3. Data

Fig. 2 shows daily natural-gas prices at PG&E Citygate and SoCal Gas for the historical period that spans our sample data: namely, some six years in the former and eight years in the latter case. These data span the energy-crisis periods for the Western electricity and natural-gas markets. Fig. 2 indicates relatively stable gas prices of under \$10/MMBtu, except for the natural-gas-crisis period of November 2000 to May 2001 when daily prices at times exceeded \$50/MMBtu.

Fig. 3 shows electricity prices at South of Path 15 (SP15) and North of Path 15 (NP15), the two major delivery points in California's wholesale electricity market. This figure shows that the daily peak period (06:00-22:00, Monday-Saturday) electricity prices were typically below

\$100/MWh, except during the electricity-crisis period of May 2000 to June 2001 when the prices at times exceeded \$500/MWh.

To capture in our model the effects of these two known crises, we introduce into Eq. (3) a pair of binary independent variables: (a) $C_{\mathrm{el}} = 1$ during the electricity-crisis period of May 2000 to June 2001, and zero otherwise; and (b) $C_{\mathrm{ng}} = 1$ during the natural-gas crisis period of November 2000 to May 2001, and zero otherwise. The crisis indicators isolate the price effect of these two unusual events characterized by extreme weather, capacity shortage, market-power abuse, and falsely reported natural-gas prices [10-15, 19]. Thus, we apply ML estimation to the following regression equation:

$$P_t = \theta + \kappa_1 C_{\mathrm{el}} + \kappa_2 C_{\mathrm{ng}} + \gamma P_{\mathrm{E}t} + \phi P_{t\text{-}1} + \Sigma_j \rho_j \mu_{t\text{-}j} + \omega_t. \tag{4}$$

The estimate of κ_j is denoted k_j and that of ρ_j is denoted r_j. The estimates of θ, γ, ϕ, and λ are denoted f, g, h, and l, respectively.

Two sets of data provided by Platts comprise our two samples of observations for the dependent variable. The first sample contains 1,930 daily PG&E Citygate volume-weighted average prices for the period of May 1998 to mid-August 2003. The second sample contains 2,598 daily SoCal Gas (Topock) volume-weighted average prices for the period of July 1996 to mid-August 2003. Corresponding observations are available for the daily Henry Hub volume-weighted average spot prices. Although "the quality of reporting to price index developers (including Platts) improved substantially" after 2002 [19, p. 2], some of the earlier data, most notably during the energy crisis, reflect trade manipulation and gaming the market by large traders such as Enron. Insofar as any "epidemic" of false reporting impacts our estimates, one would expect that impact to detract from our ability to draw statistically-significant conclusions that support our model. As will be seen, however, this does not appear to be the case.

Table 1 reports summary statistics for the prices at PG&E Citygate, SoCal Gas and Henry Hub, for the full sample as well as for sub-samples of the pre-crisis, crisis, and post-crisis periods. The summary statistics reveal that during the full sample period the California spot-market prices tended to be both higher and more volatile than were the Henry Hub prices, while being moderately correlated ($0.70 \leq r \leq 0.73$) with those at Henry Hub.

Prior to going forward with the ML estimation of Eq. (4), it is first necessary to assure that the time series for the two economic variables in the equation, P_t and $P_{\mathrm{E}t}$, are stationary. Were they otherwise, this would violate an underlying assumption of regression analysis and lead to what Granger and Newbold [20] dubbed a spurious regression whose high coefficient of determination and t statistics belie any true economic meaning. The acknowledged test for stationarity is the Augmented Dickey-Fuller test [21], the results of which are also reported in Table 1. The critical value of the Augmented Dickey-Fuller (ADF) statistic for our sample sizes of $n_1 = 1{,}930$ and $n_2 = 2{,}598$ is –2.86 ($p = 0.05$) [18, p.708, Table 20.1]. An ADF test statistic below –2.86 allows us to reject the hypothesis that the time series is not stationary and has a unit root.

The ADF statistics in Table 1 are computed with one lagged difference, a non-zero mean (drift), and no trend. We have also run this model using the Phillips-Perron test [22] and the statistical inferences are precisely the same.[3] We have also run alternative versions of both tests, with trend, and with lagged differences of up to ten days, and verified that our results and the inferences are robust, insensitive to the specification of either the Dickey-Fuller fundamental "testing" equation or the test employed. We therefore conclude that none of the three price series is non-stationary, either before the electricity crisis or over the entire sample period – from mid-1998 for PG&E City gate and from mid-1996 for SoCal Gas, through mid-August 2003. This empirical evidence of stationary price series' is an exception to the common finding in extant literature [e.g., 3-7] that energy prices typically follow a random walk. We do not have a ready explanation for this exception, other than the fact that our data series cover a more recent sample period that extends from the mid 1990s to August 2003.

