Competition Policy and Regulation in Hydro-Dominated Electricity Markets

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Abstract

This paper reviews the main competition issues that arise in electricity systems dominated by hydro generation, arguing that technological differences between hydro and thermal plants may allow hydropower producers to exert market power. The paper shows that the traditional Herfindahl-Hirschman index (HHI) is not an appropriate measure of concentration in hydrothermal electricity systems, and describes some proposed adjustments to the index. Some market simulation approaches to measuring market power in hydrothermal systems are reviewed. Finally, possible interventions to mitigate market power are analysed.

Keywords: Competition, Regulation, Electricity, Hydropower

JEL Classification: L40, L94, Q40
1. Introduction

Since the beginning of the 1990’s, the electricity industry has gone through major reforms in several countries. Restructuring, competition and privatization were introduced in markets formerly characterized by regulated and vertically-integrated monopolies. In particular, among all segments of the electricity supply chain, generation was seen as having the most favourable prospects for the successful development of competition.

Since then, however, experience in some of the markets which led this process, such as England and California, has shown that liberalized electricity industries might be subject to the exercise of market power. There are several empirical and theoretical studies showing how market power can be exercised in electricity generation; some of the most influential ones are Borenstein and Bushnell (1999), Green and Newbery (1992), Joskow and Kahn (2002), Wolak and Patrick (1997) and Wolfram (1999).

Most of these studies ignore or take a simplified approach to the effects of hydro generation, since their focus is on the operation of predominantly thermal-based systems. However, there are many countries where hydropower is the primary form of generation, such as Brazil, Canada, Colombia, Venezuela, New Zealand, Switzerland and Norway. Because of the specific characteristics of hydro generation markets, the results and methods contained in the above papers may not directly apply.

The purpose of this paper is to review the main competition issues that arise in electrical systems dominated by hydro production, presenting a survey of recent literature and showing that, because hydro and thermal generating plants have different
technological characteristics, they present different opportunities, incentives and methods of exploiting market power.

The presence of reservoirs implies that operation of hydroelectricity plants is intrinsically dynamic: each additional unit of electricity produced at a given moment lowers the level of the plant’s reservoir, thereby reducing the availability of “fuel” – water – for future production. In other words, hydropower producers can “move” energy between periods by controlling the flow of water out of their reservoirs. In contrast, the operation of thermal units has a static nature: since fuels such as coal or gas can be freely acquired at the corresponding commodity markets, the amount produced in a given period does not affect the production possibilities in subsequent periods.¹

This dynamic aspect of hydropower generation introduces some forms of anti-competitive behaviour that are not present – or are less significant – in thermal-based systems. The key market power issue becomes the strategic allocation of a given amount of output across periods, rather than a straightforward reduction of total output or increase in prices. In this sense, one could say that the methods for abusing market power in hydro systems are subtler and detection is more difficult. Furthermore, the job of competition authorities in assessing market power is made even more difficult because the traditional method of comparing prices with marginal costs is not appropriate for hydropower. In fact, we will see that marginal costs are virtually zero, so that the main determinant of prices in hydro-based systems is the opportunity cost of releasing water, which is not directly observable and depends on expectations about inflows and hydrological conditions.

¹ As will be explained later, thermal plant operation also has a dynamic aspect due to slow ramping rates and high start-up costs. However the time frame of this effect is restricted to a few hours, whereas for the operation of hydro systems the dynamic horizon is measured in months, seasons or years.
An interesting example of the different competitive strategies of hydro and thermal generators can be seen in the Spanish market. There, in 2001, hydro resources were responsible for 19% of total annual power production; however, hydro plants set the system marginal price 80% of the time during peak-demand hours, while conventional thermal generators set the price in 60% of the off-peak hours. Although this observation does not necessarily mean that the Spanish hydro firms were capable of significantly distorting market prices away from competitive levels, it does suggest that different technologies adopt different bidding strategies in the spot market.

The paper will proceed as follows. Section 2 summarizes some relevant technological aspects. Section 3 overviews factors that should be taken into account when defining the relevant wholesale power markets. In Section 4, a review of the sources and effects of market power in deregulated electricity markets is presented. Section 5 discusses how hydro generators’ market power can be enhanced by the strategic management of outflows from their reservoirs. Section 6 will explain why traditional concentration measures may give a distorted view of the ability to exercise market power in those markets. Section 7 gives examples of market-modelling approaches for measuring market power. In section 8, some remedies for reducing hydro plants’ market power are reviewed. Some final remarks are presented in section 9.

2. **Technological aspects**

There are basically three types of hydropower generating technologies. In *reservoir plants*, electricity is produced from the release of water stored in an artificial

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lake created by a dam. The reservoir is replenished through the natural water cycle by precipitations (rain or snow melt). In pumped storage plants, water is pumped up from a lower to a higher reservoir in times of low electrical demand, in order to be again released in times of peak demand. Run-of-river plants operate on the natural flow of the waterway, without the use of a dam.

This paper will focus in hydroelectricity generated by reservoir stations. Pumped storage facilities account for a very small amount of total production in most countries, making it unlikely that they significantly affect market outcomes. Run-of-river plants, in turn, do not have much leeway in controlling their production level, which is given by the natural flow of the river, and therefore are not able to strategically move production from one period to the other and to instantaneously adjust output, which – as will be argued below – are the main sources of market power in hydroelectricity markets.

3. Relevant market definition

The electricity supply industry consists of four vertical segments: generation, transmission, distribution and retail supply. This survey concentrates on market power on the generation segment, although a few words will be said about how bottlenecks in the transmission segment and lack of consumer response on the retail segment might affect market power in generation.

3 For example, among some of the countries in which hydropower is the dominant form of production, the share of pumped storage is zero or negligible in Brazil, Colombia, Venezuela, New Zealand, Norway and Canada.
In many countries, two modes of trade for wholesale electricity co-exist: a spot electricity market and a market for long-run bilateral contracts. For competition policy purposes, it is important to assess whether these two modes of trade belong to the same relevant market. Since a great variety of bilateral contracts exist, a case-by-case treatment of the issue is probably the best approach, but arguments laid out in the literature mostly support the assertion that those modes of trade are close substitutes, and therefore belong to the same relevant product market. In addition, multiple electricity “products” exist, such as day-ahead energy, real-time balancing, ancillary services and capacity. Several authors argue that, because of arbitrage opportunities, these products also belong to the same relevant market, although this ultimately depends on the specific market design and rules.

An important characteristic of the electricity industry is that there are no ways to economically store the product. Production and consumption of electricity must take place at the same instant. This introduces a temporal dimension in the definition of relevant markets; in other words, markets must be distinguished by the time at which electricity is delivered. The most important temporal division for competition policy purposes is between peak and off-peak periods. As we will see, it is usually at peak demand periods that competition is more severely limited, due to transmission and generation capacity constraints.

In periods where there are points of congestion in the transmission grid, markets must also be differentiated geographically. As we will see in the next section,

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4 In England, for example, the introduction of NETA translated into a move from a mandatory pool with no bilateral trading to a system of bilateral physical contracts with a voluntary balancing pool.
6 Borenstein, Bushnell and Wolak (2002) and Joskow and Kahn (2002) present useful discussions on this subject.
7 Subsection 4.2.3 will show, however, that market power may arise in off-peak periods if there is a large variation in operating costs among the different generation technologies.
congestion in the transmission grid isolates competing generators, reducing the potential number of competitors in a given region and facilitating the exercise of market power. Therefore, in defining the relevant markets, one has to find out which links of the transmission grids are systematically congested, separating geographical zones into different markets.

It is important to note that such temporal and geographical separation of markets is endogenous in the sense that a firm with market power may strategically induce congestion into its area of dominance. The way this is done will be detailed in sections 5 and 6.

