Options Provided by Storage Can Explain High Electricity Prices

Kevin Counsell

CRA International

Lewis Evans*

Victoria University of Wellington

Graeme Guthrie

Victoria University of Wellington

Steen Videbeck

Cornell University

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*Corresponding author: School of Economics and Finance, PO Box 600, Victoria University of Wellington, Wellington, New Zealand. Ph: 64-4-4635560. Fax: 64-4-4635014. Email: lew.evans@vuw.ac.nz

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Abstract

Generators supplying electricity markets are subject to volatile input and output prices and uncertain fuel availability. Price-risk may be hedged to a considerable extent but fuel-risk — water flows in the case of hydro and gas availability in the case of thermal plants — may not be. We show that a price-taking generator will only generate when the output price exceeds its marginal cost by an amount that reflects the value of the option to delay the use of stored fuel. The corresponding offer price is different from the theorized offer prices of static uniform auctions and more akin to pay-as-bid auction prices. We argue that the option value of delaying fuel use, which is an increasing function of spot price volatility and the uncertainty about fuel availability, must be considered when evaluating whether market power is present in electricity markets. The engineering approach to simulating an electricity supply curve, which has been used in market power evaluations to date, may lead to supply curves that are quite different from those that recognize possible fuel availability limitations, even in the complete absence of market power.

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1 Introduction

Electricity markets have high-price episodes and it is at such times that the attribution of prices between market power and resource scarcity becomes particularly controversial.[1] The most famous such episode occurred in California in 2000–2001, where the average price in December 2000 was more than ten times the average price one year earlier. This experience spurred a series of academic studies that attempted to determine how much of the high prices was due to 'market fundamental' factors such as high fuel costs, high demand, drought, and other factors beyond firms' control, and how much was due to firms exercising market power to raise prices (Borenstein et al., 2002; Bushnell, 2005; Bushnell et al., 2004; Joskow and Kahn, 2002). These studies typically find that observed prices significantly exceeded estimated marginal costs and conclude that firms were withholding supply in order to manipulate prices.

However, the empirical analysis of market power in electricity markets has mostly been performed in a static setting, with little consideration of the intertemporal linkages present in electricity generation. Specifically, generating electricity from water and natural gas typically involves storing the fuel when it is plentiful (water) or cheap (gas) and electricity prices are low, and releasing the fuel from storage to generate electricity when electricity prices are high.[2] Thus, firms will consider the option value of retaining fuel in storage, as well as the marginal cost of turning it into electricity, when they make their generation decisions. This has been noted in the existing analyses of the California experience, but none of these studies have adequately addressed the issues that arise.[3] Therefore, in this paper we develop a real options model of electricity generation by firms with fuel storage and use it to analyze the optimal generation policies of firms that have no market power. Our model includes volatility in the future spot prices of electricity and gas and allows for the fact that generators' decisions to release fuel from storage cannot be immediately reversed. In the case of hydroelectric generators, this irreversibility can arise due to uncertainty about future inflows into storage lakes; in the case

[1] It is further complicated by the fact that the net suppliers of electricity have significant sunk costs and so must expect a margin over variable cost in order to prospectively break even (Brennan, 2005). The question as to whether this margin should (largely) be recovered in high-price episodes or from average prices may depend (circularly) on the extent to which the high prices originate from market power.

[2] In 2000, 18% of net electricity generation in California was from hydroelectric generators and 53% was from burning natural gas. See Table 3 for more details.

[3] For example, Borenstein et al. (2002, p. 1388) note that hydroelectric generators' offer prices reflect "the opportunity cost of using the hydro energy at some later time". In response to the difficulties this poses for their study, they effectively exclude hydroelectric generation from their analysis. They make no allowance for the timing flexibility involved in generating electricity from natural gas. Likewise, Joskow and Kahn (2002, p. 10) recognize, but do not quantify, the effects of timing flexibility on hydroelectric generation.

of generators burning natural gas, it reflects the restrictions on the speed with which storage facilities can be emptied and refilled.

We find that an electricity generator with no market power (by which we mean it has no ability to influence the distribution of current or future electricity or gas prices) will not generally offer to generate electricity whenever the electricity price exceeds the marginal cost. Instead, such a firm will only be willing to generate electricity if the spot price of electricity is sufficiently high that the firm can recover its marginal cost *and* the value of the real options destroyed by generating electricity. We find that the value of these real options can be substantially greater than the marginal cost. In fact, the electricity price threshold above which a price-taking firm will generate is typically much more sensitive to the long-run level of the electricity price than it is to the firm's marginal cost.

If option premia (and not firms unilaterally exercising market power) are to explain high-price episodes, it must be the case that option premia are *especially high* during these periods. This occurs, for example, when electricity prices are more volatile than usual. This will typically be the case during high-demand periods, because the convexity of electricity supply curves means that at high levels of demand even a small demand shock can lead to a large shock to the market-clearing electricity price.[4] Another sufficient condition for the option premium to be relatively high is that uncertainty surrounding future fuel supplies is relatively high. Scarce or uncertain future fuel supplies make generation decisions largely irreversible, and our comparative statics analysis indicates that this makes the option premium relatively high. We find that such conditions were present in California in 2000–2001. While this does not rule out the possibility that firms were exercising market power, it does imply that simply looking at the difference between offer prices and estimated marginal costs that exclude the option premium is insufficient to prove that firms were manipulating prices.

Our approach thus differs from the existing literature assessing market power in electricity markets in that we allow for the intertemporal linkages that are present in electricity generation even in the short run. In contrast, the two most popular approaches (strategic offering and direct analysis) compare actual price and supply outcomes with those arising in a *static* perfectly competitive electricity market. Strategic offering analysis compares the actual offers of individual generators with estimates of the marginal cost of turning fuel into electricity. For example, Wolfram (1998) applies this approach to the UK electricity market and finds that firms that have a greater ability or greater incentive to manipulate market prices choose higher markups over marginal cost. Joskow and Kahn (2002) apply a similar approach to the California electricity market in the summer of 2000 and find evidence that all but one firm, which used forward markets to contract 90% of its potential output, were withholding supply. Wolak

[4]The impact of high demand on price volatility is compounded by higher fuel costs. This occurs because plants with higher costs tend to be less fuel efficient and so fuel price rises rotate the supply curve as well as shifting it upwards (Borenstein et al., 2002, p. 1385).

(2001, 2003) uses revealed bid information to estimate Lerner indices for individual generators and attributes the increase in these indices between 2000 and two previous years entirely to unilateral market power. In contrast to strategic offering analysis, direct analysis uses the entire market. Rather than focussing on individual generating firms, it estimates the marginal cost functions of all generators in the market for each period, and stacks them from least expensive to most expensive to obtain a hypothetical supply curve. Given the actual level of demand, the marginal cost of the most expensive dispatched generator is then taken as the competitive price benchmark against which actual market prices are compared. When actual market prices exceed the simulated competitive prices by a greater amount, the exercise of unilateral market power is regarded as being more likely. Borenstein et al. (2002) and Joskow and Kahn (2002) use this approach to examine the Californian electricity market and find a large gap between actual market prices and their estimated competitive prices in the summer of 2000.[5] A recent review of market power monitoring of electricity markets acknowledges opportunity cost issues in estimating marginal cost (Twomey et al., 2005, p. 23), but provides no solution or recommendation about its treatment in electricity market market power evaluations. All of these studies adopt an engineering approach to estimating the marginal cost of generating electricity, which treats suppliers as myopically responding along their supply curve. However, this approach does not model supply in the specific circumstances of electricity markets.[6] Deregulated electricity markets are characterized by volatile input and output prices and restrictions on resource availability. These market characteristics imply that generation decisions will, and should, reflect intertemporal trade-offs in the use of fuel.

Our paper also fits into the literature on commodity price behavior, especially the theory of storage and the theoretical underpinnings of the convenience yield. Much of the literature on commodity storage derives from the empirical observation that firms store commodities even when the commodity's spot price is high relative to its futures price. The usual explanation for this behavior is that there is a 'convenience yield' associated with holding commodities in inventory (Brennan, 1958; Kaldor, 1939; Telser, 1958; Working, 1948, 1949). This convenience yield reflects the flexibility created by holding inventory. For example, inventories allow firms to smooth production and thereby lower adjustment costs, and to vary production in response to changed market conditions. However, the early literature does not explicitly model this convenience yield. The dominant approach in the recent literature on the theory of storage models the convenience yield as a consequence of the nonnegativity of inventory (Chambers and

[5] Some authors supplement direct analysis by also comparing actual prices to those resulting from an oligopoly counterfactual — typically a Cournot equilibrium (Green and Newbery, 1992; Wolfram, 1999; Bushnell, 2005; Bushnell et al., 2004). This provides some indication of the economic significance of any observed price-cost margin. For example, even if actual prices exceed those simulated in a perfectly competitive market, if they are significantly less than simulated Cournot prices then any market power problems are relatively minor.