We cannot, however, reject the unit-root hypothesis for either the PG&E Citygate or SoCal Gas time series after the electricity crisis, or for the Henry Hub sequence of prices during the crisis. Though only present in the sub-periods, non-stationary price series raise the possibility that our regression results may be spurious [18, 20-24]: the estimated version of Eq. (4) indicates an apparently significant relationship between California and Henry Hub natural-gas prices when in fact no such relationship exists. Hence, our estimation of Eq. (4) will include a cointegration test of the null hypothesis that the regression residuals follow a random walk [18, Chapter 20],

[3] We ran these additional tests in response to the urgings of a referee whom we thank for helping us to solidify our confidence in the results and their implications. Our focus on the ADF test statistics rather than the Phillips-Perron test statistics is prompted by Green's [23, p. 645] observation that "[t]he Dickey-Fuller procedures have stood the test of time as robust tools that appear to give good results over a wide range of applications. The Phillips-Perron tests are very general, but appear to have less optimal small-sample properties." Assuredly, with our large-sized samples the latter qualification would not apply.

causing spurious regression results due to the California and Henry Hub natural-gas prices drifting apart without limit over time.

Both before and after the crisis, the differences between the average prices and their standard deviations for the three markets are quite modest, which suggests that the higher overall means and standard deviations for the California markets relative to those at Henry Hub is an aberration of the crisis period. The lowest correlations, which range from 0.57 to 0.66, of the California-market prices with those at Henry Hub also occur during the crisis period, hinting at a market disconnection during this period, which reduces the correlation coefficients for the entire sample.

4. The estimated regression coefficients

4.1 PG&E Citygate

Table 2A reports the estimated coefficients for four autoregressive-error forms of the PG&E Citygate price regression: AR(1), AR(2), AR (3), and AR(4). The numbers in parentheses are the respective *t*-ratios. With almost identical root-mean-squared-errors, all four regressions explain at least 96% of the PG&E Citygate price variance, suggesting that the NYMEX natural-gas futures is an effective hedge instrument. The likelihood (LLH) ratio test results and the Akaike information criterion (AIC) values indicate that the errors may follow an AR process of the fourth or higher order. With the exceptions of the intercept, the electricity-crisis indicator, and one AR(4) parameter ($r_3 = 0.009$), all of the coefficient estimates are statistically significant ($p < 0.05$).

The estimates for any single regression parameter vary across the four AR specifications. Irrespective of the AR specification, however, the values for h are highly significant. Since the corresponding values for l are determined from $l = 1 - h$, when h is significantly different from zero, l is significantly different from one and decisively rejects the instantaneous-adjustment hypothesis.

To illustrate the sensitivity of the estimates to AR specification, consider the estimated coefficients for l: namely, $l = 1 - 0.779 = 0.221$ under the AR(1) specification, $l = 0.297$ under the AR(2) specification, $l = 0.322$ under the AR(3) specification, and $l = 0.144$ under the AR(4) specification. Based on $(1 / l)$ which is an estimate of $(1 / \lambda)$, the corresponding numbers of days required for the local market to regain a perturbed equilibrium are 4.5, 3.4, 3.1, and 6.9, respectively. The speed with which the market returns to the local equilibrium price suggests it is feasible to apply the equilibrium-price condition for the purpose of forecasting prices for an extended period of time, say over a year.

The combined effect of the electricity crisis and the natural-gas crisis on the daily spot price is the sum of the estimated regression coefficients, k_1 and k_2. This effect ranges from a high of $k_1 + k_2 = 0.248 + 1.441 = \$1.689$ per MMBtu for the AR(3) specification to a low of 0.079 + 0.696 = \$0.775 per MMBtu for the AR(4) specification. At the market equilibrium, the effect is magnified by a factor of $1/l$. Taking the four values of l into account gives estimates of 1.15/0.221 = \$5.20 per MMBtu for the AR(1) specification, 1.55/0.297 = \$5.20 per MMBtu for the AR(2) specification, 1.690/0.322 = \$5.25 for the AR(3) specification, and 0.775/0.144 = \$5.38 per MMBtu for the AR(4) specification. This large effect confirms the earlier hint that during the energy-crisis period, the PG&E Citygate market disconnected from the Henry Hub market. In all four cases, however, k_2 dwarfs k_1, so that only a minor portion of the rise in natural-gas prices during the energy crisis can be attributed solely to the electricity crisis.

Further support for our assertion that except for the crisis periods, the PG&E Citygate and Henry Hub prices are cointegrated is provided by the ADF statistics on the residuals from the four regressions. These statistics enable us to reject the null hypothesis that the residuals follow a random walk and have a unit root [18, Chapter 20].

