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The effect of wind energy production on cross-border electricity pricing: The case of western Denmark in the Nord Pool market

Elizabeth A. Unger [a,*], Gudmundur F. Ulfarsson [a], Sigurdur M. Gardarsson [a], Thorolfur Matthiasson [b]

[a] University of Iceland, Civil and Environmental Engineering, Hjardarhagi 2-6, IS-107 Reykjavik, Iceland
[b] University of Iceland, Economics, Seamundargata, IS-101 Reykjavik, Iceland

HIGHLIGHTS

- Probability analysis used to estimate the effect of wind energy on price differences.
- Large wind generation of electricity in DK1 makes lower prices there more likely.
- Low wind generation of electricity in DK1 makes higher prices there more likely.
- Analyzed price differences showed large effect from planned cross-border energy flow.

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ABSTRACT

The aim of this analysis was to estimate the effect of planned cross-border energy flow and different levels of predicted wind energy share with respect to the three pricing outcomes (higher price, lower price, or equal prices) that can occur between a pair of trading partners in the Nordic day-ahead spot market. The analysis covers a four-year period (2012–2015). Three multinomial logit models were designed, one for trade with each of western Denmark's (DK1) Nord Pool day-ahead spot market trading partners: eastern Denmark (DK2); southern Norway (NO2); and Stockholm, Sweden (SE3).

It was found that both wind energy production and planned energy cross-border flow have a large effect on the probabilities of the pricing outcomes, with greater wind energy production in DK1 linked to lower prices in DK1 and lower wind energy linked to higher prices in DK1, although the effects varied considerably across trading partners. For example, if western Denmark's wind share of production was less than 33%, on average there was a 253% increase in the probability of DK1 having a higher price than NO2, and, in the SE3 model, this corresponding value was 359.8%, which encourages trading behavior to reduce the price differences. However, the existence of such large price differences suggests that interconnector transmission capacity or trading volume is not enough to balance the price in these circumstances. Overall, the results support the conclusion that increased interconnection can reduce price differences.

* Corresponding author.
E-mail addresses: eau1@hi.is (E.A. Unger), gfu@hi.is (G.F. Ulfarsson), sigmg@hi.is (S.M. Gardarsson), totimatt@hi.is (T.G. Matthiasson).

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1. Introduction

A key requirement for a electricity transmission system is that it remains in balance between the supply and demand. Highly variable energy sources can make finding this balance more complex. To keep the system balanced, a country that produces either too little or too much electricity for domestic consumption may either import or export electricity to neighboring countries. For example, in 2006, Denmark's net exports were 6936 gigawatt hours (GWh) to Norway, Sweden, and Germany, but starting in 2008 and continuing until 2016, Denmark began importing more energy than it exported, with the largest percentage coming from Norway (Danish Energy Agency, 2017). In 2016, total net imports were 5057 GWh (Danish Energy Agency, 2017).

Wind energy used to produce electricity in Denmark has grown substantially over the last decade. In 2006, total electricity production in Denmark was roughly 45,451 GWh (Danish Energy Agency, 2017). Of this value, 13% (6108 GWh) was from wind energy (Danish Energy Agency, 2017). In 2016, wind energy's share of total electricity production reached 42% (Danish Energy Agency, 2017).

As the integration of wind energy in Denmark has increased over the years, so has the number of strategies dealing with the unpredictable and variable nature of wind. At a national level, Denmark supplies roughly half of its electricity from small combined-heat-and-power (CHP) plants (Danish Energy Agency, 2017). The advantage of this is that the heat-supply network is tied to large water tanks for thermal energy storage, which provides flexibility, allowing for varying proportions of heat and electricity in response to changes in wind output (Østergaard, 2010). Improvements in weather forecasting have also helped Denmark successfully integrate higher shares of wind-produced electricity (Martinot, 2015).

Internationally, another key innovation used to respond to variations in electricity supply has been the creation of a common electricity market where energy can be either bought or sold across national borders (Directive 96/92/EC, 1997; Directive 2003/54/EC, 2003). To participate in the market, each country must first be physically connected to other national transmission systems via high voltage direct current (HVDC) interconnectors (Nord Pool, 2017). The questions of when, how much energy, and from whom, depend on factors such as available transmission capacity on the HVDC interconnectors and availability of supply. Unger et al. (2017) showed how unilateral decisions at the national level regarding reductions in selected energy sources used for electricity generation can greatly impact market prices across national borders in the Nordic region.

Watcharejyothin and Shrestha (2009), Denny et al. (2010), and Doorman and Frøystad (2013) have all concluded that increased interconnection can facilitate the integration of intermittent renewable energy sources, but that there must be enough transmission capacity available to allow energy to flow to areas where needed. When there is not sufficient interconnection capacity combined with conventional coal and gas generation plants that lack the ability to react quickly to the fluctuations in demand, according to Bell et al. (2015) the option of potentially using carbon-emission-free wind power to meet demand decreases. This too has been recognized by the European Council. Europe's initial target of capacity on interconnections being 10% of the installed electricity production capacity has come under further evaluation, with the European Council requesting that this target be increased to 15% by 2030 (COM, 2015). In 2014, there were still many European Union members operating below the 10% interconnection target. These include Spain (3%), Estonia (4%), and several others (COM, 2015). In contrast, Denmark was operating at a level almost four and a half times higher; in 2014, its interconnection level was 44% (COM, 2015).

