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The role of storage in a competitive electricity market and the effects of climate change ☆

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ABSTRACT

This paper uses a new model of a competitive electricity market to investigate the role of storage in markets dominated by hydro generation. Competition among generators leads to an endogenous shadow price of stored water, which facilitates the efficient intra-day and inter-season substitution of fuel. Overall welfare depends on storage capacity, the cost structure of non-hydro generators, and the characteristics of water inflows. If climate change reduces the long-run average level of inflows or leads to the introduction of a carbon tax then overall welfare will fall and the profitability of generators will rise. The welfare benefits from additional storage capacity will increase if climate change makes long-term inflows less predictable or leads to the introduction of a carbon tax. They will decrease if average inflows fall or the predictable seasonal cycle in inflows becomes less pronounced.

1. Introduction

This paper investigates the role of storage in a competitive electricity market that is dominated by hydro generation. We use a new theoretical model that accounts for uncertainty in the rate of inflows to the hydro storage lakes that allow water to be saved for use during high-demand periods.[1] The model is formulated in continuous time, which approximates the real-time nature of electricity markets. Our analysis predicts the behavior of electricity prices and quantities, the composition of fuels used to generate electricity, and the shadow price of stored water, and reveals how these predictions depend on storage and generation capacity. We explore the effects of potential climate change on behavior by examining the effects of four particular scenarios. Specifically, we consider changes in the average level of inflows to storage lakes, the predictable seasonal variation around this average, and the size and persistence of unpredictable shocks to inflows.[2] We also consider the possibility of a carbon tax.

Our intertemporal model features competing electricity generators—gas and hydro—that take the spot price as given and independently make generation decisions that maximize the present values of their individual profit flows. The rate at which water flows into the storage lakes is exogenously determined, and has both a predictable seasonal component and an unpredictable component. However, the hydro generator's ability to store water for future electricity production means that the supply of hydro generation can deviate from the contemporaneous level of inflows. Demand varies predictably by time of day and time of year, and at each point in time the market-clearing spot price equates the aggregate supply of electricity with demand by consumers. Like the spot price, the shadow price of stored water is endogenously determined and varies with the time of year, the level of inflows, and the amount of stored water.

The marginal cost function for gas generation is increasing in output, as high-cost generation is used only when all lower-cost generation capacity has been exhausted. The resulting convexity of the cost function

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[1] The model is calibrated to the New Zealand Electricity Market (NZEM), an energy-only market in which hydro generation accounts for approximately 55–65% of generation capacity (Evans and Meade, 2005, Chapter 3). The capacity of the storage lakes is low and inflows to these reservoirs are volatile.

[2] We do not distinguish between climate cycles of a stationary environment (Brönniman et al., 2008) and irreversible climate change (Stern, 2006).

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means that the ability to store water reduces the average cost of generating electricity by enabling the substitution of increased low-cost gas generation in low-demand periods for reduced high-cost gas generation in high-demand periods. The extra low-cost gas generation in low-demand periods allows contemporaneous hydro generation to be reduced and the water saved to facilitate increased hydro generation (and reduced high-cost gas generation) in high-demand periods. We show that competition between gas and hydro generators leads to such intertemporal substitution of fuel, at both intra-day and inter-season frequencies. We also show that the actual allocation of water among seasons and between off- and on-peak periods is materially affected by the nature of the gas plant that make up the generation supply curve. For example, increasing the capacity of gas plants reduces the amount of inter-season fuel substitution and increases off-peak hydro use.

Our analysis demonstrates that if climate change reduces the long-run average level of inflows to hydro storage lakes then it will raise average prices and reduce welfare significantly. However, as there is less water to carry forward from the high-inflow/low-demand spring and summer periods to the low-inflow/high-demand fall and winter periods, the lower average level of inflows eases the pressure on the storage system. The market thus does a better job of substituting fuel intertemporally, and the spread between the average rates of gas generation in high- and low-demand periods is much narrower than in the baseline case. If climate change reduces the magnitude of seasonal cycles in inflows then, with less variation in the average rate of inflows between summer and winter, the market makes less use of storage to transfer hydro from summer to winter and gas from winter to summer. In both cases, the change in average inflows makes additional storage capacity less valuable.

We also consider the effects of climate-induced changes in the unpredictable component of inflows, focussing on increased volatility. The resulting increased potential for very large inflows puts more pressure on the market's ability to store water for future use, so there is less intertemporal fuel substitution and additional storage capacity is more valuable than in the baseline case. However, if larger shocks to short-term inflows are accompanied by stronger mean reversion, so that inflow shocks are less persistent, then the additional pressure exerted on the market's storage capacity is not as great, the reduction in intertemporal fuel substitution is less significant, and the increase in value of additional storage capacity is minor.

Another possible consequence of climate change that we consider is the introduction of a carbon tax, which increases the marginal cost of gas generation and therefore the heterogeneity of the collection of gas generation assets. We find that gas generation during high-demand periods is reduced by more than in low-demand periods, but hydro generation is not reallocated to substitute. Instead, the shadow price of water and the average (post-tax) cost of generating electricity both rise. Overall welfare falls, but the nature of a uniform-price auction means that generators actually benefit from the introduction of the tax, because the higher spot price increases the profitability of hydro generators and infra-marginal gas generators.

The model presented in this paper extends existing intertemporal models of electricity markets in significant ways. For example, Evans and Guthrie (2009) analyze the behavior of a price-taking generator and show that uncertainty regarding future fuel availability affects behavior, but the spot price is exogenous in their model. In contrast, Hansen (2008) analyzes equilibria in a two-period model featuring multiple identical hydro generators and uncertain inflows in the second period, but there is no thermal generation and no allowance for seasonality in demand and inflows. Operational research models have been constructed to simulate electricity systems and incorporate generator behavior. They are typically in discrete time, complex, and do not have intertemporal generator decision making under uncertainty driven by time dependent stochastic inflows.[3] “Hybrid” models feature exogenous stochastic demand and supply processes, which yield predicted market-clearing spot prices in terms of observable quantities.[4] While it is possible to vary the parameters that determine the demand and supply processes and analyze the resulting changes in spot price behavior, such an approach does not enable identification of behavioral response to the environment.

Although it is not the main focus of this paper, we believe our work offers insights to the literature assessing bidding behavior in electricity markets. The usual approach is to predict the bidding behavior implied by estimated marginal cost curves, either at the level of individual firms (Joskow and Kahn, 2002; Wolfram, 1998) or for the market as a whole (Borenstein et al., 2002; Joskow and Kahn, 2002; Wolfram, 1999). The mapping from marginal cost curves to predicted bidding behavior depends on the assumptions made about the nature of competition in the market, the information available to different firms, and so on. For example, some authors assume that generators are Cournot competitors (Bushnell, 2005; Bushnell et al., 2004); others assume that firms do not know their competitors' hedge positions and derive a Bayesian–Nash equilibrium (Hortacsu and Pullar, 2008). Before these approaches can be successfully applied to markets with substantial hydro generation, an accurate measure of the shadow price of water must be calculated. However, papers applying these techniques to markets with substantial hydro generation have not calculated the shadow price of water in ways that fully capture the effects of inflow volatility, storage, and competition among generators using different fuels.[5] Twomey et al. (2005) acknowledge opportunity cost measurement issues in estimating marginal cost but do not suggest a solution. Our model demonstrates the properties that the shadow price of water has—such as its dependence on inflow conditions, lake levels, and the point in the seasonal cycle—in a competitive electricity market.

Our model is described in Section 2 and the market outcomes it produces are assessed in Section 3. We modify resource availability and consider a carbon tax in Section 4, and assess how these affect market performance. Finally, we draw conclusions in Section 5.

2. An electricity market model

2.1. The structure

Gas and hydro generators sell into an electricity spot market, and consumers purchase directly from that market. The network has three nodes: one each for the gas and hydro generators and one for consumers. The hydro and gas generators are physically separated from consumers, so that some electricity is lost during the transmission process. Of each unit of electricity produced by the hydro generator, only k_1 units are available to consumers, with the residual lost in transmission. Similarly, of each unit of electricity produced by the gas generator, only k_2 units are available to consumers. We assume that the consumers' node is closer to the gas generator's node than to the hydro generator's, so that hydro generation experiences greater transmission losses than gas generation: $k_1 < k_2 < 1$.[6]

Our model is cast in continuous time, enabling it to closely mimic the real time nature of many electricity markets.[7] We suppose that over any short interval lasting dt units of time, trading occurs in

[3] See, for example, Scott and Read (1996).

[4] See, for example, Skantze et al. (2000) and Lyle and Elliott (2009).

[5] For example, Müsgens (2006) analyzes hydro generation in the German electricity market but does not allow for inflow volatility when calculating the marginal cost of hydro generation.

[6] Gas-fired generators typically have an option that hydro-generators lack: the option to transmit fuel (gas) and generate in the vicinity of consumers.

[7] A key feature of electricity markets is that, because storage of electricity (in contrast to fuel) is not cost effective, dispatch of generation is managed to meet demand at each instant of time (Stoft, 2002). Prices are determined almost in real time. For example, the NZEM has 5-minute pricing (Evans and Meade, 2005), a time weighted average of which produces a price for each half-hour trading period. The 5-minute prices are indicator prices for market participants; the transaction prices are calculated after the trading period is closed.

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off-peak conditions for a period lasting $\tau_{off}dt$ units of time and in on-peak conditions for a period lasting $\tau_{on}dt$ units of time, where τ_{off} and τ_{on} are positive constants that add to 1.[8] Off-peak demand is described by the function $q_{off,t}=x_{off}(t)-p_{off,t}/b$, where $q_{off,t}$ is the rate at which electricity is drawn from the network at the consumers' node during off-peak conditions, $x_{off}(t)$ is a deterministic function of time, $p_{off,t}$ is the off-peak spot price at time t, measured in dollars per megawatt hour (\$/MWh),[9] and $b>0$ is a constant. Similarly, on-peak demand is described by the function $q_{on,t}=x_{on}(t)-p_{on,t}/b$, where $q_{on,t}$ is the rate at which electricity is drawn from the network at the consumers' node during on-peak conditions, $x_{on}(t)$ is a deterministic function of time, and $p_{on,t}$ is the on-peak spot price at time t. The functions $x_{off}(t)$ and $x_{on}(t)$ are periodic, with period 1, and capture the seasonal pattern in off-peak and on-peak electricity demand.

Electricity is supplied to the consumers' node at a rate equal to $q_{off,t}=k_1z_{off,t}+k_2m_{off,t}$ during the off-peak period and $q_{on,t}=k_1z_{on,t}+k_2m_{on,t}$ during the on-peak period, where $z_{off,t}$ and $z_{on,t}$ are the rates of hydro generation and $m_{off,t}$ and $m_{on,t}$ are the rates of gas generation, both measured in TWh/y. If the gas generator is producing electricity at a rate of m TWh/y then it incurs generation costs at a rate of $c(m)$ million dollars per year, for some increasing strictly convex function c. Increasing marginal cost reflects the distribution of efficient thermal plants. Older, or more fuel flexible, plants that are less efficient in converting gas to electricity will have higher marginal costs than will modern plants. Electricity generated by gas satisfies the constraints $0\le m_{off,t}\le\bar{m}$ and $0\le m_{on,t}\le\bar{m}$, where $\bar{m}$ is the maximum capacity of the thermal generation plants.