Table 2A suggests that the estimates are sensitive to the AR error specification. If this sensitivity extends to a and b in the market-equilibrium condition, it forces us to question the validity of using cross hedging to develop a natural-gas price forecast. Hence, we test the hypothesis that neither α nor β varies by AR error specification. If the data do not reject this hypothesis, we can safely conclude that the equilibrium-price condition is robust and suitable for developing a market-based natural-gas price forecast.

Table 2B presents the results of testing two null hypotheses: $\alpha = 0$ and $\beta = 1$. The former tests the hypothesis that the basis differential is equal to zero. The latter tests the hypothesis that the PG&E Citygate and Henry Hub natural-gas markets are efficient without persistent arbitrage profit; and with β equal to unity being the optimal hedge ratio, which would be the case when the traders' objective is to use hedging to minimize the price variance [25]. Neither of the null hypotheses can be rejected at even the loosest of possible rejection standards ($p = 0.75$, say), irrespective of the AR specification. Assuredly, on any given day the basis swaps price might deviate from zero. Our estimate of $a \approx 0$ is the average basis swaps price for the sample period, which fails to reject the hypothesis that $\alpha = 0$. Fig. 4, for example, displays the NYMEX basis swaps prices for PG&E Citygate on September 15, 2003 for the 25-month period of October 2003 to October 2005. These prices fall well within the 95% confidence interval for the basis differential estimate in Table 2B, thus lending statistical and visual support to our conclusion that, except for the crisis periods, the PG&E Citygate market is efficient.

4.2. SoCal Gas

Table 3A reports the analogous results for the SoCal Gas spot-price regression with AR(1), AR(2), AR(3), or AR(4) error specification. All four regressions have identical root-mean-squared-errors and each regression accounts for 97% of the spot-price variance. The LLH ratio test results and AIC values indicate an AR error process that is unlikely to be of the fifth or higher order. With the exception of the intercept, the electricity-crisis indicator and two AR parameters, all coefficient estimates are statistically significant ($p < 0.05$).

The coefficient estimates vary across the first three AR specifications, but not between the third and the fourth. Once again, however, the estimates for ϕ are highly significant, decisively rejecting the hypothesis of instantaneous adjustment. Specifically, the four estimates of λ are $l = 0.450$ under the AR(1) specification, $l = 0.490$ under the AR(2) specification, $l = 0.344$ under the AR(3) specification, and $l = 0.345$ under the AR(4) specification. The corresponding numbers of days required for the local market to regain equilibrium is 2.2, 2.0, 2.4, and 2.9, respectively. This range of required days is smaller than the one for PG&E Citygate because as Fig. 1 shows, the major supply basins (San Juan Basin, Permian Basin, and Anadarko Basin) serving Southern California are better inter-connected with Henry Hub than those (Western Canadian Sedimentary Basin and Rocky Mountain Basin) serving Northern California. This narrow range of small values further reinforces the notion that it is feasible to apply the equilibrium-price condition for the purpose of forecasting natural-gas prices for an extended period of time.

Table 3A indicates that the spot-price effect of the electricity and natural-gas crises ranges from a high of 0.800 + 2.912 = \$3.712 per MMBtu for the AR(2) specification to a low of

0.425 + 2.317 = \$2.742 per MMBtu for the AR(4) specification. At the market equilibrium, the effects are 3.475/0.450 = \$7.72 per MMBtu for the AR(1) specification, 3.712/0.490 = \$7.58 per MMBtu for the AR(2) specification, 2.741/0.344 = \$7.97 for the AR(3) specification, and 2.742/0.345 = \$7.95 per MMBtu for the AR(4) specification. As was true for PG&E Citygate, this large effect again confirms the earlier hint that during the energy crisis, the SoCal Gas market disconnected from the Henry Hub market, although the disparities between the k_2 and k_1 values are not as great as in the earlier case. Thus, the electricity crisis played a more important role in the rise in SoCal Gas prices during the energy crisis than was the case for PG&E Citygate prices.

Finally, again as was the case with the PG&E sample, the ADF statistics for the unit-root test reject the hypothesis that the residuals for the SoCal Gas regressions have a unit root, which suggests that the coefficient estimates are not susceptible to spurious interpretation.

Since Table 3A suggests that the coefficient estimates are sensitive to AR error specification, Table 3B tests the sensitivity of a and b to any such error. As was true for PG&E Citygate, Table 3B shows that the equilibrium-price condition is robust, and thus suitable for developing a market-based natural-gas price forecast. And once again we cannot reject the null hypothesis $\alpha = 0$ and $\beta = 1$, which implies that except for the crisis periods, the SoCal Gas and Henry Hub natural-gas markets are efficient without persistent arbitrage profit, and with an average basis differential of zero and an optimal hedge ratio of unity.

