REAL-TIME VERSUS DAY-AHEAD MARKET POWER IN A HYDRO-BASED ELECTRICITY MARKET*

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This paper develops a theoretical framework to analyze the link between real-time and day-ahead competition in a hydro-based wholesale electricity market. Predictions of the model are tested on a detailed data set of trades and prices from the Nordic power exchange, Nord Pool. We study market performance before and after a reform that increased the number of price areas (local markets) in Sweden, and reject the hypothesis of perfect competition in some of the Swedish price areas. Our results suggest that firms exercised some local market power during the sample period.

Key Words: Hydro power, market performance, Nord Pool, price area reform
JEL codes: D43, D92, L13, L94, Q41

I. INTRODUCTION

Electricity markets typically are concentrated: A small number of power companies control most of the generation capacity, transmission bottlenecks limit trade, and economic and political barriers prevent large scale entry. Demand is insensitive to short-term changes in prices because household consumption mostly responds to monthly or yearly price averages,

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and electricity intensive industries require stable production conditions. Concentrated markets with price inelastic demand are vulnerable to the exercise of market power by which producers behave strategically to increase price above marginal production cost.

Hydro power provides more than half of electricity production in more than one third of the countries in the world (Førsund [2007]). In Section II, we build a two-period model that illustrates the challenge of detecting market power in a hydro-based electricity market. The management's decision problem in a hydro power plant is how much of the plant's reservoir to release today and how much to save for future production. The marginal production cost consists mainly of this opportunity cost of water. The so-called *water value* has three components. Under imperfect competition, the opportunity cost depends on the expected marginal revenue the subsequent period. If producers are risk averse, then the water value depends also on the covariance of marginal profit and the marginal utility of profit. Third, production and resource constraints affect the possibility for redistributing output across time. To isolate the effects of hydro market power, one has to control for the effects of risk aversion and the resource and other technological constraints on output and prices.[1]

To address the problem of identifying hydro market power, we take advantage of the fact that liberalized wholesale electricity markets consist of a collection of sub-markets. Typically, generation companies can sell production up front in a day-ahead market, or they can take contractual positions in a forward market. They can also reserve capacity to the delivery date and sell their production closer to real-time in various balancing markets. A theoretical contribution of this paper is to recognize that firms' multi-market presence can be used to control for unobservable covariates when evaluating market performance.

First, we show that production constraints do not matter for the decision to sell a given volume of output planned for day 2 in the day-ahead market day 1 at price f_2 or instead sell it in the real-time market at expected price $E[p_2]$ the next day. How to distribute a given amount of production across time represents a portfolio selection problem, the solution to which is given by the consumption CAPM (Blanchard and Fischer [1989]): The marginal profit in the day-ahead market equals the expected marginal profit in the real-time market, corrected for the covariance between the marginal utility of profit and marginal profit. Systematic price differences $f_2 - p_2$ are due to the exercise of market power, risk aversion or they reflect bidding constraints. In particular, risk adjustment and bidding constraints are independent of the slope of the inverse day-ahead demand curve, which can then be used to identify market power. This result is valid for all types of production and can be applied to test for wholesale market power more generally.

Second, we show that the price difference $f_2 - p_1$ between electricity sold in the day-ahead market day 1 for delivery day 2 and that produced for the real-time market day 1 does not depend on price risk. Both decisions are taken simultaneously in our model and based on the same information. For a hydro producer, the opportunity costs of both depend on the (same) expectation about the real-time market day 2. Price risk thus cancels out from $f_2 - p_1$, which instead reflects market power or output constraints. Hydro firms produce up to the point at which the price equals the water value if the market is competitive, in which case $f_2 - p_1$ measures the difference in water value between day 2 and 1. The water value is higher (lower) day 2 than 1 if hydro production Q_2 day 2 is larger (smaller) than hydro production Q_1 day 1. Thus, $(Q_2 - Q_1)(f_2 - p_1) \geq 0$ under perfect competition. A negative variable is a sign of market power in a market with hydro power, but not necessarily in a non-hydro market. In a thermal plant, the marginal cost of producing for the real-time market day 1 is the fuel cost. But the firm still faces a price risk of postponing sale from the day-ahead market to the next day's real-time market. As the price difference $f_2 - p_1$ includes price risk for thermal producers, $(Q_2 - Q_1)(f_2 - p_1) < 0$ can hold in a competitive thermal market.[2]

In Section III, we apply our theoretical results to evaluate market performance on the Nordic power exchange, Nord Pool (NP). Market concentration is fairly high and accentuated by bottlenecks in the transmission network that often divide the Nordic region into a subset of smaller local markets, *price areas.* There is anecdotal evidence of market power on NP. Notably, the power company Elsam was convicted for abusing their dominant position to increase wholesale prices in Denmark during 2005-06. Our focus on Sweden is of separate interest, not least due to the Swedish Competition Authority's concern about negative effects of the joint ownership of Swedish nuclear power on competition. We consider the sample period 2010-13 and study market performance before and after a reform in 2011 that increased the number of NP price areas in Sweden from one to four.[3]

The bulk of electricity production in the Nordic market is sold on NP's day-ahead market, *Elspot*. Producers, retailers and large industrial consumers can rebalance their positions on NP's intra-day market, *Elbas*, which opens two hours after gate closure of Elspot and closes one hour prior to delivery.[4] We treat Elbas as our real-time market and match the hourly equilibrium auction prices established on Elspot with individual trade data from Elbas.

Our findings provide suggestive evidence that firms exercised some local market power in Sweden during the sample period. For electricity scheduled for simultaneous *delivery*, we find correlations between the difference $f_2 - p_2$ between the Elspot and Elbas price and the slope of firms' net demand curve on Elspot, in violation of the hypothesis of perfect competition. These correlations are statistically significant for price area Sweden (SE) before the reform and for price area Sundsvall (SE2) after the reform, but not in the other price areas. SE2 is a northern price area that exports hydro power to consumers in price areas Stockholm (SE3) and Malmö (SE4) in southern Sweden. For electricity *traded* approximately simultaneously, $(Q_2 - Q_1)(f_2 - p_1)$ is positive in SE before the reform and in the two northern price areas Luleå (SE1) and SE2 after the reform, consistent with competitive pricing. The variable is significantly negative for certain weekdays in SE3 and SE4, which is incompatible with perfect competition.

We explore marginal trading costs, bidding constraints in the day-ahead market and illiquid real-time markets as alternative explanations for our findings, but conclude that these cannot plausibly explain the patterns in the data.

In Section IV, we summarize our results and discuss some limitations of the methodology.

I(i). *Contributions*

Our theoretical contribution is to solve a two-period resource extraction model with imperfect competition, a forward (day-ahead) market, uncertainty and risk averse agents. Most models (e.g. Crampes and Moreaux [2001], Garcia et al. [2001], Johnsen [2001], Førsund [2007], Hansen [2009], Mathiesen et al. [2013]) only have real-time markets. Liski and Montero [2014] are an exception, but their model is deterministic. Uncertainty and risk aversion create scope for a forward market where market participants hedge real-time price risk (Bessembinder and Lemmon [2002]). Forward trading may in turn affect the performance of the real-time market (Allaz and Vila [1993], Hughes and Kao [1997], Mahenc and Salanié [2004], Liski and Montero [2006], Holmberg [2011]).

Our empirical contribution is to derive hypotheses of market performance based on price differences between markets and test them on the Nordic wholesale electricity market. These tests either have not been applied to this market before, or appear to be completely new. Most related to our work is the analysis of the Iberian wholesale electricity market by Ito and Reguant [2016]. They show how price differences between the day-ahead and the intra-day market significantly depend on the slope of the net demand curves in those markets, similar to our first test of market performance. Price differences arise in their model because of limited arbitrage possibilities, but market participants are risk neutral. We demonstrate the validity of this approach when one allows agents to be risk averse. In a study of the California market, Borenstein et al. [2008] show that the price differences between the day-ahead and the real-time market (also for simultaneous delivery) fluctuate between being positive and negative, and argue that this pattern cannot plausibly be explained by risk aversion or transaction costs.[5] They do not estimate slope coefficients. Our second test of market power, which considers price differences for products traded simultaneously, also rejects the hypothesis of perfect competition. We believe this test is new to the literature.

The previous empirical literature for the most part has approached the problem of unobservable marginal costs by means of structural estimation techniques, usually based on the

Bresnahan-Lau model; see Bask et al. [2011] and Graf and Wozabal [2013] for applications to European markets.[6] Such estimation results are sensitive to model specification (Kim and Knittel [2006]). In contrast, our methodology does not rely on estimating functional demand and supply functions.[7]

A separate literature builds numerical models of the electricity market to explicitly account for the inter-temporality of hydro power (Bushnell [2003]; Kauppi and Liski [2008]; Philpott et al. [2010]). Because of computational burdens, simulation models often apply an aggregate market approach. For instance, Kauppi and Liski [2008] treat the Nordic region as one single integrated market and use a weekly resolution to solve their model. At such aggregation levels, it is not possible to identify any exercise of market power arising from network bottlenecks and short-term demand variations.

II. THEORETICAL ANALYSIS

II(i). *The model*

Consider a two-period model of an electricity market with hydro production. Demand in each period is price inelastic and served by an independent retailer that purchases its electricity in the wholesale day-ahead and/or real-time market. A set $\mathcal{N}$ of producers have market power. An additional competitive fringe produces electricity for the real-time market. The timing of the game is:

1. Period 1 demand D_1 is realized.
2. Each firm $n \in \mathcal{N}$ observes D_1 and makes two simultaneous decisions:
    (a) the quantity q_{n1} to produce for the wholesale real-time market in period 1,
    (b) the quantity z_{n1} to sell in the wholesale day-ahead market for delivery in period 2.
3. Period 2 demand D_2 is realized.

4. Each firm $n \in \mathcal{N}$ observes D_2 and decides the quantity $q_{n2} - z_{n1}$ to produce for the wholesale real-time market in period 2.

We solve the game for subgame-perfect equilibrium.[8]

Every firm $n \in \mathcal{N}$ has one reservoir-based hydro power plant that produces q_{nt} MWh energy period $t = 1, 2$ by a linear production function constrained by:

$$(1) \qquad q_{nt} \in [0, \bar{q}_n] \text{ for all } n \in \mathcal{N}.^{9}$$

Firm n enters period 1 with reservoir capacity $r_n < 2\bar{q}_n$. We assume away reservoir inflow between periods, to save on notation. Hence, total production over the two periods faces the reservoir constraint $q_{n1} + q_{n2} \leq r_n$ for every firm n. Firms may have an incentive to exercise market power by not utilizing their entire reservoir capacity. However, we assume that there is a penalty for spilling water so large that firms always avoid spillage.[10] The reservoir and no-spillage constraints jointly imply that firms always optimize production in such a way as to utilize all remaining reservoir capacity in period 2:

$$(2) \qquad q_{n2} = r_n - q_{n1} \text{ for all } n \in \mathcal{N}.$$

Production capacity is limited in the sense that $\bar{q}_n < r_n$ for all n. By way of this assumption, firm n can meet constraint (2) only by producing a strictly positive output in each period. Water release is the only variable factor of production in a hydro power plant in the short run. We therefore assume that the marginal hydro production cost is zero.