[6] Brennan (2005) argues that the practice of calculating marginal cost as the average operating cost of the marginal plant is quite misleading in the presence of the (short-run) capacity constraints of electricity generation. He suggests that withheld supply is a better indicator. Our results show that this criterion is no panacea.

Bailey, 1996; Deaton and Laroque, 1992, 1996; Routledge et al., 2000).[7] Except in states when firms wish to hold negative inventory, the current spot price will be related to the future expected spot price by the usual intertemporal arbitrage condition. However, when the nonnegativity constraint on inventory is binding, firms would like to sell current stocks and drive inventory negative. They cannot do so, and so the current spot price remains above that implied by the intertemporal arbitrage condition. Storing the commodity allows firms to benefit from such temporary 'stock-outs', selling the commodity when the spot price is high and buying it again in the future when the intertemporal condition has been restored. Thus, holding inventory gives the firm the option to exploit any temporary high-price episodes that might arise in the future. More recently, some authors have analyzed the convenience yield by explicitly valuing the real options embedded in stored commodities (Heinkel et al., 1990; Litzenberger and Rabinowitz, 1995).[8] As long as releasing a commodity from storage is at least partially irreversible, reducing storage destroys (at least temporarily) the real option to wait and release the commodity in the future. The firm must be compensated for the loss of this option, so that release will only occur when the spot price exceeds the futures price by an amount that is sufficient to provide such compensation.

We extend this literature by considering the role of real options in storage in more detail than the papers discussed above. The papers that focus on the nonnegativity of inventory assume that the decision to reduce inventory is costlessly reversible. Specifically, reducing inventory and then immediately restoring it is costless, which is unrealistic for the situation — generating electricity using water or gas — considered in this paper. In contrast, the papers that adopt an explicit real options approach use simple two- and three-date models that, due to their dynamic structure, force the decision to reduce inventory to be completely irreversible: once a storage facility has been emptied the possibility of refilling it is not allowed for. We extend these two strands of the literature by modelling the case where reducing inventory can be reversed, but at a cost. Our model allows the firm to empty and refill its storage facility, but refilling the facility cannot occur instantaneously.[9] Further, the commodity can be stored and then resold on the spot market or it can be used as an input into a production process. We are thus able to highlight important issues relating to storage that are overlooked in the existing literature. In particular, we are able to consider the impact of the real options associated with storage — both the option to choose the timing of inventory reductions and the option to choose between alternative uses of the stored commodity.

The remainder of the paper is organized as follows. Section 2 formally models the optimal

[7]Routledge et al. (2001) extend the theory of storage to electricity, focussing on the non-storability of electricity and the storability of fuels such as natural gas.

[8]Kocagil (2004) and Milonas and Thamadakis (1997) report empirical evidence on the real option interpretation of the value of storage and the implications for the convenience yield.

[9]As Williams (1987, p. 1002) points out, such delays are prevalent in processing and transporting a range of commodities.

policy of hydroelectric generators, while Section 3 extends this model to firms that use natural gas to generate electricity. The difference between the two cases is that gas is traded in a spot market, whereas in many cases water is not which simplifies the analysis. Section 4 discusses the implications of our analysis for measuring market power in electricity markets, focussing on the experience in California in 2000–2001. Finally, Section 5 offers some concluding remarks.

2 Optimal electricity generation using water

2.1 Model set-up

We consider a firm that operates a hydroelectric generator capable of producing one unit of electricity from each unit of water at a cost of c. The spot price p of electricity evolves according to the diffusion process

$$dp = \mu(p)dt + \sigma(p)d\xi, \tag{1}$$

where μ and σ are functions of the spot price and $d\xi$ is the increment of a Wiener process.[10] Our choice of an exogenous spot price process means that the firm is a price taker. That is, the firm does not consider any feedback effect resulting from withholding supply. The firm can only generate electricity when it has water available, and we assume that at any date t one unit of water arrives during the interval $[t, t + dt)$ with probability $\phi\, dt$ for some constant ϕ. That is, the arrival dates of water are described by a Poisson process, with water arriving on average every $1/\phi$ years. The firm can spill this water at zero cost or it can generate electricity, yielding a cash flow of $p - c$.

We will consider the possibility that the firm has access to a storage lake with sufficient capacity to store one unit of water. The lake can be emptied and filled (provided water is available) instantaneously and without cost. Without a storage lake the firm has no control over when it can generate electricity — it can generate only when water arrives. In contrast, having a storage lake allows the firm to delay using water until the electricity spot price is high. We will quantify the value of this benefit and derive the policy for optimally managing the flexibility the lake offers the firm.

We assume risk neutrality, so that equilibrium in financial markets will ensure that the expected rate of return from owning the firm equals the risk-free interest rate, which we assume is constant and equal to r. Assuming risk neutrality, while seemingly restrictive, can easily be relaxed by subtracting a risk premium from the drift term in (1). See, for example, Cox and Ross (1976).

[10]Diffusion processes are unable to capture all of the properties of electricity spot prices, although jump-diffusion processes perform better (Knittel and Roberts, 2005). However, when we implement the model in Section 2.4 we will assume that the spot price follows a particular mean-reverting diffusion process as this keeps the analysis tractable and captures the key features, mean reversion and volatility, that must play a central role in any analysis of hydroelectric generation.

2.2 Determining the value of stored water

The present value to the firm of one unit of stored water at date t will depend on the level of the spot price on that date, but — because there is no explicit time dependence in the process for the spot price, the costs faced by the firm, or the options available to it — not explicitly on t.[11] That is, the present value to the firm of stored water at date t equals $G(p_t)$ for some function G to be determined.

At any point in time, the firm can do one of three things if its storage lake is full. First, it can empty the storage lake and spill the water, receiving a payoff of zero. Thus

$$G(p) \geq 0. \tag{2}$$

Second, it can empty the storage lake and use the water to generate electricity, receiving a payoff of $p - c$. Thus

$$G(p) \geq p - c. \tag{3}$$

Third, the firm can keep the storage lake full for the next dt units of time. At the end of this period, the stored water will be worth $G(p + dp)$, where dp is the change in the electricity price over the period. However, delay comes at a cost because the lake's limited capacity prevents the firm from storing any additional water that arrives — it will have to be spilled or used to generate electricity; it cannot be stored. If the storage lake were empty when this occurred, the firm would have the option to spill the water (for a payoff of 0), store the arriving water (for a payoff of $G(p)$) or use it to generate electricity immediately (for a payoff of $p - c$); the payoff would be $\max\{0, G(p), p - c\}$. However, because the lake is already full, all the firm can do if water arrives is spill it or use it to generate electricity immediately; the payoff is therefore $\max\{0, p - c\}$. Because water arrives with probability $\phi\, dt$, the expected cost to the firm is

$$\phi \Big(\max\{0, G(p), p - c\} - \max\{0, p - c\} \Big)\, dt.$$

However, this case only arises when delay is optimal; that is, for values of p where $G(p) > \max\{0, p - c\}$. Therefore, the expected cost can be simplified to

$$\phi \Big(G(p) - \max\{0, p - c\} \Big)\, dt.$$

Thus

$$G(p) \geq e^{-r\,dt} E[G(p + dp)] - \phi \Big(G(p) - \max\{0, p - c\} \Big)\, dt,$$

which simplifies to

$$\frac{E[dG(p)]}{dt} - (r + \phi)G(p) + \phi \max\{0, p - c\} \leq 0. \tag{4}$$

The value of stored water satisfies (2)–(4), with one of these conditions (corresponding to the optimal action) holding with equality for any particular value of p. This system determines the

[11] The value of stored water equals the difference between the value of the firm when its storage lake is full and its value when the lake is empty.

value of stored water to the firm. It is solved in Appendix A for a particular spot price process. We describe some qualitative properties of the solution to this system in Section 2.3 and present the results of our numerical analysis in Section 2.4.