Fig. 4 shows that the NYMEX basis swaps prices for SoCal Gas on 09/15/03 for October 2003 to December 2005 fall well within the 95% confidence interval for the basis differential estimate in Table 3B, thus affirming our conclusion that the SoCal Gas market is efficient.

5. Conclusions

The integration of natural-gas markets since open access and deregulation in the mid-1980s suggests that those of California should be efficient and bereft of the potential for persistent arbitrage profit. With the caveat that the energy-crisis period was an important exception, our analysis supports the suggestion. Specifically, the average difference between the California and Henry Hub prices is close to zero. *Ceteris paribus*, a $1 per MMBtu change in the Henry Hub price translates into a $1 per MMBtu change in the California price, over all AR error specifications.[4]

A key implication of our model is that traders can accurately forecast the natural-gas prices they will have to pay to meet demand. When there is trading for natural-gas futures and basis swaps contracts, this price forecast is the price of a Henry Hub futures contract and the price of a basis swaps contract. When the only trading is in natural-gas futures, the price forecast is simply the price of a Henry Hub futures contract, because the estimated basis differential is not significantly different from zero. In light of the short time required for the restoration of a perturbed equilibrium and the current availability of five-year futures contracts, a five-year forecast time horizon seems eminently viable. And an accurate five-year price forecast provides an important input to management in three especially salient decision-making contexts.

First, a spot-price forecast is useful to natural-gas *suppliers* that are involved in pricing a natural-gas forward contract, a usage demonstrated by [26] for the closely related case of electricity. Second, the forecast and its dispersion are critical input data for cost-risk management by such *purchasers* of natural gas as local distribution companies (LDCs) that resell the gas to their retail end-users and gas-fired generation owners, an application demonstrated by

[16, 27, 28] for an electricity LDC. Third, evaluating the cost-effectiveness of natural-gas *demand management* (e.g., boiler efficiency improvement) requires a comparison of the gas-price forecast and the cost of reducing gas demand.

Finally, during the energy crisis the PG&E Citygate spot price is estimated to have been more than \$5/MMBtu in excess of the non-crisis price expectation, and the SoCal Gas spot price is estimated to have been almost \$8/MMBtu in excess of the non-crisis price expectation. These estimates corroborate the corresponding \$4.18/MMBtu and \$7.03/MMBtu figures found by FERC [10]. Under the conservative assumption of a marginal generation unit's heat rate of 10,000 BTUs per kilowatt hour, the excess above normally expected natural-gas price levels could have contributed \$50 to \$70 per megawatt hour to the electricity price spike during the California electricity crisis. This is notwithstanding that it has been shown that other factors, such as capacity shortages and market-power abuses by large electricity suppliers, have contributed to the electricity price spike [8, 11-15, 29]. An important policy implication of this finding is that unless the fuel input markets are workably competitive with active spot and futures trading, an electricity market reform may fail to deliver safe and reliable service at stable and reasonable prices [30].

[4] As a final check, we also estimated the partial-adjustment model with a time-dependent variance specification, GARCH(1, 1) [18, Chapter 16]; and once again we obtained estimates of a ≈ 0 and $b \approx 1$.

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Table 1: Summary and ADF statistics ("*" = "significant at p = 0.05") for the three spot-gas price series supplied by Platts, and pair-wise correlations between a California price and the Henry Hub price. The sample periods are: (a) PG&E Citygate - 05/01/98-08/12/03 with 1930 daily observations; (b) SoCal Gas price - 07/02/96-08/12/03 with 2,598 daily observations; and (c) Henry Hub price – same as (b).

	PG&E Citygate price ($/MMBtu)				SoCal Gas price ($/MMBtu)				Henry Hub price ($/MMBtu)		
Period	Mean ($/MM Btu)	Std. ($/MM Btu)	ADF statistic	Correl-ation	Mean ($/MM Btu)	Std. ($/MM Btu)	ADF statistic	Correl-ation	Mean ($/MM Btu)	Std. ($/MM Btu)	ADF statistic
Full sample	4.19	3.46	-6.74*	0.73	4.01	4.07	-7.53*	0.70	3.27	1.57	-4.38*
Before the electricity crisis	2.49	0.38	-6.14*	0.70	2.37	0.46	-4.02*	0.92	2.35	0.48	-3.55*
During the electricity crisis	8.05	5.54	-4.25*	0.66	10.02	7.24	-4.28*	0.57	5.22	1.64	-1.58
After the electricity crisis	3.69	1.31	-2.53	0.95	3.68	1.30	-2.84	0.93	3.86	1.55	-4.08*

Table 2A. Maximum-likelihood estimates under alternative orders of the autoregressive (AR) process for the PG&E Citygate daily price regression. The sample period is 05/01/98-08/12/03, with 1930 daily observations. The t statistics are in parentheses and "*" = "Significant at p = 0.05".