The $|\mathcal{N}|$ large firms produce a total of $Q_t = \sum_{n \in \mathcal{N}} q_{nt}$ MWh electricity in period t. The competitive fringe supplies the remaining demand $D_t - Q_t$ in the real-time market at marginal cost $MC(\cdot)$, which we assume to be linear with deterministic slope $b > 0$. Hence, the firms with market power face the inverse demand

$$p_t = P_t(Q_t) = MC(D_t - Q_t) = b(D_t - Q_t)$$

in the real-time wholesale market in period t.[11] The revenue/profit of firm n thus equals

$$\pi_{n1} = \Pi_1(q_{n1}) = P_1(Q_1)q_{n1}$$

in period 1. Aggregating constraint (2) across all $|\mathcal{N}|$ producers yields $Q_2 = R - Q_1$, where $R = \sum_{n \in \mathcal{N}} r_n$ is the total initial reservoir capacity. The period 2 real-time price therefore equals $p_2 = P_2(R - Q_1)$, and we can write the period 2 revenue/profit of firm n as

$$f_2 z_{n1} + p_2(q_{n2} - z_{n1}) = (f_2 - P_2(R - Q_1))z_{n1} + P_2(R - Q_1)(r_n - q_{n1}), \tag{3}$$

where f_2 is the day-ahead price established in period 1 for electricity supplied in period 2.[12]

An independent retailer serves demand D_t. In the Nordic market, short-term retail contracts feature a retail price equal to the hourly day-ahead price plus the cost of a renewable obligation and a markup. Price-cost margins in the Nordic retail market are small.[13] For simplicity, we set the retail price $\hat{p}$ equal to f_2 plus other variable retail costs c. The retailer therefore obtains a profit

$$\Omega = (\hat{p} - c)D_2 - f_2 Z_1 - p_2(D_2 - Z_1) = (f_2 - p_2)(D_2 - Z_1), \tag{4}$$

in period 2, where $Z_1 = \sum_{n \in \mathcal{N}} z_{n1}$ is the aggregate day-ahead volume. The retailer is risk averse and participates in the day-ahead market to hedge price risk. It decides the volume of electricity to purchase in the day-ahead market to maximize $E[\Omega - \frac{1}{2}\sigma\Omega^2]$. The parameter $\sigma \geq 0$ is a measure of retailer risk aversion in the class of quadratic utility functions. If the retailer is a price-taker in the wholesale market, then the first-order condition

$$E[P_2(R - Q_1)] - F_1 + \sigma E[(D_2 - Z_1)(F_1 - P_2(R - Q_1))^2] = 0 \tag{5}$$

defines the inverse demand function $f_2 = F_1(Z_1, R - Q_1)$ in the wholesale day-ahead market.

Substituting f_2 for $F_1(Z_1, R - Q_1)$ in (3) returns the period 2 profit

$$\pi_{n2} = \Pi_{n2}(q_{n1}, z_{n1}) = (F_1(Z_1, R - Q_1) - P_2(R - Q_1))z_{n1} + P_2(R - Q_1)(r_n - q_{n1}) \tag{6}$$

of firm n as a function of period 1 decision variables.[14] The objective function of firm n equals

$$V_n(q_{n1}, z_{n1}) = U(\Pi_1(q_{n1})) + E[U(\Pi_{n2}(q_{n1}, z_{n1}))], \tag{7}$$

where $U(\Pi) = \Pi - \frac{1}{2}\gamma\Pi^2$ is strictly increasing in the relevant domain, and $\gamma \geq 0$ is a measure of producer risk aversion.

Firm n maximizes $V_n(q_{n1}, z_{n1})$ subject to the capacity constraint (1) and bidding constraints in the day-ahead market.[15] In the Nordic market, producers must submit to the TSO a production plan detailing how they aim to cover their positions in the day-ahead market. By this requirement, the electricity bid into the day-ahead market cannot deviate too far from the firm's production capacity. We impose the exogenous bidding constraints:

$$z_{n1} \in [\underline{z}_n, \bar{z}_n] \text{ for all } n \in \mathcal{N}. \tag{8}$$

The Lagrangian of firm n's problem is

(9)

$$L_n(q_{n1}, z_{n1}) = V_n(q_{n1}, z_{n1}) + \lambda_{n1}(\bar{q}_n - q_{n1}) + \lambda_{n2}(\bar{q}_n + q_{n1} - r_n) + \underline{\chi}_n(z_{n1} - \underline{z}_n) + \bar{\chi}_n(\bar{z}_n - z_{n1}),$$

where λ_{nt} is the Kuhn-Tucker multiplier associated with the capacity constraint $q_{nt} \leq \bar{q}_n$, and $\underline{\chi}_n$ ($\bar{\chi}_n$) is the multiplier of the lower (upper) bidding constraint in the day-ahead market.[16]

II(ii). *Equilibrium*

Maximization of (9) with respect to q_{n1} yields the optimal production allocation:

(10)

$$p_1 + P_1'(Q_1)q_{n1} = \frac{E[U'(\pi_{n2})]}{U'(\pi_{n1})} E[p_2 + P_2'(Q_2)q_{n2}] + \frac{cov[U'(\pi_{n2}), p_2 + P_2'(Q_2)q_{n2}]}{U'(\pi_{n1})} + \frac{\lambda_{n1} - \lambda_{n2}}{U'(\pi_{n1})}.$$

The marginal revenue in the real-time market on the left-hand side of (10) represents the value to producer n of increasing hydro output at $t = 1$. But the production increase drains the reservoir and forces the firm to produce less in period $t + 1 = 2$. The right-hand side of (10) constitutes the opportunity cost of hydro output, the *water value.* The first term is the expected marginal revenue the next period, discounted by the marginal rate of inter-temporal substitution. Uncertainty and risk aversion imply that production also is adjusted by a risk correction factor, the magnitude of which depends on the covariance between marginal profit and the marginal utility of profit; the second term on the right-hand side of (10). Finally, output is affected by the production constraints captured by the shadow prices in the final term of (10).

Based on (10), we see five potential explanations for why real-time prices would differ between periods in a hydro-based market. First, there could be time-varying differences in firms' exercise of market power, for instance because transmission bottlenecks increase market concentration in some periods relative to others. Second, risk aversion could drive a wedge between current and future prices. A third reason is binding production constraints that prevent prices from equalizing across periods. A fourth reason could be discounting, here manifested in terms of an inter-temporal rate of substitution. Finally, there can be surprise events causing price shocks.

Even under assumptions that discounting is negligible in day-to day operations and that price shocks are random with zero mean, one would still have to control for the effects of risk aversion and production constraints on prices to be able to isolate market power based solely on data from the real-time market. We now demonstrate that each of these effects can be controlled for separately by invoking also the equilibrium condition in the day-ahead market.

Maximization of (9) over z_{n1} returns firm n's optimal position in the day-ahead market:

$$f_2 + \frac{\partial F_1}{\partial Z_1} z_{n1} = E[p_2] + \frac{cov[U'(\pi_{n2}), p_2]}{E[U'(\pi_{n2})]} + \frac{\bar{\chi}_n - \underline{\chi}_n}{E[U'(\pi_{n2})]}. \tag{11}$$

For any planned production q_{n2} in period 2, firm n has the choice between allocating z_{n1} to the day-ahead market and saving $q_{n2} - z_{n1}$ for the real-time market. This decision is equivalent to a portfolio selection problem in which a share of wealth is invested up front with known return (the day-ahead market) and the rest in an asset with risky future return (the real-time market). Under expected utility maximization, the optimum (11) is a variant of the consumption CAPM (Blanchard and Fischer [1989]): The marginal revenue in the day-ahead market equals the expected real-time price the next period, corrected by a risk factor that depends on the covariance between the marginal utility of profit and the real-time price. The real-time price constitutes the marginal real-time revenue because inverse demand $P_2(R - Q_1)$ in the real-time market is independent of the day-ahead volume Z_1 and determined entirely by the reservoir capacity $R - Q_1$. Bidding constraints in the day-ahead market may lead to deviations from this CAPM rule. Observe in particular that there are no production constraints in (11). Such constraints do not affect the choice of market, day-ahead or real-time, on which to sell the planned production:

Proposition 1. *The difference $f_2 - E[p_2]$ between the day-ahead price and the expected real-time price for simultaneous delivery in period 2 is independent of firms' production constraints. All price differences can be explained by the exercise of day-ahead market power ($\frac{\partial F_1}{\partial Z_1} z_{n1} \neq 0$), producer price risk ($cov[U'(\pi_{n2}), p_2] \neq 0$) or bidding constraints in the day-ahead market ($\bar{\chi}_n - \underline{\chi}_n \neq 0$).*

Consider risk aversion. Set the marginal rate of inter-temporal substitution equal to one in (10) because of the short-term framework, subtract (10) from (11) and rearrange:

$$f_2 - p_1 = P_1'(Q_1) q_{n1} - \frac{\partial F_1}{\partial Z_1} z_{n1} - E[P_2'(Q_2) q_{n2}] - \frac{cov[U'(\pi_{n2}), P_2'(Q_2) q_{n2}]}{E[U'(\pi_{n2})]} + \frac{\lambda_{n2} - \lambda_{n1} + \bar{\chi}_n - \underline{\chi}_n}{E[U'(\pi_{n2})]}. \tag{12}$$

Corrections for price risk vanish in the above expression because the risk involved in postponing production from 1 to 2 is the same as the price risk associated with postponing sales from the day-ahead market at 1 to the real-time market at 2:

Proposition 2. *The difference $f_2 - p_1$ between the day-ahead price and the real-time price determined simultaneously in period* 1 *is independent of producer price risk if there is no discounting between adjacent periods. All price differences can be explained by the exercise of wholesale market power* ($\frac{\partial F_1}{\partial Z_1} z_{n1} \neq 0$ *and/or* $P_t' q_{nt} \neq 0$, $t = 1, 2$) *or output constraints* ($\lambda_{n2} - \lambda_{n1} + \bar{\chi}_n - \underline{\chi}_n \neq 0$).

II(iii). *Predictions of the theoretical model*

Systematic price differences between the day-ahead price f_2 and the real time price p_2 for simultaneous delivery in period 2 are due to market power, risk aversion or bidding constraints. Risk aversion depends on the covariance between the marginal utility of profit $U'(\pi_{n2})$ and the real-time price p_2, but not on the properties of the day-ahead market. Bidding constraints are entirely related to a firm's production capacity. In particular:

Hypothesis 1. *If wholesale markets are perfectly competitive, then differences $f_2 - p_2$ between the day-ahead and the real-time price for simultaneous delivery are independent of (the absolute value of) the slope* $\left|\frac{\partial F_1}{\partial Z_1}\right|$ *of the inverse day-ahead demand curve.*

Data on the slope variable are not always publicly available. When estimating (11), one could instead account for exogenous demand and supply effects such as temperature changes, seasonal variation, production failures and transmission constraints one would expect to be correlated with the slope of the day-ahead demand curve. But market power and risk aversion may go hand in hand and can be difficult to separate from one another by means of exogenous controls. For instance, transmission constraints increase local market concentration and could therefore be associated with local market power. But bottlenecks are also likely to increase the price volatility in the real-time market because it is then less probable that positive local shocks are offset by negative shocks in neighboring markets.

Hence, transmission constraints could also affect the risk correction term.

Another empirical challenge is that risk aversion may have ambiguous effects on the price differences between the real-time and day-ahead market even in a competitive market. Deferring trade to the real-time market exposes both producers and retailers to real-time price risk. Risk averse market participants would require a risk premium to be willing to postpone trade. A risk premium on the demand (supply) side tends to drive a positive (negative) wedge between the day-ahead and the real-time price ($f_2 \gtrless E[p_2]$). The net effect on the price differential depends on the relative importance of seller versus buyer risk aversion.