2.3 Optimal generation policy and the source of value

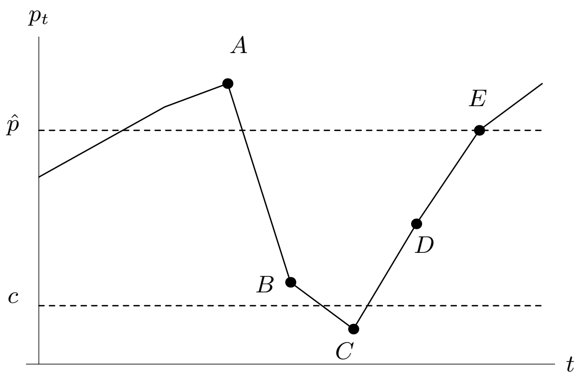
The firm should only generate electricity if the price of electricity is at least as great as the sum of all the costs involved, including any opportunity cost. If the storage lake is already full when more water arrives, the only alternative to using this water to generate electricity is to spill it. Since the opportunity cost is thus zero, the immediate cash flows fully capture the costs, so that the water should be used to generate electricity as long as $p > c$. Suppose, in contrast, that the storage lake is empty when more water arrives. There is now another alternative to generating electricity immediately — storing the water. If electricity is generated now, this opportunity is lost, and the associated opportunity cost needs to be factored into the generation decision. Delaying generation is therefore preferred if

$$p < c + G(p). \tag{5}$$

This identifies the two costs that the firm faces when it generates electricity rather than storing water. The first term on the right side, c, equals the marginal cost of turning water into electricity. The second term, $G(p)$, is the present value of the water in a full lake. (We will discuss the source of this value shortly.) The costs of generating electricity are thus the cost of turning water into electricity and the value of the option that is foregone by not storing the water.

The generation policy described above can be summarized by a single number, which we denote $\hat{p}$ and which determines whether or not water should be released from a full storage lake. The owner of a full lake will empty the lake and use the released water to generate electricity if $p \geq \hat{p}$, for some price threshold $\hat{p}$, and will otherwise wait and either spill any water that arrives (if $p < c$) or use it to generate electricity (if $c \leq p < \hat{p}$). The owner of an empty lake will either store any water that arrives in the lake (if $p < \hat{p}$) or use it to generate electricity (if $p \geq \hat{p}$). Figure 1 uses a simulated path for the electricity price to illustrate how the threshold $\hat{p}$ determines the firm's generation policy. The points labelled A, B, C, and D correspond to the dates when water arrives. Suppose the lake is initially empty. When the first load of water arrives at point A, the spot price exceeds the threshold $\hat{p}$ and the firm uses it to generate electricity, leaving the lake empty. When the second load of water arrives at point B, the spot price is below this threshold, so the firm uses the water to fill the lake rather than generate electricity. The lake will not be emptied until the spot price reaches the threshold $\hat{p}$. The third load of water arrives at point C. Since the lake is already full, this water cannot be stored; since the spot price is less than the marginal cost of generation, it is unprofitable to generate electricity; instead, the firm spills the water. In contrast, when the fourth load of water arrives at

Figure 1: Simulated path for the spot price



Notes. The curve plots a simulated path for the electricity spot price and the points indicate dates at which water arrives or is released from the lake. The lake is filled at B and emptied at E. Arriving water is used to generate electricity at A and D and is spilled at C.

point D, the firm will use it to generate electricity. Finally, the spot price reaches the threshold $\hat{p}$ at point E, so that the firm releases the water in the lake and uses it to generate electricity.

The main problem facing the firm is that it has no control over when water arrives. However, as Figure 1 demonstrates, a storage lake gives the firm some ability to shift water over time. This is the source of the lake's value. Suppose water becomes available at dates $T_1, T_2, \ldots$ If the firm has no storage lake, it receives cash flow of $\max\{0, p_{T_i} - c\}$ at each date T_i and nothing in between. In contrast, if the firm has access to a storage lake that is currently empty, it will store the first water to arrive when the spot price is below the generation threshold. Denoting this date by S_1, it follows that the firm foregoes a cash flow of $\max\{0, p_{S_1} - c\}$ at date S_1. At the first subsequent date when the spot price rises to the threshold $\hat{p}$, say S_1', the firm will release this water, creating a cash flow of $\hat{p} - c$.[12] The next water to arrive when the spot price is less than $\hat{p}$ will be stored in the now empty lake, forcing the firm to forego cash flows of $\max\{0, p_{S_2} - c\}$, and the cycle repeats. The value added to the firm by an empty storage lake is the present value of this sequence of cash flows:

$$E\left[\sum_{i=1}^{\infty}\left(e^{-rS_i'}(\hat{p} - c) - e^{-rS_i}\max\{0, p_{S_i} - c\}\right)\right]. \tag{6}$$

The value of the empty lake depends, via the expected value operator in (6), on the arrival rate of water and on the distribution of future spot prices. For example, if prices are rapidly mean reverting, the current spot price only has a small impact on the distribution of future spot prices, and it therefore has little impact on the value of the empty lake; if spot prices revert to their long-run level more slowly, the value of the empty lake will be more responsive to changes in the spot price.

[12] The continuity of the stochastic process for the spot price implies that stored water will be released when the spot price is exactly equal to $\hat{p}$.

2.4 Numerical analysis

In order to further analyze the optimal generation policy, we assume that the electricity spot price evolves according to the square root diffusion

$$dp = \eta(\mu - p)dt + \sigma p^{1/2} d\xi, \tag{7}$$

where η, μ, and σ are constants. Spot prices generated by this process are mean-reverting with the long-run spot price being drawn from the gamma distribution with shape and scale parameters $2\eta\mu/\sigma^2$ and $\sigma^2/(2\eta)$ respectively. In particular, the unconditional mean and variance of the spot price are μ and $\sigma^2\mu/(2\eta)$ respectively. Deviations of prices from the long-run level are expected to decline at rate η, the spot price can never become negative and, provided $2\eta\mu \geq \sigma^2$, there is sufficient upward drift to make the origin inaccessible, in which case the spot price will always be positive.[13] Our choice of this particular process allows us to find analytic solutions to (2)–(4), as described in Appendix A.

We calibrate this spot price process using the daily-average of the day-ahead unconstrained price from the California Power Exchange. For our baseline case we use all weekday prices from 1999, which avoids the high prices observed in California in 2000–2001 and so corresponds to 'normal' Californian conditions.[14] We contrast this using prices from May 2000, which had higher prices than normal, but not the extremely high prices observed later in 2000 and in 2001. Using the approach described in Appendix B, we fit our square root model to the electricity price series and find that in 1999

$$dp = 32.46(30.12 - p)dt + 15.06p^{1/2} d\xi.$$

When data from May 2000 is used instead, we obtain

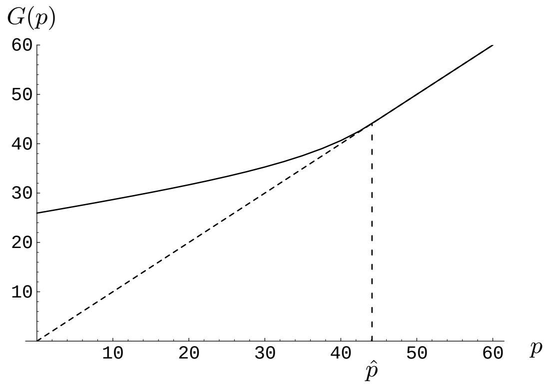
$$dp = 101.65(53.38 - p)dt + 55.77p^{1/2} d\xi.$$

In 1999, the spot price process has unconditional mean of \$30.12/MWh and standard deviation of \$10.26/MWh, while deviations of the spot price from its long-run level have a half-life of 0.0214 years (or approximately eight days). In May 2000, the unconditional mean and standard deviation rise to \$53.38/MWh and \$28.58/MWh respectively, and the half-life falls to less than three days. We set the risk-free interest rate equal to $r = 0.04$. In the numerical analysis that follows, we will consider a range of possible values for the remaining two parameters, the marginal cost of generation and the arrival rate of water. We concentrate on analyzing the impact of changes in the model's underlying parameters — especially the marginal cost of generation

[13] Cox, Ingersoll and Ross (1985) use this process to model interest rates, where properties of mean reversion and non-negativity are also important.

[14] We restrict attention to weekday prices because gas spot prices are not available on weekends or public holidays. Thus, we are forced to use weekday prices only when we calibrate our model of a gas generator in the next section. For consistency, we use the same data set in this section.

Figure 2: The value of water in a storage lake



Notes. The solid curve plots the value of the water in the storage lake as a function of the electricity spot price, while the dashed curve plots $p - c$, the value of water assuming that it is released from the lake immediately and used to generate electricity. The vertical dashed line indicates the optimal price threshold $\hat{p}$. The electricity spot price follows the process in (7) with the 1999-year estimates of $\mu = 30.12$, $\eta = 32.46$, and $\sigma = 15.06$. The risk-free interest rate is $r = 0.04$, the marginal cost of generation is $c = 0$, and the arrival rate of water is $\phi = 10$.

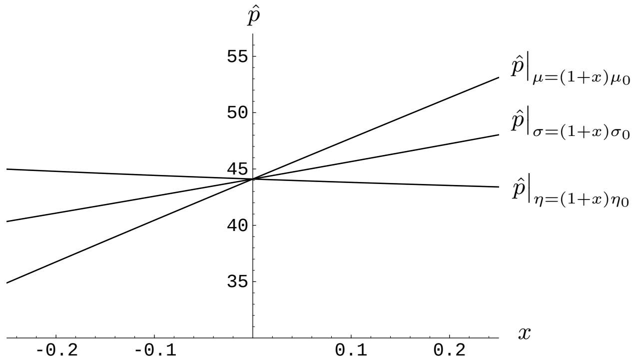
(c), the determinants of spot price behavior (μ, η, and σ), and the availability of water (ϕ) — on the firm's optimal generation policy.