Coefficient	First Order	Second Order	Third Order	Fourth Order
$f = la$	0.026 (0.34)	0.072 (0.64)	0.089 (0.82)	0.027 (0.50)
k_1	0.125 (1.21)	0.200 (1.44)	0.248 (1.58)	0.078 (1.07)
k_2	1.024 (5.47)*	1.325 (0.28)	1.441 (5.02)*	0.696 (5.18)*
$g = lb$	0.214 (7.00)*	0.276 (6.38)*	0.296 (6.96)*	0.137 (6.10)*
$h = 1 - l$	0.779 28.93)*	0.703 (14.19)*	0.678 (13.70)*	0.856 (45.60)*
r_1	0.525 (14.05)*	0.534 (10.29)*	0.567 (10.91)*	0.385 (14.19)*
r_2		0.138 (5.66)*	0.172 (6.42)*	0.148 (5.91)*
r_3			-0.061 (-2.64)*	0.009 (0.37)
r_4				-0.208 (-8.73)*
Root-mean-squared error	0.65	0.65	0.64	0.63
Total R^2	0.96	0.97	0.97	0.97
Log-likelihood (LLH) at convergence	-1906.5	-1889.5	-1886	-1855.5
LLR ratio test of H_0: AR(1) against H_1: AR($j > 1$): χ^2 statistic with d.f. = j -1		34*	7*	68*
Akaike information criterion (AIC)	3835	3793	3788	3729
ADF statistics for the unit-root test on the regression residuals	-28.4*	-29.2*	-30.3*	-30.7*

Table 2B. Testing H_1: $\alpha = 0$ and H_2: $\beta = 1$. The bounds are those of a 95% confidence interval.

Order of AR process	Basis differential (a in \$/MMBtu)					Optimal hedge ratio (b)				
	Estimate	Standard error	Lower bound	Upper bound	t-stat. to test H_1: $\alpha = 0$	Estimate	Standard error	Lower bound	Upper bound	t-stat. to test H_2: $\beta = 1$
1	0.116	0.343	-0.556	0.788	0.339	0.972	0.098	0.781	1.163	-0.287
2	0.243	0.359	-0.461	0.947	0.676	0.931	0.111	0.713	1.148	-0.626
3	0.277	0.337	-0.383	0.937	0.824	0.815	0.096	0.628	1.003	-1.927
4	0.187	0.336	-0.472	0.847	0.557	0.948	0.105	0.744	1.153	-0.493

Table 3A. Maximum-likelihood estimates under alternative orders of the autoregressive (AR) process for the SoCal Gas daily price regression. The sample period is 07/02/96-08/12/03 with 2,598 daily observations. The *t* statistics are in parentheses and "*" = "Significant at $p = 0.05$".

Coefficient	First Order	Second Order	Third Order	Fourth Order
$f = la$	-0.102 (-0.79)	-0.086 (-.61)	-0.109 (-1.00)	-0.109 (-1.00)
k_1	0.674 (3.05)*	0.799 (3.25)*	0.425 (2.27)*	0.425 (2.26)*
k_2	2.801 (8.85)*	2.912 (8.36)*	2.316 (6.79)*	2.317 (6.66)*
$g = lb$	0.480 (11.20)*	0.515 (13.16)*	0.377 (8.16)*	0.377 (8.07)*
$h = 1 - l$	0.550 (17.10)*	0.510 (13.12)*	0.656 (15.77)*	0.655 (15.31)*
r_1	0.770 (30.07)*	0.823 (19.58)*	0.680 (15.51)*	0.680 (15.00)*
r_2		-0.031 (-1.19)	-0.069 (-2.92)*	-0.069 (-2.91)*
r_3			0.096 (4.88)*	0.096 (4.02)*
r_4				-0.000 (-0.00)
Root-mean-squared error	0.71	0.71	0.71	0.71
Total R^2	0.97	0.97	0.97	0.97
Log-likelihood (LLH) at convergence	-2794	-2793	-2784	-2784
LLR ratio test of H_0: AR(1) against H_1: AR(j > 1): χ^2 statistic with d.f. = j -1		2	18*	18*
Akaike information criterion (AIC)	5600	5600	5584	5586
ADF statistics for the unit-root test on the regression residuals	-38.2*	-37.9*	-35.5*	-35.5*

Table 3B. Testing H_1: $\alpha = 0$ and H_2: $\beta = 1$. The bounds are those of a 95% confidence interval.

