THE IMPACT OF RENEWABLE ENERGY ON THE NORDIC ELECTRICITY MARKET

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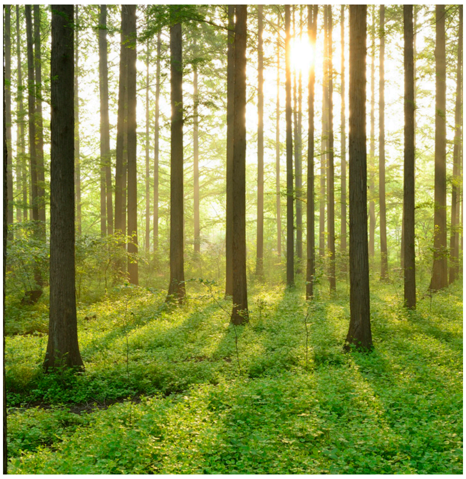

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The impact of renewable energy on the Nordic electricity market

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Foreword

This study was conducted on behalf of EFORIS – a research program on electricity market design. The program was initiated by Energiforsk and involves dozens of highly reputable Swedish and international researchers.

The study has been accomplished by Matti Liski at the economics department of the Aalto University (matti.liski@aalto.fi) and Iivo Vehviläinen at Gaia Group and Aalto University (iivo.vehviläinen@aalto.fi).

Sammanfattning

Vindkraftsproduktionen i Norden har de senaste 13 åren ökat med i genomsnitt 1 procent per månad. Den väntade förnybara expansionen de kommande 5 till 10 åren kommer att öka inträdet av förnybar kraftproduktion ytterligare. Det subventionerade inträdet av kraftproduktion, som har noll i marginalkostnader, leder till kraftiga reduktioner i priserna i grossistledet.

Denna prissänkning utgör en utmaning för den nordiska marknadsdesignen som vilar på en marginalkostnadsprissättning. Konventionella kraftproducenter kan möta situationer då de ej får full täckning för sina rörliga kostnader. I den här rapporten kvantifieras först prispressen och intäkter från operativ verksamhet i sken av den det pågående inträdet av subventionerad vindkraft. Vi finner då att cirka 20 till 30 procent av prisfallet på den nordiska marknaden kan hänföras till vindkraftsproduktion. Därefter kvantifierar vi konsekvenserna av kärnkraftens utfasning. Vår slutsats är att en utfasning mer eller mindre neutraliserar den prisdämpande effekten en ökning av vindkraften har. Klart är dock att övergången – mer vind och mindre kärnkraft – skapar vinnare och förlorare.

Summary

Wind power production in the Nordic region has increased on average at one percent monthly rate over the last 13 years. The Nordic renewable energy expansion path for the coming 5-10 years will further speed up the entry of the renewable capacity. The subsidized entry of technologies that operate with zero marginal costs lead to a potentially significant reduction in the final wholesale prices. This presents a serious challenge to the Nordic market design that is based on the idea of marginal cost pricing. The traditional technologies may face a situation where they can no longer cover their running costs in a market-based manner. In this report, we first quantify the pressure on prices and operating revenues that follows from the current subsidized entry of wind generation. We find that about 20-30 percent of the price reduction in the Nordic market is attributable to the wind generation. We then quantify the impact of the Swedish nuclear power phase-down on the market. We find that the phase-down plan can more or less neutralize the impact of wind on the market prices, although the transition - increasing wind and declining nuclear - creates winning and losing technologies.

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1 Introduction

The objective of this research is to quantify the impact of the recent increase in the wind power generation on the Nordic electricity market. We are particularly interested in quantifying to what extent the forthcoming phase-down of the Swedish nuclear capacity will offset the impacts from the increased wind power generation.

Our companion paper Liski and Vehviläinen (2016, henceforth LV 2016) reports the technical details of the analysis and provides the starting point for the current report. LV 2016 estimate the reduction in consumer prices attributable to the entry of wind power in the Nordic market, taking as given the current incumbent production capacity. With 5% share of annual consumption, the entry of wind power eliminates 20% of the electricity market revenues. With 10% market share, revenues for producers (expenditures for consumers) decline by more than 30% . Incumbent hydro and nuclear technologies lose the bulk of their scarcity rents, and traditional thermal power technologies become close to fully stranded. The consumers' estimated willingness to pay for subsidies to entry, defined through their impact on expenditures, exceeds the actual paid subsidies in this market.