Figure 2 plots the present value of the water in a full lake as a function of the spot price of electricity when $c = 0$ and $\phi = 10$. It is drawn as the solid curve, while the dashed curve plots $p - c$, the value of water assuming that it is released from the lake immediately and used to generate electricity. These two curves coincide when $p \geq \hat{p}$, since for these high levels of the spot price the firm will optimally release the water immediately. However, for lower spot prices, the water is more valuable if kept in the lake for future release than it is if released immediately — in these circumstances, the firm will continue to hold the water in its storage lake. Even though the marginal cost of generation is zero, the price threshold is positive — in fact, for the parameters used here, the price threshold is substantially greater than the long-run level of the spot price.

Figure 2 is reminiscent of the graph plotting the value of an American call option as a function of the underlying share price, with the dashed curve corresponding to the payoff from exercising the option.[15] This is not surprising, since stored water effectively gives the firm the option to buy electricity (at a price equal to the marginal cost of generating electricity from water) at a future date of its choosing. The main difference from the usual graph for an American call option is that the value of water is positive when the spot price is zero, whereas a stock option will be worthless when the underlying stock is worthless. If a stock's value ever falls to zero (due to bankruptcy, for example), it is reasonable to assume that its value will remain at zero,

[15]An American call option gives its owner the right to buy the underlying asset at a specified price on or before a specified date.

Figure 3: The optimal price threshold



Notes. Each curve plots the optimal price threshold $\hat{p}$ as a function of the change in the indicated parameter from its baseline value, which is based on Californian spot price data during 1999. Baseline values are $\mu_0 = 30.12$, $\eta_0 = 32.46$, and $\sigma_0 = 15.06$. In all cases, the risk-free interest rate is $r = 0.04$, the marginal cost of generation is $c = 0$, and the arrival rate of water is $\phi = 10$.

making an option to buy the asset at some fixed (positive) price worthless. However, if the electricity spot price is mean reverting, the spot price will never remain at zero: mean reversion will push the spot price back towards its long-run level. Thus, even if the electricity spot price is currently zero, the option to buy electricity in the future at some fixed price c is still valuable. A further difference between stored water and an American call option is that the latter dies when it is exercised — it cannot be used again. In contrast, if the firm exercises its option to buy electricity by releasing stored water, the option will be renewed as soon as more water is stored.

We begin our analysis of the determinants of $\hat{p}$ by considering the role that the electricity spot price process plays. Figure 3 shows how $\hat{p}$ varies with the parameters — μ, σ, and η — that govern the behavior of the spot price. Each curve corresponds to a different parameter and shows how $\hat{p}$ varies when the indicated parameter is scaled from its calibrated value by a factor of $1+x$. The baseline calibration uses prices from California during 1999. In all cases, the risk-free interest rate is $r = 0.04$, the marginal cost of generation is $c = 0$, and the arrival rate of water is $\phi = 10$. Thus, for example, raising the long-run level of the spot price (μ) by ten percent increases $\hat{p}$ from approximately 44.11 to 47.73. Raising σ, instead, by ten percent increases $\hat{p}$ to 45.66, while raising η by ten percent reduces $\hat{p}$ to 43.81. The optimal price threshold is increasing in the long-run level of the spot price and the volatility of spot price movements, and decreasing in the rate of mean reversion.[16]

[16]These findings suggest that studies such as Wolfram (1998), who analyzed the amount by which UK firms' offer prices exceed their estimated marginal cost, need to control for such factors as price volatility. For example, if firms have timing flexibility regarding their generation decisions, the markup will be relatively high during periods of greater price volatility. Omitting such controls could lead to mistakenly concluding that firms are exercising unilateral market when they are actually behaving competitively.

The behavior of the optimal price threshold is most easily understood in terms of the option value of stored water. From (5), the price threshold satisfies

$$\hat{p} = c + G(\hat{p}),$$

and is therefore the sum of the marginal cost of generating electricity, c, and the option value of water, $G(\hat{p})$. The observations above therefore amount to the option value of stored water being positive, increasing in the long-run average spot price and the volatility of spot price movements, and decreasing in the rate of mean reversion. The analogy between stored water and an American call option, described at the end of Section 2.3, provides an intuitive explanation for these results. The option value is positive because the firm can never be forced to accept a negative cash flow: it can wait and only release the water when the spot price exceeds c. Its value is an increasing function of the long-run level of the spot price because a higher long-run level raises the expected cash flow from waiting and generating electricity in the future. The option value of water is an increasing function of spot price volatility because more volatile prices increases the upside potential of the option without affecting its downside potential: more volatility means that extremely high and low spot prices become possible, with only the former affecting the firm's cash flow. Weaker mean reversion has a similar impact, since this allows the spot price to deviate further from its long run level, in much the same way as greater volatility allows such price movements.

However, unlike the case of a standard call option, exercising the firm's option to release water from a storage facility is not entirely irreversible. At some point in the future, more water will become available, and it can be stored in the storage facility for subsequent release. If ϕ is high, emptying the storage facility can be quickly reversed, since more water will soon become available; the option value of water is low and the price threshold is determined primarily by the marginal cost of turning water into electricity. At the other extreme, when $\phi = 0$, no more water will ever become available, so that the firm's decision to generate electricity from stored water is completely irreversible; the option value of water is high and the price threshold is determined primarily by the distribution of future spot prices. Another way to think of this is to note that stored water is most valuable when water is scarce because the option value of refilling the storage facility is low, so the firm is under less pressure to release water prematurely.[17] Consistent with the intuition from real options analysis, the price threshold should be highest when releasing water is completely irreversible ($\phi = 0$).[18]

This is confirmed in Table 1, which examines the role of direct marginal cost (c) and water availability (ϕ) in determining the price threshold ($\hat{p}$). The entries in the table give the optimal

[17]In markets dominated by hydroelectric generation, we would expect electricity spot prices to be relatively high when water is scarce. However, the analysis here shows that stored water is more valuable when water is scarce *even when* the electricity spot price is held constant.

[18]Kandel and Pearson (2002) describe a real options model of investment involving a mix of reversible and irreversible technologies that offers insights into the role of irreversibility on optimal investment in physical capital.

Table 1: Optimal price thresholds for generating electricity from water

	Average no. days to refill	1999 $c=0$	1999 $c=1$	1999 $c=10$	May 2000 $c=0$	May 2000 $c=1$	May 2000 $c=10$
Price threshold							
$\phi = 0$	∞	68.92	69.01	69.88	201.73	201.83	202.78
$\phi = 1$	365.0	55.10	55.11	55.21	149.67	149.68	149.77
$\phi = 10$	36.5	44.11	44.11	44.14	111.67	111.68	111.71
$\phi = 100$	3.7	35.76	35.76	35.78	80.13	80.13	80.16
$\phi \to \infty$	0.0	0.00	1.00	10.00	0.00	1.00	10.00

Notes. The entries in the table give the optimal price threshold $\hat{p}$ (in \$/MWh) such that the firm should generate electricity from stored water if and only if $p \geq \hat{p}$. The left and right parts of each panel show results when the model is calibrated to spot price behavior in California during 1999 and May 2000 respectively. In each case, results are reported for three different levels of the direct marginal cost of generating electricity from water. In all cases, $r = 0.04$.

price threshold $\hat{p}$ (in \$/MWh) for different combinations of ϕ and c. The left and right parts of each panel show results when the model is calibrated to spot price behavior in California during 1999 and May 2000 respectively. The table confirms that (i) the optimal price threshold is greater than the firm's marginal cost of generation when there is any uncertainty about future water availability, and that (ii) the price threshold is higher when water is more scarce. Unless water is plentiful, the direct marginal cost has only a minor impact on the firm's optimal price threshold. Finally, comparison of the two parts of the table shows that the changed price distribution in California in May 2000, relative to 1999, significantly raises the optimal price threshold. Recall that this is before the extremely high prices arose later in 2000, when optimal price thresholds would be even higher. (This is discussed in more detail in Section 4.)

3 Optimal electricity generation using natural gas

In this section we modify our model of a hydroelectric generator so that it can be applied to firms that generate electricity from natural gas or any other storable fuel that can be traded on a spot market. Consequently, the value of the firm and its optimal generating policy will depend on two prices (the spot prices of electricity and gas), which complicates the analysis.