1.1. Nord Pool day-ahead market operations

The planned cross-border energy that flows across HVDC interconnectors in the Nordic day-ahead market, Nord Pool, is used for price settlement with the aim of either eliminating price differences between areas or at least reducing the price difference (Nord Pool, 2017). Once all bids and offers have been received, a market clearing price (also known as the system price) that assumes no physical constraints on the transmission system is calculated (Nord Pool, 2017). However, during some trading hours, there may be locations on the grid where there is not enough transmission capacity to support the power needed to meet energy demand.

Bids and offers are submitted to the market but attached to an area to which they belong. These geographical areas are defined by the transmission system operators, and in the Nordic region there are twelve: five in Norway, four in Sweden, one in Finland, and two in Denmark. Like the market clearing price, based on the bids and offers for each area, the supply and demand curves form the equilibrium price for each area (Nord Pool, 2017). Given the different levels of demand and available supply, there can be price differences between areas. The interconnection mechanism between areas and different markets works so that the transmission system operators, those who oversee operating and controlling HVDC interconnectors (Nord Pool, 2017), decide on a specific volume of energy that may flow unilaterally across borders in a particular hour. The intended effect of these exchanges is that by either increasing or decreasing the supply in different areas, this will eliminate or decrease price differences between areas, allowing the planned cross-border energy exchange to reduce the risk of arbitrage and increase transparency (Weber et al., 2010), while leading to price convergence between areas since these volumes are used in price settlement (Meeus et al., 2009).

While these interconnections serve the purpose of creating more price stability in market prices, consequently, until the new EU target of 15% is reached, the increased penetration of intermittent renewable energy sources is potentially a force working against price convergence (Gianfreda et al., 2016). This is due to wind energy's ability to drive prices almost to zero or even be negative, which occurs in periods when demand is low and supply is very high. There are therefore three possible pricing scenarios that exist between any two areas: higher price in area A–lower price in area B, lower price in area A–higher price in area B, or equal price in both areas.

In this paper, the Nord Pool area of western Denmark, one of two Nord Pool areas in Denmark, has been selected as the primary focus, since it has a higher share of wind generation compared to the Nord Pool area of eastern Denmark and other Nord Pool areas. Within the Nord Pool day-ahead market, there is planned cross-border energy flow between western Denmark and eastern Denmark, southern Norway, and Stockholm in Sweden, along with Germany. Each area has its own unique electricity generation mix. On average, Denmark imports more energy from Norway compared to Sweden and Germany. This most likely can be explained by Norway's high share of hydropower (97%), the flexible dispatch nature of hydropower (Hirth, 2016) and its ability to complement the variability of wind (Jaramillo et al., 2004). This could potentially change, however, if Norway were to experience heat waves and droughts such as occurred in 2003 (Fink et al., 2004), although by being connected to other energy systems, the level of diversification can increase energy security and reduce risk when these types of events arise.

This study estimates the effect of western Denmark's wind energy production levels and planned cross-border energy flow on interconnectors between western Denmark and the trading partners of eastern Denmark, southern Norway, Stockholm, Sweden, and Germany, on the three price scenarios. In other words, the research question was: Do wind energy and energy flow on interconnectors lead to western Denmark tending to have a higher or lower or equal price than its Nordic Nord Pool trading partners?

This is investigated by employing a multinomial logit model. Multinomial logit models (MNL) are a common form of probability models that allow researchers to estimate the effect of different regressors on a set of discrete alternatives. While MNL has been used in the field of energy (Heltberg, 2004) before, it has not been used in the context as presented here.

2. Data and methods

The analysis uses hourly market data from the Nord Pool market for the years 2012 through 2015 (Nord Pool, 2016a). Four price series (EUR/MWh) from Nord Pool were selected: (1) western Denmark (DK1), (2) eastern Denmark (DK2), (3) southern Norway (NO2), and (4) Stockholm, Sweden (SE3). These abbreviations, DK1, DK2, NO2, SE3, are used by Nord Pool and will be used throughout the rest of this paper to refer to these areas.

These price series were used to construct a multinomial dependent variable for the three price scenarios that can exist between DK1 and each of its Nordic trading partners. Three such dependent variables were created, using the price differences between DK1 and each one of its Nordic trading partners (DK2, NO2, and SE3). For example, eastern Denmark's (DK2) price was subtracted from western Denmark's (DK1). If the difference was positive, this was indicated as the first pricing outcome, where DK1 has a higher price than DK2 in hour h even after the planned cross-border energy flow between the two areas has occurred. If the difference was negative, this was indicated as the second pricing outcome when in hour h, DK1's price was lower than DK2's. The third outcome was set when prices were equal (i.e., the price difference was zero) between DK1 and DK2. This was repeated for NO2 and SE3.