Although temporal and geographical factors are also important in defining relevant markets in thermal-based systems, sections 5 and 6 will also show that hydro generators can exploit transmission constraints and peak/off-peak demand fluctuations in different – and perhaps subtler – ways compared to thermal plants. Furthermore, in hydro-based systems, there is an additional temporal factor that has to be taken into account: the seasonality of the natural water cycle. Indeed, some of the works to be reviewed below demonstrate that the incentive and capability of a hydro firm to influence market outcomes is related to the reservoir levels and to the probability of replenishment.

4. Market power in hydrothermal systems: sources and facilitating factors

The traditional definition of market power is the ability of a firm (or a set of coordinating firms) to increase the market price above marginal costs in a sustainable way, by raising its own price and/or reducing quantities. Following the taxonomy put
forth in OECD (2003), the factors that constrain firms’ ability to affect the market price may be classified into three categories:

- **Demand substitutability**: faced by an increase in prices, consumers may decide to reduce their consumption of the good/service, switch to substitute goods/services, or postpone their consumption if they expect price to come back down in the future.

- **Supply substitutability**: existing competing firms react to an increase in market prices by increasing their own production, thereby causing the price to fall back down.

- **Potential competition**: an increase in price may make the market attractive to firms who are not already producing the good/service. Those firms would then enter the market, increasing competition and bringing down the price.

Market power may arise in markets where some, or all, of the above constraining effects are not at work. In liberalized electricity generation markets, there are a number of reasons why those factors do not curtail the ability of generators to unilaterally raise their prices. Although many of the arguments laid out below are valid regardless of the predominant generation technology, we will point out how they relate to some particular features of hydro-based systems.

4.1. Factors limiting demand substitutability

It is widely agreed that electricity markets are characterized by a very low sensitivity of consumers to changes in wholesale prices. Inelastic demand facilitates the
exercise of market power since a rise in market price does not cause a corresponding fall in consumption. There are two main reasons for this lack of responsiveness.

First, close substitutes for electric power do not really exist. For some appliances, such as heating, both electricity and gas can be used as a source of energy, but substitution possibilities are somewhat limited: to change the source of fuel, one usually needs to change the appliance itself, which can be costly.

Second, in most countries the average end user does not face retail prices that vary on a real-time basis with wholesale prices. Instead, conventional meters record only the total amount of electricity consumed over a relatively long period, usually a month, so that consumers are billed according to a time-averaged fixed-price schedule. As a result, demand does not respond to a rise in wholesale market price.

In hydro systems, the issue of price volatility is somewhat different. There is very low volatility on the short-term (i.e., hourly or daily), due to the ability of hydro reservoir operators to transfer water between adjacent hours and days. In contrast, there is high volatility on the long-term (i.e., seasonally or yearly): under normal hydrological conditions, reservoirs will be relatively full, meaning very low (sometimes even zero) marginal costs and prices for very long periods; however, if a dry period occurs, marginal costs (which include the opportunity cost of not saving water for future periods) can attain extremely high levels, sometimes even reaching system rationing levels.

The relevant time frame for evaluating consumer response is therefore longer compared to thermal systems, in which hourly or daily price spikes are much more common. To put it differently, in hydro systems the adequate measure of consumer responsiveness is the long-term price elasticity, which is generally higher than the short-
term price elasticity relevant for thermal systems. In this respect, hydro systems are in a relatively favourable position, as retail contracts in which prices vary seasonally should be easier to implement than contracts in which prices vary on a hour-to-hour or day-to-day basis.

4.2. Factors limiting supply substitutability

In the power generation industry, the main factors limiting supply-side substitution are: (1) production capacity constraints; (2) transmission constraints; and (3) differences in production technology.

4.2.1. Generation capacity constraints

When a dominant generator tries to unilaterally increase the market price by holding back production, competitors would tend to react by increasing their own production, partially offsetting the initial quantity reduction. Yet, if the competitors operate at their maximum generating capacities, they will not able to increase production. In the limit, if all competitors of a dominant producer are operating at maximum capacity, that plant will actually be a monopolist towards the residual demand. We would expect this situation to arise in peak demand periods since, as demand increases, more and more firms will be producing at their maximum capacity.

In this respect, it is important to note that, in contrast to conventional thermal technologies, hydro plants are usually energy-constrained rather than capacity-constrained. In other words, the binding constraint for hydro generators is to have
enough water stored to supply energy in a dry period, while for thermal plants the binding constraint is to have enough turbine capacity to cover demand in the annual peak hours. The reason for this difference is that the main fixed costs of a hydropower plant are the construction of the dam and the water-inflow pipes; given these, extra output capacity can be added at a relatively low cost. Therefore, when evaluating the potential for market power of a given firm, competition authorities should give special attention to the type of technology of the competitors: if those are mainly other hydro plants, capacity constraints are less stringent and less likely to hinder competition; however, if the main competitors are thermal plants, the situation described in the above example is more likely to occur.

To illustrate these points, consider the following hypothetical market.\(^8\) There is one large hydro generator, with capacity of 60 MW and a fringe of 20 price-taking generators, composed of either thermal or small hydro plants, each with capacity of 10 MW. The marginal cost of production is constant and equal to $10 for all producers. Demand is given by \(Q(p) = Ap^{-0.25}\), so that elasticity of demand is constant and equal to 0.25.

Table 1 shows the equilibrium market outcome for different values of \(A\), which is a parameter that measures the demand level. When the demand parameter is relatively low (for example, \(A = 250, 300\) or 350), the market price is $10, and the quantity demanded is less than the fringe’s total capacity of 200 MW. The larger generator has no market power, since the small producers are able to cover the entire demand. This will be the case until \(A\) reaches a value of approximately 355. For \(A\) higher than this value, small generators are not able to cover the whole demand anymore, so that the

\[^8\] This example, as well as the others in this subsection, is a variation of the one in OECD (2003).
large generator becomes a monopolist with respect to the residual demand and can force the price up by withholding production.

<table>
<thead>
<tr>
<th>A</th>
<th>Demand</th>
<th>Price</th>
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<tbody>
<tr>
<td>250</td>
<td>140.6</td>
<td>10.00</td>
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<tr>
<td>300</td>
<td>168.7</td>
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<tr>
<td>700</td>
<td>252.4</td>
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<tr>
<td>800</td>
<td>257.5</td>
<td>93.22</td>
</tr>
</tbody>
</table>

4.2.2. Transmission constraints

A similar argument holds for constraints in the capacity of transmission lines. As noted in section 3, these bottlenecks split the market into separate geographic zones. If grid capacity were unlimited, any attempt by a dominating generator to reduce production levels would tend to be offset by an increase in energy imports into that zone. When transmission capacity is at its limit, however, the dominating generator is able to hold back production without inducing more imports. In this case, competing generators are actually geographically isolated; the number of potential competitors is reduced, aggravating market power.⁹

⁹ A market that is isolated due to transmission constraints is known as a load pocket.
The effects of transmission grid congestion can be seen in an example similar to the one above. Assume that there are two regions and that demand, which is given by 
\[ Q(p) = Ap^{-0.25} \], is entirely concentrated in region 2. In region 1 the production of electricity is competitive; in region 2, there is only one generator. The marginal cost of all producers is $10. Although there are no generation capacity constraints in either region, there is a transmission line between the two regions with capacity of 200 MW.

The outcome of this market is entirely analogous to the one described in Table 1. For low values of the demand parameter, the transmission link is not congested, so the region 2 dominant producer cannot raise price without inducing increased imports from region 1. However, for high demand levels, there is a transmission bottleneck, and the region 2 generator has an effective monopoly over all the demand in excess of 200 MW.