Because of the above problems, we would like to evaluate market performance without having to deal with risk aversion. To do so, we invoke Proposition 2. Let wholesale markets be competitive, $\frac{\partial F_1}{\partial Z_1} z_{n1} = 0$ and $P_1' q_{n1} = P_2' q_{n2} = 0$ in (12), and multiply both sides of the equation by $q_{n2} - q_{n1}$:

(13)

$$\begin{aligned}(q_{n2} - q_{n1})(f_2 - p_1) = &\ \tfrac{1}{E[U'(\pi_{n2})]}[\lambda_{n2}(q_{n2} - q_{n1}) + \lambda_{n1}(q_{n1} - q_{n2}) + (\bar{\chi}_n - \underline{\chi}_n)(q_{n2} - q_{n1})] \\ = &\ \tfrac{1}{E[U'(\pi_{n2})]}[\lambda_{n2}(\bar{q}_n - q_{n1}) + \lambda_{n1}(\bar{q}_n - q_{n2}) + (\bar{\chi}_n - \underline{\chi}_n)(q_{n2} - q_{n1})].\end{aligned}$$

We added and subtracted $\bar{q}_n$ inside the parentheses and applied the complementary slackness condition $\lambda_{nt}(q_{nt} - \bar{q}_n) = 0, t = 1, 2$ to get the second row. The first two terms inside the square brackets are non-negative. So is the last term if day-ahead sales are positively correlated with production in the sense that $z_n > \underline{z}_n$ ($\underline{\chi}_n = 0$) if $q_{n2} > q_{n1}$ and $z_n < \bar{z}_n$ ($\bar{\chi}_n = 0$) if $q_{n2} < q_{n1}$. Then $(q_{n2} - q_{n1})(f_2 - p_1) \geq 0$ for all $n \in \mathcal{N}$ under perfect competition. Intuitively, price equals marginal cost–the water value–in a competitive market, in which case $f_2 - p_1$ reflects the difference in water values between days 2 and 1. Also firms' water values are higher (lower) day 2 than 1 if production is larger (smaller) day 2 than 1. Summing up over all hydro firms yields:

Hypothesis 2. *If wholesale markets are perfectly competitive, then* $(Q_2 - Q_1)(f_2 - p_1) \geq 0$, *where* $f_2 - p_1$ *is the difference between the day-ahead and the real-time price simultaneously* *determined day* 1*, and* $Q_2 - Q_1$ *is the change in total hydro production between day* 2 *and* 1*.*

To see how this intuition carries over to a market that only has flexible thermal power, let one firm possess all market power and supply electricity at strictly increasing marginal cost $\beta(\cdot)$. If Q_t is that firm's output in period $t = 1, 2$, then $p_t = \beta(Q_t)$ under perfect competition. By (11) and a simplifying assumption that bidding constraints are non-binding ($\bar{\chi}_n = \underline{\chi}_n = 0$):

(14)

$$(Q_2 - Q_1)(f_2 - p_1) = (Q_2 - Q_1)[\beta(Q_2) - \beta(Q_1) + E[\beta(Q_2)] - \beta(Q_2) + \frac{cov[U'(\pi_{n2}), \beta(Q_2)]}{E[U'(\pi_{n2})]}].$$

The term $(Q_2 - Q_1)(\beta(Q_2) - \beta(Q_1))$ is strictly positive for $Q_2 \neq Q_1$. Then $(Q_2 - Q_1)(f_2 - p_1) > 0$ if the marginal cost is sufficiently close to its expectation and risk aversion is relatively unimportant. If not, then (14) can be strictly negative in a thermal market even under perfect competition. The marginal production cost in a thermal plant is the fuel cost and independent of real-time prices the next day. But the cost of postponing sale from the day-ahead to the real time market the next day does depend on price risk. This explains why the risk adjustment term is still there in (14).

III. EMPIRICAL ANALYSIS: THE NORDIC WHOLESALE ELECTRICITY MARKET

III(i). *Market description*

The cornerstone of the Nordic wholesale electricity market is the power exchange, Nord Pool (NP).[17] In 2012, NP traded 337.2 TWh of electricity, amounting to 77 per cent of total consumption in the Nordic countries that year.[18] NP operates two main markets, the most important of which is the day-ahead market, *Elspot.* Elspot handled 99 per cent (334 TWh) of the traded volume on NP in 2012. The remaining 3.2 TWh were traded on the intra-day market, *Elbas*, which we refer to as our real-time market.[19]

Vattenfall is the largest producer with 16 per cent of production capacity (NordREG

[2013]). Network capacity constraints often split the Nordic market into local markets known as price areas. The five largest power companies, except E.ON, are former national monopolies with generation assets concentrated in their domestic markets. For this reason, local market concentration is higher than what aggregate numbers would seem to suggest. For instance, Vattenfall owns 37 per cent of Swedish generation capacity (NordREG [2013]). Joint ownership is widespread and creates collective market concentration. In particular, all Swedish nuclear power is jointly owned by the three large producers Vattenfall, Fortum and E.ON. Owing to local market concentration and joint ownership, there is reason to be concerned about market performance in the Nordic wholesale electricity market.

There are two price areas in Denmark and five in Norway, whereas Finland, Estonia, Latvia and Lithuania all constitute separate price areas for the time being. Sweden was one single price area until October 31, 2011, when the country was split into four price areas. Below we explore the implications from the theoretical model using data from Nord Pool in the Swedish price area(s). We examine the period from January 1, 2010 until December 31, 2013 and estimate market performance separately before and after the price reform.

[Table 1 about here.]

Table I displays the main energy sources of electricity production in Sweden. Around 40 per cent of production comes from hydro power mostly located in the two northern price areas Luleå (SE1) and Sundsvall (SE2). Nuclear power located in the middle price area Stockholm (SE3) is the second fundamental energy source. Two thirds of Swedish wind power is produced in SE3 and price area Malmö (SE4) furthest to the South. This is also where most of thermal capacity other than nuclear power is located. Almost all of this production comes from combined heat and power plants (CHP). Swedish electricity production generates an annual surplus that is exported abroad.[20]

[Figure 1 about here.]

Domestic imbalances between production and consumption cause electricity to flow south from SE1 and SE2 via SE3 and down to SE4. Sometimes electricity flows are so high that the transmission network reaches its capacity limit. Such congestion increases the electricity price in the south relative to the north. Figure 1 shows the day-ahead (Elspot) price in areas SE2, SE3 and SE4 divided by the SE1 price in our sample. Hours with equal prices in all areas indicate periods without bottlenecks in the domestic transmission grid. Conversely, periods with diverging prices reveal congestion. SE1 furthest to the north acts as a price floor for the other price areas. SE1 and SE2 are integrated most of the time. Congestion is more frequent in the south: SE4 is the area that most often constitutes a price area of its own.

III(ii). *The applicability of the theory to the Nordic market*

Hypothesis 1 is valid no matter the underlying generation mix. Hypothesis 2 builds on the assumption that hydro power is a flexible source of production on the margin. All four Swedish price areas have reservoir-based hydro power. The second row of Table I shows hydro reservoir capacity in every area. Reservoir capacity is larger in the north than the south in absolute terms and relative to production. This relationship suggests that hydro output on average is more constrained in SE3 and SE4 than SE1 and SE2. Our market power tests control for output constraints.

The two southern price areas, in particular, have flexible thermal capacity in terms of gas turbines and diesel aggregates. The combined capacities of those units were 226 MW in SE3 and 193 MW in SE4 in 2013. Our theoretical results do not depend on reservoir-based hydro power being the only flexible source of production. We only excluded gas-fired power plants and other technologies from our model to emphasize hydro power. Still, the assumption makes sense in this context because flexible thermal production was so small during our sample period. Compared to the 8.9 TWh hydro power production in SE3 and the 1.2 TWh in SE4 during 2013, the 25 GWh supplied by gas and diesel units in SE3 and the 14 GWh in SE4 were negligible. The other years in our sample produced similar numbers; see svk.se.

We conclude, based on Table I and the above discussion, that the supply of non-hydro power in Sweden almost entirely came from nuclear, wind and CHP during the sample period. These are inflexible technologies that produce at full capacity unless prices are extremely low.[21] Hydro power was the dominant flexible source of production in SE1-SE4 during 2010-13. Our two hypotheses therefore should apply to all Swedish price areas in our empirical application.

III(iii). *The data*

In the day-ahead market, *Elspot*, bidding for day $t+1$ begins at noon day $t-1$ and closes at noon day t. Only the final bids prior to gate closure are binding. The market is best described as a collection of local markets (price areas) with inter-regional trade limited by the capacity of the network. Producers with local generation capacity, local industrial consumers and retailers serving local end users are the only ones allowed to participate in the local market (price area). Market participants submit price-dependent offers/bids for each hour over the next day's 24-hour period. Nord Pool aggregates the individual supply offers and demand bids and clears the market by means of a uniform price for each hour and price area, taking into account the transmission constraints. We let $f_{ah(t+1)}$ be the day-ahead price in area a for delivery hour h of day $t+1$ (determined day t). This corresponds to 110 000 observations during the sample period. The prices we use are in Euros per Megawatt-hour (EUR/MWh). Day-ahead prices can be downloaded from nordpoolgroup.com.

The intra-day market, *Elbas*, opens two hours after gate closure of the day-ahead market and closes one hour prior to physical delivery. Participants are generation companies, retailers and large energy intensive industries re-balancing their portfolios. Elbas resembles a regular stock market in the sense of having continuous trading. One can think of this as a market with pay-as-bid prices, with the distinction that the same product typically is traded at multiple prices over the course of the trading period as new market information arrives.[22] In our regressions, we use data on settled prices of individual trades so that p_{iaht} represents the accepted price of trade i for delivery in price area a, hour h of day t. Our model assumes that trade in the real-time market at t and in the day-ahead market for delivery at $t+1$ takes place simultaneously at t. In particular, those two decisions are taken subject to the same information set. Day-ahead offers on Elspot are submitted day t at 12.00. To ensure that the information on which Elbas trades are made is as comparable as possible with the information upon which trade on Elspot takes place, we include in the sample only Elbas trades that are made between 08.00 and 12.00 day t. We are then left with approximately 22 000 trades between January 1, 2010 and December 31, 2013 where the seller is located in Sweden. Elbas trades and clearing prices are available upon request from Nord Pool.

Turning to the independent variables, the slope of the net demand curve on Elspot can be interpreted as the price increase in EUR/MWh a firm with market power would achieve by a marginal reduction in its supply to the day-ahead market during that hour and day. Nord Pool releases hourly Elspot supply offers and demand bids at the *system level*, i.e. aggregated across all countries in the Nordic market. We calculate (the absolute value of) the inverse net demand slope, $\left|\frac{\partial F_{ht}}{\partial Z_{ht}}\right|$, by linearly extrapolating the aggregate net demand curve plus and minus .5 GWh around the market clearing quantity (Lundin [2016]).[23] NP's solution algorithm aggregates supply and demand bids into continuous and piecewise linear supply and demand curves, unlike in most other wholesale markets where these curves are discontinuous step functions. Hence, our approximation should be accurate in most cases.[24]

Additional variables include hourly consumption and output data for each production technology and price area in Sweden. These are available at the website svk.se of the TSO Svenska Kraftnät. Let Q_{aht} be the total hydro production in price area a, hour h of day t. One can also find data on reservoir levels, inflow and international trade flows at svk.se. We include a measure of inflow into storage reservoirs, $inflow_t$, in units of TWh/w (Terawatt hours per week). The variable $level_t$ is the weekly reservoir level in terms of the reservoir fill percentage in Sweden. Reservoir capacity seldom represents a binding production constraint: The fill percentage was above 45 for 75 per cent of our sample observations, and the lowest fill percentage was 12. We also include a variable, $net\_exchange_t$, representing daily changes in GWh in Sweden's net power exchange with its neighbors. We use the first-differenced series of power exchange rather than the level for two main reasons. The first is that the level is highly correlated with the weather and hydrological variables, and the inclusion of the level variable could lead to multicollinearity. Furthermore, changes in trade flows are of particular interest when analyzing changes in market performance over time.

We measure temperature in terms of Heating degree days (HDD). These are calculated as the Celsius-day units during which temperatures were below a base temperature, set at 15.5°C in this data. A higher value of HDD is thus associated with colder weather. For example, if the temperature was 10°C for 24 hours, this would be recorded as 5.5 HDD, whereas HDD is equal to zero if the temperature was above 15.5°C the entire 24 hour period. The temperature data are for the main cities in the four different price areas: Luleå to the far north (SE1), Sundsvall further down (SE2), Stockholm in the middle price area (SE3) and Malmö to the far south (SE4). Let HDD_{at} refer to the heating degree day in price area a during day t. The vector of heating days during day t is $\mathbf{HDD}_t$. Weather data are available from smhi.se.

III(iv). *Results*

We first consider results related to simultaneous delivery. Proposition 1 states that systematic price differences between the day-ahead market and the real-time market for simultaneous delivery are due either to market power, risk aversion or bidding constraints.

[Figure 2 about here.]

Figure 2 shows scatter plots for the joint Swedish price area (SE) and each of the four price areas (SE1-SE4). The y-axis shows the difference between the Elspot price $f_{ah(t+1)}$ (determined day t) in price area a, hour h of day $t+1$ and the Elbas price $p_{iah(t+1)}$ (determined day $t+1$) of trade i for the same price area, hour and day. On the x-axis is the absolute value $\left|\frac{\partial F_{ht}}{\partial Z_{ht}}\right|$ (determined day t) of the slope of the inverse net demand curve hour h of day $t+1$. Observations are color coded in red (peak hours) and black (off-peak hours). We follow Nord Pool practice and define peak hours as occurring between 08.00 and 18.00. Hypothesis 1 asserts that the variables should be uncorrelated if markets are competitive because the slope of the net demand curve is a measure of market power. The unconditioned linear correlation lines are relatively flat for most of the price areas. Exceptions are SE2, where the peak and off-peak data have pronounced negative and positive slopes, and SE1, where off-peak data seem to have a positive slope.