Table 1 presents the three pricing outcome variables for the three sets of trading partners tabulated across the four years (2012–2015) under study. Table 1 shows that DK1–DK2 had the highest share of equal prices compared to DK1–NO2 and DK1–SE3, when in 2012, prices were equal between DK1 and DK2 86.3% of the time. This percentage fell by 15% in 2013, and remained around 70.8% for 2013 and 2014. While the frequency of equal prices between DK1 and DK2 fell, the frequency of equal prices increased for the other two sets of partners. In 2012, the share of equal prices compared to the other pricing outcomes for DK1 and NO2 was 44.7%, and by 2015, this figure had increased to 60.8%. Whereas overall there were more equal prices between DK1–SE3 (57.4%) than there were between DK1–NO2, the share of equal prices for DK1–SE3 did not increase from 2012 to 2015 by the same percentage points (16.2%) as they did for DK1–NO2.

Because there are three possible pricing outcomes between western Denmark and its trading partners – DK1's price is higher, lower, or equal – this leads to the development of a discrete probability model. In this study, the independent categorical pricing variable is at the hourly level. The probability that an area during hour h has pricing outcome i is written

$$P_{hi} = P\left(O_{hi} \geq O_{hi'}\right), \quad \forall i' \in I, i' \neq i, \tag{1}$$

where O_{hi} is the unobserved propensity of the pricing outcome i that western Denmark will have for hour h with one trading partner, where the i is drawn from a set of I possible pricing outcomes (here the three outcomes: higher in DK1, lower in DK1, and equal prices). Assuming that O_{hi} has a linear-in-parameters form, it may be expressed

$$O_{hi} = \boldsymbol{\beta}_i \boldsymbol{x}_h + \varepsilon_{hi}, \tag{2}$$

where $\boldsymbol{\beta}_i$ is a vector of estimable coefficients for pricing outcome i and $\boldsymbol{x}_h$ is a vector of exogenous variables that significantly influence price differences in hour h. ε_{hi} is a random component (an error term) that captures unobserved influences. Given the assumption that ε_{hi} is identically and independently distributed with a type 1 extreme value distribution, and the assumption that the bidding area will experience the pricing outcome i that has the highest propensity this leads to the multinomial logit model (McFadden, 1981):

$$P_{hi} = \frac{e^{\boldsymbol{\beta}_i \boldsymbol{x}_h}}{\sum_{j=1}^{I} e^{\boldsymbol{\beta}_j \boldsymbol{x}_h}}. \tag{3}$$

Table 1
The number of hours across years when western Denmark's (DK1) price was higher, lower or equal to its DK2, NO2, and SE3 trading partners' price.

	2012	2013	2014	2015	2012	2013	2014	2015
		N				Column %		
DK1–DK2								
DK1 higher price ($N = 677$)	219	230	128	100	2.5	2.7	1.5	1.5
DK1 lower price ($N = 7242$)	983	2296	2349	1614	11.2	26.5	26.8	24.6
Equal price ($N = 24{,}812$)	7557	6137	6281	4837	86.3	70.8	71.7	73.8
Total ($N = 32{,}731$)	8759	8663	8758	6551				
DK1–NO2								
DK1 higher price ($N = 13{,}489$)	4362	2654	4408	2065	49.9	30.6	50.3	31.5
DK1 lower price ($N = 4898$)	470	2612	1313	503	5.4	30.2	15.0	7.7
Equal ($N = 14{,}320$)	3903	3397	3037	3983	44.7	39.2	34.7	60.8
Total ($N = 32{,}707$)	8735	8663	8758	6551				
DK1–SE3								
DK1 higher price ($N = 6726$)	3239	997	1295	1195	37.1	11.5	14.8	18.2
DK1 lower price ($N = 7237$)	673	2696	2698	1170	7.7	31.1	30.8	17.9
Equal ($N = 18{,}743$)	4823	4969	4765	4186	55.2	57.4	54.4	63.9
Total ($N = 32{,}706$)	8735	8662	8758	6551				

Table 2
Western Denmark's number of hours per year at high, medium and low levels of wind energy.

		2012	2013	2014	2015	2012	2013	2014	2015
	N total		*N*				Col.%		
Predicted wind share <33%	14,145	4187	4602	3593	1763	47.8	53.1	41.0	26.9
Predicted wind share 33–66%	12,938	3410	3215	3843	2470	38.9	37.1	43.9	37.7
Predicted wind share 67–100%	5,329	1137	825	1294	2073	13.0	9.5	14.8	31.6
Total	32,731	8759	8663	8758	6551[a]	100.0	100.0	100.0	100.0

[a] In October 2015, Nord Pool changed its definition of predicted wind production being a share of total predicted production. After this period, to calculate total predicted production, predicted wind production must be added to predicted total production. To handle this data discrepancy, October, November, and December in 2015 were omitted from the data set.

The coefficients, $\boldsymbol{\beta}_i$, are estimated with the method of maximum likelihood. Three models were developed, for DK1–DK2, DK1–NO2, DK1–SE3. To develop the models, all identified explanatory variables were inserted and tested in the models. To improve statistical efficiency, only coefficients that were statistically significantly different from zero at the 0.05 level of significance were kept in the final results; less significant coefficients were constrained to zero. Without loss of generality the coefficients for one pricing outcome need to be set to zero and that outcome becomes the base case. In this work the equal prices outcome was selected as the base case and equations were estimated for the higher and lower prices.