We consider a firm that operates an electricity generator capable of producing h units of electricity from each unit of natural gas at a cost of c.[19] The spot prices of electricity (p) and gas (g) evolve according to diffusion processes

$$dp = \mu(p,g)dt + \sigma(p,g)d\xi, \quad dg = \nu(p,g)dt + \phi(p,g)d\zeta, \tag{8}$$

where μ, ν, σ, and ϕ are functions of the two prices and $d\xi$ and $d\zeta$ are the increments of Wiener

[19] $1/h$ is the heat rate, which is the amount of gas required to produce one unit of electricity. Heat rates vary across gas-fired plants according to the efficiency of the plant.

processes, with $(d\xi)(d\zeta) = \rho\, dt$ for some $\rho \in (-1, 1)$. In a risk-neutral world without storage costs or a convenience yield, $\nu(p, g)$ would equal rg, so that storing natural gas would earn an expected rate of return equal to the risk-free interest rate. We assume that storage costs are zero, but the presence of a convenience yield embedded in the market price of gas means that $\nu(p, g)$ will not generally equal rg. We allow $\nu(p, g)$ to be arbitrary. As in Section 2, the firm is a price taker.

As in Section 2, the firm has access to a storage facility with sufficient capacity to store one unit of gas, which gives the firm some ability to shift its gas flows over time. The facility can be emptied and filled (provided gas is available) instantaneously and without cost.[20] We assume that the firm receives no benefit from its inventory apart from the cash flow generated by its subsequent release. The firm can only generate electricity when it has gas available. We assume that at any date t, one unit of gas becomes available during the interval $[t, t + dt)$ with probability $\phi\, dt$ for some constant ϕ. This friction, which ensures that the real options associated with storage facilities are valuable, could be motivated in various ways, but we interpret it as primarily representing the delays involved in transporting natural gas and emptying and refilling storage facilities.[21]

Let $G(p, g)$ denote the present value to the firm of one unit of stored gas. At any point in time, the firm can do one of three things if its storage facility is full. First, it can empty the storage facility and sell the gas on the spot market, receiving a payoff of g. Thus

$$G(p, g) \geq g. \tag{9}$$

Second, it can empty the storage facility and use the gas to generate electricity, receiving a payoff of $ph - c$. Thus

$$G(p, g) \geq ph - c. \tag{10}$$

Third, the firm can keep the storage facility full for the next dt units of time. At the end of this period, the stored gas will be worth $G(p + dp, g + dg)$. However, delay comes at a cost because it prevents the firm from storing any additional gas that arrives. If the storage facility were empty when this occurred, the firm would have the option to purchase the arriving gas and either store it (for a payoff of $G(p, g) - g$) or use it to generate electricity immediately (for a payoff of $ph - g - c$); the payoff would be

$$\max\{0, G(p, g) - g, ph - g - c\}.$$

[20] In the natural gas sector, storage opportunities take the form of 'seasonal facilities' (with typical injection and withdrawal periods of 200 and 60–100 days respectively) and 'high deliverability facilities' (with typical injection and withdrawal periods of 20 and 10–15 days respectively). Susmel and Thompson (1997, p. 21) discuss the various opportunities to store natural gas in the US, while Uria and Williams (2005) provide useful background of natural gas storage in California.

[21] A more natural way to model these delays would be to assume that emptying (or filling) a storage facility takes a specified amount of time. However, adopting this approach would introduce an explicit time-dependence into the value of the firm that would greatly complicate the analysis without offering any fundamental additional insights.

But because the facility is already full, all the firm can do if it purchases the gas is use it to generate electricity immediately; the payoff is therefore

$$\max\{0, ph - g - c\}.$$

Because gas arrives with probability $\phi\, dt$, the expected cost to the firm is

$$\phi \Big(\max\{0, G(p,g) - g, ph - g - c\} - \max\{0, ph - g - c\} \Big)\, dt.$$

However, this case only arises when delay is optimal; that is, for combinations of p and g where $G(p,g) > \max\{ph - c, g\}$. Therefore, the expected cost can be simplified to

$$\phi \Big(G(p,g) - \max\{g, ph - c\} \Big)\, dt.$$

Thus

$$G(p,g) \geq e^{-r\,dt} E[G(p + dp, g + dg)] - \phi \Big(G(p,g) - \max\{g, ph - c\} \Big)\, dt,$$

which simplifies to

$$\frac{E[dG(p,g)]}{dt} - (r + \phi) G(p,g) + \phi \max\{g, ph - c\} \leq 0. \tag{11}$$

The value of stored gas satisfies (9)–(11), with one of these conditions (corresponding to the optimal action) holding with equality for any particular values of p and g. This system determines the value of stored gas to the firm. Unlike the model of hydroelectric generation in Section 2, we are unable to find a closed-form solution to this equation. Therefore, we analyze the behavior of the optimal policy using numerical analysis.

We use daily data from 1999 on electricity and gas prices in California to calibrate the model. The electricity price used is the daily-average of the day-ahead unconstrained price from the California Power Exchange (as in Section 2.4) and the gas price is the daily average natural gas spot prices at PG&E city gate reported by Natural Gas Intelligence. Since the gas price is unavailable on weekends or public holidays, we only use weekday observations. Using the approach described in Appendix B, we fit our square root model to the electricity and gas price series separately and find that in 1999

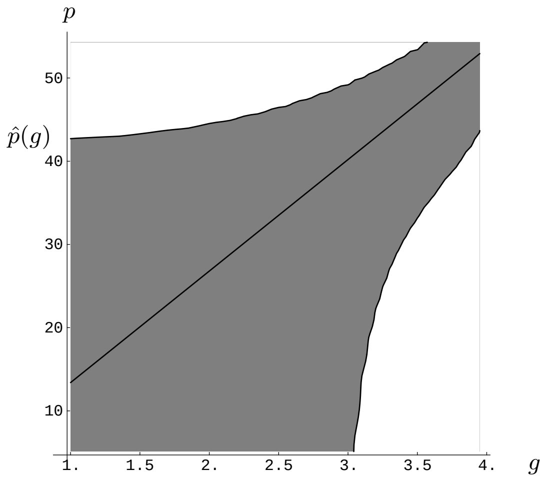
$$dp = 32.46(30.12 - p)dt + 15.06 p^{1/2} d\xi, \quad dg = 5.35(2.50 - g)dt + 0.79 g^{1/2} d\zeta,$$

with $\rho = 0.22$. When data from May 2000 is used instead, we obtain[22]

$$dp = 101.65(53.38 - p)dt + 55.77 p^{1/2} d\xi, \quad dg = 11.11(5.52 - g)dt + 2.33 g^{1/2} d\zeta.$$

Figure 4 displays the optimal gas inventory management policy for a firm facing electricity and gas prices that follow the calibrated process using the price process obtained from 1999 data. The graph shows the optimal generation policy for a generator with a heat rate of 13.4 MMBtu/MWh. The optimal decision when the firm's storage facility is full depends on the

Figure 4: Optimal policy for managing gas inventory



Notes. The graph shows the optimal generation policy for a generator with a heat rate of 13.4 MMBtu/MWh. When (g, p) lies in the top unshaded region the firm will release gas from a full storage facility and use it to generate electricity. When it lies in the top part of the shaded region (that is, above the solid line) the firm will keep its storage facility full, but will purchase any additional gas that becomes available and use it to generate electricity. The firm will also keep its storage facility full when (p, g) lies in the bottom part of the shaded region, but now it will not purchase any more gas that becomes available. Finally, when (p, g) lies in the bottom unshaded region, the firm will release gas from a full storage facility and sell it on the gas spot market. The processes for p and g are calibrated to data in California in 1999. Other parameters are $r = 0.04$, $c = 0$ and $\phi = 10$.

current values of g (the horizontal axis) and p (the vertical axis). When (g, p) lies in the top unshaded region the firm will release gas from a full storage facility and use it to generate electricity. When it lies in the top part of the shaded region (that is, above the solid line) the firm will keep its storage facility full, but will purchase any additional gas that becomes available and use it to generate electricity. The firm will also keep its storage facility full when (p, g) lies in the bottom part of the shaded region, but now it will not purchase any more gas that becomes available. Finally, when (p, g) lies in the bottom unshaded region, the firm will release gas from a full storage facility and sell it on the gas spot market. Similarly, if the firm's storage facility is empty when gas arrives, the firm should buy the gas and use it to generate electricity immediately if (p, g) lies in the top unshaded region, buy the gas and store it if (p, g) lies in the shaded region, and otherwise not buy the gas.

As long as the storage facility is full, the firm has the option to delay using the gas. This option will be especially valuable if $ph - g - c$ is close to zero, since then it is not clear whether the firm should sell the gas on the spot market (and receive g) or use it to generate electricity

[22] The correlation for the month of May 2000 was negative, which we regard as implausible. We therefore use the same correlation as for 1999.