To probe deeper, we run an OLS regression with the price difference as the dependent variable:

$$
\begin{aligned}
f_{ah(t+1)} - p_{iah(t+1)} &= \beta_0 + \beta_1 \left|\frac{\partial F_{ht}}{\partial Z_{ht}}\right| + \beta_2 peak_{h(t+1)} + \beta_3 \left|\frac{\partial F_{ht}}{\partial Z_{ht}}\right| * peak_{h(t+1)} \\
&+ \beta_4 net\_exchange_{t+1} + \beta_5 inflow_{t+1} + \beta_6 level_{t+1} \\
&+ \boldsymbol{\beta}_7 \mathbf{HDD}_{t+1} + \epsilon_{iah(t+1)}.
\end{aligned} \tag{15}
$$

The independent variables of particular interest for market performance are $\left|\frac{\partial F_{ht}}{\partial Z_{ht}}\right|$ and an interaction term with the dummy variable $peak_{h(t+1)}$ representing peak hours. With this specification, β_1 is the estimated effect of the slope on the price difference during off-peak hours (when $peak_{h(t+1)} = 0$). The effect for peak hours is $\beta_1 + \beta_3$. The null hypotheses of $\beta_1 = 0$ for off-peak hours and $\beta_1 + \beta_3 = 0$ for peak hours are the results consistent with a competitive market.

Additional covariates control for market, hydrological and demand effects. Daily changes in the Swedish net export of electricity, which could potentially have asymmetric effects on Elspot and Elbas prices, are controlled for by the variable $net\_exchange_{t+1}$. Weekly variables for $inflow_{t+1}$ and $level_{t+1}$ (in per cent of storage capacity) of Swedish reservoirs control for the hydrological state of Swedish hydro power. Electricity consumption is strongly correlated with temperature because of the demand for heating. The heating degree days vector $\mathbf{HDD}_{t+1}$ of the different price areas controls for electricity demand. The estimated coefficients on the net demand slopes must be interpreted conditional on these variables that could plausibly affect the incentive of producers to exploit market power. For example, increased hydro inflow might reduce market power owing to the resulting increase in production capacity. One could try to account for such effects by adding interaction terms. But multiple interaction terms render coefficients more difficult to interpret. The problem of committing a type-1 error (incorrectly rejecting the null hypothesis) also increases with the number of coefficients. As the peak-hour dummy probably captures most of the variation in the incentive to exercise market power, we maintain this as our single interaction term.

[Table 2 about here.]

The data plots in Figure 2 particularly suggest variable correlation in SE2. Table II displays regression results for that area. Column I shows a significant negative slope coefficient β_1 in the baseline regression with (15) estimated on all hourly observations. Column II distinguishes between off-peak and peak hours. Correlations now differ between the two subsamples: The off-peak slope coefficient is significantly positive ($\beta_1 > 0$), and the peak slope coefficient at the bottom of the table is significantly negative ($\beta_1 + \beta_3 < 0$). The remaining two columns in Table II successively introduce additional covariates that could potentially be correlated with the slope of the net demand curve and the Elspot and Elbas price differences. Column III adds *net_exchange*, representing changes in cross-border power trade, and variables on inflow and reservoir levels. These covariates reflect supply capacity and are correlated with price differences to varying degree. Column IV adds additional temperature variables for the four price areas. Controlling for such demand variables reduces the off-peak slope coefficient, indicating that the slope coefficient is picking up a demand effect. This is consistent with demand being correlated with the slope. Still, the β_1 and $\beta_1 + \beta_3$ coefficients do not change dramatically across the final three specifications and are significant in all of them. We therefore reject Hypothesis 1 for SE2. Full results for all price areas, before and after the area reform, are found in Table IV in Appendix B. We estimate a positive and significant peak-hour coefficient for price area SE prior to the reform, but find no significant effects for SE1, SE3 or SE4.

We believe that OLS is an appropriate estimation method in this context because the dependent variable $f_2 - p_2$ is realized after gate closure of the day-ahead market that determines the slope of the inverse demand curve. But to err on the side of caution, we report results of an IV regression in tables V and VI in Appendix B. We follow Ito and Reguant [2016] and instrument the slope by means of our exogenous weather variables, heating degree days and inflow.[25] Results are more conservative, but nevertheless support our main conclusion that observed price differences are inconsistent with competitive behavior during the sample period. We reject the null hypothesis of competitive markets at the 10% level during off-peak and peak hours in SE prior to the reform and at the 5% level during peak hours in SE3 after the reform.

We next consider results related to simultaneous trade. Proposition 2 states that all systematic price differences between the day-ahead market and the real-time market for electricity traded simultaneously are due either to market power or output constraints.

[Figure 3 about here.]

Figure 3 plots kernel densities for price area Sweden (SE) before the reform and each of the price areas SE1-SE4 after the reform. The x-axis shows the Elspot price $f_{ah(t+1)}$ in price area a, hour h of day $t+1$ minus the Elbas price p_{iaht} of trade i for the same price area and hour of day t (both determined day t). The y-axis shows the change $Q_{ah(t+1)} - Q_{aht}$ in hydro production between day $t+1$ and t, hour h in price area a. Hypothesis 2 asserts that the product is non-negative if the market is competitive: $(Q_{ah(t+1)} - Q_{aht})(f_{ah(t+1)} - p_{iaht}) \geq 0$. Intuitively, the output difference and the price difference are both associated with the same directional change in water values between consecutive days. The product of the two is proportional to the square of the water value difference under perfect competition and thus non-negative. Moving clockwise from the north-east quadrant in each panel of Figure 3, the product of the two variables is positive in quadrants 1 and 3 and negative in 2 and 4. Percentages show the share of observations in each quadrant. Consistent with perfect competition, densities are centered around zero or are positive in quadrant 3 in SE as well as in the post-reform areas SE1-SE3. Price area SE4 is the exception with a density centered around quadrant 2, seemingly inconsistent with perfect competition.

We run an OLS regression with the product of the two variables as the dependent variable:

$$(16) \qquad (Q_{ah(t+1)} - Q_{aht})(f_{ah(t+1)} - p_{iaht}) = \beta_0 + \sum_{j=1}^{6} \beta_j Dow_{jt} + \epsilon_{iaht}.$$

The demand for electricity varies across the week, which may have a systematic effect on producers' incentive to exercise market power. Regression (16) controls for fixed day-of-week effects. A dummy variable, Dow_{jt}, is attached to each of the six weekdays Monday through Saturday. In this specification, the intercept β_0 should be interpreted as the average $(Q_{ah(t+1)} - Q_{aht})(f_{ah(t+1)} - p_{iaht})$ for trades completed on Sundays. The null hypothesis of perfect competition is $\beta_0 \geq 0$. The average dependent variable for Monday would be $\beta_0 + \beta_1$, with $\beta_0 + \beta_1 \geq 0$ if the market is competitive.

[Table 3 about here.]

The first two columns of Table III present the regression results of (16) for the two southern price areas Stockholm (SE3) and Malmø (SE4) after the area price reform. The intercept β_0 is positive in SE3, consistent with perfect competition, but significantly negative in SE4, which is inconsistent with perfect competition. The two last columns of Table III show regression estimates $(\beta_0 + \beta_j)$ of the average dependent variable of (16) in SE3 and SE4 for the other six weekdays and corresponding Wald statistics [in brackets] for the null hypothesis $\beta_0 + \beta_j \geq 0$. The estimates for SE3 are positive for Wednesday ($j = 3$) and Friday ($j = 5$), which is again consistent with perfect competition. However, the average $(Q_{ah(t+1)} - Q_{aht})(f_{ah(t+1)} - p_{iaht})$ is significantly negative for the remaining weekdays in SE3 and for all weekdays in SE4. Overall, we reject Hypothesis 2 for SE3 and SE4 after the area reform. Full results for all price areas, before and after the reform, are in Table VII in Appendix B. The average dependent variable is positive for all weekdays in price area SE prior to the reform and in the two northern price areas Luleå (SE1) and Sundsvall (SE2) after the reform. Hence, we cannot reject Hypothesis 2 in those areas.

III(v). *Interpretation of the results*

While the availability of detailed bidding data is a limiting factor, our regressions show examples of how predictions of the theoretical model can be tested. Regression estimates for Nord Pool lead to a rejection of Hypothesis 1 for price area Sundsvall (SE2) in the off-peak period and for price areas Sweden (SE) and SE2 in the peak period. We reject Hypothesis 2 for price areas Stockholm (SE3) and Malmö (SE4). This section explores possible explanations for the data pattern.

Can marginal trading costs explain the results? The variable fee for trading on Nord Pool is 0.04 EUR/MWh for Elspot and 0.11 EUR/MWh for Elbas.[26] Modifying the model to account for such costs is straightforward; details are available on request. The difference in marginal trading costs reduces $f_2 - E[p_2]$ in (11), but does not affect Hypothesis 1. The dependent variable for testing Hypothesis 2 changes to

$$(Q_{ah(t+1)} - Q_{aht})(f_{ah(t+1)} - p_{iaht} + 0.07).$$

This adjustment of the dependent variable amounts to a parallel shift to the left of the vertical line in Figure 3, thus increasing the relative sizes of quadrants 1 and 2. By visual inspection, this should not have much of an effect on the results in price areas SE and SE4, but perhaps in the other areas. But regressing the new variable with fixed day-of-week effects produces similar results as before. We conclude that marginal trading costs cannot plausible explain the price patterns in our sample.

Can bidding constraints in the day-ahead market explain the results? The equilibrium price differences $f_2 - p_2$ and $f_2 - p_1$ depend on whether bidding constraints in the day-ahead are binding, i.e. $\bar{\chi}_n > 0$ or $\underline{\chi}_n > 0$; see (11) and (12). Such bidding constraints are unrelated to the slope of the inverse demand curve in a competitive market and therefore have no consequences for Hypothesis 1. Hypothesis 2 is valid if $y_n = (\bar{\chi}_n - \underline{\chi}_n)(q_{n2} - q_{n1}) \geq 0$ for all firms n with market power. Potentially, $(Q_2 - Q_1)(f_2 - p_1) < 0$ could hold in a competitive market if $y_n < 0$ for a sufficient number of large firms; see (13). Let z_{nt} be the volume of electricity sold by firm n in the day-ahead market day t (for delivery day $t+1$). Then $(q_{n2}-q_{n1})(z_{n2}-z_{n1})>0$ if $y_n<0$ and $z_{n2}\neq z_{n1}$.[27] We only observe the aggregate variable $(Q_2-Q_1)(Z_2-Z_1)$ on Nord Pool, but firm-specific variables would be roughly proportional to the aggregate if either one firm has most of the market power, or the firms with market power are similar to one another. To test for bidding constraints, we run the regression

$$(Q_{ah(t+1)}-Q_{aht})(Z_{ah(t+1)}-Z_{aht})=\delta_0+\sum_{j=1}^{6}\delta_j Dow_{jt}+\epsilon_{aht},$$

controlling for fixed day-of-week effects. In this regression, Z_{aht} is the total volume of electricity sold in the day-ahead market day t for delivery in price area a, hour h of day $t+1$. If the estimated coefficients δ_0 and $\delta_0+\delta_j$ are positive and significant, then bidding constraints can potentially explain why $(Q_{ah(t+1)}-Q_{aht})(f_{ah(t+1)}-p_{iaht})$ on average would be negative in a competitive market. Table VIII in Appendix B reports the regression results for SE3 and SE4. We cannot reject the null hypothesis $\delta_0\leq 0$ or $\delta_0+\delta_j\leq 0$ for any weekday in the two price areas. We conclude that bidding constraints in the day-ahead market cannot plausible explain the price patterns in our sample.

[Figure 4 about here.]

Can market illiquidity explain the results? We use the Nordic intra-day market, Elbas, as our proxy for the real-time market. Elbas handles only 1 per cent of the traded volume on NP. Low market liquidity could create a concern about the reliability of Elbas prices as a predictor of real-time prices. Figure 4 plots the density of the number of Elbas trades per day for each of the price areas NS, SE3 and SE4, depending on whether the market was congested the subsequent day for the roughly 22 000 trades in our sample.[28] The distribution of daily trades does not depend on congestion in any of the price areas. Elspot and Elbas price differences correspond well with the predictions of Hypothesis 1 in SE1 and SE3 and with Hypothesis 2 in SE1 and SE2. This correspondence and the relatively large number of trades in NS and SE3, give reason to believe that the estimates reflect average day-ahead and real-time price differences. Market liquidity is the lowest in SE4. If price estimates are otherwise unbiased, then the small number of trades merely imply a higher standard error. The estimated coefficients for SE4 in Table III are statistically significant. From Figure 3, we see that the large number of observations in quadrant 2 is what causes rejection of Hypothesis 2 in SE4. Biased price estimates would then lead to a false rejection of the hypothesis only if Elbas prices were systematically below and real-time prices systematically above day-ahead prices in situations with reductions in hydro production. Given that Elbas is open until one hour prior to production, one would expect persistent price differences to be arbitraged away in a competitive market. Overall, these observations lend support to a conclusion that market illiquidity is not a plausible explanation for the observed deviations from competitive pricing.