To identify explanatory variables influencing the pricing outcomes in the models, we first considered that equilibrium area prices are always determined by the aggregate supply and demand curves for each area. Furthermore, day-ahead prices are based on predicted levels of production and consumption. Therefore, in each model, the explanatory variables may be categorized into two main categories: predicted production (i.e., supply) and predicted consumption (i.e., demand).

To test the effect of western Denmark's different wind levels on the three pricing outcome scenarios, the approach used by Jónsson et al. (2010) was applied. Jónsson et al. (2010) agreed with Karakatsani and Bunn (2008) that fuel prices and weather conditions affect the supply function indirectly and in a highly non-linear fashion. To handle this issue, Jónsson et al. (2010) used a method that more directly linked these types of variables to the supply function by creating a wind share variable that divided predicted wind levels into predicted production levels. Here, that same method was applied using western Denmark's observed total production[1] for hour *h* divided by western Denmark's predicted next-day wind energy supply for hour *h*. This generated a wind share variable, which was used to create three predicted wind share binary variables, for high, medium, and low wind energy supply. The lowest predicted wind share level was defined as 1 if the contribution of wind energy to production was less than 33% and zero otherwise. The medium predicted wind share level was defined as 1 when the wind share was from 33% and up to 66%. It should be noted that the medium level variable was omitted from all three models to prevent perfect multicollinearity with the low and high wind level variables. The highest predicted wind share level was defined as 1 in hours when the share of wind was 67–100% and 0 otherwise.

Table 2 presents the number of hours when electricity was generated by wind energy in western Denmark at the three predicted wind share levels. Examining the highest predicted wind share category (67–100%), from 2012 to 2015, the percentage of times when the wind share was at this level increased from 13.0% to 31.6%. The lowest wind share category (<33%) fell from 47.8% in 2012 to 26.9% in 2015.

[1] Until October 2015, Nord Pool defined predicted wind levels as a share of total predicted production; therefore, their quotient should not exceed one. Despite this definition and prior to October 2015, there existed hours in the Nord Pool database when this quotient exceeded one. To avoid this data artifact, observed total production was used in lieu of total predicted production.

Table 3
Descriptive statistics for area consumption and planned cross-border energy flow.

	N	Median	Mean	Std. Dev.	Min.	Max.
			MWh			
Planned flow from DK1 to DK2	32,707	338.3	311.9	250.2	0	590
Planned flow from DK2 to DK1	32,707	0.0	11.5	56.6	0	600
Planned flow from DK1 to NO2	32,731	0.0	188.2	370.8	0	1,632
Planned flow from NO2 to DK1	32,731	550.0	513.7	470.7	0	1,532
Planned flow from DK1 to SE3	32,707	0.0	169.2	242.5	0	740
Planned flow from SE3 to DK1	32,707	0.0	168.0	262.0	0	680
Planned flow from DK1 to DE	32,731	123.1	208.4	391.0	0	1,500
Planned flow from DE to DK1	32,731	0.0	331.0	416.2	0	1,780
Predicted consumption for DK1	32,731	2,216.0	2,271.3	490.7	1184	3,687
Predicted consumption for DK2	32,731	1,512.0	1,519.3	329.6	725	2,545
Observed consumption for NO2[a]	32,707	3,790.0	3,897.9	744.6	2327	6,702
Observed consumption for SE3[a]	32,706	9,632.0	9,820.7	2,228.9	5057	17,466

[a] Nord Pool does not publish the individual predicted consumption for each of the five Norwegian pricing areas (NO1, NO2, NO3, NO4, and NO5) and the Swedish pricing areas (SE1, SE2, SE3, SE4); however, for observed consumption it does. In this study, the observed values for NO2 and SE3 have been used as a substitute for predicted values.

Nord Pool defines planned cross-border energy flow as a share of total production for each area and given that the planned cross-border energy flow occurs before the price is settled in each area, it is assumed that these variables are strictly independent of one another. To avoid a double count of production levels, planned cross-border energy flow variables that were directly related to the set of trading partners were omitted from the model due to endogeneity. For example, if the MNL model was based on the pricing outcomes between DK1 and NO2, then the planned cross-border energy flow across the DK1–NO2 HVDC interconnector was omitted, while the energy flow across the other HVDC interconnectors was included. The average planned cross-border energy flow levels between the partners are presented in Table 3.

Also presented in Table 3 are the four consumption variables that correspond to the total demand for each area (DK1, DK2, NO2, and SE3). Nord Pool publishes hourly predicted consumption for DK1 and DK2, whereas it publishes predicted consumption at the national level only for Norway and Sweden. Since Nord Pool does publish observed consumption levels for NO2 and SE3, it was decided to use these variables in lieu of predicted consumption for NO2 and SE3.

Finally, to account for the temporal trends that occur in electricity prices, fixed effects at different time scales were created to control for annual, seasonal, daily and intraday correlation. An hourly indicator variable was used to control for the differences in demand that occur daily in peak and off-peak periods. The peak period is defined by Nord Pool as 8 am–8 pm (Nord Pool, 2016b). The peak-period fixed effect is defined as 1 in the peak hours and 0 otherwise. Fixed effects were also created for each season defined as: winter (December, January, and February), spring (March, April, and May), summer (June, July, and August), and fall (September, October, and November). Fall was omitted from the models to avoid perfect multicollinearity with the other seasons. Finally, fixed effects were created for each year of analysis, omitting 2013 to prevent perfect multicollinearity.