Transmission constraints may hinder competition more severely in hydro-based systems, since hydro sites are often located far from major population centres and are thus strongly dependable on complementary transmission investments, while thermal plants have more leeway to locate near or inside the load centres.

4.2.3. Generation technology constraints

One of the most significant constraints on the real-time operation of generation plants is the unit-commitment problem. In short, the amount of output that a generator can produce at a given moment, as well as the cost of doing so, is related to the amount being produced at the immediately previous moment. First, increasing or reducing the amount of output may be a slow process; the rate of change in output from a power plant is called ramping rate. Second, if the unit is not operating at a given moment, it is
usually costly to turn it on; these costs are called *start-up costs*. Conversely, turning off a plant that is currently operating may be costly and time-consuming; such costs are labelled *shut-down costs*.

The key technological aspect of interest is that reservoir hydro plants are *flexible*: they can be started and stopped, and output levels can be changed, almost instantaneously.\(^\text{10}\) Thermal technologies, on the contrary, are *inflexible*: maximum ramp-rates are considerably smaller, while start-up and shut-down costs are higher. In other words, unit-commitment constraints are more stringent for thermal than for hydro plants. In terms of the competitive process, the situation is then similar to capacity and transmission constraints: plants with an inflexible technology are not able to quickly respond to competitor’s actions and to increase production on a short notice, even if they are producing below maximum capacity.

Another important difference between hydro and thermal technologies is the cost structure. Operating costs for hydro are very low compared to thermal, since it does not incur fuel costs. Indeed, the main cost component is the *opportunity cost* of having less water available for the next period. This *marginal value of water* can be very high (possibly equal to the value of lost load) in periods of drought, or very low (effectively close to zero) in periods of normal or above average inflow conditions. In the latter case, it is economical for higher cost thermal units to respond to an output decrease by a hydro generator, even though they are below their capacity limit. As shown in OECD (2003), it may then happen that market power will be observed in off-peak hours: when demand is very low, it may not be economically cost-effective for thermal plants to come into production, and the market will be entirely left for the low-cost hydro units.

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\(^{10}\) In practice, environmental regulations might impose minimum and maximum instantaneous flow constraints, so that the operational flexibility of the hydro plant is reduced whenever one of these constraints become binding.
As demand increases, however, the thermal units may come in, thereby increasing competition.

Consider, as an example, a market in which there is one hydro generator, with constant marginal cost of $10 and capacity of 50 MW, and a fringe of price-taking thermal generators, with constant marginal cost of $25. The demand is given by \( Q(p) = Ap^{-2} \). The hydro generator has an effective monopoly until demand reaches 50 MW, since the monopoly price for any demand lower than this level is $20, below the fringe’s marginal cost. When demand is above this level, the hydro producer is capacity constrained. The thermal units then come into service and the price goes up to $25, which is the competitive price for this level of output.\(^{11}\)

In summary, the assessment of market power in mixed hydro and thermal systems should acknowledge these technological factors. For example, the more concentrated the ownership of hydro plants is, so that most of the competition comes from thermal suppliers, the more likely it is that a dominant hydro producer will be able to manipulate the market price through short-run output withholding. Conversely, a dominant thermal producer may not be able to strongly influence the market outcome if it is competing against a fringe of flexible and capacity-unconstrained hydro plants.

4.3. Factors limiting potential competition

In perfectly contestable markets, even a monopolistic firm is not able to unilaterally increase prices above the competitive level, since this would bring about

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\(^{11}\) This example also illustrates that a reduction in market power does not necessarily imply a reduction in the market price. The relevant issue is a reduction in the mark-up of market price over the marginal cost of the last MW generated.
entry from firms not yet operating in the market, causing the prices to fall back down.\textsuperscript{12} In electricity systems where hydropower is the main source of production, this ideal situation is very far from reality. Private investors face risks associated with the planning, development and management of hydro plants that are not present (or are present to a lesser degree) in other infrastructure projects, which may make them more reluctant to sink the necessary investment for entering the market or expanding capacity.

First, the construction of a new hydropower plant faces extremely high fixed initial costs and there is a significant delay between planning and operation, since construction time may vary between 4 and 10 years, depending on the size and the type of plant.\textsuperscript{13} This obviously increases the risk faced by potential investors.

Second, forecasting about the timing of recovery of capital costs can be quite complex. Not only demand conditions must be estimated, as in any other infrastructure project, but forecasts of hydrological conditions should also be considered. As mentioned earlier, price volatility follows a different pattern in hydro-based systems. Prices tend to be very low (often close to zero) for extended periods of time, but can reach extremely high levels in periods of drought. This extreme volatility of long-term price levels in hydro-based systems, which does not have a parallel in any other infrastructure projects, makes investment analyses more complex.

Third, the possibility of competitive entry taking place is limited by the fact that existing hydro generators are, in most cases, already located in the places with the best potential hydrological resources. In such a situation, new hydro entrants have no option other than locating in places that are not so favourable, for example, in far away regions.

\textsuperscript{12} A perfectly contestable market is a market in which any firm can produce and sell without incurring any fixed entry or exit costs.

\textsuperscript{13} Some small scale hydro projects, for example with capacity below 1000 kW, may be cheaper and quicker to implement, but they are also less likely to curb the market power of larger operators, because of their small size and the fact that they are usually run-of-river.
Of course, this will be especially problematic in systems with significant transmission constraints.

Fourth, environmental regulations and opposition of environmental activists are also a limiting factor for potential investments in hydroelectric generation. Hydro projects involve large costs of population resettlement, interference with the ecological equilibrium of river systems and inundation of land that could have valuable alternative uses. However, global warming effects and the Kyoto protocol may make the costs and benefits more favourable for the development of hydro and other renewable energy projects. The net balance has to be analysed in a case-by-case basis, but environmental constraints mean that the future trend will be toward the development of smaller sized projects which, as noted before, may not be able to curb the market power of large, less capacity-constrained operators.

Fifth, legislation regarding water rights is also an important determinant of the potential gains and risks of investment projects. In some countries (e.g., Chile) water rights are owned and controlled by the generation companies. This makes entry of new competitors more difficult, since the incumbents, when analysing the construction of a new plant, will internalize the impact on its existing plants. Conversely, entry is easier in countries where water rights are owned by the state, and the right to use these water rights is franchised to the generating companies through a public bidding process.

Given the above constraints on hydro projects, investment in thermal power may sometimes be more favourable for private investors, and entry of thermal generators should also be considered as an important source of potential competition. Even though traditional thermal marginal costs are higher, and they also take time to build, the recent Combined Cycle Gas Turbine (CCGT) technology mitigates both problems, since they
have lower marginal costs and can be built in about two years. Besides, an advantage of thermal generation is that they face much less constraint with respect to the choice of location, and could potentially be built in regions in which market power arises due to transmission constraints. Nevertheless, a cautious approach should be taken regarding the ability of CCGT plants to curb the market power of hydro generators, since they face the same operational and technological constraints as other thermal plants (see subsection 4.2.3).

5. Market power in hydrothermal systems: strategic allocation of water resources

The essential difference between thermal and hydro operation is that for the former inputs (coal, gas, oil) are commodities traded in international markets, while for the latter the amount of available input (water) is exogenously given and its replenishment is uncertain, depending on natural inflow cycles. Water stored in a reservoir can be moved from one period to another, and the amount of energy available in the future depends on the amount currently produced. Except for the unit-commitment problem explained above, this dynamic dimension is not present in thermal-dominated electricity markets.

Scott and Read (1996) compute the profit maximizing scheduling by mixed hydro-thermal firms competing in a wholesale electricity market model matching the characteristics of the New Zealand system. They find that, in the absence of long-term contracts between generators and consumers, inter-temporal strategic water management could lead to an increase in market prices of about 20%. If generators are
fully contracted, however, the incentive for strategic behaviour disappears, so that spot prices match the perfectly competitive level. They do not address the question of what contract level and prices would be observed in the competitive market equilibrium.