(and receive $ph - c$). Thus, in order for immediate electricity generation to be optimal, $ph - c$ must exceed both the cash flow from immediate resale and the value of the delay option; that is, generation is only optimal if $ph \geq c + G(p, g)$. The optimal policy is to generate electricity from stored gas as soon as the electricity price reaches a threshold (denoted by $\hat{p}(g)$ in Figure 4) that is relatively insensitive to the level of the gas price for all but the highest values of g. This result is consistent with our findings in Section 2 that the marginal cost of generating electricity has little impact on the optimal (price-taking) offer price. Similarly, in order for resale to be optimal, g must exceed not just the cash flow from the alternative use, but also the value of the option destroyed when the storage facility is emptied; that is, resale is only optimal if $g \geq G(p, g)$.[23] The optimal inventory policy therefore depends crucially on the value of the delay option.

In order to better understand the determinants of the optimal generation policy, in Table 2 we summarize the optimal generation policy when the model is calibrated to spot price behavior in California in 1999 (the left part of each panel) and in May 2000 (the right part of each panel). The entries in the table give the optimal price threshold (in \$/MWh) $\hat{p}(g)$ such that the firm should generate electricity from stored gas if and only if $p > \hat{p}(g)$. The top and bottom panels report the results for a representative generator with low (6.8 MMBtu/MWh) and high (13.4 MMBtu/MWh) heat rates respectively.[24] In each case, results are reported for the long-run level of the gas spot price (in \$/MMBtu), as well as one standard deviation above and below this long-run level. Notice how similar the table is to Table 1, which shows the optimal price threshold for a hydroelectric generator. Like the earlier case, the optimal price threshold is greater than the firm's marginal cost of generation when the arrival of more gas is subject to delay, and this threshold is higher when gas is more scarce. Unless the decision to release gas from storage can be easily reversed (that is, unless ϕ is large), the spot price of gas has only a minor impact on the firm's optimal price threshold. As in Table 1, comparison of the two parts of the table shows that the changed price distribution in California in May 2000, relative to 1999, significantly raises the optimal price threshold.

4 The California electricity crisis

Many electricity market power studies have, naturally, focussed on the Southern California market of 2000–2001, which witnessed extremely high electricity spot prices for a sustained

[23]If storage could be continuously and instantaneously adjusted without cost, firms would increase storage until the marginal value of gas to the firm equalled the spot price — in equilibrium, any option value would be reflected in the spot price. However, the spot price is volatile, whereas changes in storage levels are slow. This friction allows a wedge to appear between spot price and marginal value to the firm.

[24]The generator with a low heat rate is representative of a new combine cycle gas turbine. The high heat rate generator is representative of older less efficient plants. See Sweeney (2002, pp. 120–121) for further discussion of heat rates.

Table 2: Optimal price thresholds for generating electricity from natural gas

	Average no. days to refill	1999			May 2000		
		$g = 2.12$	$g = 2.50$	$g = 2.88$	$g = 4.36$	$g = 5.52$	$g = 6.68$
Low heat rate							
$\phi = 0$	∞	68.92	68.92	68.92	201.73	201.73	201.73
$\phi = 1$	365.0	53.24	53.26	53.27	144.71	144.77	144.85
$\phi = 10$	36.5	41.95	41.98	42.03	108.69	109.09	109.56
$\phi = 100$	3.7	33.84	33.88	33.96	79.49	81.29	83.60
$\phi \to \infty$	0.0	14.40	17.00	19.60	29.64	37.54	45.43
High heat rate							
$\phi = 0$	∞	68.92	68.92	68.92	201.73	201.73	201.73
$\phi = 1$	365.0	54.16	54.31	55.30	149.61	149.98	150.36
$\phi = 10$	36.5	44.08	45.73	47.60	116.37	118.41	124.41
$\phi = 100$	3.7	37.18	39.75	43.60	91.61	101.38	111.97
$\phi \to \infty$	0.0	28.38	33.50	38.62	58.41	73.97	89.53

Notes. The entries in the table give the optimal price threshold $\hat{p}(g)$ (in \$/MWh) such that the firm should generate electricity from stored gas if and only if $p > \hat{p}(g)$. The top and bottom panels report the results for a representative generator with low (6.8 MMBtu/MWh) and high (13.4 MMBtu/MWh) heat rates respectively. The left and right parts of each panel show results when the model is calibrated to spot price behavior in California during 1999 and May 2000 respectively. In each case, results are reported for the long-run level of the gas spot price (in \$/MMBtu), as well as one standard deviation above and below this long-run level. In all cases, $c = 0$ and $r = 0.04$.

period.[25] The dark gray bars in Figure 5 plot the average spot price in the indicated month and the light gray bars plot the standard deviation across that month. The electricity price is the day-ahead unconstrained price from the California Power Exchange,[26] while the gas price is the spot price at PG&E city gate.[27] As the left graph shows, both the average and standard deviation of electricity prices were substantially higher during the crisis period than in 1999. Such episodes can be caused by abuses of market power, an unusually high opportunity cost of generation due to factors outside firms' control, or some combination of the two. The challenge facing policymakers is to distinguish between these potential causes.

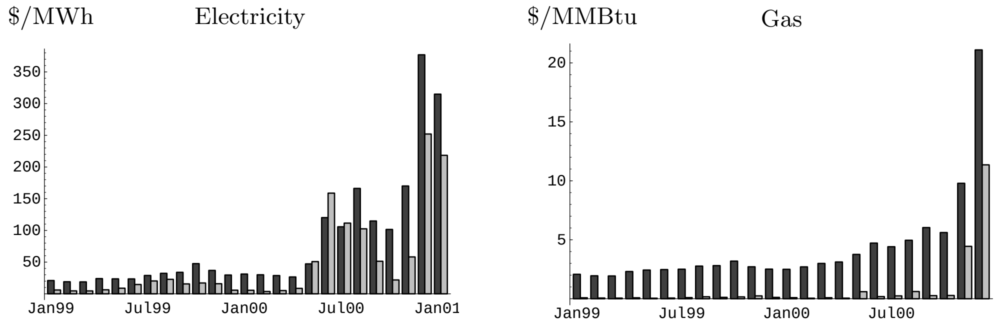
Although the effects of electricity price volatility and uncertain resource availability on suppliers' decisions have not been formally analyzed in these studies, the conditions for option values to be high are present in the California market during this period. Demand had been growing faster than most had anticipated since deregulation and establishment of the spot market in 1997, reflecting extremely rapid growth of the California economy over this period, and

[25] Different studies were conducted for different purposes, including the quantification of compensatory amounts to be paid to consumers. Studies of the California market, at least as of 2004, are reviewed by Cicchetti et al. (2004), who themselves study the California electricity and gas prices by comparing price paths of estimated reduced forms based upon fundamentals, such as weather, with the actual price paths.

[26] There is one price for each hour of the day.

[27] A daily-average price is reported by Natural Gas Intelligence.

Figure 5: Electricity and gas prices in California



Notes. In each graph the dark gray bars plot the average spot price in the indicated month and the light gray bars plot the standard deviation across that month. The electricity price is the day-ahead unconstrained price from the California Power Exchange, while the gas price is the daily average natural gas spot prices at PG&E city gate reported by Natural Gas Intelligence.

environmental constraints and uncertainty surrounding restructuring had limited investment in additional generation (Joskow, 2001, pp. 374–375). The unusually hot summer in 2000 raised air conditioner demand, while the unusually dry and cold winter in 2001 raised electricity and gas demand. The convex shape of typical electricity supply curves means that even a small demand shock can lead to a relatively large shock to the market-clearing electricity price when demand is relatively high. Thus, prices would have been more volatile than usual — and generation timing options more valuable than usual — during this period even in the absence of any fuel shortages and uncertainties. However, as we now explain, the fuel situation in California during this period was such that option premia would have been even greater.

California, using its hydroelectric plants, typically sent electricity north in the winter and received electricity south in the summer from hydroelectric plants in the Pacific Northwest. However, the hot summer in California in 2000 was accompanied by drought in the Pacific Northwest, so hydroelectric imports were hugely curtailed. This is evident in the top panel of Table 3, which reports monthly net electricity generation by fuel type for the years 1999 and 2000. It shows that net generation by hydroelectric plants in Oregon and Washington during the second half of 2000 was significantly less than in the previous year. The table also shows that the deficit was made up primarily by increased generation by Californian natural gas-fired powerplants; the drought left Californian hydroelectric generators with limited stored water and unable to replace the reduced imports (Cicchetti et al., 2004, p. 87).