Can market power explain the results? We reject both Hypothesis 1 and 2 for some price areas on Nord Pool in our period of examination. The question remains whether market power can reasonably explain observed price differences. The results of Table II for off-peak hours are intuitive. The day-ahead (Elspot) price tends to increase relative to the real-time (Elbas) price if the day-ahead price is more sensitive to a reduction in output (the absolute value of the slope is larger). In Table IV, we find the same effect in peak periods for price area Sweden (SE) prior to the area reform in 2011. Less intuitive is the finding from Table II that the Elspot and Elbas price difference during peak hours is smaller in SE2 when the day-ahead price is more sensitive to changes in output.

In addition to participating in the wholesale market, producers sell long-term contracts that clear against the day-ahead price. Such contracts soften the incentive to exercise seller power in the day-ahead market (Bushnell et al. [2008]). The β_1 and $\beta_1 + \beta_3$ coefficients can be interpreted as estimates of the average contract coverage of firms with market power. Those estimates suggest that the net contracting positions are close to zero, or even negative, $z_{n1} < 0$ in (11), in some circumstances. In the latter case, firms exercise monopsony power. We have no detailed information about contract volumes, but small net contracting positions are consistent with anecdotal evidence. For instance, the largest producer in the Nordic market, Vattenfall, states in its annual reports that the company aims to cover around 80 per cent of its average production through various long-term contracts.

The slope of inverse net demand at the integrated Nordic (system) level is an appropriate measure of the incentive to exercise market power during off-peak hours because the transmission network is relatively unconstrained during those hours. Indeed, the estimated slope coefficients are of the expected sign during off-peak hours. System level variables are less ideal during peak hours because of network bottlenecks that yield local market concentration. It is possible that the negative slope estimates in SE2 during peak hours would change sign if market power was estimated on slope variables calculated at price area level. Such disaggregated data are not yet publicly available.

Turning to our findings from Table III, recall that SE3 and SE4 import electricity from SE1 and SE2. Bottlenecks restrict import competition from the north during peak hours. Flexible production capacity (hydro power) is small in the south, particularly in SE4. Hence, local market concentration can be very high in SE3 and SE4. From Figure 3, we see that the Elspot-Elbas price difference is generally positive in SE4. This is consistent with an exercise of market power by which producers withhold supply to increase the day-ahead (Elspot) price in SE4 in periods of network congestion.

IV. CONCLUSION

This paper has analyzed in a theoretical framework the link between day-ahead and real-time competition in a hydro-based wholesale electricity market. We have derived tests of market performance and applied them to evaluate prices on the Nordic power exchange, Nord Pool, before and after a reform that increased the number of price areas in Sweden. We reject the hypothesis of perfect competition in some of the Swedish price areas, which suggests that firms were able to exercise some local market power during the sample period.

The informational requirements of the methodology are relatively mild. We use equilibrium prices, aggregate supply and demand slopes and hydro output to derive our results. The approach is to relate prices in different sub-markets to each other, which also permits to control directly for the effects of risk aversion, rather than to impose risk neutrality on market participants.

A methodology of comparing outcomes across markets necessarily brings with it some drawbacks. First, it is a diagnostic test of whether markets can be considered competitive. In case of rejection, it is impossible to estimate markups in specific markets without more detailed data. Also, we run the risk of underestimating market power because price relations consistent with perfect competition sometimes are consistent with the exercise of market power. Hence, the methods proposed in this paper are by no means perfect substitutes for elaborate simulation models or estimation methods built upon detailed bid data. Rather, we see the methodology as a first and relatively simple step in the analysis of the performance of hydro-based wholesale electricity markets.

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APPENDIX A: EQUILIBRIUM CHARACTERIZATION AND EXISTENCE

We first derive properties of the inverse demand function $F_1(Z_1, Q_1)$ for the day-ahead market. Define $\Phi = \frac{F_1}{b} + R - Q_1$ and substitute into (5) to get

$$E[D_2] - \Phi + \sigma b E[(D_2 - Z_1)(D_2 - \Phi)^2] = 0.$$

This quadratic equation has two real solutions if σb is sufficiently small. Let $\Phi(Z_1)$ be the maximal of those solutions. Demand in the day-ahead market is additively separable in Z_1 and Q_1,

$$F_1(Z_1, Q_1) = E[P_2(R - Q_1)] + b(\Phi(Z_1) - E[D_2]), \tag{17}$$

and

$$F_1(Z_1, Q_1) - P_2(R - Q_1) = b(\Phi(Z_1) - D_2) \tag{18}$$

is independent of Q_1 in this model. Also, for future reference

$$\frac{\partial F_1(Z_1, Q_1)}{\partial Z_1} = b\Phi'(Z_1) \text{ and } \frac{\partial F_1(Z_1, Q_1)}{\partial Q_1} = -b,$$

$$\Phi'(Z_1) = \frac{-\sigma b E[(D_2 - \Phi)^2]}{1 + 2\sigma b E[(D_2 - \Phi)(D_2 - Z_1)]}, \tag{19}$$

$$\Phi''(Z_1) = 2\sigma b \frac{2(E[D_2] - \Phi) + (E[D_2] - Z_1)\Phi'(Z_1)}{1 + 2\sigma b E[(D_2 - \Phi)(D_2 - Z_1)]} \Phi'(Z_1). \tag{20}$$

To characterize the equilibrium, differentiation of the Lagrangian (9) yields the two first-order conditions:

$$U'(\pi_{n1})\Pi_1'(q_{n1}) + E[U'(\pi_{n2})\frac{\partial \Pi_{n2}(q_{n1}, z_{n1})}{\partial q_{n1}}] - \lambda_{n1} + \lambda_{n2} = 0,$$

$$E[U'(\pi_{n2})\frac{\partial \Pi_{n2}(q_{n1}, z_{n1})}{\partial z_{n1}}] + \underline{\chi}_n - \bar{\chi}_n = 0$$

for firm n. Substituting in the marginal profit expressions

$$\Pi_1'(q_{n1}) = P_1(Q_1) + P_1'(Q_1)q_{n1}$$

$$\frac{\partial \Pi_{n2}(q_{n1}, z_{n1})}{\partial q_{n1}} = -P_2(R - Q_1) - P_2'(R - Q_1)(r_n - q_{n1})$$

$$\frac{\partial \Pi_{n2}(q_{n1}, z_{n1})}{\partial z_{n1}} = F_1(Z_1, Q_1) - P_2(R - Q_1) + \frac{\partial F_1(Z_1, Q_1)}{\partial Z_1} z_{n1}$$

and invoking covariance terms, we obtain the first-order conditions (10) and (11). These conditions, and the complementary slackness conditions

(21) $$q_{nt} \le \bar{q}_n, \lambda_{nt} \ge 0, \lambda_{nt}(\bar{q}_n - q_{nt}) = 0, t = 1, 2,$$

(22) $$z_{n1} \in [\underline{z}_n, \bar{z}_n], \underline{\chi}_n \ge 0, \bar{\chi}_n \ge 0, \underline{\chi}_n(z_{n1} - \underline{z}_n) = \bar{\chi}_n(\bar{z}_n - z_{n1}) = 0$$

jointly constitute the necessary equilibrium conditions for firm n.

To establish existence, recall that each firm $n \in \mathcal{N}$ maximizes $V_n(q_{n1}, z_{n1})$ subject to $(q_{n1}, z_{n1}) \in [r_n - \bar{q}_n, \bar{q}_n] \times [\underline{z}_n, \bar{z}_n]$. This game satisfies the sufficient existence conditions of Rosen [1965] if each player's objective function is concave in its own strategies. The elements of the Hessian matrix H_n of V_n are

$$\frac{\partial^2 V_n}{\partial q_{n1}^2} = -\gamma(\Pi_1')^2 - \gamma E[(\frac{\partial \Pi_{n2}}{\partial q_{n1}})^2] - 2bU'(\pi_{n1}) - 2bE[U'(\pi_{n2})],$$

$$\frac{\partial^2 V_n}{\partial z_{n1}^2} = -\gamma E[(\frac{\partial \Pi_{n2}}{\partial z_{n1}})^2] + E[U'(\Pi_{n2})]\frac{\partial^2 \Pi_{n2}}{\partial z_{n1}^2},$$

$$\frac{\partial^2 V_n}{\partial q_{n1}\partial z_{n1}} = -\gamma E[\frac{\partial \Pi_{n2}}{\partial q_{n1}}\frac{\partial \Pi_{n2}}{\partial z_{n1}}].$$

Note that $\frac{\partial^2 V_n}{\partial q_{n1}^2} < 0$ if γ is sufficiently small because then $U' > 0$. Consider next the determinant

$$\det H_n = \frac{\partial^2 V_n}{\partial q_{n1}^2}\frac{\partial^2 V_n}{\partial z_{n1}^2} - (\frac{\partial^2 V_n}{\partial q_{n1}\partial z_{n1}})^2.$$

After some algebraic manipulations,

(23)

$$\begin{aligned}\det H_n = \quad & -\gamma E[(\tfrac{\partial \Pi_{n2}}{\partial q_{n1}})^2]E[U'(\pi_{n2})]\tfrac{\partial^2 \Pi_{n2}}{\partial z_{n1}^2} \\ & +[\gamma(\Pi'_{n1})^2 + 2bU'(\pi_{n1}) + 2bE[U'(\pi_{n2})]][\gamma E[(\tfrac{\partial \Pi_{n2}}{\partial z_{n1}})^2] - E[U'(\pi_{n2})]\tfrac{\partial^2 \Pi_{n2}}{\partial z_{n1}^2}] \\ & +\gamma^2[E[(\tfrac{\partial \Pi_{n2}}{\partial q_{n1}})^2]E[(\tfrac{\partial \Pi_{n2}}{\partial z_{n1}})^2] - E^2[\tfrac{\partial \Pi_{n2}}{\partial q_{n1}}\tfrac{\partial \Pi_{n2}}{\partial z_{n1}}]].\end{aligned}$$

The expression on the first row is non-negative and the one on the second row is strictly positive if γ is sufficiently small and

$$\frac{\partial^2 \Pi_{n2}}{\partial z_{n1}^2} = 2b[1 + \sigma b\frac{2(E[D_2] - \Phi) + (E[D_2] - Z_1)\Phi'(Z_1)}{1 + 2\sigma bE[(D_2 - \Phi)(D_2 - Z_1)]}z_{n1}]\Phi'(Z_1) < 0.$$

This inequality holds if σb is sufficiently small. One can simplify the expression on the third row of (23) to

$$\gamma^2[2E[p_2] - f_2 - bq_{n2} - b\Phi'(Z_1)z_{n1}]^2 var[p_2] \geq 0.$$

We conclude that H_n is negative definite and $V_n(q_{n1}, z_{n1})$ therefore strictly concave in the domain $[r_n - \bar{q}_n, \bar{q}_n] \times [\underline{z}_n, \bar{z}_n]$ if γ and σb are sufficiently small.

APPENDIX B: FULL EMPIRICAL RESULTS

[Table 4 about here.]

[Table 5 about here.]

We can compare the above results with an OLS regression without the temperature and inflow data below. Those OLS results are very similar to the ones in the main text.

[Table 6 about here.]

[Table 7 about here.]

[Table 8 about here.]

NOTES

[1]More generally, this paper addresses the problem of imperfect competition in a market with storable goods. One can think of a non-hydro power market where technological development has reduced the cost of large scale storage; see Carson and Novan [2013] for an analysis in a competitive setting. Another relevant application is the extraction and refinement of fossil fuels. Yet, differences in market structure imply than one should be careful about drawing inferences about markets with storable goods based on the performance of hydro power markets. In a hydro power market, producers are the only ones that can store the good efficiently, but this is not necessarily the case in other markets. Such third-party storage could have an effect on competition by equalizing prices across periods.