The hydro generator's fuel supply is limited by the availability of stored water and river flows (inflows to the hydro lakes). The inflow at date t, measured in TWh/y, equals $i_t=\mu(t)y_t$, where $\mu(t)$ is a positive-valued periodic function with period 1 and y_t evolves according to the diffusion process[10]

$$dy_t=\frac{\eta^2}{2}(1-y_t)dt+\sigma\eta\sqrt{y_t}d\xi_t, \tag{1}$$

where η and σ are constants and ξ_t is a Wiener process. The function $\mu(t)$ determines the seasonal pattern in inflows and the positive-valued multiplier y_t determines the stochastic component. The stationary distribution of y_t is a gamma distribution with shape parameter $1/\sigma^2$ and scale parameter σ^2. It follows that the unconditional mean and standard deviation of y_t equal 1 and σ, respectively, so that the unconditional mean and standard deviation of inflows at time t equal $\mu(t)$ and $\sigma\mu(t)$, respectively. The parameter η determines the short-run behavior of y_t and has no effect on the long-run distribution. Large values of η mean that short-term changes in inflows have a large standard deviation but quickly die out.

We assume that the storage lake has the capacity to hold water capable of producing $\bar{s}$ TWh of electricity. At time t, the storage lake contains water capable of producing s_t TWh of electricity and the hydro generator is producing electricity at a rate of $z_{off,t}$ TWh/y during off-peak conditions and $z_{on,t}$ TWh/y during on-peak conditions. Hydro generation is subject to the constraint of plant capacity, $\bar{z}$, so that hydro electricity production satisfies $0\le z_{off,t}\le\bar{z}$ and $0\le z_{on,t}\le\bar{z}$. It is also subject to the availability of water. Whenever the lake has some spare capacity, the lake level evolves according to $ds_t=(\mu(t)y_t-(\tau_{off}z_{off,t}+\tau_{on}z_{on,t}))dt$. If the lake is empty then output is constrained by $z_{off,t}\le\mu(t)y_t$ and $z_{on,t}\le\mu(t)y_t$, so that $ds_t\ge0$. If the lake is full then the lake level evolves according to $ds_t=min\{0,\mu(t)y_t-(\tau_{off}z_{off,t}+\tau_{on}z_{on,t})\}dt$; that is, electricity is generated at rate $\tau_{off}z_{off,t}+\tau_{on}z_{on,t}$ and any inflow in excess of this amount is not used in storage or hydro generation but rather is spilled from the lake.

Our model includes six variables that evolve over time. The rates of hydro ($z_{off,t}$ and $z_{on,t}$) and gas ($m_{off,t}$ and $m_{on,t}$) generation are chosen by the generators at each point in time. The inflow multiplier, y_t, is an exogenous state variable. The amount s_t of stored water is an endogenous state variable, determined by the history of inflows, and the hydro generation decisions. At any date t, therefore, the state of the electricity market is defined by (t,s_t,y_t). All present values are calculated using the constant discount rate r.

2.2. Solving the model

We suppose that the gas and hydro generators are price-taking value-maximizing firms. In Appendix A.1 we show that competition between these firms yields an outcome that corresponds to the one chosen by a hypothetical social planner that maximizes the expected present value of total surplus. For computational simplicity, we solve the planner's problem rather than the more complicated competitive one, but this is purely a computational device.

The planner's objective is to maximize the expected present value of the total surplus produced by the electricity market, which looking forward from date 0 is

$$W(0,s_0,y_0) = E_0\left[\int_0^\infty e^{-rt}(\tau_{on}TS_{on}(z_{on}(t,s_t,y_t),m_{on}(t,s_t,y_t);t)+\tau_{off}TS_{off}(z_{off}(t,s_t,y_t),m_{off}(t,s_t,y_t);t))dt\right],$$

where

$$\begin{aligned}TS_{on}(z,m;t) &= \int_0^{k_1z+k_2m} b(x_{on}(t)-q)dq-c(m)\\ &=\frac{b}{2}(k_1z+k_2m)(2x_{on}(t)-k_1z-k_2m)-c(m)\end{aligned} \tag{2}$$

is the rate at which total surplus is produced during the on-peak period and $TS_{off}(z,m;t)$, given by a similar expression, is the rate at which total surplus is produced during the off-peak period. The planner's objective function has generation expressed in terms of the state of the market (that is, time of year, storage, and the inflow multiplier) and thus implies optimal generation policies that depend on the three state variables. Total surplus does not include costs associated with hydro generation. It assumes that the variable cost of the hydro generation is zero, and that reservoirs and their costs are fixed over time.[11] The presence of the storage option provided by reservoirs will affect the present value of surplus by enabling hydro generation to be shifted over time. Depending on inflows and generation capacity, it can also provide more useable water for generation in aggregate.

The maximum of the planner's objective function satisfies the Hamilton–Jacobi–Bellman equation

$$0=\sup_{z_{off},z_{on},m_{off},m_{on}}\begin{array}{l}\frac{\eta^2\sigma^2}{2}y\frac{\partial^2W}{\partial y^2}+\frac{\partial W}{\partial t}+(\mu(t)y-\tau_{off}z_{off}-\tau_{on}z_{on})\frac{\partial W}{\partial s}+\frac{\eta^2}{2}(1-y)\frac{\partial W}{\partial y}\\ -rW+\tau_{on}TS_{on}(z_{on},m_{on};t)+\tau_{off}TS_{off}(z_{off},m_{off};t),\end{array} \tag{3}$$

subject to the generation constraints $0\le z_{off}\le\bar{z}$, $0\le z_{on}\le\bar{z}$, $0\le m_{off}\le\bar{m}$, $0\le m_{on}\le\bar{m}$, and, if and only if $s=0$, $z_{off}\le\mu(t)y$ and $z_{on}\le\mu(t)y$.[12]

[8] One way to motivate this is as the limiting case of a model in which time is broken into a sequence of trading periods—alternating between off-peak and on-peak—that are sufficiently short that the rate of inflows, the level of storage, and the shadow price of water do not change by significant amounts between the start of an off-peak period and the start of the following on-peak period.

[9] If one MWh of electricity costs p dollars, then one terawatt hour (TWh) of electricity (which we adopt as our unit for measuring quantity) costs p million dollars. Thus, we can interpret $p_{off,t}$ as the price in millions of \$/TWh.

[10] This stochastic process is often used in applications requiring a non-negative mean-reverting variable, such as interest rates (Cox et al., 1985) and share price volatility (Heston, 1993).

[11] The calculations also assume that factors such as price volatility have no direct effect on total surplus. However, if this volatility affected decisions outside the model—such as transmission and generation related investments—total surplus would be mis-measured by Eq. (2).

[12] If the lake is full, then the coefficient of $\partial W/\partial s$ in Eq. (3) is replaced with min$\{0,\mu(t)y-\tau_{off}z_{off}-\tau_{on}z_{on}\}$.

Neglecting the elements of Eq. (3) that are not functions of (z_{off},z_{on}, m_{off},m_{on}), the generation policy will maximize

$$TS_{\text{off}}(z_{\text{off}}, m_{\text{off}}; t) - z_{\text{off}}\frac{\partial W}{\partial s} = \frac{b}{2}(k_1 z_{\text{off}} + k_2 m_{\text{off}})(2x_{\text{off}}(t) - k_1 z_{\text{off}} - k_2 m_{\text{off}}) - (h z_{\text{off}} + c(m_{\text{off}})), \quad (4)$$

and

$$TS_{\text{on}}(z_{\text{on}}, m_{\text{on}}; t) - z_{\text{on}}\frac{\partial W}{\partial s} = \frac{b}{2}(k_1 z_{\text{on}} + k_2 m_{\text{on}})(2x_{\text{on}}(t) - k_1 z_{\text{on}} - k_2 m_{\text{on}}) - (h z_{\text{on}} + c(m_{\text{on}})), \quad (5)$$

where $\partial W/\partial s$ measures the marginal increase in the present value of future welfare resulting from additional stored water—that is, h is the shadow price of stored water. It embodies the intertemporal concerns that affect optimal storage policy, and reflects all the characteristics of the electricity market contained in the model, including the inflow process—its average level, volatility, and predictability—the capacity of the storage lake, and the overall market structure. Notice that our assumption that at each arbitrary date t the shadow price is the same during off-peak and on-peak periods allows us to split the four-variable maximization problem in Eq. (3) into the two independent two-variable maximization problems in Eqs. (4) and (5).

A necessary condition for maximizing the functions in Eqs. (4) and (5) is that, for the planner's chosen level of electricity supplied at the consumers' node, the cost of generation, $hz + c(m)$, is minimized. In the case of hydro generation, marginal cost comprises the opportunity cost of using stored water immediately rather than leaving it in storage and using it for generation at some later date. The planner ranks individual generation plants according to their marginal cost, with the lowest marginal-cost plants used to meet demand. The resulting marginal cost curve is shown in Fig. 1 for the case where $0 < s_t < \bar{s}$, with the two graphs differing according to whether the shadow price of water is greater (the left-hand graph) or less (the right-hand graph) than the marginal cost of the highest-cost gas plant. The amount of electricity supplied to consumers corresponds to the point where the marginal cost curve intersects the demand curve, where the latter is shown by the dashed lines in Fig. 1 for various levels of the demand driver $x(t)$. The precise outcome depends on the state variables (t,s_t,y_t), the shadow price h_t, and whether we are considering off-peak or on-peak demand conditions. For example, when $0 < s_t < \bar{s}$, the planner's generating policy is

$$z_t = \max\left\{0, \min\left\{\bar{z}, \frac{bk_1 x(t) - h_t - bk_1 k_2 \min\{u(k_2 h_t/k_1), \bar{m}\}}{bk_1^2}\right\}\right\}$$

and

$$m_t = \max\{\min\{v(x(t)), \min\{u(k_2 h_t/k_1), \bar{m}\}\}, \min\{v(x_t - k_1\bar{z}), \bar{m}\}\},$$

where the functions u and v are defined implicitly by $c'(u(g)) = g$ and $\frac{c'(v(g))}{bk_2} + k_2 v(g) = g$ for all g. Policies for an empty lake ($s_t = 0$) and a full lake ($s_t = \bar{s}$) are given in Appendix A.3, together with derivations for all three cases. The seasonal nature of demand means that in some situations the system's capacity to generate electricity might be insufficient to meet demand if the price equals the marginal cost of the highest-cost generator. In this case, we set the spot price to clear the market: $p = b(x_t - k_1\bar{z} - k_2\bar{m})$. The shaded triangles in Fig. 1 show the loss of consumers' surplus when this happens—that is, the "value of lost load" (Stoft, 2002, p. 157).

The solution to the planner's problem must satisfy Eq. (3) and simultaneously maximize the expressions in Eqs. (4) and (5). However, it can be partitioned into a static and a dynamic problem with the link provided by the shadow price of water, h_t. The shadow price can be taken as exogenous when choosing generation levels at time t (that is, when maximizing the functions in Eqs. (4) and (5)), but W, and hence h_t, must satisfy Eq. (3). We use this partition to solve the model using the method of policy iteration (Judd, 1998, Ch. 12). This process yields the social planner's optimal generation policies $\{z_{\text{off}}(t,s,y), z_{\text{on}}(t,s,y), m_{\text{off}}(t,s,y), m_{\text{on}}(t,s,y)\}$ for all (t,s,y).