In the case of three or more alternatives in an MNL model, the direct interpretation of the sign of coefficients as either increasing or decreasing the probability of an outcome can yield misleading results about the effect of a variable on the probability of a pricing outcome. A negative (positive) coefficient on a variable in a pricing outcome cannot be freely interpreted as decreasing (increasing) the probability of that pricing outcome. This is due to the fact that the rate of change in probability is not a simple linear function of the coefficient in that pricing outcome, but is also a function of its effect and the effects of all the other coefficients in all other pricing outcomes (Greene, 2003). Observing a negative coefficient and claiming this indicates the variable decreases the probability can therefore be wrong.

This problem may be avoided by exploring the marginal effects of each variable on the probability using elasticity, defined in a standard way and derived from (3):

$$E_{x_{hk}}^{P_{hi}} = \frac{\partial P_{hi}}{\partial x_{hk}} \frac{x_{hk}}{P_{hi}} = \left(\beta_{ik} - \sum_{j=1}^{I} \beta_{jk} P_{hj} \right) x_{hk}, \tag{4}$$

which yields the direct elasticity of the probability with respect to a change in the kth variable, x_{hk}, and accounting for that it can enter one or more equations. The interpretation is a percentage change in probability per percentage change in a variable. Values that exceed 1 represent a large, elastic effect between the independent regressor and pricing outcome.

For binary indicator variables, it is not possible to calculate the elasticity since then (3) is not differentiable by the variable, which only takes on the values 0 and 1. Instead, we calculated the percentage change in probability when each binary indicator variable was switched, either 0–1 or 1–0. This has been termed pseudo-elasticity and was applied, e.g., by Shankar and Mannering (1996) and Ulfarsson and Mannering (2004). Writing this out yields:

$$E_{x_{hk}}^{P_{hi}} = \frac{P_{hi}\,[\text{given } x_{hk} = 1] - P_{hi}\,[\text{given } x_{hk} = 0]}{P_{hi}\,[\text{given } x_{hk} = 0]}, \tag{5}$$

Table 4
Multinomial logit pricing outcome models for electricity trade between western Denmark and selected partners.

	DK1–DK2 Higher price	Lower price	DK1–NO2 Higher price	Lower price	DK1–SE3 Higher price	Lower Pr.
	Est. Coeff.	Est. Coeff.	Est. Coeff.	Est. Coeff.	Est. Coeff.	Est. Coeff.
Constant	-2.1592^{***}	-3.3886^{***}	0.7242^{***}	-1.0536^{***}	-2.7811^{***}	-2.3302^{***}
Predicted wind share <33%	0.5189^{***}	-0.6407^{***}	1.4453^{***}	-1.3383^{***}	1.4777^{***}	-1.1044^{***}
Predicted wind share 67–100%	-0.2738^{*}	0.2825^{***}	-0.7693^{***}	1.6839^{***}	-0.9540^{***}	0.7557^{***}
Planned flow from DK1 to DK2	---	---	-0.0006^{***}	-0.0003^{**}	-0.0006^{***}	0.0029^{***}
Planned flow from DK2 to DK1	---	---	0.0011^{***}	0.0031^{***}	0.0041^{***}	-0.0104^{***}
Planned flow from DK1 to NO2	0.0014^{***}	0.0004^{***}	---	---	0.0021^{***}	0.0011^{***}
Planned flow from NO2 to DK1	-0.0005^{***}	0.0005^{***}	---	---	-0.0002^{***}	0.0004^{***}
Planned flow from DK1 to SE3	0.0009^{***}	0.0021^{***}	0.0010^{***}		---	---
Planned flow from SE3 to DK1	-0.0007^{***}		0.0014^{***}	0.0026^{***}	---	---
Planned flow from DK1 to DE	0.0005^{***}	-0.0014^{***}	0.0007^{***}	-0.0046^{***}	0.0014^{***}	-0.0036^{***}
Planned flow from DE to DK1	-0.0012^{***}	0.0006^{***}	-0.0014^{***}	0.0015^{***}	-0.0026^{***}	0.0005^{***}
Predicted consumption for DK1		0.0004^{**}	0.0036^{***}	-0.0013^{***}	0.0029^{***}	
Predicted consumption for DK2	-0.0020^{***}	0.0012^{***}	†	†	†	†
Observed consumption for NO2 †	†	†	-0.0026^{***}	0.0010^{***}	†	†
Observed consumption for SE3 †	†	†	†	†	-0.0007^{***}	0.0002^{***}
2012		-0.4865^{***}	-0.1150^{**}	-2.1096^{***}	1.3984^{***}	-0.9374^{***}
2014	-0.4656^{***}	-0.1365^{**}	0.8766^{***}	-1.1944^{***}	0.1145^{*}	
2015	-0.3490^{**}	-0.1207^{*}		-2.9135^{***}	0.9116^{***}	-1.4009^{***}
Winter	0.5472^{***}	-0.7888^{***}		0.5258^{***}	-0.4741^{***}	-0.5327^{***}
Spring		-1.1755^{***}		-0.1430^{*}	-0.1123^{*}	-1.4079^{***}
Summer		-0.8215^{***}	-0.3917^{***}	-1.6997^{***}	0.1206^{*}	-1.2694^{***}
Sun.	0.7539^{***}	-0.1256^{*}		-0.1874^{**}	0.2440^{***}	-0.3003^{***}
Mon.	1.0110^{***}		-0.1802^{***}			
Tues.	0.9364^{***}	-0.1755^{***}	-0.2074^{***}	-0.3357^{***}		-0.1940^{**}
Wed.	0.9910^{***}	-0.2052^{***}			0.1817^{***}	-0.1935^{***}
Thur.	0.8954^{***}	-0.1476^{**}				-0.1505^{**}
Fri.	0.6611^{***}	-0.0996^{*}			-0.1063^{*}	
Peak time (08:00–20:00)	1.1035^{***}			-0.5196^{***}	0.2533^{***}	
Log-likelihood at zero	−20,422.50		−33,074.88		−31,988.58	
Log-likelihood at convergence	−16,558.11		−19,740.11		−20,548.37	
ρ^2	0.1899		0.4143		0.3670	
Number of observations	32,731		32,707		32,706	