[2]If one has reason to believe that price risk matters little for production decisions, then the second test can be applied even to wholesale markets without hydro production.

[3]The Swedish price area reform was introduced to comply with demands by the EU competition authority to improve how Sweden handled domestic supply and demand imbalances.

[4]National balancing markets operated by the national transmission system operators (TSOs) subsequently take over. Each TSO compares the positions market participants have taken in the physical markets with their actual output and penalizes them for any imbalances. Financial markets enable market participants to hedge their production or consumption portfolios further ahead in time.

[5]See Jha and Wolak [2015] for an empirical analysis of transaction costs in the California electricity market. We control directly for marginal transaction costs in the present context.

[6]In electricity markets that rely mainly on thermal energy, one can sometimes use plant level engineering data to derive industry marginal cost curves and compare with prices to evaluate market performance; see Wolfram [1999] and Borenstein et al. [2002] for classical applications to the UK and California electricity markets.

[7]Wolak [2003] has bid data at individual firm level from California, and McRae and Wolak [2014] use similar bid data from New Zealand to estimate firm-specific demand elasticities. These studies are exceptional insofar as individual bid data are difficult to obtain in most electricity markets.

[8]The two period set-up and the functional form assumptions below are for analytical tractability and to ensure that the objective functions are concave. A previous version of the paper considered a recursive reduced-form model with qualitatively similar predictions.

[9]Two factors affect the efficiency with which water is converted into electricity. First, the height difference between the dam level and the turbine, the *gross head*, goes down as water is released from the dam. All else equal, a lower gross head implies less production for a given water release. For large reservoir power plants, day-to-day variations in release have negligible effects on the gross head, so this effect can safely be disregarded with the short time horizon considered here. Second, a turbine converts water into energy more or less efficiently depending on how much water is released through it. Turbines have an efficient operating span at which production increases linearly with water release. Hydro plants often have multiple turbines to achieve maximum efficiency over a wider production range. A linear specification, as considered in most of the theoretical literature (e.g. Crampes and Moreaux [2001], Garcia et al. [2001], Førsund [2007], Hansen [2009]) and in simulation models (e.g. Bushnell [2003], Kauppi and Liski [2008], Philpott et al. [2010]) therefore seems a reasonable first approximation to normal day-to-day operations.

[10]Reservoirs very seldom hit upper or lower capacity bounds in the Nordic electricity market. The Nordic power exchange, Nord Pool, publishes weekly reservoir data at price area level since 2016. Between week 1 of 2016 and week 7 of 2018, reservoir levels never exceeded 90 per cent or fell below 15 per cent of capacity in any Swedish price area.

[11]Cournot competition against a competitive fringe featuring a marginal cost curve with deterministic slope would yield horizontal shifts in the aggregate supply curve across time. This is exactly the short-run pattern we see in the Nordic day-ahead market, but also in some other wholesale electricity markets (Lundin and Tangerås [2017]).

[12]Participating in the day-ahead market is formally equivalent to selling a forward contract that clears against the real-time price p_2.

[13]For instance, the largest Swedish retailer, Vattenfall, offered in February 2018 a short-term contract with a markup of 2 Euros per MWh to cover trading fees, network charges and other costs; see www.vattenfall.se/elavtal/elpriser/rorligt-elpris/prishistorik/ accessed February 26, 2018. Consumers can also choose long-term retail contracts that fix prices for six months or more. Other network costs and taxes add to the total retail cost. Those are separately specified on the electricity bill and charged by the distribution network owner.

[14]We assume that producers only participate in the wholesale market, but allowing vertical integration between retail and wholesale would not add anything to the model. Suppose firm n supplies z^c_{n1} directly to

consumers and z_{n1}^d to the day-ahead market at the same price f_2, and let $z_{n1} = z_{n1}^c + z_{n1}^d$. It is easy to verify that the following holds: Inverse demand in the real-time market in period t equals $P_t(Q_t)$ as a function of the total production Q_t that period of all producers with market power, inverse demand in the day-ahead market is given by (5) as a function of Q_1 and Z_1, and the total profit of firm n in period 2 is given by (6). Since firm n's profit only depends on its total position z_{n1}, it is optimal for it to set $z_{n1}^c = 0$ and $z_{n1}^d = z_{n1}$.

[15]Such bidding constraints are what limits arbitrage in Ito and Reguant [2016] and lead to price differences across time in their model.

[16]The reservoir constraint (2) turns this into a static problem, so the set of subgame-perfect and Nash equilibria are the same. We go through the details in Appendix A, where we also show that a pure strategy equilibrium exists if γ and σb are sufficiently small.

[17]Nord Pool traces its origin back to 1991 when Norway introduced a trading system for wholesale electricity as part of liberalizing its electricity sector. Sweden, Finland and Denmark subsequently joined to create what was then the world's first multinational power exchange. NP has later coupled with continental Europe and the Baltic countries.

[18]Bilateral contracts between producers and industrial consumers, direct deliveries internal to vertically integrated producers and retailers and trade with neighboring countries made up the differential.

[19]All numbers are from the NP Annual Report 2013, which can be accessed at nordpoolgroup.com.

[20]SE3 and SE4 also have tiny amounts of solar power and unspecified production that in 2013 made up the difference between total production and the production detailed in Table I.

[21]Electricity from CHP is an inflexible supply source because it is a bi-product of heat production. A related issue is if one can count imports as flexible marginal generation. This is not the case if market participants behave non-strategically. By the design of the Nordic wholesale market, all TSOs (the transmission network owners) are required to bid in all available network capacity inelastically into Elspot, i.e. at price zero. By implication, imports represent base-load instead of marginal production.

[22]For simplicity, electricity is sold at a uniform price in the real-time market in the theoretical model.

[23]Let Z_{ht} be the total quantity sold in the Nordic day-ahead market day t for delivery hour h of day $t+1$. Denote by $f_{h(t+1)}^-$ ($f_{h(t+1)}^+$) the day-ahead price at which total demand (supply) at the integrated Nordic (system) level is 0.5 GWh in excess of Z_{ht}. We calculate the slope variable as $f_{h(t+1)}^+$ - $f_{h(t+1)}^-$. This variable mostly captures supply elasticity as the aggregate (system level) demand curve typically is near vertical around Z_{ht}.

[24]We would have preferred to use the slope of the net demand facing each individual firm in the empirical analysis, although the slope aggregated at price area level would be sufficient under Cournot competition; see Section II. Bid data at such disaggregated levels are currently not publicly available. Still, the slope of the system level net demand curve is a good proxy for competition in off-peak periods because transmission

constraints then are less severe.

[25]Here, the instruments HDD and inflow are measured at daily values while the instrumented slope is measured at an hourly value. Ideally, the instruments would also be at hourly values, but this data limitation should not have any significant effect on the point estimates as long as the pattern of correlation is similar across and within days. The reduction in the effective sample size can and does have an effect on the standard errors of the estimation.

[26]Market participants have to pay an annual fee and there are fixed overhead costs associated with trading on NP, but these should have no short-term effects on equilibrium prices. An overview of the current trading fees on NP can be found at nordpoolgroup.com/TAS/Fees.

[27]$y_n < 0$ implies $\bar{\chi}_n > 0$ for $q_{n2} < q_{n1}$ and therefore $z_{n1} = \bar{z}_n$ by complementary slackness, $\bar{\chi}_n(\bar{z}_n - z_{n1}) = 0$. Then $(q_{n2} - q_{n1})(z_{n2} - z_{n1}) = (q_{n2} - q_{n1})(z_{n2} - \bar{z}_n) > 0$ if also $z_{n2} \neq z_{n1}$. Similarly, $y_n < 0$ implies $(q_{n2} - q_{n1})(z_{n2} - z_{n1}) = (q_{n2} - q_{n1})(z_{n2} - \underline{z}_n) > 0$ for $q_{n2} > q_{n1}$ and $z_{n2} \neq z_{n1}$.

[28]We have formed price area North (NS) by merging SE1 and SE2 because these two were nearly always integrated in our sample; see Figure 1.