Order of AR process	Basis differential (a in \$/MMBtu)					Optimal hedge ratio (b)				
	Estimate	Standard error	Lower bound	Upper bound	t-stat. to test H_1: $\alpha = 0$	Estimate	Standard error	Lower bound	Upper bound	t-stat. to test H_2: $\beta = 1$
1	-0.227	0.289	-0.794	0.341	-0.783	1.067	0.085	0.900	1.234	0.786
2	-0.176	0.295	-0.754	0.403	-0.595	1.052	0.087	0.881	1.222	0.594
3	-0.316	0.324	-0.951	0.32	-0.973	1.095	0.126	0.848	1.342	0.756
4	-0.315	0.326	-0.954	0.324	-0.966	1.095	0.097	0.906	1.285	0.985

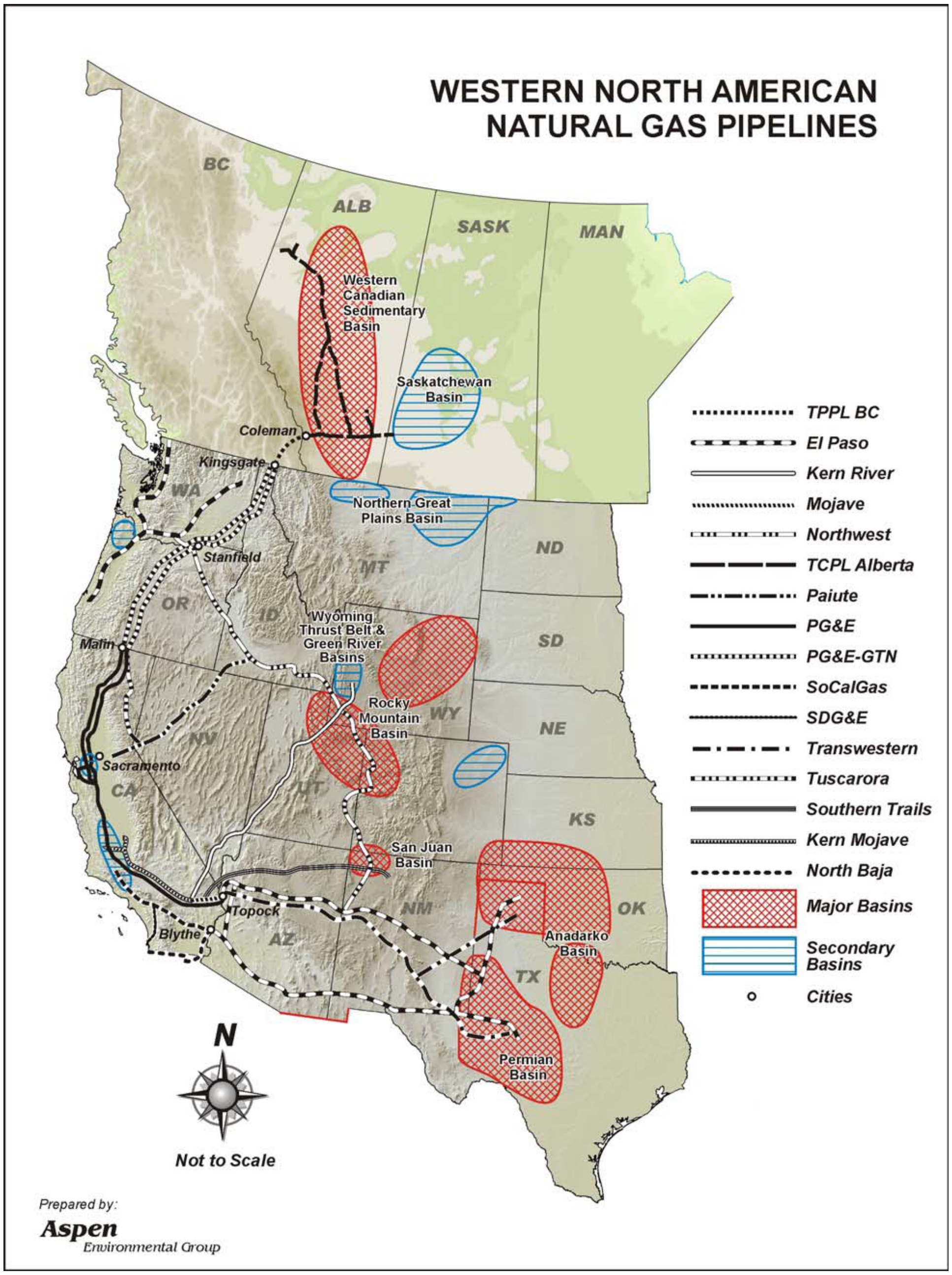

Fig.1. Natural-gas pipelines and supply basins in Western North America. Major supply basins serving California include the Western Canadian Sedimentary Basin, serving Northern California, the San Juan, Permian and Anadarko Basins, serving Southern California, and the Rocky Mountain Basin, serving both. Source: California Energy Commission.