In two related papers, Kelman, Barroso and Pereira (2001) and Barroso et al. (2002) present results from a simulation of the Brazilian system. Their results indicate that spot prices rise as firms with market power decrease output. More interestingly, price spikes are stronger in the dry season (June to October), even though, in Brazil, the highest demand months coincide with the wet season (November to May). This pattern arises since strategic hydro plants decrease water transfers from wet to dry periods, i.e., storage is lower under generator market power.

In the above studies, anti-competitive management of hydro storage is associated with water spillage: output is decreased in all periods, so that the total amount of energy produced within the relevant time horizon is reduced. In practice, however, spillage can be easily detected by regulators, and thus generators are likely to pursue the more subtle strategy of reallocating a given amount of total energy across sub-periods, instead of simply reducing this amount. Contrary to thermal operators, that can only exert market power by reducing total output, hydro producers may exert market power without any reduction in total production at all.

Crampes and Moreaux (2001) and Bushnell (2003), in contrast to the previous two papers, incorporate in their models the constraint that the whole stock of water must be used for energy production within the appropriate time horizon, so there is no spillage. They demonstrate that in a perfectly competitive hydro system, demand peaks tend to be shaved-off: Price-taking hydro generators would like to transfer production from off-peak periods, when prices are low, to peak periods, when prices are high. By
doing so, they decrease the off-peak market supply and increase the peak supply, thereby causing an equalization of prices and reducing the temporal separation of markets. Conversely, when hydro generators have market power the temporal separation is further increased: strategic plants shave marginal revenues rather than demand, which means that they would tend to allocate relatively more hydro production to off-peak demand periods than to peak periods. By doing so, they can exploit competitors’ capacity constraints, reducing their own supply and driving up the market price when demand is at the peak.

Bushnell (2003) provides additional insight by performing simulations of the Western U.S. electricity market. He considers several different scenarios corresponding to different assumptions about the number of strategic firms. In the scenario where BPA (the largest hydro operator in California) is the only strategic player, the simulations for the month of September indicate that, compared to the outcome under perfect competition, spot prices decrease by 11% in the lowest demand hours but increase by 18% in the peak demand hours. This price pattern arises as BPA reallocates hydro energy and are also observed in simulations for the other months. In June, for example, BPA’s hydro output is around 13,500 MW in the peak hours and 12,900 MW in the lowest demand hours, while the perfectly competitive outputs for those same hours would be around 20,200 MW and 9,800 MW, respectively.¹⁴

In summary, the main insight from Crampes and Moreaux (2001) and Bushnell (2003) is that, compared to thermal-based systems, hydroelectric resources have the ability to smooth the price profile if they are operated in a perfectly competitive environment; in contrast, strategic hydro generators tend to sharpen the peaks.

¹⁴ Not surprisingly, the simulation results indicate even higher price distortions for the scenarios in which thermal generators also behave strategically. In these scenarios, however, prices increase in the lowest demand hours as well, since output withholding by thermal plants offsets the increased hydro production.
Therefore, for competition policy authorities trying to assess market power in hydro-based systems, it is important to examine the inter-temporal distribution of prices and mark-up levels within the period under analysis, rather than just computing average mark-ups for the whole period, as is sometimes done in thermal-based systems.

These results should nevertheless be qualified. Price differences between peak and off-peak periods do not necessarily mean abuse of market power: even in a perfectly competitive hydro-based electricity market, average prices may differ across periods. For example, Mathiesen, Skaar and Sørgard (2003) demonstrate that if the system’s reservoir capacity is limited and future inflows are expected to be high, prices will not be equalised. In this case, there is a threat that water may be lost due to overflow of reservoirs, and thus it may be better reduce the price and to sell more energy now than to risk a waste of water if there is a large inflow in the future. The more general intuition for this result is that the ability to transfer water between periods is what drives the inter-temporal equality of prices in hydro systems; if there are any limits on this ability due to constraints given by reservoir capacity, minimum and maximum instantaneous flows and transmission bottlenecks, equality of prices under perfect competition might not hold.\(^{15}\) However, market power may still increase the amplitude of price differences. Of course, whether observed price spikes are due to normal functioning of markets or reflect market power is an empirical issue that should be investigated in a case-by-case basis.

The ability of hydro producers to exercise market power is related not only to the state of demand, as is also the case in thermal-dominated systems, but to hydrological conditions and reservoir levels as well. In other words, prospects for market power

\(^{15}\) Indeed, in the model of Crampes and Moreaux (2001) those additional constraints are not present.
differ from dry to wet seasons and from years when reservoirs are at a “normal” level to years when a drought occurs.

Indeed, simulation results from Bushnell (2003) show that, even though peak loads are higher in June than in September and the impact of strategic behaviour on hydro output is also more pronounced in June, the impact on prices follows the opposite pattern: price distortions are actually less dramatic in the late spring month of June, when much more water is available, than in the early autumn month of September, when reservoirs are low and the marginal value of water is high. A similar result is obtained from simulations by Barroso et al. (2002) which show, as pointed out earlier, that the highest spot prices in the Brazilian electricity market would occur in the dry winter season, even though demand is at its highest during the wet summer season.

The above studies suggest that there is a reallocation of hydro outputs from peak to off-peak periods, even though the effects on prices may be more pronounced in dry periods, whether or not those coincide with peak demand. Mathiesen, Skaar and Sørgard (2003) refine this result: the reallocation of hydro output is actually related to relative demand elasticities, rather than demand levels. Market power leads to increased hydro output (lower storage) in periods where demand is relatively more price elastic and decreased hydro output (higher storage) in periods where demand is relatively less price elastic. The intuition is that the firm has more incentives to increase prices in periods when quantities sold are less affected. Whether demand is more or less price elastic in dry than wet seasons, or in peak than off-peak periods, are empirical questions that are
likely to depend on the country’s specific climatic conditions and the exact shape of the demand curves.\textsuperscript{16,17}

Although some of the papers cited above include inflow uncertainty, Garcia, Reitzes and Stacchetti (2001) were the first to perform an analytical study of the effects of the stochastic nature of inflows on oligopoly hydro scheduling. They show that prices increase as the reservoir levels and the probability of replenishment decrease. The reason is that, in such a case, the opportunity cost of releasing water to produce power now increases, as each producer foresees the possibility of having more market power in the future if they hold onto water and let their competitors deplete their own reservoirs. This argument reveals that, in hydro-based systems, individual generators have an additional incentive to withhold production: not only the current profits tend to increase, as in any other industry, but also the prospect of reaching a future state with weaker competitors and stronger market power.

Another interesting point regards the effects of a regulatory price-cap. It is shown that a price-cap affects the whole inter-temporal distribution of prices. In fact, equilibrium prices are affected even at times when they are below the cap, since it affects the opportunity cost of releasing water in the current period. A lower price-cap means lower potential future profits from each additional unit of water withheld, thus decreasing the current marginal value of water, which translates into lower current prices. Price-caps therefore play an even stronger disciplining role in hydro-based systems.

\textsuperscript{16} For example, if the demand curve is linear, there is a direct relationship between the demand level and the elasticity: at equal prices, the elasticity decreases as the intercept of the demand function increases. This result, however, does not necessarily extend to more general demand curves.

\textsuperscript{17} In temperate climate countries, it is more likely that peak loads coincide with the dry season, since demand for heating rises during winter, while a significant part of inflow comes from snow melt during spring and summer. In tropical countries, the opposite is more likely, since demand rises in summer and most inflows come from summer rainfall. Again, the relationship between demand levels and elasticities is ultimately an empirical question.
markets compared to thermal-based markets, since the cap affects prices even when it is not binding.