The mechanism delivering these results is well understood; the quantitative magnitude has remained open until the results in LV 2016. The Nordic electricity market with close to 25 million electricity customers offers an interesting case for quantifying the effect of wind power: On average, 50 per cent of incumbent production comes from hydroelectricity. This creates several notable features relevant for the evaluation.

The first feature that makes the Nordic market special in contrast with many other markets is that the availability of the hydroelectricity significantly mitigates the problems that arise because wind generators only produce when it is windy. In most markets, scaling up the share of such intermittent technologies presents a serious challenge to the current ways of organizing transmission, distribution, and production of electricity (Gowrisankaran, Reynolds and Samano, 2015).[1] Since the hydro generators provide a natural source of balancing power for the renewables, the market can reasonably well accommodate intermittent entry.[2]

The second special feature of the Nordic market is that the pressure on the existing assets materializes as a clean case since the bulk of inframarginal production remains in the market in the short run. The implications of subsidized entry can become convoluted if the supply mix changes dramatically on a short notice as a response to the wind power generation. In particular, for the hydro technology the supply price is determined by the high marginal cost of the alternative technologies such as thermal power. Since the subsidies are targeted at alternative technologies that have low or even zero running costs, their entry to the market

[1] Gowrisankaran et al. (2015) evaluate quantitatively the intermittency cost for southeastern Arizona. For example, Ambec and Crampes (2012) study the optimal energy mix with reliable and intermittent energy sources.

[2] For the Nordic region, there is no clear evidence that renewable energy generation has increased the volatility of electricity prices (Rintamäki et al., 2014).

lowers the opportunity cost of hydro and thus the subsidies to entrants become indirect taxes on the hydro rents. The same applies to the quasi-rents that the nuclear power generators earn.[3] The main incumbent technologies, hydro and nuclear, are trapped to bear the cost of entry in the short run, so that the subsidy-induced fall in prices implies a loss of rents for the incumbents.[4] The quantified pressure on the assets is informative of the renewable energy wealth transfer and also destruction reshaping electricity markets in general.

The third feature of the Nordic setting is that the availability of the hydro resource together with the conspicuous Nordic climatic variation determines the equilibrium division of labor between the technologies in this market. It turns out that, when the focus is on the seasonal outputs, the equilibrium generation patterns for different technologies depend on the natural fundamentals such as temperatures, wind, and rainfalls. In LV 2016, we scale up the observed wind generation patterns to recover changes in the seasonal equilibrium, and to identify the implications for surpluses across technologies and consumers in the Nordic countries.

The question that remains open in LV 2016 is the longer term price impact of the wind power generation. Currently, the wind power generation comes close to 30 TWh annually, which has been accommodated by the market on a short notice by adjustments in the marginal generation capacity, that is, by thermal power generation. However, in the medium or longer term, a significant fraction of the nuclear power capacity is coming to the end of its political, technical, and economic life time. The question is if the nuclear becomes an adjusting margin that is large enough to lead to a price recovery in the Nordic market. From the electricity industry point of view, it is important to assess if the planned nuclear phase-downs "save" the Nordic market model based on marginal cost pricing, with incentives for replacement investments provided by the prices rather than governmental subsidy programs.

We seek to answer to the following questions. We identify first what are the plausible scenarios for the nuclear capacity development. We identify six scenarios associated with specific plant shutdowns, with annual nuclear generation reductions ranging from 0 to 55 TWh. The overall size of the annual market is ca. 400 TWh, so the nuclear capacity phase-out has the potential of significantly restructuring the overall supply curve in this market. In the most extreme scenario, the decline in the nuclear generation exceeds the currently added wind generation to the market -- yet, in the coming 5-10 years the expected new additions of wind imply that the total generation capacity will not decline.