3. Generator behavior

The graphs in Fig. 2 plot the most important model outcomes for the calibration described in Appendix A.2, with each column showing results for a different season.[13] The first row of graphs plots the shadow price of water as a function of the amount of stored water (expressed as a proportion of total storage capacity) for inflows corresponding to the 2.5 and 97.5 percentiles of the unconditional distribution of y. Stored water is most valuable when it is scarce: $h(t,s,y)$ is a decreasing function of both storage and inflows. The shadow price of water is positive at all times, except during spring and summer in the event that the storage lake is full and inflows are especially high. It takes extremely high values when storage levels are low, except in summer (and, to a lesser extent, spring). This is consistent with the fact that average inflows are highest in summer and spring: stored water is less valuable then as it is more likely to be replaced before the period of higher-than-average demand (that is, the following winter). The shadow price of water is most sensitive to current inflows when the gap between the two curves is widest. This occurs in winter when lake levels are low and in summer when they are high. In the former case, low storage means that the market is relying on inflows to provide the fuel for hydro generators until the high inflows arrive in spring and summer: low current inflows make current stored water especially valuable. In the latter case, ample storage means that there is limited ability to store inflows for the fall and winter, so that high current inflows will need to be used for generation during the low-demand summer period.

The two solid curves in each of the remaining graphs in Fig. 2 plot the particular on-peak outcome for the same two inflow levels, and the dashed curves plot the corresponding off-peak outcomes. The second row of graphs plots the rate of hydro generation, $z(t,s,y)$, which is an increasing function of both storage and inflows. During winter, hydro generation operates at or close to full capacity during on-peak periods, unless storage levels are extremely low; off-peak hydro generation is lower, but still higher than off-peak generation in other seasons. In contrast, during summer, even during the on-peak period hydro operates at less than full capacity unless inflows are unusually high and lake levels high. Off-peak hydro generation is also lower than at other times of the year, controlling for inflow and lake levels. The third row of graphs plots the rate at which electricity is produced from gas, $m(t,s,y)$. It is a decreasing function of both storage and inflows. Gas generation increases dramatically during both off- and on-peak periods when lake levels are extremely low. It decreases moderately during off-peak periods if both lake levels and inflows are high, but the sensitivity is very weak during fall.

Finally, the fourth row of graphs plots the spot price at the consumers' node, $p(t,s,y)$, showing it to be a decreasing function of storage and inflows. Both off-peak and on-peak spot prices are extremely sensitive to the state variables when water is scarce (low storage and low inflows), and the off-peak price is moderately sensitive to them when water is plentiful (high storage and high inflows). Off- and on-peak prices diverge most during winter and, at other times, when the storage level is very high. In both situations, hydro

[13] We represent (the southern hemisphere) winter by the middle of July ($t = 6.5/12$), spring by the middle of October ($t = 9.5/12$), summer by the middle of January ($t = 0.5/12$), and fall by the middle of April ($t = 3.5/12$).

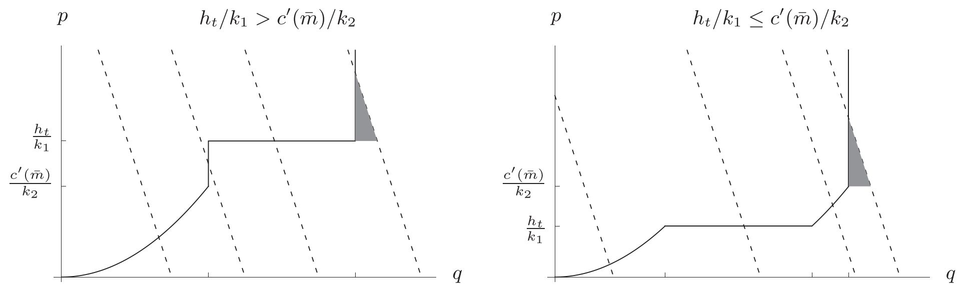

Fig. 1. The planner's optimal generation policy when $0<s_t<\bar{s}$. Note. The solid curve in each graph shows the marginal cost curve for the case where $0<s_t<\bar{s}$, with the two graphs differing according to whether the shadow price of water is greater (the left-hand graph) or less (the right-hand graph) than the marginal cost of the highest-cost gas plant. The amount of electricity supplied to consumers corresponds to the point where the marginal cost curve intersects the demand curve, where the latter is shown by the dashed lines for various levels of the demand driver $x(t)$. The areas of the shaded triangles equal the value of lost load for the highest levels of demand shown.

generation is operating at full capacity during the on-peak period, so that the spot price is set by the marginal cost of the most costly gas plant in operation at the time, which exceeds the shadow price of water. In contrast, during the off-peak period, both gas generation and hydro generation are below capacity, so that the spot price equals the common marginal cost of both types of generation, which equals the shadow price of water (adjusted to reflect transmission losses).

Fig. 2 displays market outcomes as functions of storage and the inflow multiplier. As storage is endogenous, we simulate 200 years of daily data for our model, again using the calibration described in Appendix A2. In each case we simulate daily data for the inflow multiplier y_t using the stochastic process in Eq. (1) and then use the policy functions $m_t = m(t,s_t,y_t)$ and $z_t = z(t,s_t,y_t)$ for both off-peak and on-peak periods to update the lake level s_t. For each model output, we compare our results with the distributions that would result if there were no storage facility. This establishes the properties of the model and gives a reference point for assessing the effect of climate-based changes to inflows.

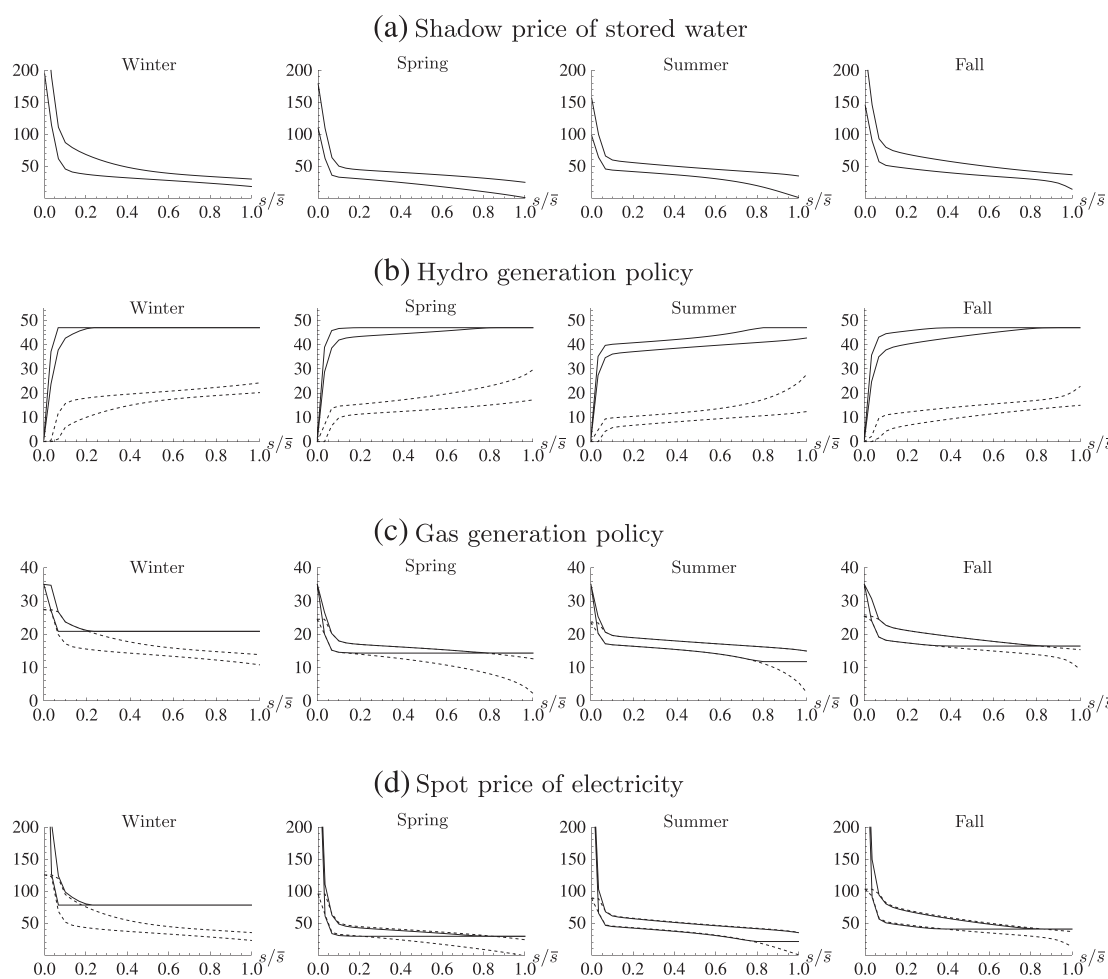

Fig. 2. Market outcomes under competition as functions of storage and inflows. Note. The graphs plot the key model outputs for the calibration described in Appendix A.2, as functions of the amount of stored water (expressed as a proportion of total storage capacity). Each pair of curves plots the indicated quantity for inflows corresponding to the 2.5 and 97.5 percentiles of the unconditional distribution of y. In the second and subsequent rows of graphs, the dashed and solid curves plot off-peak and on-peak quantities, respectively.