So far, we have been implicitly considering unilateral market power. Garcia, Reitzes and Stacchetti (2001) also analyze the issue of collusion between hydro generators. They show that the likelihood of collusion increases with reservoir levels and the probability of water inflow, since punishment becomes more credible: indeed, a generator with an empty reservoir cannot credibly commit to punish a deviating rival by flooding the market, as in the usual collusion game.

A further competition issue arises when there are plants in cascade, that is, plants located along the same river. In this case, all water released by a given plant eventually reaches the reservoir of the plant located immediately downstream, therefore adding to its production capacity. In other words, all energy produced by an upstream plant provides an input to the downstream plant. This would not represent a problem if all of those plants belonged to the same owner, since the effect just described would be internalized. However, in many countries there are examples of cascade plants belonging to different owners. This situation might in fact increase the ability and the incentive of an upstream plant to distort its generation level downward, especially in dry periods, when reservoir levels are low: not only this strategy causes an increase in prices due to a reduction in supply, but it also constrains the access of the downstream competitors to the water input. When analysing concentration cases involving generation plants located along the same river, competition authorities should therefore have in mind the trade-off between increasing the number of competitors and enhancing the beneficial effects that come from coordinated reservoir operation.
6. Market power in hydrothermal systems: interaction of water allocation with transmission constraints

In all electricity markets, transmission congestion may create load pockets, excluding competitors located in other regions and enhancing market power of local firms. Moreover, as first demonstrated in Borenstein, Bushnell and Stoft (2000), these transmission bottlenecks are not always exogenous: firms may have incentives to strategically induce congestion in order to enjoy local market power. This section will show that the geographical aspect of transmission constraints interact in interesting ways with the temporal features of hydro production.

We have seen in the previous section that, in the presence of market power, the distribution of prices departs from the socially optimal solution as generators arbitrage inter-temporal differences in demand: they increase prices above competitive levels in periods where demand is relatively inelastic. One might then conclude that if demand is stationary, so that elasticity (at given prices) does not vary, the outcome under generator market power would match the competitive outcome. This is indeed true in models that do not take into account transmission congestion.

With transmission bottlenecks, Førsund and Hoel (2004) show that, even if the demand function is the same all periods, prices will depart from perfect competitive levels as a hydro monopolist exploits capacity constraints on imports and exports. In their model, with constant demand, no inflow uncertainty and no constraints other than total annual production being equal to total available energy, the socially optimum outcome is to have constant electricity production all days of the year. The authors then show that transmission constraints cause the profit function of the hydro generator to be
non-concave. Therefore, starting from the socially-optimal constant production level, the monopolist can get higher profits by increasing output and exporting electricity on some days, while reducing output so as to induce as much imports as the transmission constraint allows in other days, in such a way that total annual output does not change.

Johnsen (2001) shows that under generator market power, limited transmission capacity and inflow uncertainty firms have excessive incentives to export energy early on, so that storage is below the socially optimal. This strategy increases the probability that there will be an import constraint in the future if inflows are low, transforming the region in a high price load pocket; in addition, it decreases the risk of being export constrained and of substantial price drops in later periods if inflows are high. The implication of this result is for transmission investment is surprising: increasing transmission capacity may actually be detrimental to competition. On one hand, it increases import possibilities, enhancing access from generators located in different zones and thus reducing market power; on the other hand, it allows the generator located inside the load pocket to get rid of more water by increasing exports early on, so in later periods storage will be even lower and prices higher.

Skaar and Sørgard (2006) study the issue of cross-regional mergers and acquisitions in hydropower markets with transmission bottlenecks. Their framework consists of two hydro-dominated regions, W and E, and two time periods, 1 and 2. There is a firm which is the sole generator operating region W. This firm also owns some capacity in region E, but there it faces competition from other hydro-generators (possibly including a price-taking fringe). There is a transmission line between the two regions, so that competitors in E have access to the market at W up to the transmission capacity. It is shown that, in the first period, the firm that has capacity on both regions may have an
incentive to withhold output in region W, in order to create congestion and become a \textit{de facto} monopolist in an import-constrained load-pocket at W. The withheld energy is then released in period 2, when both markets are integrated.\footnote{Since the authors assume no spillage, total production in the two periods must be equal to total available energy. Therefore, region W firm cannot adopt the strategy of withholding energy in both periods.}

The authors then go on to demonstrate that if region W’s generator acquires additional capacity in region E, say by merging with another firm in that region, welfare may actually improve, even if there are no synergies or efficiency gains. This interesting result is due to the fact that the firm will now take into account revenues on sales from the newly-acquired capacity. Since more of the energy sold in region E now accrues to the firm, it benefits by withholding production in the low-price exporting region E while increasing production in the high-price importing region W. The price difference between the two markets in period 1 will decrease compared to the pre-acquisition outcome. Since there is no spillage by assumption (total sales are equal to total available energy), the only effect of the acquisition is a reallocation of electricity from low valuation consumer in region E to high valuation consumers in region W in period 1, increasing welfare.\footnote{Note that in the case of a thermal system, the result would probably not hold, since after the acquisition the firm would have an incentive to cut down total production, as opposed to just changing its allocation. In this sense, the assumption of no spillage is crucial.}

\section{7. Market power in hydrothermal systems: effects on system reliability}

The literature reviewed above established that market power in hydro-thermal systems will change the storage pattern. An interesting question is then how this affects system reliability and the probability of energy shortages.
Garcia, Reitzes and Stacchetti (2001) analyse the conditions under which hydro replaces thermal production. As noted above, a price cap influences electricity prices even if it is not binding, since it affects the opportunity cost of releasing water. The authors show that, if price caps are set too low, reliability is compromised: the value of holding onto water will be low, so hydro producers will undercut thermal producers and storage levels may drop too low.

The authors also study the situation in which different plants face different hydrological conditions and inflow probabilities. On one hand, firms with higher probability of replenishment may have a higher opportunity cost of selling power in the current period, since they stand a greater probability of reaching a future state of increased market power if they refrain from releasing water now and let competitors’ deplete their reservoirs. On the other hand, the opposite may also be true: firms with lower probability of replenishment may have a higher opportunity cost, since these firms face the prospect of a longer period of starvation if they releases water now. The dominating effect depends on the parameter values such as the relative probabilities of inflow and the discount factor. The interesting point is that if firms with lower probability of inflow undercut firms with high probability, there will be a greater likelihood of reaching a state where some of the system’s reservoir are depleted, leading to energy shortages and increased threat of rationing.

Skaar (2004) observes that more market power for hydro generators may have a beneficial effect on reliability in hydro-thermal mixed systems, as less competition among hydro producers means that they will undercut thermal producers less often, and more water will be stored.
These observations are, in fact, an example of the more general result that, in any market, there is a trade-off between competition and coordination. As Ambec and Doucet (2003) point out, it is important that regulators and competition authorities be aware of such trade-off in hydro-based electricity markets, where coordinated reservoir management is especially important. In practice, the level of complementarity of the different plants’ hydrological conditions and reservoir characteristics are the key for determining the relative benefits of increased competition versus the value of coordination.

For example, Ambec and Doucet (2003) state that “in the case of Pacific Gas and Electric’s assets in California, it might be preferable (…) not to bundle plants along the same river. The cost of this, in terms of reduced coordination of water use, might be more than offset by the increased competition induced along the river.” In this context, indeed, complementarities across reservoirs are not very important, since all plants are subject to similar hydrological conditions. A contrasting example is the case of the Brazilian system: for instance, in years when El Niño occurs, there is above average rainfall in the southern region, often causing reservoirs to flood, while droughts occur in the northern part of the system; the reverse happens during La Niña episodes. To take advantage of this hydrological diversity, coordination becomes relatively more important. Indeed, Brazilian market designers chose to adopt centralized dispatch based a computer model of the system reservoir conditions and of hydrological scenarios, as opposed to bid-based decentralized dispatch commonly adopted in other liberalized electricity markets.
8. Market concentration measures

This section briefly reviews the concentration measures that are traditionally used in antitrust analyses, shows why they might not be appropriate in electricity markets and presents a modified concentration measure that better captures the specificities of those markets.