The reduction in imported hydroelectric generation, combined with the inability of Californian hydroelectric generators to make up the shortfall, meant that demand would have to be met by increased production by inefficient gas-fired powerplants that would not normally be dispatched. This would have shifted the supply curve up and, by dispatching inefficient gas-fired plants at lower levels of demand, made it steeper. This was compounded by increases in fuel

Table 3: Summary of the situation in California

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Electricity generation in California and the Pacific Northwest (GWh)													
Total (Ca)	1999	13454	11806	13643	13578	14444	16440	18824	18889	16782	17977	15621	15824
	2000	14416	14153	15462	14782	18123	21338	21953	24492	20461	16903	15736	16674
Gas (Ca)	1999	5990	4697	4699	5302	4850	6509	8794	9331	8761	11233	8155	7730
	2000	7140	6382	5759	5548	8344	11461	12025	15015	12794	10446	9142	9189
Hydro (Ca)	1999	2898	3802	4142	3905	4362	4233	4198	3736	2827	2403	1976	2033
	2000	1972	2780	4303	3914	4654	4482	4259	3793	2594	2160	2236	2053
Other (Ca)	1999	4566	3307	4802	4371	5232	5698	5832	5822	5194	4341	5490	6061
	2000	5304	4991	5400	5320	5125	5395	5669	5684	5073	4297	4358	5432
Hydro (Or)	1999	4656	4195	4873	4139	4027	4305	3409	2741	2953	2879	3204	4174
	2000	4331	3786	4040	4261	3609	2886	2579	2148	2175	2521	2722	3108
Hydro (Wa)	1999	8934	8119	9175	7789	8116	9893	9022	8302	6079	5696	6757	8936
	2000	8667	6942	6973	8172	8165	7022	6708	5802	4990	5063	5699	6130
Natural gas (stored working gas, in Bcf)													
	1999	146	128	114	117	144	165	176	173	183	187	192	169
	2000	142	120	123	143	154	161	160	141	142	152	125	118
	2001	79	59	74	91	119	153	174	187	199	214	228	200

Notes. Generation data is from the Energy Information Administration, "Electric Power Monthly"; generation data from non-utility power plants is unavailable at the state-level from January 2001. Natural gas storage data is from the Energy Information Administration.

costs, which reflected a nationwide increase in natural gas prices.[28] In addition to shifting the supply curve upwards, the higher fuel prices made the supply curve steeper at high levels of production as the marginal cost of less fuel-efficient plants is more sensitive to fuel prices than that for more fuel-efficient plants (Borenstein et al., 2002, p. 1385). Shifting the supply curve upwards raises prices, while making it steeper raises price volatility. Since both changes would have been predicted by market participants, the option premium of generators with storage facilities should have risen as soon as the drought conditions became apparent — even for firms that did not themselves experience any greater fuel scarcity or uncertainty than usual. Tables 1 and 2 suggest that the effect on offer prices could be substantial. Recall that the left part of each table reports optimal price thresholds when the model parameters reflect price behavior in 1999, while the right part reflects price behavior in May 2000 — which, from Figure 5, involves only a relatively minor increase in the level and volatility of prices. Nevertheless, these two tables show that, holding fuel availability (ϕ) constant, optimal offer prices more than double.

However, many of the firms with storage facilities were themselves experiencing an unfavorable fuel situation, which compounds the effects described above. For example, Californian hydroelectric generators were affected by the drought, facing reduced storage and reduced future inflows. As the ϕ comparative statics in Section 2 show, this would have further increased the option value of what water they did have in storage. From Table 1, price-taking hydroelectric generators would respond by setting higher offer prices. Natural gas-fired generators also experienced unusual fuel supply conditions during the 2000–2001 period. Gas is pumped into storage at times of low prices and released when prices rise and when peak demand approaches the capacity of the transmission system. At the time of the crisis, there was storage capacity for 217 Bcf (billion cubic feet) of natural gas in California, while the maximum injection and withdrawal rates were 1.3 and 4.9 Bcf per day, respectively (California Energy Commission, 2001, Figure 6-1). In contrast, interstate pipelines had a capacity of 7.3 Bcf per day, so there was clearly the potential for stored gas to play an important role in electricity generation. Moreover, California imports approximately 85% of the natural gas it requires[29] and during this period the interstate pipelines into California were congested, decoupling natural gas prices in the region from prices in other parts of the country (Cicchetti et al., 2004, pp. 88–89).[30] Therefore, the only way to raise electricity output to offset the reduced hydroelectric generation was to use stored gas.[31]

[28] The average gas spot price at the Henry Hub in May 2000 was 59 percent higher than the average price in May 1999. The average price at the Henry Hub during November–December 2000 was more than three times the average price there one year earlier. In addition, the price of NO_x permits soared over the relevant period, further raising the marginal cost of gas plants. To the extent that there were any frictions producing illiquidity in the spot market for NO_x permits, qualitatively the same issues would arise for NO_x permits as for stored gas.

[29] California Energy Commission (2001, p. 35).

[30] The average gas spot price at the P&G city gate in November–December 2000 was more than twice that at the Henry Hub during the same period. In contrast, for November–December 1999 the difference was just ten percent.

[31] The problem was compounded by an explosion on the El Paso pipeline in August 2000. One firm, Southern

The bottom panel of Table 3, which reports the amount of 'working gas' stored in California in each month before and during the crisis period, shows that the greater demand on storage meant that inventories fell to historically low levels as the crisis progressed.[32] As Table 2 shows, even a price-taking firm would set a higher price threshold as dwindling supplies raise the option value of what gas remains.

It is apparent that during the 2000–2001 period a collection of circumstances arose in California that each had the effect of making the generation-timing option embedded in stored fuel more valuable. The real options interpretation offers one explanation of the high prices observed in California, one that has not been adequately considered by existing industry studies.

5 Concluding remarks

We developed a simple model of a price-taking firm that generates electricity using a storable fuel source, which enabled us to analyze the impact of uncertainty surrounding future electricity and fuel prices and future fuel availability. These sources of uncertainty are essential components of any modeling effort because they determine the value of the real options that are embedded in fuel storage facilities and the fuel that they contain. We found that a price-taking and value-maximizing electricity generator will only generate electricity if the electricity spot price exceeds the sum of the direct cost of creating one unit of electricity (comprising the marginal cost of transforming fuel into electricity and the cost of the fuel itself) and the indirect cost of destroying, at least temporarily, the option to turn stored fuel into electricity in the future.[33] Even when the direct component is small, the indirect component can be large. The volatile nature of electricity spot prices means that the value of this option can be significant. It will be especially high in regions where, and during periods when, anticipated fuel inflows are low.

An implication of our analysis is that when firms are observed not generating electricity when the spot price is significantly higher than their direct marginal cost, one cannot conclude that they must be exploiting market power. They may, as is the case of the firm in our model, simply be comparing the current electricity price with the true cost of generating and recognizing that the apparent profit derived from generating at that date is insufficient to cover the value of the real options embedded in stored fuel that will be destroyed when the fuel is released from storage. If policymakers do not allow for the real options embedded in generation, they risk inducing behavior by generators that is inconsistent with price-taking value-maximization (such

California Gas Company Gas, was forced to increase withdrawals of gas from storage by approximately 0.2 Bcf per day to compensate for the reduced supply of gas (California Energy Commission, 2001, p. 75).

[32]So-called 'working gas' volumes measure the amount of gas in a storage facility that can be withdrawn as part of the facility's normal operations.

[33]We have not examined the implications of generation timing options for the provision and terms of electricity supply hedge contracts. Nevertheless, these will be affected since entering hedge contracts will generally extinguish delay options provided by participation in the spot market. In addition, longer-term hedge arrangements can be expected to incorporate recognition that demand and fuel availability scenarios vary over time.

as suboptimal investment in storage), thereby lowering overall welfare.

We showed that the optimal price threshold depends on the distribution of future levels of electricity and fuel prices and the scarcity of fuel; the direct marginal cost is relatively unimportant.[34] Our approach has been to model expectations of future prices in terms of stochastic processes for electricity prices and fuel prices. However, this just shifts the formation of expectations to the parameters of these models, about which it is reasonable for different generators to have entirely different views.[35] Our application to California in the 1999–2001 period illustrates that views about these parameters can be expected to change, especially in the short- to medium-term as relevant commodity prices and supplies, and demand, evolve.

Recent studies of market power in electricity markets presume static, albeit in some cases subject to random shocks, supply curves. Our work suggests that if functions that are static are to be reasonable inputs to assessing electricity market outcomes they should include those factors that affect the option to delay. In particular they should include measures of the volatilities of electricity prices, fuel supplies, and prices. Such is the role of expectations and individual circumstance in bid behavior that it will continue to be very difficult to obtain a credible measure of market power. The difficulty is exacerbated by any correlation between market-wide fuel scarcity and individual bidding behavior. As fuel supplies are expected to become less readily available and the option of delay becomes more valuable, aggregate electricity prices will rise even if there is no market power whatsoever. Such is the difficulty in assessing market power in spot electricity markets that the preferred approach may be to focus on reducing barriers to entry and studying whether market performance is reasonable in light of market fundamentals of supply and demand; this is the approach Cicchetti et al. (2004) apply to the California market.