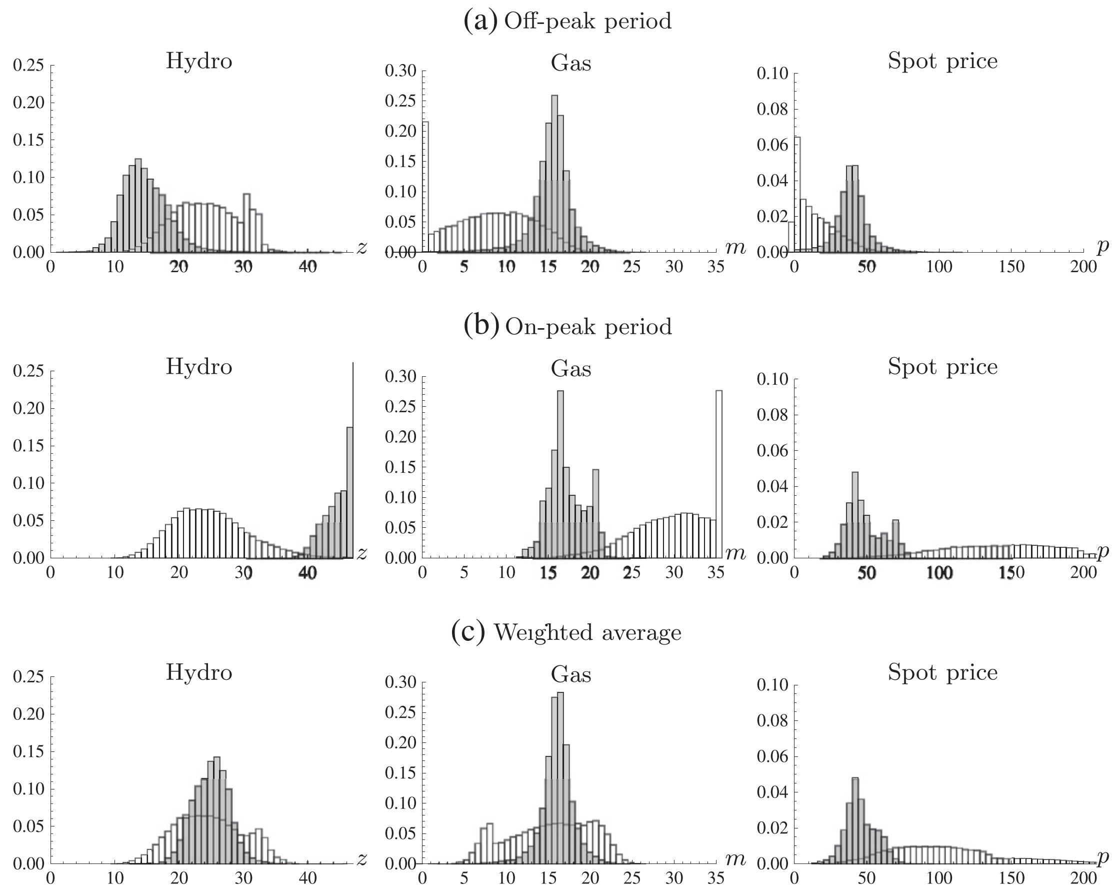

Fig. 3. Intra-day variation in generation policies and spot prices. Note. The graphs show the distributions of the rates of hydro generation and gas generation, as well as the spot price, for off-peak and on-peak periods and the average across both periods. The calculations use the calibration described in Appendix A.2. The shaded and unshaded distributions show results when the storage facility is and is not available, respectively.

The distributions of three of the most important outputs are shown in Fig. 3, with the three columns showing results for the rate of hydro generation, the rate of gas generation, and the spot price, respectively.

The first two rows show results for the off-peak and on-peak periods, respectively. The third row shows the time-weighted average generation rates and the load-weighted spot price. We show results for the situations with a storage facility (the shaded distribution) and without a storage facility (the unshaded distribution). During the off-peak period, the ability to store water leads to reduced hydro generation being offset by increased gas generation, and a higher spot price as a result. The substitution of fuels is reversed in the on-peak period, with the ability to store water leading to increased hydro generation and reduced gas generation; storage reduces the spot price. Demand is greater during the on-peak period, so the load-weighted average spot price is lower when storage is possible. The cost function for gas generation is convex in output, so the ability to store water means that increased low-cost gas generation during off-peak periods is substituted for reduced high-cost gas generation during on-peak periods. The ability to store water thus contributes to a lower average cost of generating electricity.

Fig. 4 shows the distribution of the rates of hydro generation and gas generation, as well as the load-weighted spot price, for each season.[14] As in Fig. 3, the shaded and unshaded distributions show results when the storage facility is and is not available, respectively. The graphs show that the ability to store water means that increased low-cost gas generation during low-demand periods is substituted for reduced high-cost gas generation during high-demand periods, but here the substitution occurs between seasons instead of within a single day. Compared to the case without storage, the rate of gas generation is reduced in winter (and, to a lesser extent, fall), which is achieved by increasing the rate of hydro generation during the period. The rate of gas generation is increased in summer (and, to a lesser extent, spring), and the reduced rate of hydro generation allows water to be stored for future use. Thus, storage allows a competitive electricity market to substitute extra low-cost gas generation at low-demand times of the year for reduced high-cost gas generation at high-demand times of the year.

Summary statistics of various model outputs are reported in Table 1 for different levels of storage capacity (columns (a)–(d)), hydro generation capacity (column (e)), and gas generation capacity (column (f)). Results for the calibrated level of storage capacity are reported in column (c). Without storage, the average rate of hydro generation is similar in off-peak and on-peak periods (24.51 TWh/y and 25.10 TWh/y), and largely determined by the rate of inflows. The average rate of gas generation varies significantly between the periods (7.71 TWh/y and 29.83 TWh/y), and is determined by the level of demand. In contrast, for the calibrated storage capacity, it is the average rate of hydro generation that varies widely across the day (14.75 TWh/y and 45.64 TWh/y), and the average rate of gas generation that does not (15.44 TWh/y and 17.25 TWh/y). Similar patterns emerge with regard to the inter-season substitution of fuel. The ability to store water reduces the average rate of hydro generation in summer from 28.00 TWh/y to 23.29 TWh/y, and raises it in winter from 21.64 TWh/y to 26.85 TWh/y. Relatedly, it raises the average rate of gas generation in summer from 10.60 TWh/y to 15.13 TWh/y, and reduces it in winter from 19.55 TWh/y to 17.33 TWh/y. Comparing the average rate of inflows (25.11 TWh/y)

[14] The (southern hemisphere) fall is represented by $t\in[2/12,5/12]$, winter by $t\in[5/12,8/12]$, spring by $t\in[8/12,11/12]$, and summer by $t\in[11/12,12/12]\cup[0/12,2/12]$.

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with the average rate of hydro generation shows that some water is spilled without generating electricity. When there is no storage facility, water is spilled when inflows exceed generation capacity. However, when water can be stored, water is spilled only when inflows exceed generation capacity and the storage lake is full. Thus, the average rate of spillage falls as storage capacity increases.

Comparing columns (a)–(d) in Table 1 reveals the effect of the amount of storage capacity on competitive market outcomes. The amount of storage capacity has a relatively minor effect on the amount of intra-day fuel substitution: as expected, all that is needed for this to occur is a small amount of storage capacity. However, the amount of inter-season fuel substitution is more sensitive to storage capacity: substantial storage is needed to transfer large amounts of hydro generation from the high-inflow/low-demand summer to the low-inflow/high-demand winter. These differences are reflected in the ratio of spot prices in high- and low-demand periods. For example, the ratio of average on-peak to average off-peak prices falls from 11:1 when no storage is possible to 1.2:1 for the three storage capacities we consider. However, the ratio of average winter spot prices to average summer ones is more sensitive to the amount of capacity, falling from 2.2:1 when no storage is possible, to 1.7:1 when capacity is 2.22 TWh, and then to 1.5:1 for the two greater capacities.

The bottom panel of Table 1 focusses on the flows of surplus generated by a competitive electricity market. It reports the average annual flow of four surplus measures—total surplus, producers' surplus (that is, generators' profits) for gas and hydro separately, and consumers' surplus—as well as the value of lost load. Comparison of the entries in each row shows that greater storage capacity increases the average flow of consumers' surplus but reduces the average flow of combined producers' surplus, with the first effect dominating the second. That is, extra storage capacity raises total surplus and also transfers surplus from generators to consumers. Extra storage capacity increases the average flow of total surplus by facilitating substitution of increased low marginal-cost gas generation in periods when demand is low for reduced high marginal-cost gas generation in periods when demand is high. The average cost of meeting demand therefore falls, and the average flow of total surplus rises. However, the spot price is set by a uniform-price auction, so that all operating plants—including infra-marginal plants—sell electricity at the market-clearing price. Thus, both gas and hydro generators benefit from the use of high marginal-cost gas plants during high-demand periods. Greater storage capacity reduces the use of the highest-cost plants, lowers the average profit flow of gas and hydro generators, and raises the average flow of surplus to consumers.

The final two columns of Table 1 show the effects of generation capacity on market performance. Column (e) holds all parameters at their calibrated levels, except for the maximum possible rate of hydro generation, $\bar{z}$, which is increased by 25%. In the baseline case, the hydro generation capacity constraint is often binding during winter and fall on-peak periods, which limits the hydro generator's incentive to save water in summer for use in winter. Relaxing the hydro generation capacity constraint allows more water to be used in winter on-peak periods, so that more inter-season fuel substitution occurs. The higher average spot price in summer is more than offset by the lower average spot price in winter. Total welfare increases slightly, but generators are worse off as the lower spot prices reduce the profitability of hydro generation and, to a lesser extent, infra-marginal gas generation.

Column (f) shows the effects of increasing the quantity of gas generation assets, holding all other parameters at their calibrated levels. We increase the gas generation capacity from $\bar{m}$ to $\gamma\bar{m}$, where $\gamma = 1.25$, and replace the cost function $c(m)$ with $\hat{c}(m) = \gamma c(m/\gamma)$, which implies that the new marginal cost equals $\hat{c}'(m) = c'(m/\gamma)$. As in the baseline case, the marginal cost of generation ranges from 0 to $\hat{c}'(\gamma\bar{m}) = c'(\bar{m})$, but the range of marginal costs is spread over a larger collection of gas generation assets. In effect, we have increased the capacity of each individual gas plant by 25%. The change approximates the effect of adding base-load plant and more efficient peaking plant to the supply of gas generation units available to the market. This change produces an average level of storage that is considerably lower and significantly less inter-season substitution of fuel than in the baseline case in column (c). This behavior is due to the reduced heterogeneity of the gas plant, which reduces the benefits from substituting increased low-cost gas generation in summer for decreased high-cost gas generation in winter. The average flow of total surplus increases relative to the baseline case, which is to be expected as the cost of generating electricity from gas has fallen for each level of output. By widening the spread between average summer and winter spot prices, the reduced inter-season fuel substitution raises the profit flows of both hydro generation and (infra-marginal) gas generation, leaving consumers worse off.

The bottom panel of Table 1 shows that, given the current level of the demand driver $\{x(t): 0 \le t \le 1\}$, value-maximizing hydro and gas generators have little incentive to invest in additional storage or hydro generation capacity. Additional gas generation assets would increase the gas generator's average profit flow, but investment would occur only if the generator could recover the required capital costs. However, increasing demand has the potential to justify investment by both generators.

4. Effect of climate change

In this section we examine the effects of possible changes in model parameters attributable to climate change. Recall that the inflow at time t equals $i_t = \mu(t)y_t$, where $\mu(t)$ is a positive-valued periodic function with period 1 and y_t evolves according to the diffusion process in Eq. (1). We consider changes to $\mu(t)$ and the process driving y_t separately. We also consider the effects of higher prices for gas that would reflect the introduction of carbon taxes. In all cases, we keep the other parameters at their calibrated levels. Because the qualitative effects of these changes can generally be inferred from two points, we limit consideration to one-sided changes in the parameters of interest.

The effects of a reduction in the overall average level of inflows, while retaining the current seasonal variation, are indicated in the left-hand panel of Table 2. In this case, we replace the average inflow profile $\mu(t)$ with $\mu(t) - 0.25\bar{\mu}$, where $\bar{\mu} = \int_0^1 \mu(t)dt$ is the overall average inflow across the entire year. Holding capacity $\bar{s}$ fixed, reducing the average level of inflows makes it easier to substitute fuel intertemporally because the system can store 11.3 weeks of average inflows rather than 9.0 weeks as in the baseline case. The spread between the average rates of on-peak and off-peak generation widens for hydro and narrows for gas, relative to the baseline case in Table 1. The spread between the average rates of generation in winter and summer also widens for hydro and narrows for gas. Thus, the reduced pressure on storage caused by lower average inflows enhances the market's ability to substitute fuel intertemporally. Although the gap between prices in high- and low-demand periods narrows significantly, the reduced availability of (free) hydro fuel raises average prices by increasing the use of high marginal-cost gas plants. Due to the uniform price auction, these higher prices increase the profitability of generators. Thus, although total surplus falls, producer surplus rises. Consumers are significantly worse off.