8.1. Traditional concentration measures

Competition analyses often make use of concentration measures as a screening device to assess market power. Probably the most well-known of these is the Herfindahl-Hirschman index (HHI), which is given by:

$$HHI = \sum_{i=1}^{n} s_i^2$$

where $n$ is the total number of firms in the market and $s_i$ is the market share of the $i$-th firm.\(^{20}\)

The theoretical justification for the use of the HHI comes from the fact that it is positively related to the price-marginal cost mark-up. In a perfectly competitive market, such mark-up should be equal to zero; however, when market power is present, it can be positive. Traditionally, the mark-up is measured by the Lerner index:

$$L = \frac{p-c}{p}$$

---

\(^{20}\) When market shares are expressed in percentages, the HHI will vary between 0 (atomistic industry) to 10,000 (monopoly). The U.S. Department of Justice considers as potentially problematic markets where the HHI is over 1000.
where $p$ is the market price and $c$ is a weighted average of producers’ marginal cost. It can be shown that, in a market where firms compete by setting quantities (Cournot competition), industry-wide mark-up obeys the following relationship:

$$\frac{p - c}{p} = \frac{HHI}{\varepsilon}$$

where $\varepsilon$ is the elasticity of demand at the market equilibrium price $p$. In other words, market power, measured as the percentage difference between price and marginal costs, is increasing with industry concentration and decreasing with demand elasticity.

Another widely-used measure of market concentration is the market-share of the $n$ largest firms, where $n$ is usually taken to be between 1 and 4. The idea is that the larger a firm is in proportion to the whole market, the easier it is for it to affect market prices.

8.2. *Why traditional measures might fail in electricity markets*

The use of the above concentration measures in markets in which a significant number of firms might be capacity constrained – such as the power generation market – is not appropriate: they may give a distorted view of the ability to exercise market power in those markets. In fact, because of capacity, transmission or technological constraints, the HHI and the market share of the largest producers may actually decrease as market power and mark-up increase.

To illustrate this point, it is useful to consider again the example described in section 4.2.1. Recall that the market consisted of one large hydro generator with 60 MW of capacity and a fringe of 20 small hydro or thermal generators with 10 MW of capacity each. Table 2 below shows the values of the Lerner index and the HHI for different demand levels.
Note that, even though the demand elasticity is held constant in our example, there is no systematic relation between market power (measured by the Lerner index) and the HHI. In particular, when $A$ is between 360 and 400, the Lerner index and the HHI are actually moving in opposite directions. The HHI is approximately the same for $A = 360$ and $A = 440$, but in the former case the mark-up over marginal cost is 2% and in the latter case it is 37%. Note that the mark-up can be as big as 90%, but the HHI never reaches more than 828, which is below the threshold of 1000 considered as “problematic” by the DOJ. Finally, the market share of the dominant hydro generator is never above 23%, a number that would not be considered excessive by most competition policy analysts.

### 8.3. The adjusted Herfindahl-Hirschman index

A simple way to adjust the HHI that takes into account the possibility of some generators being capacity constrained can be found in OECD (2003). Consider the

<table>
<thead>
<tr>
<th>$A$</th>
<th>Price</th>
<th>Lerner index</th>
<th>HHI</th>
</tr>
</thead>
<tbody>
<tr>
<td>360</td>
<td>10.25</td>
<td>0.02</td>
<td>494</td>
</tr>
<tr>
<td>370</td>
<td>10.84</td>
<td>0.08</td>
<td>485</td>
</tr>
<tr>
<td>380</td>
<td>11.45</td>
<td>0.13</td>
<td>479</td>
</tr>
<tr>
<td>390</td>
<td>12.10</td>
<td>0.17</td>
<td>477</td>
</tr>
<tr>
<td>400</td>
<td>12.79</td>
<td>0.22</td>
<td>476</td>
</tr>
<tr>
<td>420</td>
<td>14.26</td>
<td>0.30</td>
<td>484</td>
</tr>
<tr>
<td>440</td>
<td>15.88</td>
<td>0.37</td>
<td>497</td>
</tr>
<tr>
<td>500</td>
<td>21.82</td>
<td>0.54</td>
<td>557</td>
</tr>
<tr>
<td>600</td>
<td>36.39</td>
<td>0.73</td>
<td>664</td>
</tr>
<tr>
<td>700</td>
<td>59.13</td>
<td>0.83</td>
<td>745</td>
</tr>
<tr>
<td>800</td>
<td>93.22</td>
<td>0.89</td>
<td>800</td>
</tr>
<tr>
<td>900</td>
<td>143.57</td>
<td>0.93</td>
<td>828</td>
</tr>
</tbody>
</table>
situation of a market with \( n \) generators, where generators 1 through \( m \) (where \( m < n \)) operate below their capacity constraint for relevant time period being examined, while the others (generators \( m+1 \) through \( n \)) are capacity constrained. A situation like this could potentially be observed on a mixed hydro-thermal system where, for example, generators 1 through \( m \) are large hydro plants and the others are thermal or small hydro plants.\(^{21}\) The adjusted Herfindahl-Hirschman index is defined as:

\[
HHI^{adj} = \sum_{i=1}^{m} s_i \left( s_i + s_c / m \right)
\]

where \( s_i \) is the market share of the \( i \)-th unconstrained firm \((i = 1, \ldots, m)\) and \( s_c \) is the total market share of the constrained firms.

<table>
<thead>
<tr>
<th>( A )</th>
<th>Lerner</th>
<th>HHI</th>
<th>( HHI^{adj} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>380</td>
<td>0.13</td>
<td>479</td>
<td>317</td>
</tr>
<tr>
<td>400</td>
<td>0.22</td>
<td>476</td>
<td>545</td>
</tr>
<tr>
<td>420</td>
<td>0.30</td>
<td>484</td>
<td>747</td>
</tr>
<tr>
<td>440</td>
<td>0.37</td>
<td>497</td>
<td>926</td>
</tr>
<tr>
<td>500</td>
<td>0.54</td>
<td>557</td>
<td>1356</td>
</tr>
<tr>
<td>600</td>
<td>0.73</td>
<td>664</td>
<td>1813</td>
</tr>
<tr>
<td>700</td>
<td>0.83</td>
<td>745</td>
<td>1963</td>
</tr>
<tr>
<td>800</td>
<td>0.89</td>
<td>800</td>
<td>2232</td>
</tr>
<tr>
<td>900</td>
<td>0.93</td>
<td>828</td>
<td>2308</td>
</tr>
</tbody>
</table>

To see how the use of the adjusted HHI gives a better picture of market power, consider again the market of the previous example. In this case, none of the firms is constrained when demand is below 200 MW (that is, when \( A \) is below 355), so that the adjusted HHI is just equal to the traditional HHI. However, when demand is above this

\(^{21}\) Although such situation could also arise in thermal-dominated markets, it is more likely in mixed hydro-thermal systems since, as we have pointed out in section 4.2.1, thermal generators are much more often capacity constrained than large hydro plants.
level, there is only one unconstrained firm, so that \( m = 1 \). The resulting values of the adjusted HHI are shown in table 3.

Clearly, the adjusted HHI reflects the level of market power much better. For example, when the demand parameter is 600, the mark-up is very large, at 73\%. The traditional HHI, however, is only 664, well below the threshold of 1000. The adjusted HHI is 1813, almost three times as large as the traditional HHI.