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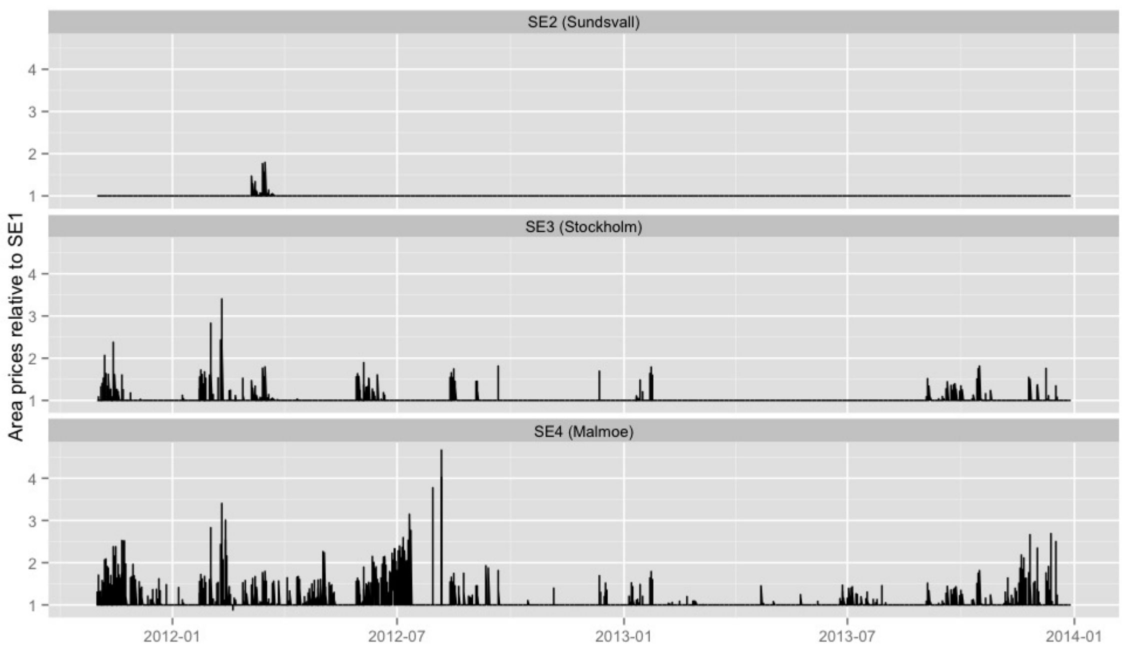
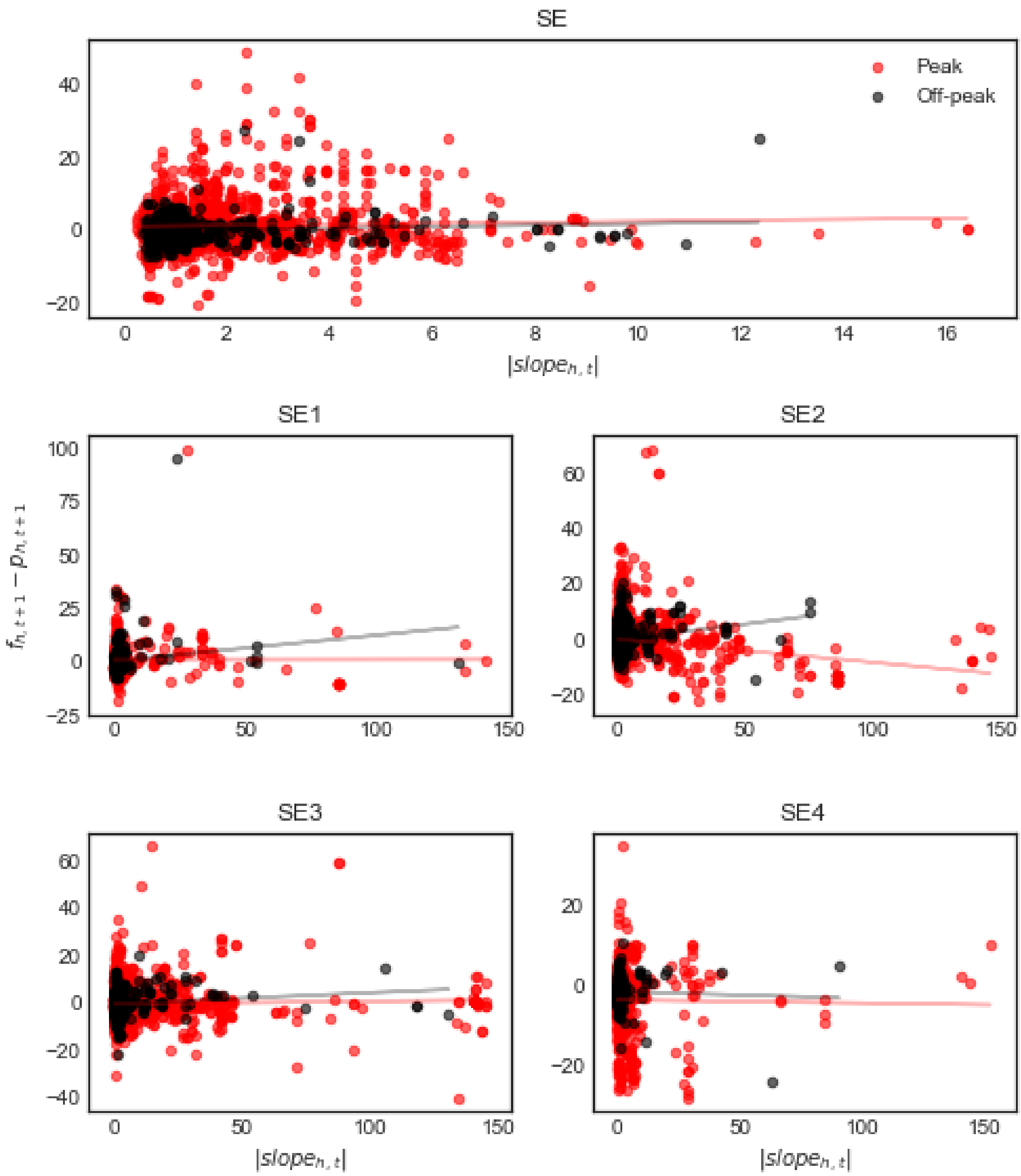
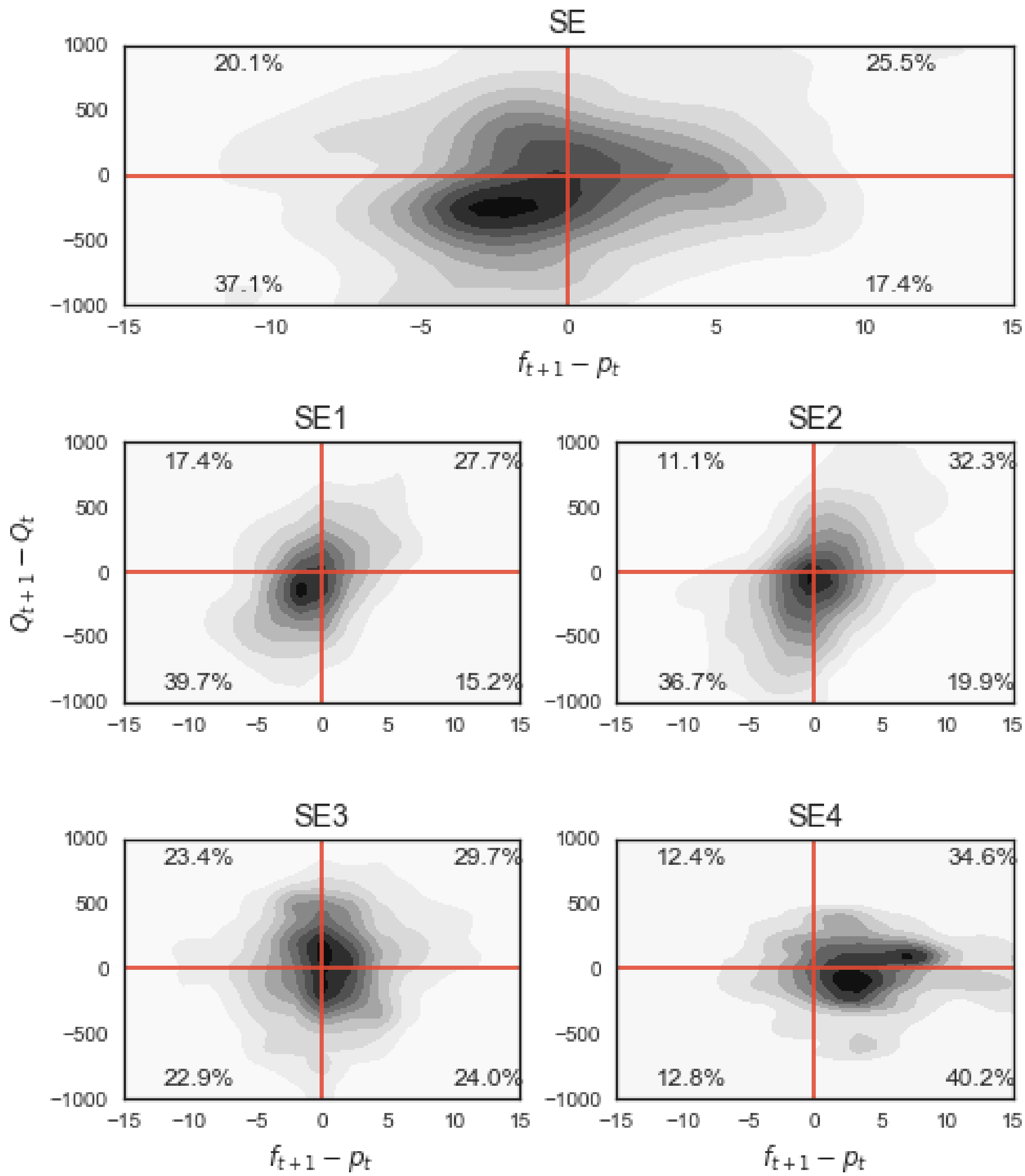


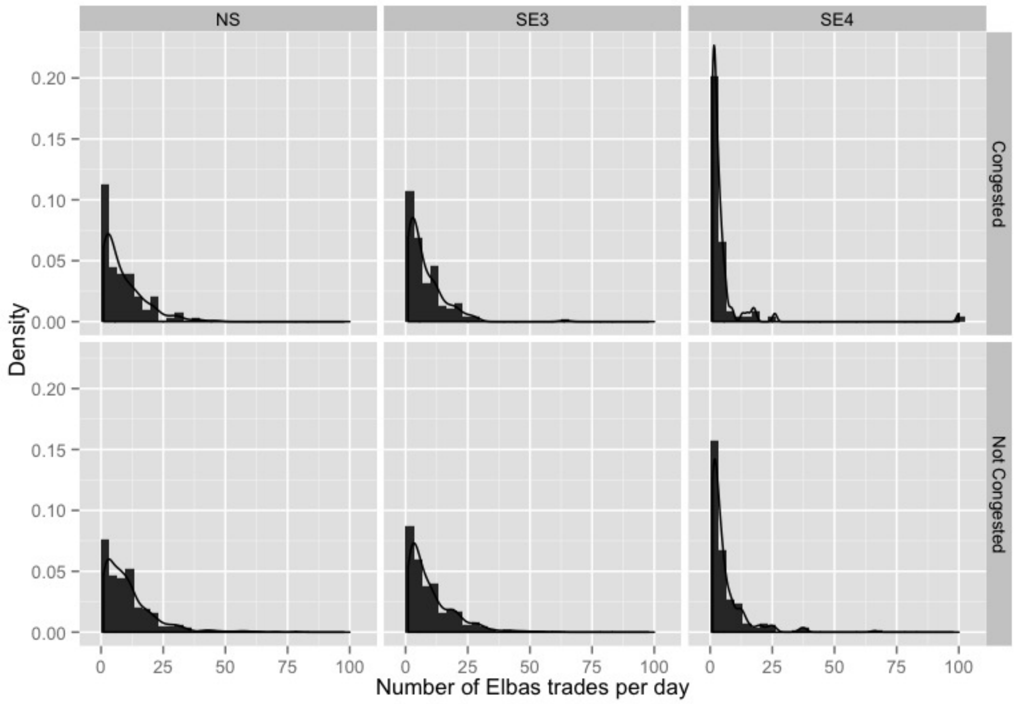
Elspot prices in areas SE2, SE3 and SE4 divided by the Elspot price in area SE1 between November 1, 2011 and December 31, 2013.



The Elbas and Elspot price differences (EUR/MWh) for simultaneous delivery regressed on the slope of the net demand curve on Elspot. The top panel shows data from the SE area before the area reform. The bottom four panels show data from the four price areas after the reform.



The figure plots the kernel density of $f_{ah(t+1)} - p_{iaht}$, the Elspot price for delivery in price area a, hour h of day $t+1$ minus the price of Elbas trade i for delivery in price area a, hour h of day t (both determined day t), on the x-axis and the daily change in aggregate hydro power production at price area level, $Q_{ah(t+1)} - Q_{aht}$, on the y-axis. The dependent variable for Hypothesis 2 is the product of these variables. Starting from the north-east corner and moving clockwise, quadrants 1 and 3 (2 and 4) contain the observations where the dependent variable is positive (negative). Percentages show the shares of observations in each quadrant.



Density plots of the daily number of Elbas trades by price area and whether there was congestion the following day. NS (SE1-2) and SE3 appear to see heavier trading. However, little difference between congested and not-congested days can be seen.

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Production and consumption of electricity (GWh) in Sweden in 2013

	SE1 (Luleå)	SE2 (Sundsvall)	SE3 (Stockholm)	SE4 (Malmö)	Total
Hydro	19 820	31 811	8 851	1 202	61 684
(Reservoir capacity)	(14 810)	(15 730)	(2 911)	(224)	(33 675)
Nuclear	–	–	63 843	–	63 843
Gas & diesel units	1	1	25	14	41
Other thermal	231	733	5 163	1 971	8 098
Wind	966	2 173	4 024	2 837	10 000
Total production	21 018	34 718	81 918	6 027	143 681
Consumption	9 356	16 255	84 596	23 532	133 739

Sources: svk.se, nordpoolspot.com

Regression results of Elspot and Elbas price differences for the same delivery hour in the SE2 price area. The null hypothesis of perfect competition is that the coefficients on the slope of the inverse net demand curve, $\left|\frac{\partial F}{\partial Z}\right|$ and $(\left|\frac{\partial F}{\partial Z}\right| + \left|\frac{\partial F}{\partial Z}\right| : peak)$, are insignificantly different from zero.

Variable	Label	I	II	III	IV
Intercept		0.396***	0.164	-0.885***	-3.827***
		(0.064)	(0.113)	(0.210)	(0.412)
Slope off-peak	$\left\|\frac{\partial F}{\partial Z}\right\|$	-0.073***	0.113**	0.115***	0.080**
		(0.014)	(0.044)	(0.043)	(0.042)
Peak hour dummy	peak		0.248*	0.281**	0.337**
			(0.135)	(0.133)	(0.133)
Interaction slope, peak	$\left\|\frac{\partial F}{\partial Z}\right\|$:peak		-0.197***	-0.197***	-0.184***
			(0.046)	(0.045)	(0.044)
Net exchange (MWh)	net_exchange			0.010**	0.007
				(0.005)	(0.005)
Reservoir inflow (GWh)	inflow			0.013***	0.049***
				(0.004)	(0.006)
Reservoir level (%)	level			0.011***	0.024***
				(0.003)	(0.003)
HDD Luleå (SE1)	HDD_lulea				0.051**
					(0.021)
HDD Sundsvall (SE2)	HDD_sundsvall				-0.054**
					(0.026)
HDD Stockholm (SE3)	HDD_stockholm				-0.010
					(0.063)
HDD Malmø (SE4)	HDD_malmo				0.173***
					(0.043)
Slope peak	$\left\|\frac{\partial F}{\partial Z}\right\| + \left\|\frac{\partial F}{\partial Z}\right\|$:peak		–0.084***	-0.082***	-0.104***
			[35.622]	[33.710]	[60.770]
	N	7111	7111	7111	7111
	R^2	0.02	0.03	0.04	0.06

$^{***}p < 0.01$, $^{**}p < 0.05$, $^{*}p < 0.1$. HAC robust standard errors in parentheses on first rows. Wald statistics of null hypothesis $\beta_1 + \beta_3 = 0$ in square brackets on final row.

Regression of $(Q_{ah(t+1)} - Q_{aht})(f_{ah(t+1)} - p_{iaht})$ on trade day-of-week. *Intercept* represents the Sunday average. The Monday average is $Intercept + Dow_1$, etc. Coefficient sums for SE3 and SE4 are in the two columns to the right.