The right-hand panel of Table 2 summarizes the effects of a reduction in predictable seasonal fluctuations by 25% while retaining the average level of inflows. In this case, we replace the average inflow profile $\mu(t)$ with $0.75\mu(t) + 0.25\bar{\mu}$. That is, we reduce the size of the predictable seasonal deviation from the overall mean by 25%. The results reveal that less use is made of storage to substitute fuel intertemporally. For example, compared to the baseline case in Table 1, the spread between the average rates of on-peak and off-peak generation narrows for hydro and widens for gas, indicating that there is less intra-day fuel substitution. Although the spread between the average rates of winter and summer generation widens for hydro and narrows for gas, this is due primarily to the increased average rate of inflows in winter and reduced average rate in summer, relative to the baseline case. For example,

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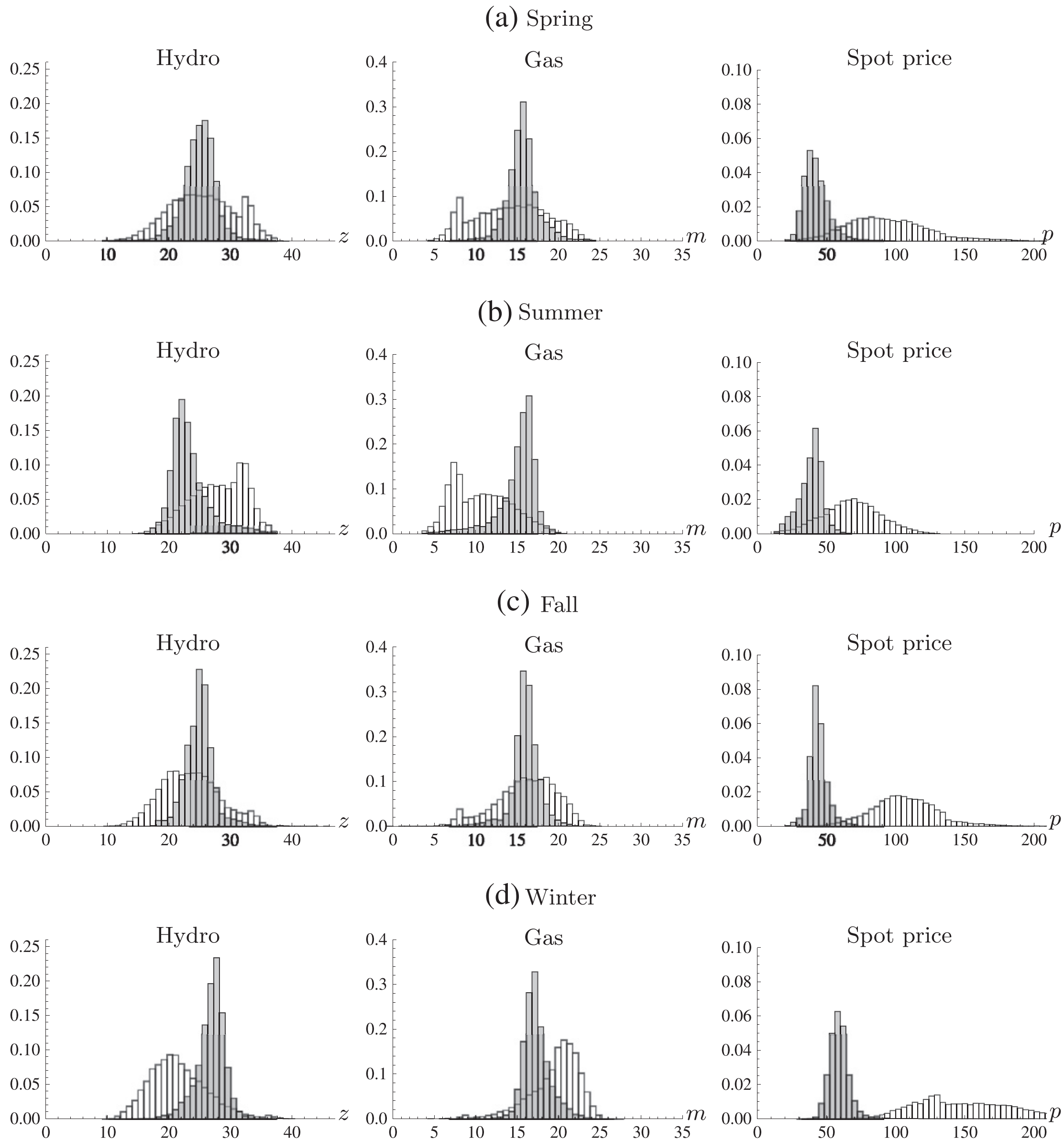

Fig. 4. Seasonal variation in generation policies and spot prices. Note. The graphs show the distributions of the rates of hydro generation and gas generation, as well as the load-weighted spot price, for each season, for the calibration described in Appendix A.2. The rates of hydro generation and gas generation are measured by time-weighted averages, $\tau_{\mathrm{off}}z_{\mathrm{off},t}+\tau_{\mathrm{on}}z_{\mathrm{on},t}$ and $\tau_{\mathrm{off}}m_{\mathrm{off},t}+\tau_{\mathrm{on}}m_{\mathrm{on},t}$ respectively, whereas the spot price is measured by the load-weighted average, $(q_{\mathrm{off},t}p_{\mathrm{off},t}+q_{\mathrm{on},t}p_{\mathrm{on},t})/(q_{\mathrm{off},t}+q_{\mathrm{on},t})$. The shaded and unshaded distributions show results when the storage facility is and is not available, respectively.

when no storage is possible ($\bar{s}=0$), the average rate of winter hydro generation rises from 21.64 TWh/y to 22.66 TWh/y due to the weaker seasonal pattern, and the average rate of summer hydro generation falls from 28.00 TWh/y to 27.37 TWh/y. These changes reflect the differences in inflows relative to the baseline case. However, for $\bar{s}=4.44$, the average rate of winter hydro generation rises from 26.85 TWh/y to 27.06 TWh/y, and the average rate of summer hydro generation rises from 23.29 TWh/y to 23.39 TWh/y, both relative to the baseline case. These changes are much smaller than the changes in average inflows, revealing that a smaller volume of summer inflows is being stored and less winter generation is fueled by stored water. Overall, less intertemporal fuel substitution occurs.

The behavior of the inflow multiplier is determined by the parameters σ and η. Increasing σ while holding η constant increases the short-run volatility of inflows and also increases the standard deviation of the unconditional distribution. Increasing η while holding σ constant also increases the short-run volatility of inflows, but in addition it increases the speed with which the inflow multiplier is pulled back towards its mean.[15] The stronger mean reversion exactly offsets the increased short-run volatility, so that the standard deviation of the unconditional distribution is unchanged. We consider the effects of these two changes separately.

The left-hand panel of Table 3 summarizes the effect of increasing σ by 25% while holding η fixed at its calibrated level. The predictability of inflows falls and, in particular, the increased potential for very large inflows puts more pressure on the system's ability to store water for future use, so there is less intertemporal fuel substitution. Compared to the baseline case, the spread between the average rates of on-peak and off-peak generation narrows for hydro and widens for gas. The corresponding price spread widens, indicating that the greater inflow volatility reduces intra-day fuel substitution in a competitive market. Similarly, the spread between the average rates of winter and summer generation narrows for hydro and

[15] The half-life of inflow shocks equals $(2log2)/\eta^2$.

Table 1
Market outcomes and the capacity of storage and generation assets.

			Storage assets				Gen. assets	
			(a)	(b)	(c)	(d)	(e)[a]	(f)[b]
Storage capacity ($\bar{s}$)		TWh	0.00	2.22	4.44	6.66	4.44	4.44
Storage level (s_t)		TWh	0.00	1.28	2.39	3.42	2.36	1.49
Inflow (y_t)		TWh/y	25.11	25.11	25.11	25.11	25.11	25.11
Hydro gen. (z_t)	Off-peak	TWh/y	24.51	14.70	14.75	14.75	13.94	14.81
	On-peak	TWh/y	25.10	45.53	45.64	45.72	47.34	45.67
	Summer	TWh/y	28.00	24.53	23.29	23.01	22.70	24.17
	Winter	TWh/y	21.64	25.80	26.85	27.12	28.08	25.96
	Average	TWh/y	24.71	24.98	25.04	25.08	25.07	25.09
Gas gen. (m_t)	Off-peak	TWh/y	7.71	15.42	15.44	15.46	16.04	15.37
	On-peak	TWh/y	29.83	17.31	17.25	17.19	16.04	17.20
	Summer	TWh/y	10.60	14.16	15.13	15.35	15.56	14.51
	Winter	TWh/y	19.55	18.05	17.33	17.15	16.49	17.90
	Average	TWh/y	15.08	16.05	16.04	16.04	16.04	15.98
Spot price (p_t)	Off-peak	$/MWh	13.86	40.66	39.63	39.29	42.40	39.76
	On-peak	$/MWh	157.52	49.70	49.08	48.70	42.49	49.38
	Summer	$/MWh	68.17	35.80	38.64	39.02	40.15	34.98
	Winter	$/MWh	148.91	61.68	58.91	58.19	45.55	62.99
	Average	$/MWh	104.27	46.70	45.95	45.58	42.46	46.19
Total surplus (TS_t)		Billion $/y	14.43	14.98	14.99	15.00	15.00	15.07
Hydro gen. surplus (PSH_t)		Billion $/y	1.34	1.06	1.07	1.07	1.00	1.06
Gas gen. surplus (PSG_t)		Billion $/y	1.20	0.50	0.47	0.46	0.46	0.57
Consumer surplus (CS_t)		Billion $/y	11.90	13.42	13.46	13.47	13.55	13.44
Value of lost load		billion $/y	0.01	0.00	0.00	0.00	0.00	0.00

[a] Hydro capacity increased by 25%.
[b] Capacity of each individual gas plant increased by 25%.

widens for gas. The corresponding price spread widens significantly, and by more for low levels of storage capacity, which is to be expected as greater inflow volatility also makes inter-season fuel substitution more difficult. Consistent with this, additional storage capacity increases the average flow of total surplus by more than in the baseline case. Overall average spot prices are higher than in the baseline case, and the flow of total surplus is lower. However, the greater price volatility increases the average flow of surplus to generators (via the uniform price auction), who benefit at the expense of consumers—especially when storage capacity is low.

Table 2
Effects of changes to the seasonal inflow profile.