† Nord Pool does not publish individual predicted consumption for NO2 and SE3; however, it does for observed consumption. In this study, the observed values for NO2 and SE3 have been used as a substitute for predicted values. The symbol --- is used to indicate variables that were omitted from the model due to endogeneity. † indicates that it was omitted due to irrelevance in the equation.

* $p < 0.05$.

** $p < 0.01$.

*** $p < 0.001$.

which is called the direct pseudo-elasticity of the probability and captures the percentage change in probability when the k-th variable from the vector x_h in hour h is switched (0–1, 1–0). Because the elasticity and pseudo-elasticity are point values, holding for each observation h, each elasticity and pseudo-elasticity is aggregated by taking the average value for all observations. For pseudo-elasticities, they are then multiplied by 100 to represent the value in percent. In this way the sign of the pricing outcome can be interpreted as increasing (positive) or decreasing (negative).

3. Results

Three multinomial logit models are presented in Table 4, showing the estimated effects of the explanatory variables on the pricing outcome between western Denmark (DK1) and its Nordic partners: (1) eastern Denmark (DK2); (2) southern Norway (NO2); and (3) Stockholm, Sweden (SE3). Table 5 presents the average direct elasticities for the continuous explanatory variables and Table 6 presents the average direct pseudo-elasticities for the binary indicator variables. Contrary to the estimated coefficients for which at least one outcome must be restricted to zero, the average direct elasticities and average direct pseudo-elasticities can be calculated for all outcomes.

Overall the results show that there are large differences in the size of the direct elasticity and pseudo-elasticity effect for many variables across the three models, though, often the signs are the same in all three models.

The signs of the calculated pseudo-elasticity for the predicted wind share variables (wind share <33% and wind share 67–100%) were intuitively correct in all three models, with low wind share in DK1 tending to increase the probability of higher

Table 5
Average direct elasticities showing the percentage change in probability per percentage change in area consumption and planned cross-border energy flow variables.

	DK1-DK2			DK1-NO2			DK1-SE3		
	Higher Pr.	Lower Pr.	Equal Pr.	Higher Pr.	Lower Pr.	Equal Pr.	Higher Pr.	Lower Pr.	Equal Pr.
Planned flow from DK1 to DK2	---	---	---	-0.12	-0.02	0.08	-0.48	0.62	-0.29
Planned flow from DK2 to DK1	---	---	---	0.002	0.02	-0.01	0.02	-0.15	-0.03
Planned flow from DK1 to NO2	0.22	0.04	-0.04	---	---	---	0.26	0.08	-0.14
Planned flow from NO2 to DK1	-0.32	0.23	-0.04	---	---	---	-0.10	0.21	0.02
Planned flow from DK1 to SE3	-0.01	0.20	-0.16	0.12	-0.04	-0.04	---	---	---
Planned flow from SE3 to DK1	-0.12	0.002	0.002	0.06	0.25	-0.18	---	---	---
Planned flow from DK1 to DE	0.19	-0.43	0.04	0.12	-1.63	-0.11	0.33	-1.33	-0.13
Planned flow from DE to DK1	-0.29	0.08	-0.04	-0.38	0.23	-0.09	-0.60	0.07	-0.04
Predicted Consumption for DK1	-0.19	0.63	-0.19	5.05	-6.10	-3.24	5.26	-1.43	-1.43
Predicted Consumption for DK2	-3.45	1.43	-0.36	†	†	†	†	†	†
Observed Consumption for NO2✝	†	†	†	-6.74	7.45	3.47	†	†	†
Observed Consumption for SE3✝	†	†	†	†	†	†	-6.05	2.61	1.08

✝Nord Pool does not publish individual predicted consumption for NO2 and SE3; however, it does for observed consumption. In this study, the observed values for NO2 and SE3 have been used as a substitute for predicted values. The symbol --- is used to indicate variables that were omitted from the model due to endogeneity. † indicates that it was omitted due to irrelevance in the equation. Variables with elasticity greater than 0.1 are shaded light gray, and those with elasticity greater than 1 are shaded darker gray.