Variable	Label	SE3	SE4	SE3	SE4
				Inter. + Dow_j	
Sunday	*Intercept*	2953.23	-703.23**		
		(161.01)	(273.77)		
Monday	Dow_1	-3432.51***	631.22	-479.28***	-72.01**
		(178.06)	(289.69)	[376.153]	[7.176]
Tuesday	Dow_2	-3874.57***	-125.84	-921.34***	-829.07***
		(246.33)	(347.94)	[360.848]	[21.505]
Wednesday	Dow_3	-2812.97***	296.92	140.26	-406.31***
		(178.78)	(305.00)		[15.732]
Thursday	Dow_4	-3301.34***	-116.68	-348.11***	-819.91***
		(196.20)	(327.71)	[346.062]	[27.318]
Friday	Dow_5	-2293.63***	613.94	659.60	-89.29**
		(185.59)	(329.02)		[6.837]
Saturday	Dow_6	-3283.86***	568.63*	-330.63***	-134.60**
		(206.70)	(311.73)	[342.930]	[7.413]
	N	7889	1993	7889	1993
	R^2	0.08	0.01		

***$p < 0.01$, **$p < 0.05$, *$p < 0.1$ from a one-sided t-test. HAC robust standard errors in parentheses in first two columns. Wald statistics of null hypothesis $\beta_1 + \beta_j \geq 0$ in square brackets in last two columns.

Regression results of Elspot and Elbas price differences for the same delivery hour. The null hypothesis of perfect competition is that the coefficients on the slope of the inverse net demand curve, $\left|\frac{\partial F}{\partial Z}\right|$ and $(\left|\frac{\partial F}{\partial Z}\right| + \left|\frac{\partial F}{\partial Z}\right| : peak)$, are insignificantly different from zero.

Variable	Label	SE	SE1	SE2	SE3	SE4
Intercept		-5.563***	-4.340***	-3.827***	-3.024***	-6.509***
		(0.851)	(0.808)	(0.412)	(0.390)	(0.847)
Slope off-peak	$\left\|\frac{\partial F}{\partial Z}\right\|$	0.215	0.065	0.080**	0.008	-0.028
		(0.236)	(0.087)	(0.042)	(0.024)	(0.091)
Peak hour dummy	peak	0.442	0.571**	0.337**	-0.035	-1.824***
		(0.478)	(0.263)	(0.133)	(0.113)	(0.270)
Interaction slope, peak	$\left\|\frac{\partial F}{\partial Z}\right\|$:peak	0.104	-0.103	-0.184***	-0.023	0.015
		(0.256)	(0.097)	(0.044)	(0.025)	(0.095)
Net exchange (MWh)	net_exchange	0.026**	0.020	0.007	-0.003	-0.036***
		(0.011)	(0.014)	(0.005)	(0.004)	(0.010)
Reservoir inflow (GWh)	inflow	0.080***	0.049***	0.049***	0.040***	0.067***
		(0.014)	(0.012)	(0.006)	(0.005)	(0.015)
Reservoir level (%)	level	0.014**	0.023***	0.024***	0.010***	0.035***
		(0.006)	(0.006)	(0.003)	(0.003)	(0.008)
HDD Luleå (SE1)	HDD_lulea	0.044	0.048	0.051**	0.098***	-0.004
		(0.033)	(0.054)	(0.021)	(0.017)	(0.044)
HDD Sundsvall (SE2)	HDD_sundsvall	-0.130*	0.101	-0.054**	-0.178***	0.129
		(0.071)	(0.063)	(0.026)	(0.026)	(0.079)
HDD Stockholm (SE3)	HDD_stockholm	0.980***	0.315**	-0.010	0.009	0.092
		(0.126)	(0.142)	(0.063)	(0.041)	(0.119)
HDD Malmö (SE4)	HDD_malmo	-0.607***	-0.277***	0.173***	0.247***	-0.091
		(0.097)	(0.102)	(0.043)	(0.037)	(0.095)
Slope peak	$\left\|\frac{\partial F}{\partial Z}\right\| + \left\|\frac{\partial F}{\partial Z}\right\|$:peak	0.319**	-0.038	-0.104***	-0.015	-0.013
		[8.260]	[2.029]	[60.770]	[4.320]	[0.247]
	N	2300	1970	7111	7895	1993
	R^2	0.19	0.07	0.06	0.04	0.07

$^{***}p < 0.01$, $^{**}p < 0.05$, $^{*}p < 0.1$. HAC robust standard errors in parentheses on first rows. Wald statistics of null hypothesis $\beta_1 + \beta_3 = 0$ in square brackets on final row.

Two-stage Least Squares (2SLS) regression results of Elspot and Elbas price differences for the same delivery hour. The null hypothesis of perfect competition is that the coefficients on the slope of the inverse net demand curve, $|\frac{\partial F}{\partial Z}|$ and $(|\frac{\partial F}{\partial Z}| + |\frac{\partial F}{\partial Z}| : peak)$, are insignificantly different from zero. Weather variables (Heating degree days, HDD) and inflow into hydro reservoirs serve as instruments for the slope of the inverse net demand curve and the peak hour interaction term.

Variable	Label	SE	SE1	SE2	SE3	SE4
Intercept		-78.53^{***}	-8.14	51.15	14.98^{***}	14.09
		(21.97)	(5.34)	(46.49)	(5.44)	(62.89)
Slope off-peak	$\lvert\frac{\partial F}{\partial Z}\rvert$	38.30^{*}	1.49	-5.77	0.05	13.29
		(20.49)	(1.12)	(7.75)	(0.74)	(22.34)
Peak hour dummy	peak	91.83^{***}	9.83	-64.82	-18.57^{***}	-19.85
		(24.46)	(7.13)	(57.87)	(6.45)	(64.98)
Interaction slope, peak	$\lvert\frac{\partial F}{\partial Z}\rvert$:peak	-43.03^{*}	-1.46	6.36	0.09	-15.6
		(21.96)	(1.3)	(8.45)	(0.79)	(26.53)
Net exchange	net_exchange	0.14^{***}	0.03	-0.05	-0.01	0.06
		(0.05)	(0.03)	(0.05)	(0.01)	(0.23)
Reservoir level (%)	level	-0.03	0.02^{***}	-0.01	-0.02^{**}	-0.02
		(0.07)	(0.01)	(0.03)	(0.01)	(0.18)
Slope peak	$\lvert\frac{\partial F}{\partial Z}\rvert+\lvert\frac{\partial F}{\partial Z}\rvert$:peak	-4.73*	0.03	0.59	0.04**	2.31
		[2.949]	[0.024]	[0.675]	[5.423]	[0.280]
	N	2300	1970	7111	7895	1993

$^{***}p < 0.01$, $^{**}p < 0.05$, $^{*}p < 0.1$. HAC robust standard errors in parentheses on first rows. Wald statistics of null hypothesis $\beta_1 + \beta_3 = 0$ in square brackets on final row.

Regression results of Elspot and Elbas price differences for the same delivery hour. The null hypothesis of perfect competition is that the coefficients on the slope of the inverse net demand curve, $\left|\frac{\partial F}{\partial Z}\right|$ and $\left|\frac{\partial F}{\partial Z}\right| + \left|\frac{\partial F}{\partial Z}\right| : peak$, are insignificantly different from zero.

Variable	Label	SE	SE1	SE2	SE3	SE4
Intercept		1.559***	-0.515	-0.641***	0.021***	-3.586***
		(0.561)	(0.406)	(0.204)	(0.210)	(0.479)
Slope off-peak	$\left\|\frac{\partial F}{\partial Z}\right\|$	0.366	0.122	0.110**	0.047	-0.009
		(0.228)	(0.104)	(0.043)	(0.029)	(0.092)
Peak hour dummy	peak	1.128**	0.690**	0.278**	-0.105	-1.841***
		(0.478)	(0.281)	(0.134)	(0.118)	(0.271)
Interaction slope, peak	$\left\|\frac{\partial F}{\partial Z}\right\|$:peak	-0.053	-0.124	-0.196***	-0.035	0.007
		(0.249)	(0.112)	(0.045)	(0.030)	(0.096)
Net exchange	net_exchange	0.054***	0.020	0.011**	0.002	-0.037***
		(0.011)	(0.014)	(0.005)	(0.004)	(0.010)
Reservoir level (%)	level	-0.032***	0.017***	0.012***	-0.004	0.036***
		(0.006)	(0.005)	(0.003)	(0.003)	(0.007)
Slope peak	$\left\|\frac{\partial F}{\partial Z}\right\|+\left\|\frac{\partial F}{\partial Z}\right\|$:peak	0.313**	-0.002	-0.086***	0.012	-0.002
		[8.182]	[1.364]	[43.367]	[4.574]	[0.019]
	N	2300	1970	7111	7895	1993
	R^2	0.05	0.02	0.03	0.00	0.05

$^{***}p < 0.01$, $^{**}p < 0.05$, $^{*}p < 0.1$. HAC robust standard errors in parentheses on first rows. Wald statistics of null hypothesis $\beta_1 + \beta_3 = 0$ in square brackets on final row.

Regression of $(Q_{ah(t+1)} - Q_{aht})(f_{ah(t+1)} - p_{iaht})$ on trade day-of-week. *Intercept* represents the Sunday average. The Monday average is $Intercept + Dow_1$, etc.

Day	Label	SE	SE1	SE2	SE3	SE4
Sunday	Intercept	8343.09	5127.25	7739.10	2953.23	-703.23**
		(880.29)	(550.33)	(298.16)	(161.01)	(273.77)
Monday	Dow_1	-7471.77***	-4585.39***	-6924.38***	-3432.51***	631.22
		(904.17)	(608.10)	(307.70)	(178.06)	(289.69)
Tuesday	Dow_2	-7426.53***	-4405.92***	-6917.59***	-3874.57***	-125.84
		(905.47)	(597.03)	(314.31)	(246.33)	(347.94)
Wednesday	Dow_3	-7765.46***	-4731.08***	-7372.74***	-2812.97***	296.92
		(891.93)	(567.00)	(307.88)	(178.78)	(305.00)
Thursday	Dow_4	-6005.20***	-3758.66***	-6882.10***	-3301.34***	-116.68
		(1004.09)	(627.57)	(315.92)	(196.20)	(327.71)
Friday	Dow_5	3206.07	-2638.16***	-5277.62***	-2293.63***	613.94
		(1457.48)	(635.73)	(335.03)	(185.59)	(329.02)
Saturday	Dow_6	-6772.56***	-3964.31***	-6547.14***	-3283.86***	568.63*
		(904.35)	(571.27)	(314.72)	(206.70)	(311.73)
	N	2297	1970	7105	7889	1993
	R^2	0.16	0.08	0.20	0.08	0.01

$^{***}p < 0.01$, $^{**}p < 0.05$, $^{*}p < 0.1$ from a 1-sided t-test. HAC robust standard errors in parentheses.

Regression of $(Q_{ah(t+1)} - Q_{aht})(Z_{ah(t+1)} - Z_{aht})$ on trade day-of-week. *Intercept* represents the Sunday average. The Monday average is $Intercept + Dow_1$, etc. Coefficient sums for SE3 and SE4 are in the two columns to the right.

Day	Label	SE3	SE4	SE3	SE4
				Inter. + Dow_j	
Sunday	Intercept	6242	-3778		
		(37571)	(36328)		
Monday	Dow_1	-45345	25476	-39104	21698
		(47849)	(50026)		[0.408]
Tuesday	Dow_2	-44057	-71590	-37816	-75368
		(52828)	(61580)		
Wednesday	Dow_3	15086	16574	21327	12796
		(49789)	(59560)	[0.453]	[0.084]
Thursday	Dow_4	3595	21511	9836	17732
		(53407)	(52182)	[0.095]	[0.234]
Friday	Dow_5	8034	12744	14274	8966
		(53775)	(60879)	[0.165]	[0.044]
Saturday	Dow_6	3448	-27654	9689	-31433
		(57373)	(72276)	[0.077]	
	N	18960	18960	18960	18960
	R^2	0.00	0.00		

$^{***}p < 0.01$, $^{**}p < 0.05$, $^{*}p < 0.1$ from a 1-sided t-test. HAC robust standard errors in parentheses in first two columns. Wald statistics of null hypothesis $\delta_0 + \delta_j \leq 0$ in square brackets in last two columns.