			Reducing average inflows				Reducing seasonal fluctuations			
			(a)	(b)	(c)	(d)	(a)	(b)	(c)	(d)
Storage capacity (s)		TWh	0.00	2.22	4.44	6.66	0.00	2.22	4.44	6.66
Storage level (s_t)		TWh	0.00	1.24	2.23	3.03	0.00	1.27	2.38	3.40
Inflow (y_t)		TWh/y	18.66	18.66	18.66	18.66	25.28	25.28	25.28	25.28
Hydro gen. (z_t)	Off-peak	TWh/y	18.61	7.56	7.57	7.56	24.78	14.94	14.97	14.97
	On-peak	TWh/y	18.66	40.79	40.82	40.84	25.28	45.62	45.73	45.82
	Summer	TWh/y	22.58	17.55	16.05	15.80	27.37	24.31	23.39	23.19
	Winter	TWh/y	15.20	20.50	21.76	21.99	22.66	26.24	27.06	27.28
	Average	TWh/y	18.63	18.64	18.65	18.65	24.95	25.16	25.22	25.25
Gas gen. (m_t)	Off-peak	TWh/y	12.42	20.45	20.47	20.48	7.51	15.26	15.28	15.30
	On-peak	TWh/y	32.59	20.57	20.58	20.57	29.83	17.25	17.18	17.12
	Summer	TWh/y	14.74	19.17	20.22	20.40	11.08	14.34	15.06	15.23
	Winter	TWh/y	23.04	21.69	20.86	20.71	18.93	17.74	17.18	17.03
	Average	TWh/y	19.14	20.49	20.51	20.51	14.95	15.92	15.92	15.91
Spot price (p_t)	Off-peak	$/MWh	28.83	68.65	68.19	68.11	12.92	39.65	38.80	38.50
	On-peak	$/MWh	208.92	69.40	68.93	68.77	154.96	49.32	48.71	48.33
	Summer	$/MWh	91.83	60.71	66.60	67.55	71.02	36.16	38.12	38.33
	Winter	$/MWh	202.74	78.08	72.43	71.26	141.55	60.70	58.50	57.87
	Average	$/MWh	140.59	69.15	68.69	68.56	102.42	46.10	45.42	45.08
Total surplus (TS_t)		Billion $/y	14.00	14.66	14.67	14.68	14.46	14.99	15.00	15.01
Hydro gen. surplus (PSH_t)		Billion $/y	1.43	1.20	1.21	1.22	1.33	1.06	1.06	1.06
Gas gen. surplus (PSG_t)		Billion $/y	1.86	0.95	0.93	0.92	1.16	0.48	0.46	0.45
Consumer surplus (CS_t)		Billion $/y	10.71	12.51	12.53	12.54	11.97	13.45	13.48	13.49
Value of lost load		Billion $/y	0.05	0.00	0.00	0.00	0.01	0.00	0.00	0.00

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Table 3
Effects of changes to inflow volatility.

			Increasing σ				Increasing η			
			(a)	(b)	(c)	(d)	(a)	(b)	(c)	(d)
Storage capacity (s)		TWh	0.00	2.22	4.44	6.66	0.00	2.22	4.44	6.66
Storage level (s_t)		TWh	0.00	1.28	2.41	3.47	0.00	1.26	2.37	3.37
Inflow (y_t)		TWh/y	25.16	25.16	25.16	25.16	25.08	25.08	25.08	25.08
Hydro gen. (z_t)	Off-peak	TWh/y	24.26	14.71	14.77	14.80	24.46	14.59	14.68	14.70
	On-peak	TWh/y	25.11	45.25	45.46	45.59	25.07	45.68	45.73	45.79
	Summer	TWh/y	27.59	24.70	23.45	23.13	27.93	24.54	23.20	22.93
	Winter	TWh/y	21.64	25.47	26.66	27.01	21.58	25.74	26.88	27.14
	Average	TWh/y	24.54	24.89	25.00	25.06	24.66	24.95	25.03	25.06
Gas gen. (m_t)	Off-peak	TWh/y	7.88	15.37	15.39	15.40	7.75	15.51	15.51	15.51
	On-peak	TWh/y	29.69	17.50	17.37	17.29	29.84	17.21	17.18	17.15
	Summer	TWh/y	10.91	14.00	14.98	15.25	10.65	14.18	15.21	15.42
	Winter	TWh/y	19.44	18.25	17.44	17.21	19.59	18.11	17.31	17.14
	Average	TWh/y	15.15	16.08	16.05	16.03	15.11	16.08	16.07	16.05
Spot price (p_t)	Off-peak	$/MWh	14.92	41.31	40.02	39.46	13.96	40.74	39.64	39.32
	On-peak	$/MWh	159.30	50.92	49.87	49.28	157.78	49.10	48.68	48.41
	Summer	$/MWh	69.26	36.03	38.71	39.14	68.36	35.29	38.56	39.02
	Winter	$/MWh	150.95	63.22	59.76	58.69	149.28	61.48	58.65	58.03
	Average	$/MWh	105.66	47.71	46.59	46.02	104.47	46.33	45.69	45.41
Total surplus (TS_t)		Billion $/y	14.41	14.96	14.98	15.00	14.43	14.98	15.00	15.00
Hydro gen. surplus (PSH_t)		Billion $/y	1.32	1.06	1.06	1.07	1.34	1.06	1.07	1.07
Gas gen. surplus (PSG_t)		Billion $/y	1.23	0.52	0.49	0.47	1.20	0.49	0.47	0.46
Consumer surplus (CS_t)		Billion $/y	11.86	13.39	13.43	13.46	11.89	13.43	13.46	13.48
Value of lost load		Billion $/y	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00

Now suppose that the increased short-run volatility is accompanied by an increase in the strength of mean reversion that keeps the standard deviation of the inflow multiplier's unconditional distribution equal to its calibrated value. Specifically, suppose that η increases by 25% and σ takes its calibrated value, leading to the results summarized in the right-hand panel of Table 3.[16] Compared to the increase in σ, when η increases by the same proportion the spread between the average rates of on-peak and off-peak generation widens for hydro and narrows for gas; the price spread is narrower as well. Similarly, compared to the increase in σ, when η increases by the same proportion the spread between the average rates of winter and summer generation widens for hydro and narrows for gas; the price spread is narrower as well. That is, when the greater short-term volatility is accompanied by stronger mean reversion, there is greater intra-day and inter-season fuel substitution: because the larger shocks to inflows are only short-term in nature, less pressure is exerted on the market's storage capacity. The first row of the bottom panel of Table 3 shows that additional storage capacity increases the average flow of total surplus by less when the greater short-run inflow volatility is accompanied by stronger mean reversion than when it is not accompanied by stronger mean reversion.

Finally, we consider the introduction of a carbon tax that raises the marginal cost of generating electricity using gas.[17] We assume that the marginal cost of gas generation is the cost of the gas, and increase it by 24.5%, which mimics the effect of a carbon tax of $25/t$CO_2$.[18] The resulting market outcomes are described in Table 4. Average hydro generation levels are almost unaffected by the introduction of a carbon tax. However, the higher effective marginal cost of gas generation means that the average rates of gas generation fall, compared to the baseline case, in all the categories we consider. The spread between the average rate of gas generation in on-peak and off-peak periods narrows, as does the spread between winter and summer average generation levels. That is, the higher marginal cost of gas leads to a larger reduction in output in high demand periods than in low demand ones. This is not offset by increased hydro generation in the high demand periods on average, because the shadow price of water increases in line with the marginal cost of gas generation.

5. Conclusion

We have developed a tractable model of a competitive electricity market that accounts for key characteristics of such markets, including intra-day and inter-season variations in demand, predictable and unpredictable fluctuations in the availability of fuel, and the ability to manage the associated volatility by means of storage. The level of storage capacity materially affects market performance by determining the extent to which increased low-cost gas generation during low-demand periods can be substituted for reduced high-cost gas generation in high-demand periods. The link between the intertemporal allocation of generation and the mix of generation at any point in time is determined by the shadow price of water, which is endogenously determined in our model. It is affected by the cost structure of the gas generation plants as well as the size of reservoirs.

Our analysis suggests that if climate change reduces the long-run average level of inflows or leads to the introduction of a carbon tax then it will reduce overall welfare significantly; if it increases the unpredictability of long-term inflows, overall welfare will fall slightly. However, electricity consumers and producers are affected differently by such changes, with generators gaining significantly from reduced long-run average inflows and the introduction of a carbon tax—the resulting higher spot prices increase the profitability of hydro generation, which has a zero fuel cost, and infra-marginal gas generation.

[16] This change has the effect of reducing the half-life of inflow shocks from 4.4 weeks to 2.8 weeks.

[17] New Zealand has not implemented a carbon tax, having instead introduced an emissions trading scheme (ETS) that progressively includes industries, with electricity being among the first (Ministry for the Environment, 2008). A key feature of an ETS scheme is the volatility of the price of carbon.

[18] Table 7 of ACIL Consulting (2001) reports that an emissions tax of $10 per tonne CO_2 (t/CO_2) would induce a cost per Gigajoule (GJ) of gas of $0.52/GJ. At the 2007 gas price of $5.34/GJ (reported at www.crownminerals.govt.nz >*Home*>*News*> 2009, accessed 29 April 2010) this tax produces an increase in gas price of 9.7%. We adjust this figure for a tax rate of $25/t$CO_2$.

Table 4
Effects of introducing a carbon tax.

			$25/tCO_2			
			(a)	(b)	(c)	(d)
Storage capacity ($\bar{s}$)		TWh	0.00	2.22	4.44	6.66
Storage level (s_t)		TWh	0.00	1.27	2.38	3.40
Inflow (y_t)		TWh/y	25.11	25.11	25.11	25.11
Hydro gen. (z_t)	Off-peak	TWh/y	24.51	14.70	14.75	14.75
	On-peak	TWh/y	25.10	45.53	45.64	45.72
	Summer	TWh/y	28.00	24.53	23.29	23.01
	Winter	TWh/y	21.64	25.81	26.85	27.11
	Average	TWh/y	24.71	24.98	25.05	25.08
Gas gen. (m_t)	Off-peak	TWh/y	7.53	14.95	14.98	15.00
	On-peak	TWh/y	28.72	16.76	16.70	16.64
	Summer	TWh/y	10.22	13.76	14.68	14.90
	Winter	TWh/y	19.06	17.45	16.77	16.60
	Average	TWh/y	14.60	15.55	15.55	15.55
Spot price (p_t)	Off-peak	$/MWh	16.41	47.50	46.39	46.02
	On-peak	$/MWh	173.75	57.89	57.19	56.76
	Summer	$/MWh	77.58	41.97	45.25	45.71
	Winter	$/MWh	158.28	71.41	68.28	67.46
	Average	$/MWh	115.01	54.44	53.62	53.21
Total surplus (TS_t)		Billion $/y	14.31	14.92	14.94	14.95
Hydro gen. surplus (PSH_t)		Billion $/y	1.50	1.24	1.24	1.25
Gas gen. surplus (PSG_t)		Billion $/y	1.25	0.56	0.53	0.52
Consumer surplus (CS_t)		Billion $/y	11.56	13.12	13.16	13.18
Value of lost load		Billion $/y	0.00	0.00	0.00	0.00

We show that the welfare benefits from expanding storage capacity increase substantially when long-term inflows become less predictable and when a carbon tax is introduced.

Our approach could be developed in a number of ways, although it will have tractability limitations as it requires a low number of state variables. Several extensions seem worthwhile, but all require the inclusion of additional state variables, considerably complicating the analysis. For example, one possible extension would be to make demand stochastic: the extra volatility is characteristic of electricity markets and would likely affect the management of storage and the value attached to storage facilities. This would require adding the current level of demand to the set of state variables. Likewise, incorporating the most important features of an emissions trading scheme would require inclusion of the (volatile) price of emission credits as an additional state variable. Lastly, various oligopoly structures could be considered. For example, ownership of hydro generation could be split between various firms, but then their individual storage levels would need to be added as state variables. All of these extensions would enrich the model, but implementing them would require a significantly more complex model, and so is left for future research.