Table 6
Average direct-pseudo elasticities that show the percentage change when each binary variable is switched from 0 to 1 across the three pricing outcome models.

	DK1-DK2			DK1-NO2			DK1-SE3		
	Higher Pr.	Lower Pr.	Equal Pr.	Higher Pr.	Lower Pr.	Equal Pr.	Higher Pr.	Lower Pr.	Equal Pr.
Predicted wind share <33%	91.2	-40.0	13.8	253.0	-78.2	-16.8	359.8	-65.2	4.9
Predicted wind share 67-100%	-28.3	25.0	-5.7	-46.8	517.1	14.6	-59.9	121.8	4.2
2012	10.7	-31.9	10.7	31.3	-82.1	47.3	291.1	-62.2	-3.4
2014	-34.7	-9.3	3.9	123.2	-71.9	-7.1	9.5	-2.3	-2.3
2015	-27.1	-8.4	3.4	70.5	-90.7	70.5	197.5	-70.5	19.5
Winter	102.7	-46.7	17.3	-7.1	57.1	-7.1	-23.2	-27.5	23.5
Spring	27.6	-60.6	27.6	2.2	-11.4	2.2	27.4	-65.1	42.5
Summer	18.9	-47.7	18.9	1.5	-72.6	50.2	47.8	-63.2	31.0
Sun.	113.9	-11.2	0.7	2.9	-14.7	2.9	30.0	-24.6	1.9
Mon.	166.4	-3.1	-3.1	-10.0	7.7	7.7			
Tues.	157.4	-15.3	0.9	-7.1	-18.3	14.3	4.4	-14.0	4.4
Wed.	173.0	-17.5	1.3				20.7	-17.1	0.6
Thur.	146.1	-13.3	0.5				3.4	-11.1	3.4
Fri.	94.4	-9.1	0.4				-8.1	2.2	2.2
Peak time (07:00-19:00)	193.8	-2.5	-2.5	8.9	-35.2	8.9	22.6	-4.8	-4.8

Shading indicates a percentage change greater than 100%.

price in DK1 and high wind share tending to increase the probability of lower price in DK1. This effect was smallest between western Denmark and eastern Denmark (DK1–DK2). The effect of different predicted wind levels on the pricing outcomes between DK1–NO2 and DK1–SE3 were much larger. As shown in Table 6, when the wind energy in western Denmark was less than 33% of its total electricity production, on average there was a 253% increase in the probability of DK1 having a higher price than southern Norway, a 78.2% decrease in the probability of DK1's area price being lower, and a 16.8% decrease in the probability of the prices being equal between DK1 and NO2.

The average increase in probability of DK1 having a higher price than SE3 was 359.8%, while in the DK1–NO2 model this percentage change is 253.0%. When the predicted wind share was 67–100%, the highest percentage change corresponded to DK1–NO2, where the average increase in probability of DK1 having a lower price than NO2 was 517.1%. Respectively, the average percentage change in probability of lower price was 121.8% between DK1 and SE3.

Overall, the elasticity values corresponding to planned cross-border energy flow shown in Table 5 appear small for planned cross-border energy flow variables; however, elasticity values larger than 0.1 in absolute value, in this case, did still have a large effect on the probability because the variation in the flow was large, on the order of 100%, as shown by the standard deviations on the flow variables in Table 3, and even greater when the mean is compared with the maximum value. This result differs from Higgs et al. (2015) who found that Australian interregional flows did not significantly affect prices or price volatility.

When DK1 exported 1% more energy to NO2, the average probability of DK1 having a higher price than DK2 increased 0.22%. When the energy flow was reversed and energy entering DK1 from NO2 increased by 1%, the average probability of

DK1 having a higher price than DK2 fell (−0.32%). Interestingly, when DK1 exported 1% more energy to Germany (DE), the average probability of DK1 having a lower price than NO2 fell 1.63% and respectively for SE3 it fell 1.33%. The results also showed that when DK1 exported 1% more energy to DK2, that the average probability of there being equal prices between DK1–SE3 fell by 0.29%. There was only one planned cross-border trade variable whose calculated average elasticity was greater than 1%. When there was a 1% increase in the total volume of energy exported from western Denmark to Germany, this decreased the average probability of DK1's price being lower than NO2's price by 1.63%. Respectively, between DK1–SE3, the probability of DK1's price being lower than SE3's price fell 1.33%.

While electricity supply was represented by two types of variables (wind and planned cross-border energy flow), consumption was represented directly as itself. The results in Table 5 show that the effect on the pricing outcomes between DK1 and DK2 was much larger when there was a 1% increase in predicted consumption for DK2 versus a 1% increase in predicted consumption for DK1. In this case, the average probability of DK1 having a lower price than DK2 increased 1.43%. In contrast, the different pricing outcomes for NO2 and SE3 were highly sensitive. For example, if there was a 1% increase in DK1's predicted consumption, the average probability of DK1 having a lower price than NO2 fell 6.10%. If consumption in NO2 increased 1%, the average probability of NO2 having a higher price (i.e., DK1's price is lower) increased 7.45%.