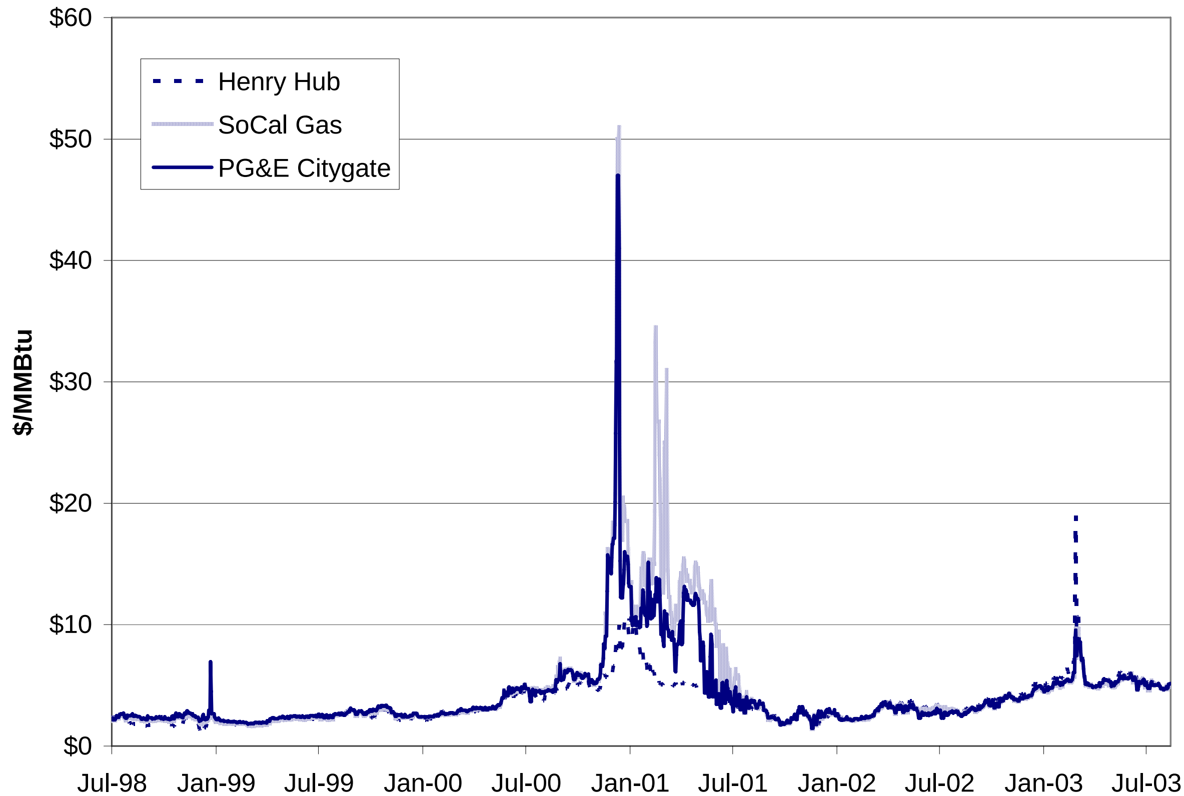

Fig. 2. Daily spot natural-gas prices for Henry Hub, SoCal Gas, and PG&E Citygate, July 1998 to July 2003. Source: Platts.