Appendix A

A.1. Proof that the planner's policy describes a competitive equilibrium

Consider the problem facing the hydro generator, assuming that it takes the spot price as given and that the spot price follows the process implied by the planner's generation policy. If the hydro generator follows the planner's policy, it will generate electricity at rate z_t^* at each date t. Suppose that it follows a different policy, which involves changing the rate of generation at date t' by Δz and at date t'' by $-\Delta z$, for some t', t'', and Δz. The hydro generator's profit flows at date t' and t'' change by $k_1 p_{t'} \Delta z$ and $-k_1 p_{t''} \Delta z$, respectively. The flow of total surplus also changes at these dates. The respective changes are $k_1\theta(k_1 z_{t'}^* + k_2 m_{t'}^*)\Delta z$ and $-k_1\theta(k_1 z_{t''}^* + k_2 m_{t''}^*)\Delta z$, where $\theta()$ is the inverse demand function. These are identical to the changes in the hydro generator's profit flow. The planner uses the same discount rate as the hydro generator, so the policy change's effect on the hydro generator's market value is identical to its effect on the planner's objective function. The definition of z_t^* implies that this change cannot increase the planner's objective function, proving that the hydro generator's market value is maximized by following the planner's hydro generation policy z_t^*.

The problem facing the gas generator is similar, except that both the generator and the planner include the cost of gas generation in their surplus flows. The same argument as for the hydro generator shows that the gas generator's market value is maximized by following the planner's gas generation policy m_t^*.

A.2. Calibration

We calibrate the model to the New Zealand electricity market.[19] In common with many other electricity markets, the NZEM operates with dispatch determined by a uniform price auction. The auction results in a single price at each market node of the network.[20]

The transmission cost parameters are estimated by price ratios between nodes taken to represent the generators and consumers.[21] Because the bulk of hydro generation is in the South Island the node taken for this generation plant is the southern, Benmore, node. Given that the largest consumer market is towards the north of the North Island, Otahuhu is assumed to be the consumer node, and the Haywards node lying between the two previously described nodes is taken as that for gas generation. Using daily average prices for the 2007 calendar year, we find that the average Benmore–Otahuhu relative price is $k_1 = 0.956$ and the average Haywards–Otahuhu relative price is $k_2 = 0.984$.

We assume that all non-hydro generation is gas generation and calibrate the hydro and gas plant capacities as follows.[22] In December 2007 the installed capacity of NZEM was 9396 MW, of which 5349 MW was hydro. If all generators ran at full capacity continuously for a year, hydro generation would be 47 TWh and non-hydro generation 35 TWh. These are used as the annual capacities of hydro and gas plants, respectively. We take the capacity of the lake to be that reported for storage capacity in June 2006, 4.44 TWh. The average daily price of electricity at the Haywards node in the 2007 calendar year was $52.41/MWh and total gas generation was 18 TWh. We consider a cost function of the form $c(m) = \bar{c}m^3$ and choose the constant $\bar{c}$ so that the marginal cost of gas generation equals $52.41 when evaluated at a generation level of 18 TWh; that is, $\bar{c} = 0.0531$.

Monthly data on New Zealand aggregate water inflows for the period July 1931–June 2008 imply the annualized monthly averages $\mu(t)$ shown in Table A-1. Linear interpolation completes the definition of $\mu(t)$. If the inflow multiplier y_t evolves according to

$$dy_t = \frac{\eta^2}{2}(1-y_t)dt + \sigma\eta\sqrt{y_t}d\xi_t \qquad (A-1)$$

[19] All inflow, demand, and spot-price data were obtained from the New Zealand Electricity Commission's Centralised Dataset (now provided by the New Zealand Electricity Authority). Generation capacity figures are from the Ministry of Economic Development (2009).

[20] This is a characteristic of the institutional electricity markets of the CAISO, PJM, ERCOT and NYISO (see http://www.ferc.gov/industries/electric/indus-act/rto.asp, accessed 11 May 2010), and the Australian electricity market (NEM) (see http://epress.anu.edu.au/cs/mobile_devices/ch11s03.html, accessed 11 May 2010). The NZEM is described in Electricity Commission (2009).

[21] Evans et al. (2008) estimate that the New Zealand market was, for the period of the study 1996–2006, and particularly 1999–2006, integrated into one market. Thus the differences between at least the central nodes of the network represented predictable transmission losses that were not dominated by regional network separations brought about by regional constraints.

[22] In 2008 only 13.5% of generation was not fossil-fuel fired or hydro (Electricity Commission, 2009, p. 6). It largely consisted of plants such as geothermal and wind that are must-run in nature. To some extent these are captured in the model by increasing marginal cost and the relatively low transmission cost of gas, which means that some "gas" plants always run in the model. Coal produced 10.5% of generation in 2008, and this too can be assumed to be treated in the gas component of the model.

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Table A-1
Estimates of seasonal parameters.

Month	Units	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
t	y	$\frac{1}{24}$	$\frac{3}{24}$	$\frac{5}{24}$	$\frac{7}{24}$	$\frac{9}{24}$	$\frac{11}{24}$	$\frac{13}{24}$	$\frac{15}{24}$	$\frac{17}{24}$	$\frac{19}{24}$	$\frac{21}{24}$	$\frac{23}{24}$
$\mu(t)$	TWh/y	28.74	25.88	23.38	22.44	22.79	21.94	20.43	21.28	23.69	28.36	29.60	30.62
$x(t)$	TWh	38.64	40.83	42.41	42.58	44.12	46.56	47.15	45.16	42.35	40.69	41.14	39.47
$x_{\text{off}}(t)$	TWh	28.98	30.62	31.81	31.93	33.09	34.92	35.37	33.87	31.76	30.52	30.85	29.60
$x_{\text{on}}(t)$	TWh	57.97	61.25	63.61	63.86	66.19	69.84	70.73	67.75	63.52	61.04	61.70	59.20

then Itô's Lemma implies that

$$d\left(y_t^{1/2}\right) = \left(\frac{\eta^2}{4}\left(1-\frac{\sigma^2}{2}\right)y_t^{-1/2} - \frac{\eta^2}{4}y_t^{1/2}\right)dt + \frac{\sigma\eta}{2}d\xi_t.$$

We use our monthly data on New Zealand aggregate water inflows to estimate the regression model

$$y_{n+1}^{1/2} = \alpha y_n^{-1/2} + \beta y_n^{1/2} + e_n,\ \ E\left[e_n^2\right] = \phi^2,$$

with the parameter restriction $\alpha+\beta+\frac{1}{2}\phi^2=1$, where $y_n = i_{t_n}/\mu(t_n)$ is the multiplier implied by the observed inflow at time t_n and $\mu(t_n)$ is the monthly average inflow in Table A-1. Our estimates of the parameters defining the process in Eq. (A-1) are related to the regression coefficients by

$$\alpha = \left(1-\frac{\sigma^2}{2}\right)\frac{\eta^2\Delta t}{4},\ \ \beta = 1-\frac{\eta^2\Delta t}{4},\ \ \phi = \frac{\sigma\eta\sqrt{\Delta t}}{2},$$

which imply that

$$\eta = 2\sqrt{\frac{1-\beta}{\Delta t}},\ \ \sigma = \frac{\phi}{\sqrt{1-\beta}}.$$

We obtain $\eta=4.03$ and $\sigma=0.206$, with $R^2=0.986$. The histogram in Fig. A-1 shows the distribution of the inflow multipliers $y_n = i_{t_n}/\mu(t_n)$ implied by our aggregate inflow data, and the solid curve shows the unconditional distribution implied by our calibration, which is a gamma distribution with shape parameter $1/\sigma^2$ and scale parameter σ^2. The 95% confidence interval for this distribution is [0.638,1.442].

The rate of electricity consumption at time t equals

$$\begin{aligned} q_t &= \tau_{\text{off}}q_{\text{off},t} + \tau_{\text{on}}q_{\text{on},t} \\ &= (\tau_{\text{off}}x_{\text{off}}(t) + \tau_{\text{on}}x_{\text{on}}(t)) - \frac{\tau_{\text{off}}p_{\text{off},t} + \tau_{\text{on}}p_{\text{on},t}}{b}, \end{aligned} \quad (A-2)$$

implying a price elasticity of demand at time t equal to $-p_t/(bq(t))$. We choose $b=14.94$, so that this elasticity equals -0.1 at the average electricity consumption (38 TWh) and price ($52.76/MWh) for the 2007 calendar year.[23] This elasticity was the smallest considered by Borenstein and Bushnell (1999) in their study of the California electricity market. They used a constant elasticity, but linear demand enables the elasticity to vary with price–quantity pairs, which seems a reasonable assumption where these vary significantly.

We assume that the on-peak period lasts 8 hours each day, so that $\tau_{\text{off}}=2/3$ and $\tau_{\text{on}}=1/3$, and that the off-peak and on-peak demand drivers are related by $x_{\text{on}}(t)=2x_{\text{off}}(t)$. Eq. (A-2) implies that

$$x(t) = \tau_{\text{off}}x_{\text{off}}(t) + \tau_{\text{on}}x_{\text{on}}(t) = q_t + \frac{p_t}{b},$$

where $p_t=\tau_{\text{off}}p_{\text{off},t}+\tau_{\text{on}}p_{\text{on},t}$. For each month during the period 1997–2011, we calculate q_t+p_t/b and use the average as our estimate of $x(t)$. We adjust total consumption for trend growth and use the spot price at the Otahuhu node, expressed in 2007 dollars. The resulting estimates for $x(t)$, and the implied values of $x_{\text{off}}(t)$ and $x_{\text{on}}(t)$, are reported in Table A-1.

[23] The year 2007 was chosen as it was not a year of extreme inflows.

A.3. Closed-form solutions for the planner's generation policies

A.3.1. Price-taking generators when $0<s_t<\bar{s}$

We start by considering the situation where the lake is neither empty nor full ($0<s_t<\bar{s}$). We need to consider two separate cases, according to whether hydro generation is more or less expensive than the most expensive units of gas generation.

The first case we consider has $h_t/k_1 > c'(\bar{m})/k_2$. The price-taking offer curve for this situation, which is shown in the left-hand graph in Fig. 1, passes through four points.

- No generation: $q=0$ and $p=0$. This occurs when the demand driver is $x_t=0$.
- Gas generation at full capacity, no hydro generation: $q=k_2\bar{m}$ and $p=c'(\bar{m})/k_2$. This occurs when the demand driver is

$$x_t = k_2\bar{m} + \frac{c'(\bar{m})}{bk_2}.$$

- Gas generation at full capacity, still no hydro generation: $q=k_2\bar{m}$ and $p=h_t/k_1$. This occurs when the demand driver is

$$x_t = k_2\bar{m} + \frac{h_t}{bk_1}.$$

- Gas generation and hydro generation both at full capacity: $q=k_1\bar{z}+k_2\bar{m}$ and $p=h_t/k_1$. This occurs when the demand driver is

$$x_t = k_1\bar{z} + k_2\bar{m} + \frac{h_t}{bk_1}.$$

We need to consider four separate situations according to where the demand curve intersects the offer curve. The four situations are defined according to the level of the demand driver.