Note that the adjusted HHI can be applied as an adjustment to other constraints, such as transmission capacity or flexibility of the different production units. In the first case, \( s_i \) would be the market share of the \( m \) firms located in the load pocket, and \( s_c \) the share of production coming from transmission constrained areas. In the second case, \( s_i \) would be the market share of the \( m \) flexible technology (hydro) plants, and \( s_c \) the market share of the inflexible (thermal) units, which are not able to increase production on a short notice even if operating below capacity.

8.4. *Introducing cross-ownership*

Another limitation of the traditional HHI in capturing the true degree of market power is cross-ownership between competitors. The reason is that, in general, an increase in prices by one firm raises the demand for the products of the competing firms. When the owner of the first firm also owns shares of the competitors this effect will be internalized, so that a given increase in price becomes more profitable. In short, cross-ownership makes each firm more concerned about the profitability of the whole industry, leading to less aggressive competition. The traditional HHI will therefore underestimate the actual degree of market power in the industry.
The following cross-ownership adjusted HHI was proposed by the Nordic Competition Authorities (2003). Define $\beta_{ij}$ as the share of firm $j$ owned by firm $i$, and assume, by accounting convention, that $\beta_{ii} = 0$. Let $B^*$ be the $m$-by-$m$ matrix having $\beta_{ij}$ in the $i$-th row and $j$-th column. Finally, define $B = (I - B^*)^{-1}$, where $I$ is the identity matrix, and let $b_{ij}$ be the element contained in the $i$-th row and $j$-th column of $B$. The HHI adjusted for cross-ownership is then given by the following expression:

$$HHI^{co} = \sum_{i=1}^{m} \sum_{j=1}^{m} b_{ij} s_i s_j$$

It is possible to show that $HHI^{co} > HHI$, so that cross-ownership increases the measure of concentration. This index, however, takes only into account ownership of shares, ignoring the issue of control: cross-ownership not only gives the owner of one company a stake in the competitors, but may also allow owners to coordinate actions of the competing firms. For extensions in that direction, and examples of the application of the cross-ownership adjusted index, see Nordic Competition Authorities (2003) and Campo and Vega (2003).

9. Market modelling and econometric techniques for measuring market power in hydro-based systems

Market equilibrium models have been a very widely used tool to investigate strategic behaviour of firms in deregulated electricity markets. It is beyond the scope of this work to give detailed accounts of how to proceed, but some of the approaches developed in the literature applied to hydro markets are reviewed below.

The first studies incorporating strategic producer behaviour in deregulated hydro-based power systems came from the operations research literature. The approach of
Scott and Read (1996) was to simulate hydro system operation using a dual dynamic programming (DDP) method. The key to this method is to solve the firm’s optimisation problem focusing on the dual variable, the marginal value of water, instead of the primal variable, generation levels. The method involves computing analytically the marginal water value function for a small number of reservoirs (two, in the simulation presented in the paper).

Kelman, Barroso and Pereira (2001) algorithm of stochastic dynamic programming (SDP) recursion is similar, but uses more complex sampling techniques of hydrological scenarios and inflow uncertainty in order to produce an approximation of water value functions, as opposed to an analytical solution for these functions. This approach allows them to deal with a much larger number of reservoirs.

In both these simulation methods, the Cournot equilibrium at each time period is computed numerically. Bushnell (2003), instead, develops an approach in which the equilibrium first-order conditions of the Cournot game are derived analytically, and then the resulting system of equation is solved through a mixed linear complementarity (LCP) method.

Nordic Competition Authorities (2003) provide a simulation of the Nordpool market. The specific feature of this simulation model is that it uses a supply function equilibrium approach, as opposed to the Cournot approach found in the previous models. In the supply function approach, firms submit a schedule of price-quantity pairs, stating what quantity they are willing to supply at each price, while in the Cournot approach the decision variable is just a perfectly inelastic quantity level.\(^\text{22}\)

\(^{22}\) See Borenstein, Bushnell and Knittel (1999) for a discussion about the advantages and disadvantages of Cournot versus supply function approaches.
An alternative to the numerical simulation methods summarized above is the econometric estimation of market power, if enough data is available. Hjalmarsson (2000) applies a variation of the well-known Bresnahan-Lau econometric model to study the Nord Pool spot market, the joint electricity exchange of the Nordic countries. He uses a subset of the price and quantity data corresponding to periods when no transmission constraints are binding. The model consists of a demand and supply system. The supply equation has price as the dependent variable, while the right-hand side is composed of one term reflecting marginal costs plus a second term related to the demand elasticity. The main idea of this method is that, in theory, the coefficient on this last term should be zero under perfect competition (i.e., price should be equal to marginal costs and not depend on demand elasticity), whereas under monopoly it should be one. The magnitude of the coefficient is thus a proxy for market power: the closer to one, the farther away the market is from the competitive outcome. The authors find no evidence of market power: the coefficient on the elasticity term is never significantly different from zero.

Steen (2003) uses a similar model to study the effects of transmission bottlenecks on local market power in Southern Norway. The estimation method is similar to Hjalmarsson (2000), but hours with binding transmission constraints are also included in the data. Moreover, the author allows for separate coefficient estimates in hours when transmission constraints are binding and when they are not binding. The result is that markets seem to be competitive on average, but may present a statistically significant but economically small short run mark-up in hours when congestion is present.

Johnsen, Verma and Wofram (1999) also analyse the Norwegian market in hours of transmission congestion. However, they have access only to price data, but not to
quantity data, so their econometric model differs from the ones above. The method involves comparing prices across periods with different demand elasticity and with and without congestion. They find evidence that prices in local markets are higher during periods with binding transmission constraints when demand is less elastic.

10. Regulatory and competition policy measures for reducing market power in hydrothermal systems

This section reviews the main policies and remedies that can be adopted in hydrothermal electricity markets found to be prone to market power.

10.1. Increasing demand elasticity

Section 4.1 showed that low demand elasticity facilitates market power and discussed the reasons why this problem may be particularly acute in the electricity industry. It was noted that most final consumers are billed on a time-average basis, so they do not face prices that vary in line with the market price. This suggests that policies that stimulate the use of real-time metering and billing can be an effective way of countering market power, by increasing the responsiveness of costumers to changes in market price.

There are, however, limits to the extent of this policy. Meters are still costly, and it may be too burdensome for small residential consumers to constantly monitor electricity prices and adjust their household consumption to real-time variations in prices. For large industrial or commercial users, on the other hand, the use of real-time meters
should be justified. In the future, it is expected that the cost of *smart meters* will drop and their use will become more widespread.

We have also pointed out in section 4.1 that hydro markets are characterized by long periods of very low prices, interceded by infrequent periods of extremely high prices. Real time metering and billing is therefore less important in hydro-dominated systems where the main price swings are between seasons and years. Retail contracts in which prices vary seasonally or can be readjusted with a few weeks notice provide sufficient price signals, are easier to implement and may have greater public acceptance than contracts in which prices vary on a hour-to-hour or day-to-day basis.  

10.2. Increasing competition across geographic areas

Local market power that stems from capacity constraints on the transmission network can be offset by the construction of new transmission links, by the enhancement of existing ones or by a more efficient use of the grid.

Unfortunately, the debate about the best methods to induce efficient investment in transmission capacity in a liberalised electricity market is still far from conclusive. It is unclear whether private agents will have the correct incentives to build links of sufficient capacity, in the desired location and that improve overall welfare.  

At this point, all one can say with certitude is that improving transmission capacity should be an active concern of regulators and competition authorities. This is especially true in hydro-based systems, where load areas are usually far from the generation sites, which

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23 Von der Fehr, Amundsen and Bergman (2005) provide an interesting account of the widespread use of variable price retail contracts in Norway, and how they helped to cope with a supply shock caused by an extremely dry winter in 2002-2003.