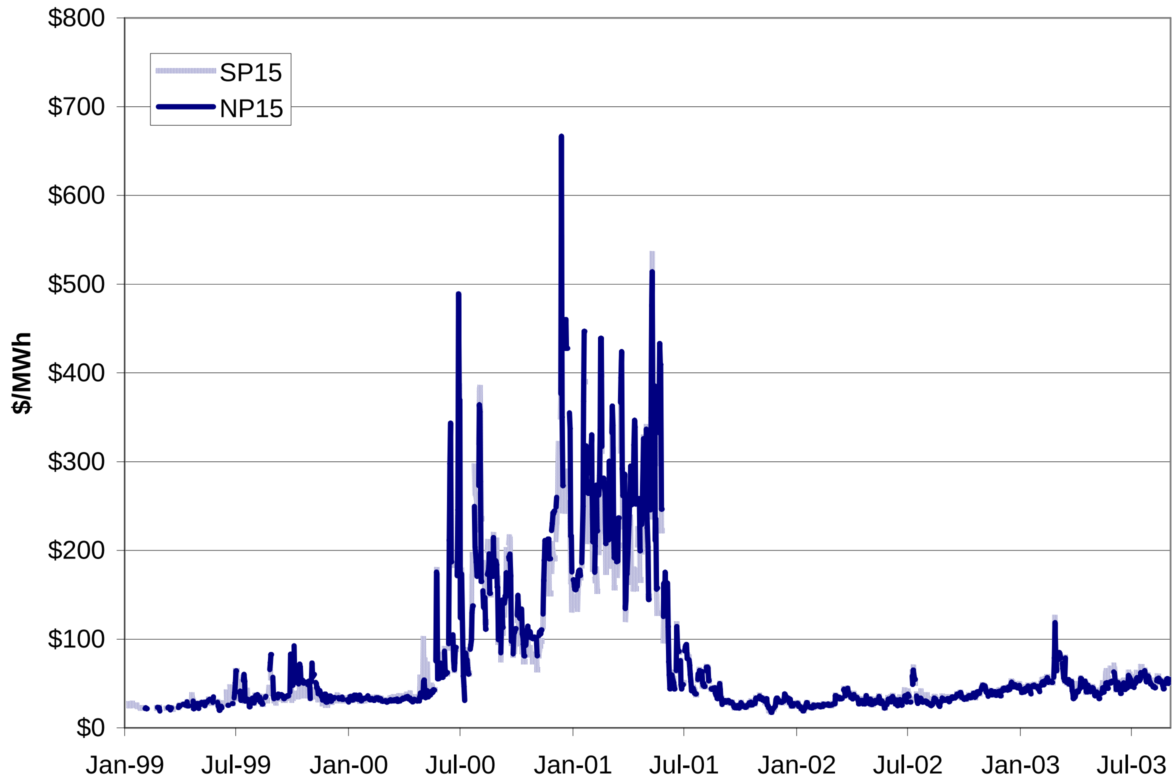

Fig. 3. Daily peak period (06:00 – 22:00, Monday-Saturday) bilateral electricity prices for SP15 (Southern California) and NP15 (Northern California). Source: Platts.

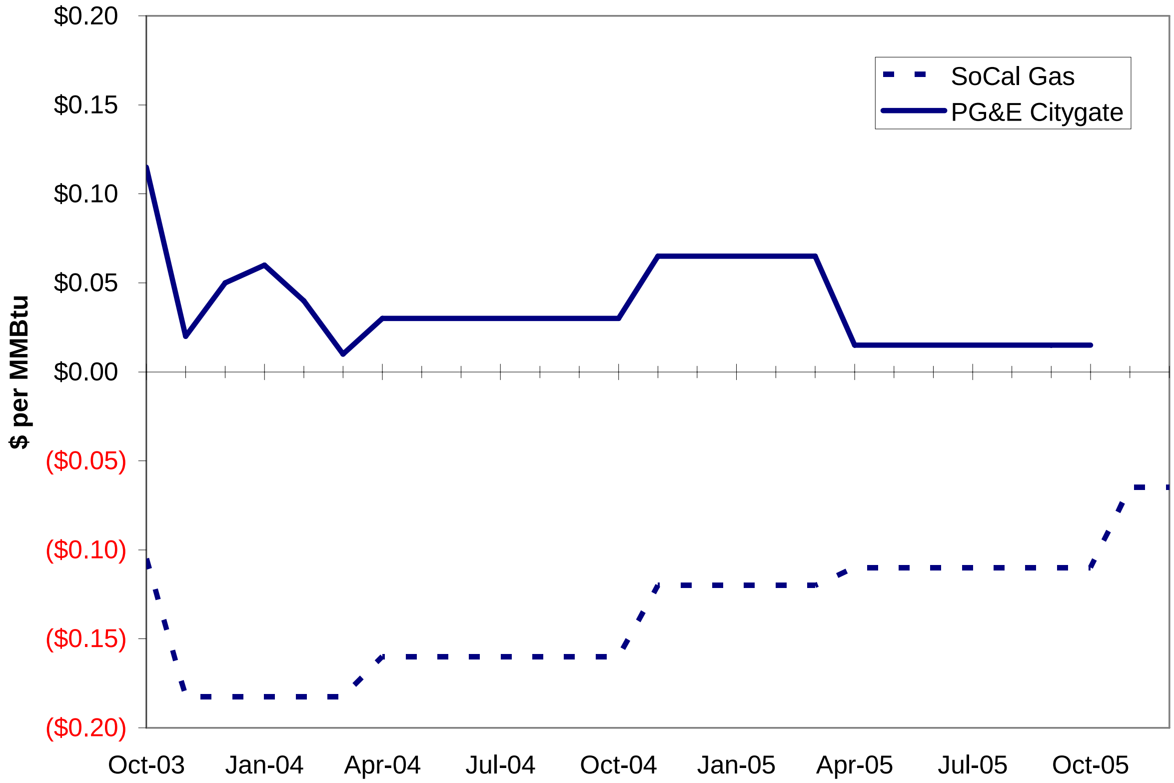

Fig. 4. Settlement prices ($/MMBtu) of NYMEX basis swaps contracts on 09/15/03 for PG&E Citygate (October 2003 to October 2005) and SoCal Gas (October 2003 to December 2005). Source: New York Mercantile Exchange.