- If $0\le x_t<k_2\bar{m}+\frac{c'(\bar{m})}{bk_2}$ then all demand is met by gas generation, so that $z_t=0$ and m_t satisfies $b(x_t-k_2m_t)=c'(m_t)/k_2$. That is,

$$x_t = k_2m_t + \frac{c'(m_t)}{bk_2} \quad \Leftrightarrow \quad m_t = v(x_t).$$

- If $k_2\bar{m}+\frac{c'(\bar{m})}{bk_2}\le x_t<k_2\bar{m}+\frac{h_t}{bk_1}$ then gas generation operates at full capacity and there is no hydro generation, so that $z_t=0$ and $m_t=\bar{m}$.
- If $k_2\bar{m}+\frac{h_t}{bk_1}\le x_t<k_1\bar{z}+k_2\bar{m}+\frac{h_t}{bk_1}$ then gas generation operates at full capacity and there is just enough hydro generation that the spot price equals the marginal price of hydro generation. That is, $z_t=\frac{bk_1(x_t-k_2\bar{m})-h_t}{bk_1^2}$ and $m_t=\bar{m}$.
- If $k_1\bar{z}+k_2\bar{m}+\frac{h_t}{bk_1}\le x_t$ then both gas generation and hydro generation operate at full capacity, so that $z_t=\bar{z}$ and $m_t=\bar{m}$.

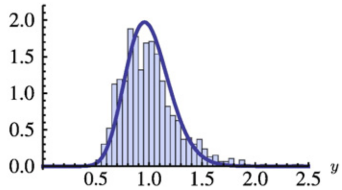

Fig. A-1. Actual and calculated distribution of inflow multiplier y_t. Note. The histogram shows the distribution of the inflow multipliers $y_n = i_{t_n}/\mu(t_n)$ implied by our aggregate inflow data, and the solid curve shows the unconditional distribution implied by our calibration, which is a gamma distribution with shape parameter $1/\sigma^2$ and scale parameter σ^2.

A tidy way to write the two generation policy functions in this case is

$$z_t = \max\left\{0, \min\left\{\bar{z}, \frac{bk_1x_t - h_t - bk_1k_2\bar{m}}{bk_1^2}\right\}\right\} \quad \text{and} \quad m_t = \min\{\bar{m}, v(x_t)\}.$$

Now we turn to the second case, which has $h_t/k_1 \le c'(\bar{m})/k_2$. The price-taking offer curve for this situation, which is shown in the right-hand graph in Fig. 1, passes through four points.

- No generation: $q = 0$ and $p = 0$. This occurs when the demand driver is $x_t = 0$.
- Gas generation operates at the level where the marginal cost of generation equals the marginal cost of hydro generation, at no hydro generation. In this case, q satisfies $c'(q/k_2)/k_2 = h_t/k_1$, so that $q = k_2u(k_2h_t/k_1)$ and $p = h_t/k_1$. This occurs when the demand driver is

$$x_t = k_2u(k_2h_t/k_1) + \frac{h_t}{bk_1}.$$

- Gas generation operates at the level where the marginal cost of generation equals the marginal cost of hydro generation, with hydro generation at full capacity: $q = k_2u(k_2h_t/k_1) + k_1\bar{z}$ and $p = h_t/k_1$. This occurs when the demand driver is

$$x_t = k_2u(k_2h_t/k_1) + k_1\bar{z} + \frac{h_t}{bk_1}.$$

- Gas generation and hydro generation both operate at full capacity: $q = k_1\bar{z} + k_2\bar{m}$ and $p = c'(\bar{m})/k_2$. This occurs when the demand driver is

$$x_t = k_1\bar{z} + k_2\bar{m} + \frac{c'(\bar{m})}{bk_2}.$$

We need to consider four separate situations according to where the demand curve intersects the offer curve. The four situations are defined according to the level of the demand driver.

- If $0 \le x_t < k_2u(k_2h_t/k_1) + \frac{h_t}{bk_1}$ then all demand is met by gas generation, so that $z_t = 0$ and m_t satisfies $b(x_t - k_2m_t) = c'(m_t)/k_2$. That is,

$$x_t = k_2m_t + \frac{c'(m_t)}{bk_2} \quad \Leftrightarrow \quad m_t = v(x_t).$$

- If $k_2u(k_2h_t/k_1) + \frac{h_t}{bk_1} \le x_t < k_2u(k_2h_t/k_1) + k_1\bar{z} + \frac{h_t}{bk_1}$ then gas generation and hydro generation operate at levels such that marginal cost and the spot price both equal h_t/k_1. These conditions imply $m_t = u(k_2h_t/k_1)$ and

$$z_t = \frac{x_t - k_2u(k_2h_t/k_1)}{k_1} - \frac{h_t}{bk_1^2}.$$

- If $k_2u(k_2h_t/k_1) + k_1\bar{z} + \frac{h_t}{bk_1} \le x_t < k_1\bar{z} + k_2\bar{m} + \frac{c'(\bar{m})}{bk_2}$ then gas generation operates to the point where the marginal cost of gas generation equals the spot price, and hydro generation operates at full capacity. That is, $z_t = \bar{z}$ and m_t satisfies $b(x_t - k_1\bar{z} - k_2m_t) = c'(m_t)/k_2$. That is,

$$x_t - k_1\bar{z} = k_2m_t + \frac{c'(m_t)}{bk_2} \quad \Leftrightarrow \quad m_t = v(x_t - k_1\bar{z}).$$

- If $k_1\bar{z} + k_2\bar{m} + \frac{c'(\bar{m})}{bk_2} \le x_t$ then both gas generation and hydro generation operate at full capacity, so that $z_t = \bar{z}$ and $m_t = \bar{m}$.

A tidy way to write the two generation policy functions in this case is

$$z_t = \max\left\{0, \min\left\{\bar{z}, \frac{x_t - k_2u(k_2h_t/k_1)}{k_1} - \frac{h_t}{bk_1^2}\right\}\right\}$$

and

$$m_t = \max\{\min\{v(x_t), u(k_2h_t/k_1)\}, \min\{v(x_t - k_1\bar{z}), \bar{m}\}\}.$$

Summarizing where we have got to, if $h_t/k_1 > c'(\bar{m})/k_2$ then

$$z_t = \max\left\{0, \min\left\{\bar{z}, \frac{bk_1x_t - h_t - bk_1k_2\bar{m}}{bk_1^2}\right\}\right\} \quad \text{and} \quad m_t = \min\left\{\bar{m}, v(x_t)\right\}.$$

If $h_t/k_1 \le c'(\bar{m})/k_2$ then

$$z_t = \max\left\{0, \min\left\{\bar{z}, \frac{bk_1x_t - h_t - bk_1k_2u(k_2h_t/k_1)}{bk_1^2}\right\}\right\}$$

and

$$m_t = \max\{\min\{v(x_t), u(k_2h_t/k_1)\}, \min\{v(x_t - k_1\bar{z}), \bar{m}\}\}.$$

These combine to give

$$z_t = \max\left\{0, \min\left\{\bar{z}, \frac{bk_1x_t - h_t - bk_1k_2\min\{u(k_2h_t/k_1), \bar{m}\}}{bk_1^2}\right\}\right\}$$

and

$$m_t = \max\{\min\{v(x_t), \min\{u(k_2h_t/k_1), \bar{m}\}\}, \min\{v(x_t - k_1\bar{z}), \bar{m}\}\}.$$

This describes the generation policy when $0 < s_t < \bar{s}$.

A.3.2. Price-taking generators when $s_t = 0$

When the lake is empty, hydro generation is capped by the level of inflows and generation capacity, so that z_t cannot exceed $\min\{\mu(t)y_t, z\}$. This is the only difference from the case where $0 < s_t < \bar{s}$, where z_t could not exceed $\bar{z}$. Therefore, we use the generation policies derived for the earlier case, but with $\bar{z}$ replaced with $\min\{\mu(t)y_t, z\}$ everywhere.

A.3.3. Price-taking generators when $s_t = \bar{s}$

The planner can generate $\min\{\bar{z}, \mu(t)y_t\}$ units of electricity at zero cost as no stored water is used in doing so. Therefore, there are $k_1\min\{\bar{z}, \mu(t)y_t\}$ "free" units of electricity available at the consumers' node. Effectively, the marginal cost curve in the partly-full case above is shifted right a distance $k_1\min\{\bar{z}, \mu(t)y_t\}$. However, at most $\bar{z} - \min\{\bar{z}, \mu(t)y_t\} = \max\{0, \bar{z} - \mu(t)y_t\}$ units of electricity can be generated by hydro using stored water, so that the marginal cost curve is compressed horizontally: $\bar{z}$ is replaced with $\max\{0, \bar{z} - \mu(t)y_t\}$.

If $x_t < k_1\min\{\bar{z}, y_t\}$ then the demand curve intersects the offer curve where marginal cost is zero, in which case $z_t = x_t/k_1$ and $m_t =$

0. The spot price is $p_t = 0$ and demand at the consumers' node is $q_t = x_t$.

Now consider the case where $x_t \geq k_1 \min\{\bar{z}, \mu(t) y_t\}$. The demand curve intersects the offer curve where marginal cost is positive. One way to find the intersection is to shift both curves left by the amount $k_1 \min\{\bar{z}, \mu(t) y_t\}$ and interpret the horizontal coordinate of the intersection as the amount of electricity delivered to the consumers' node in excess of $k_1 \min\{\bar{z}, \mu(t) y_t\}$. It follows that the generation policies equal

$$z_t = \min\{\bar{z}, \mu(t) y_t\} + \max\left\{0, \min\left\{\max\{0, \bar{z} - \mu(t) y_t\}, \frac{bk_1(x_t - k_1 \min\{\bar{z}, \mu(t) y_t\}) - h_t - bk_1 k_2 \min\{u(k_2 h_t / k_1), \bar{m}\}}{bk_1^2}\right\}\right\}$$

and

$$m_t = \max\{\min\{v(x_t - k_1 \min\{\bar{z}, \mu(t) y_t\}), \min\{u(k_2 h_t / k_1), \bar{m}\}\}, \min\{v(x_t - k_1 \bar{z}), \bar{m}\}\}.$$

The following policy functions capture both of the special cases above:

$$z_t = \min\{\mu(t) y_t, \bar{z}, x_t / k_1\} + \max\left\{0, \min\left\{\max\{0, \bar{z} - \mu(t) y_t\}, \frac{bk_1(x_t - k_1 \min\{\bar{z}, \mu(t) y_t\}) - h_t - bk_1 k_2 \min\{u(k_2 h_t / k_1), \bar{m}\}}{bk_1^2}\right\}\right\}$$

and

$$m_t = \max\{0, \min\{v(x_t - k_1 \min\{\bar{z}, \mu(t) y_t\}), \min\{u(k_2 h_t / k_1), \bar{m}\}\}, \min\{v(x_t - k_1 \bar{z}), \bar{m}\}\}.$$

Therefore, these functions describe the generating policy for an arbitrary level of x_t.

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