24 For an overview of important research, see Bushnell (1999) and Joskow and Tirole (2005).
puts even more weight in the efficiency of the transmission network. An example of how this policy tool could be employed is in merger control cases between two generators operating in the same load pocket area: one potential remedy to be considered would be to require the merging parties to upgrade transmission links going from their region into neighbouring export areas.

Policy-makers should nevertheless be careful with unexpected effects of transmission investment that may arise in hydro-based markets. We have seen the surprising result from Johnsen (2001) that transmission investment may have ambiguous effects on competition in areas where there is an import-constraint some of the time, since it allows generators to located inside that to export more electricity in periods when the constraint is not binding, thereby reducing storage and inducing even higher prices when the import-constraint is binding. Skaar (2004) also points out that, in a mixed hydro-thermal system, reinforcing transmission capacity induces more fierce competition among hydro producers located in different areas, thus increasing the probability that hydropower replaces thermal production in a socially-inefficient fashion, leading to lower storage and higher probability of shortages. These results indicate that there may be a trade-off between increasing competition and securing system reliability, which has to be taken into account in decisions regarding transmission investment.

10.3. Increasing competition between time periods

As noted in section 5, hydro generators with market power would tend to allocate more hydro production to off-peak hours than to peak hours, thereby further increasing demand-driven price fluctuations; conversely, in a perfectly competitive market, hydro
generators allocate more production to peak hours, thereby reducing the temporal separation. It follows that if enough price-taking hydro generators are present, there would be no longer a distinction between peak and off-peak hours. This suggests that the number of price-taking hydro producers is important for increasing the temporal scope of the market, more so than the number of thermal competitors, who often have less freedom to reallocate production across periods due to capacity constraints and slow ramping rates.

Structural policies should therefore aim at reducing the concentration of hydro plants. For example, if some divestiture is being considered as a condition for a merger, it is more useful from a competition standpoint to divest hydro than thermal units.

10.4. Interaction between competition and market design

Market design may influence the ability of generators to exert market power. For example, Wolak and Patrick (1997) and Newbery (2000) provide accounts of how the capacity payments in place from 1990 to 2001 in the English market enhanced market power of the dominant generators, by providing them with incentives to withhold capacity and to declare plants unavailable.\textsuperscript{25}

One point that has been stressed in the debate is the importance of bilateral forward contracts. In particular, the incentive of a given generator to raise spot market price is inversely related to the proportion of its sales locked in by forward bilateral contracts, since the generator does not receive the higher spot price from output sold

\textsuperscript{25} Indeed, the New Electricity Trading Arrangements (NETA) that came into effect in March 2001 abolished such payments.
through such contracts at a previously agreed price.\textsuperscript{26} A tool that competition authorities could consider is to require firms to sell some fraction of their future output through long-term contracts. For example, a merger could be allowed conditional on the merged entity locking in some part of its future sales (e.g., 80\% of forecast output in the following 15 years) in the bilateral contract market.

10.5. Structural policies and merger analyses

Let us now review a few points that should be looked at with care by competition authorities in merger control cases and a number of structural remedies that can be considered. The previous discussions suggest that the total number of firms operating in the market is not so much important; what is really relevant is the number and the market share of generators whose production is not constrained by capacity limits, transmission bottlenecks or inflexible technologies. There are a number of implications of this remark:

- A merger between two generators who are unconstrained most of the time should be viewed with great care. Divestiture of units that operate unconstrained most of the time can be a very effective tool when establishing conditions for allowing a merger.

- Conversely, a merger between two generators that are capacity-constrained most of the time would not affect market power when the resulting generator’s is still constrained most of the time; and it would actually be beneficial to competition if the resulting generator becomes unconstrained.

\textsuperscript{26} See, for example, Scott and Read (1996), Newbery (1998) and Barroso et al. (2002) for technical analyses of bilateral contracts in electricity markets. See Newbery (2000) for a more heuristic discussion. In 2001, the NETA introduced the possibility of long-term bilateral contracts in the English market.
• Similarly, a merger between two generators with flexible production technologies (e.g., reservoir hydro) should raise more concern than a merger between two generators with inflexible technologies (e.g., thermal).

• Mergers between generators located inside the same load pocket deserve more careful analysis than mergers between generators located in different geographic areas.

• A merger between generators that are close to each other in the merit order is more problematic than a merger between generators with very different marginal costs.

Finally, it should be noted that vertical separation between generation and transmission is also important when non-discriminatory grid access is hard to enforce.

10.6. Facilitating entry

In a hydro-based system, the issue of entry is particularly delicate, for many reasons. First, the environmental impact of the construction of a reservoir hydro plant can be very large, which complicates the licensing and approval process. However, environmental regulations are usually out of the reach of competition authorities. Second, as was already noted, the best hydro sites are usually already occupied by existing hydro plants. If this is indeed the case, the best regulators and competition authorities could do is to promote entry of low-cost thermal generators, since they have much more leeway in choosing where to locate (see section 3.3).

As argued by Newbery (1998, 2000), policies that promote long-term bilateral contracts facilitate entry, since they represent a guarantee of future revenue streams for
the firm, which reduces the risks associated with the entry decision and allows small entrants to raise the necessary capital.

The argument in favour of long-term contracts may be even stronger in the case of hydro-based systems. As noticed before, recovery of capital costs in such systems is problematic since, due to reservoir storage capacity, they are characterized by very low cost periods that occur frequently and last for a long time, separated by very high cost periods caused by droughts. Policy tools that seek to separate the price paid to generators from the system marginal cost, like long-term contracts, can greatly reduce risk associated with hydrological uncertainty and improve entry prospects.

11. Conclusion

The liberalisation of electricity markets is expected to make markets more efficient and improve welfare, at least in the long-run. However, until competition is fully functioning, there is significant scope for the exercise of market power by dominant firms, as the examples from California and England demonstrate. The main objective of the present work was to discuss the ways by which market power can be exercised in hydro-dominated electricity generation markets, drawing upon a review of relevant recent literature.

Electricity markets have to be separated not only according to relevant geographic markets (a feature that is common to most industries), but also according to the time at which electricity is delivered. Moreover, due to transmission capacity constraints, the relevant geographic markets may change from hour to hour. In thermal-based systems, the incentive and capability of firms to exploit this temporal and geographical
separation of markets depend basically on demand factors and capacity constraints; in hydro-based systems, they depend additionally on factors such as hydrological conditions, reservoir levels and inflow probability.

Market power in hydro markets arises from the strategic management of reservoirs. In some sense, anti-competitive behaviour is subtler and more difficult to detect compared to thermal systems, since it implies a reallocation of a given amount of energy across periods, as opposed to a reduction of the total amount of energy produced. Market power may be enhanced by factors such as: (i) very low responsiveness of demand to price variations; (ii) generation capacity and transmission constraints; (iii) differences in production technologies; (iv) limited scope for entry.

Hydro-based markets combine very small short-term price fluctuations (since hydro production can be always adjusted up or down almost instantaneously and moved across adjacent periods), with potentially very high fluctuations in the longer run (due to unpredictable variations in hydrological conditions and inflow). Therefore, episodes of very high price spikes are a normal feature of those markets, and not necessarily a sign of market power. Nevertheless, market power can exacerbate such fluctuations.

Traditional concentration measures have to be modified to take into account factors such as capacity constraints, transmission bottlenecks and inflexibility of production technologies.

Competition authorities and regulators have a number of tools in hand to control market power. Interventions should aim at increasing demand elasticity, increasing competition across geographic areas, lessening concentration of hydro units and facilitating the development of a bilateral forward contract market.
Bibliographical References