Future research might extend the model described in Section 2 so that the water arrival rate, ϕ, is a decreasing function of the electricity spot price. This would reflect the fact that in markets that are dominated by hydroelectric generation the spot price will tend to be high when water is scarce. The likely effect of this is to raise the price threshold above that found to be optimal in this paper, since water will tend to be scarce during periods when the spot price is relatively high and the opportunity cost of generating electricity run-of-river will be higher than in the current model. The restrictive assumption that the storage facility is either full or empty at any point in time, which is a feature of both models, could also be relaxed. This would enhance our understanding of how the level of storage affects generating behavior as well

[34]To the extent that intertemporal choice is important in short run decisions about electricity generation there will be a confounding of supply and demand curves. A common element of static models is that demand is determined by preferences and income, while supply is determined by available technology. However, where expectations are relatively important they will influence both supply and demand factors, rendering it extremely difficult to separate demand from supply without good structural models of all relevant factors (Sims, 1980).

[35]In their report on the high-price episode in New Zealand during 2001, which drew on a confidential survey of market participants, the Market Surveillance Committee of the New Zealand Electricity Market report that there had been quite different expectations about the state of fuel supplies and their implications for prices among market participants (Market Surveillance Committee, 2001, p. 25).

as allow us to construct hypothetical bid *curves*. It will also offer insights into how the level of inventory affects the convenience yield associated with a much wider variety of commodities than fuels for generating electricity. Finally, a model of the market-clearing spot price might be developed for a market in which firms are of the type considered in this paper. Our result that the optimal price threshold for an electricity generator is driven more by the distribution of future prices than the marginal cost of generation should lead to the sort of bidding behavior that characterizes pay-as-you-bid auctions, where firms offer to generate electricity at a price that reflects the distribution of likely spot prices rather than the firms' individual marginal costs. Such an extension would greatly enhance our understanding of how competition occurs in electricity markets.

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A Solving for the value of stored water

In this appendix we value water stored by a hydroelectric generator in the special case where the spot price follows the mean reverting process

$$dp = \eta(\mu - p)dt + \sigma p^{1/2} d\xi,$$

where η, μ and σ are constants and $d\xi$ is the increment of a Wiener process.

As part of the solution process, we will have to solve the ordinary differential equation

$$\frac{1}{2}\sigma^2 p F''(p) + \eta(\mu - p)F'(p) - (r + \phi)F(p) = 0. \tag{A-1}$$

Making the substitution

$$F(p) = p^{1-\frac{2\eta\mu}{\sigma^2}} y(x), \quad x = \frac{2\eta p}{\sigma^2},$$

shows that y must satisfy Kummer's equation

$$0 = xy''(x) + (b - x)y'(x) - ay(x),$$

where

$$\begin{aligned} a &= \frac{r+\phi}{\eta} + 1 - \frac{2\eta\mu}{\sigma^2}, \\ b &= 2 - \frac{2\eta\mu}{\sigma^2}. \end{aligned}$$

Two linearly independent solutions to Kummer's equation are $x^{1-b}M(1 + a - b, 2 - b, x)$ and $U(a, b, x)$, where M and U are the confluent hypergeometric functions of the first and second kind respectively. Therefore, two complementary functions for (A-1) are

$$C_1(p) = M\left(\frac{r+\phi}{\eta}, \frac{2\eta\mu}{\sigma^2}, \frac{2\eta p}{\sigma^2}\right)$$

and

$$C_2(p) = p^{1-\frac{2\eta\mu}{\sigma^2}} U\left(\frac{r+\phi}{\eta} + 1 - \frac{2\eta\mu}{\sigma^2}, 2 - \frac{2\eta\mu}{\sigma^2}, \frac{2\eta p}{\sigma^2}\right).$$

Notice that $C_1(0) = 1$ and $\lim_{p\to\infty} C_2(p) = 0$.

We consider generation policies described by a single price threshold $\hat{p}$. When its lake is empty, the firm will generate electricity from any water that arrives if $p > \hat{p}$ and will store it otherwise. When its lake is full, the firm will immediately generate electricity by releasing the water stored in the lake if $p > \hat{p}$; it will keep the water in the lake and generate electricity from any water that arrives if $c < p \leq \hat{p}$; it will keep the water in the lake and spill any water that arrives if $p \leq c$.

We calculate the value of water to the firm over the intervals $[0, c]$, $(c, \hat{p}]$ and $(\hat{p}, \infty)$.

- If $0 \leq p \leq c$, the firm waits and spills any water that becomes available. Since the lake is already full to capacity, newly available water cannot be stored. Thus

$$0 = \frac{E[dG(p)]}{dt} - (r + \phi)G(p),$$

so that G satisfies the ordinary differential equation

$$0 = \frac{1}{2}\sigma^2 p G''(p) + \eta(\mu - p)G'(p) - (r + \phi)G(p), \quad 0 \le p \le c,$$

together with the requirement that $G(0)$ is finite. The solution is

$$G(p) = A_1 C_1(p), \quad 0 \le p \le c,$$

where A_1 is a constant to be determined.

- If $c < p \le \hat{p}$, the firm waits and generates electricity from any water that becomes available. Thus

  $$0 = \frac{E[dG(p)]}{dt} - (r + \phi)G(p) + \phi(p - c),$$

  so that G satisfies the ordinary differential equation

  $$0 = \frac{1}{2}\sigma^2 p G''(p) + \eta(\mu - p)G'(p) - (r + \phi)G(p) + \phi(p - c), \quad c < p \le \hat{p}.$$

  The solution is

  $$G(p) = \phi\left(\frac{p - \mu}{r + \phi + \eta} - \frac{c - \mu}{r + \phi}\right) + A_2 C_1(p) + A_3 C_2(p), \quad c \le p < \hat{p},$$

  where A_2 and A_3 are constants to be determined.

- If $p > \hat{p}$, the firm immediately empties the lake and generates electricity. Thus,

  $$G(p) = p - c, \quad \hat{p} < p.$$

The form of (4) implies that G and G' are continuous at $p = c$, whence

$$\begin{aligned} A_1 C_1(c) - A_2 C_1(c) - A_3 C_2(c) &= \phi\left(\frac{c - \mu}{r + \phi + \eta} - \frac{c - \mu}{r + \phi}\right), \\ A_1 C_1'(c) - A_2 C_1'(c) - A_3 C_2'(c) &= \phi\left(\frac{1}{r + \phi + \eta}\right). \end{aligned}$$

Similarly, G is continuous at $p = \hat{p}$, requiring that

$$A_2 C_1(\hat{p}) + A_3 C_2(\hat{p}) = \hat{p} - c - \phi\left(\frac{\hat{p} - \mu}{r + \phi + \eta} - \frac{c - \mu}{r + \phi}\right).$$

There are three constants and three equations, enough to solve for these constants in terms of $\hat{p}$. This completely determines the value of water to the firm as a function of the generation threshold $\hat{p}$. The optimal policy is found by choosing $\hat{p}$ in order to maximize A_1. This corresponds to imposing the so-called smooth-pasting condition that G' is continuous at $p = \hat{p}$ (Dixit, 1993).

B Calibrating the spot price process

If p follows the square root diffusion (7), then $q = p^{1/2}$ follows the process

$$dq = \left(\left(\frac{\eta\mu}{2} - \frac{\sigma^2}{8} \right) q^{-1} - \frac{\eta}{2} q \right) dt + \frac{\sigma}{2} d\xi.$$

Assuming discrete time steps of length Δt, the corresponding Euler approximation is

$$q_{n+1} = \alpha_1 q_n^{-1} + \alpha_2 q_n + \varepsilon_{n+1}, \qquad \text{(B-1)}$$

where ε_{n+1} is normally distributed with mean zero and variance ϕ^2,

$$\begin{aligned} \alpha_1 &= \left(\frac{\eta\mu}{2} - \frac{\sigma^2}{8} \right) \Delta t, \\ \alpha_2 &= 1 - \frac{\eta}{2} \Delta t, \\ \phi^2 &= \frac{\sigma^2}{4} \Delta t. \end{aligned}$$

We estimate equation (B-1) and, given the estimated parameters $\hat{\alpha}_1$, $\hat{\alpha}_2$, and $\hat{\phi}$, solve the above equations to obtain the parameter estimates for the square root diffusion:

$$\begin{aligned} \hat{\eta} &= \frac{2(1 - \hat{\alpha}_2)}{\Delta t}, \\ \hat{\mu} &= \frac{\hat{\alpha}_1}{1 - \hat{\alpha}_2} + \frac{\hat{\phi}^2}{2(1 - \hat{\alpha}_2)}, \\ \hat{\sigma} &= \frac{2\hat{\phi}}{\sqrt{\Delta t}}. \end{aligned}$$