Four levels of fixed effect temporal indicators were included in each model. Overall, the fixed effect of each year (2012, 2014, and 2015) was found to be small, although there were a few exceptions. In 2012, there was a 291.1% increase in probability that DK1 would have a higher price than SE3 (Table 6) compared to 2013, with everything else kept constant. In 2014, this corresponding value fell to 9.5% and increased again to 197.5% in 2015. Comparing these results to the DK1–NO2 model, while the direction of the signs was the same, the size of the effect was reversed. In 2012, the average probability of DK1 having a higher price than NO2 increased by 31.3%. However, in 2014, respectively, this value jumped to 123.2%, and fell to 70.5% in 2015. This shows there has been significant annual variation and supports the need for including fixed effects for the relevant years.

The pseudo-elasticities calculated for the seasons in Table 6 do in some cases show seasonal changes in demand patterns. For example, when it was winter, the average probability of DK1 having a higher price than NO2 decreased −7.1% compared to fall. In spring this percentage showed an increase of 2.2% and dropped slightly to 1.5% in summer compared to fall. In terms of average production and average consumption in DK1 in winter and spring there was an inverse relationship. In winter, respectively, the average production and consumption levels for DK1 were 3219 MWh and 2542 MWh. In summer, DK1's production was less (1703 MWh) than its average consumption (2082 MWh). However, in other cases, it did not drop, which may reflect the influence of other regressors in the model.

At the shorter temporal levels (daily and hourly) there were more variables that were shown to have a larger effect on the pricing outcomes than the seasonal and yearly indicator variables. The pseudo-elasticities shown in Table 6 show that every daily indicator variable, except for Friday (Saturday was omitted to prevent perfect multicollinearity), and the peak time indicator variable, defined as 8 am–8 pm, had an effect on the outcome of DK1, resulting in a higher price than DK2. In comparison to the other two models, DK1–NO2 and DK1–SE3, the size of the effect from these temporal indicator variables was much smaller, suggesting lesser short-term variation in the probabilities of the international energy trade pricing scenarios compared to the domestic DK1–DK2 trade.

4. Conclusion

The main purpose of this paper was to estimate the effect of different predicted wind levels and planned cross-border energy flow on the probability of different pricing outcomes between western Denmark and its three Nordic trading partners (eastern Denmark, southern Norway, and Stockholm in Sweden). While the results in this analysis do not estimate a specific value by which the prices change, it does support earlier research such as that of Jónsson et al. (2010) and Gelabert et al. (2011) to show the large, negative association between increased levels of wind energy and market prices. In addition, this analysis showed differences in price sensitivity for the different Nordic trading partners. For example, if western Denmark's wind share of production was less than 33%, on average there was a 253% increase in the probability of DK1 having a higher price than NO2; however, in the SE3 model, this corresponding value was 359.8%. This example shows that, although the price difference with Sweden was more sensitive to Western Denmark's wind energy production, the effect for Norway was also considerable. Hydropower is an important energy source used to mitigate the effects of wind variability and in addition it has low production costs. Therefore, if DK1's production is low (i.e., higher price), these results may indicate the use of trading.

An overreaching result was that both of the key variable types, i.e., different levels of wind production (<33% of total production and 67–100% of total production) and planned cross-border energy flow, had a considerable effect on the average probabilities of pricing differences. Oggioni and Smeers (2013) showed that electricity produced from intermittent renewable energy sources, such as wind, not only increased price differences but became more pronounced in markets that use pricing areas to mitigate congestion. Nord Pool implements this type of area pricing scheme, and in this study the large effect from the different predicted wind share levels were noted in the DK1–NO2 and DK1–SE3 models but to a lesser degree in the DK1–DK2 model.

This result opens future research for at least two topics: firstly, to investigate the percentage of time with equal prices required in two trading areas so that predicted wind levels have little effect on pricing outcomes; and secondly, could the percentage of time with equal prices be smaller if a nodal pricing scheme were employed?

In the four years studied here, there was no year when the time share of equal prices was less than 70% between DK1–DK2 (see Table 1). Among the four trading partners, DK1 exported on average the most energy to DK2 (311.88 MWh) in its day-ahead market (see Table 3), which may indicate that there is enough transmission capacity between DK1–DK2 to keep price differences relatively uninfluenced from different predicted wind share levels.

Finally, this may lead to the conclusion that increased interconnection can reduce price differences such as occurred between Belgium, the Netherlands, and France when the percentage of the time the price was different fell from 90% to 37% after market coupling in 2007 (Küpper et al., 2009). Therefore, it may be possible to conclude that if different wind levels do not have a large effect on pricing differences between trading partners, then there may be enough interconnector transmission capacity between trading partners.

In conclusion, price sensitivity to wind may be thwarted by increasing transmission capacity between countries, although one caveat for policy makers to consider will be the uncertain future of nuclear power, as Sweden and Germany seek to phase out nuclear power generation in the coming years (de Menezes and Houllier, 2015; World Nuclear Association, 2016a, b). This decrease in supply could disrupt price convergence between different countries operating in one common market.

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