We consider then the price recovery that follows from each nuclear phase-down scenario. The answer cannot be found by directly comparing the capacity changes of wind and nuclear since the two technologies have different annual generation patterns. Our analysis controls for the changes in the seasonal generation patterns, and thereby for the changing revenue streams over a typical Nordic year. We find

[3] See Borenstein and Bushnell (2015) for an elaboration of quasi-rents in the electricity market context.
[4] Hydro is a fixed factor and can evade the policy only if there is a political decision to restructure the market area. In contrast, nuclear, which is the second-largest source of power and a carbon-free technology, can respond to policies by the timing of phase downs.

that the nuclear exit has the potential of bringing annual revenues (and thus the consumer expenditures) to a level and even above the ones that prevailed in the market before the large scale entry of wind power. Thus, the strategy of "taking nuclear out and bringing wind in" can lead to a full price recovery. We estimate that the electricity market expenditures in the market can rise to 23 billion euros annually which is almost by factor two larger than the currently prevailing level with 30 TWh of wind power (and the current fleet of nuclear plants running). The Swedish nuclear capacity is critical to the longer term equilibrium prices in this market.

Finally, we quantify the impacts on the consumer expenditures, producing technologies' revenues, and on the countries in the region in each scenario.

The report is structured as follows. In the next Section, we summarize the main findings of LV 2016. This is important since the impact of capacity exit cannot be appropriately quantified before identifying the relevant benchmark. The difficulty here lies in the rapid recent change of wind power capacity. LV 2016 provides the benchmark that would prevail without capacities leaving the market. Then, in Section 3, we identify the nuclear phase-out scenarios and quantify the impact on the market.

2 The impact of wind on the market: LV 2016

2.1 THE APPROACH

We now describe the approach in LV 2016 for evaluating the impact of wind power generation on the Nordic electricity market. The same approach is used in our evaluation of the nuclear capacity. We are interested in the market-level outcomes: the quantities produced by each technology are aggregated to the Nordic level, and the system price is used as a measure of the Nordic price level. We acknowledge that the regional prices have diverged in the recent past, reflecting a set of changes in the market environment that include trade links to non-Nordic countries, changes in the wind power capacity, and the construction delays of the nuclear capacity in Finland. Yet, the system price is the best available measure of the general price level in the Nordic region. Historically, the pressure on transmission links, and thereby the degree of market integration, varies across years depending on the availability of hydropower. Norway's capacity is close to 100 per cent hydropower; Sweden has more equal shares of hydro and nuclear power; Finland has diversified between nuclear, thermal, and hydro power; Denmark has no hydropower but the largest share of wind. In years of abundant hydro availability, the direction of exports is from the hydro-abundant regions (Norway and Sweden) to the rest of the market; the reverse holds in dry years. Thus, the division of labor between capacities changes from one year to another. In addition to the internal links, the Nordic market is also interconnected with the surrounding market areas. The main links are towards Germany, the Netherlands, the Baltic States and Russia which all are dominated by thermal power generation. The net supply from the neighboring regions is included in the analysis.

Our data covers years 2001-2014. All data in the analysis is at the monthly level, and it has been corrected to 30 day months to remove the variations caused by shorter (e.g. February) and longer months. We also correct for the number of working days within a month. Electricity demand is higher during the working days (Mon-Fri) than during weekends and public holidays.

The following equation provides the breakdown of the technologies that can be used to meet the demand:

$$DEMAND = HYDRO + THERMAL + WIND + CHP + NUCLEAR$$

The data for HYDRO, WIND, and NUCLEAR is compiled from the national system operators' databases. Combined Heat and Power (CHP) is taken as traditional CHP that is run against heat or industrial loads. CHP and THERMAL require a manual separation due to ambiguities in statistics. We have carefully implemented this separation through a breakdown of the Danish data reporting system (details available on request). We have also checked the consistency of our CHP/THERMAL division with the ones used by the industry analysts. Note that while CHP can to some extent respond to prices in the hourly market, at the monthly level the CHP is driven by heat and industrial loads. THERMAL includes the trade with the neighboring regions. We add the traded quantities as net supply (can be negative) to the thermal output in the Nordic region.

DEMAND is the total monthly demand for electricity in the Nordic region. Importantly, the monthly demand is a very different concept from the hourly demand that can to some extent respond to price differentials across hours in the Nord Pool Spot (NPS). Such an arbitrage is inconceivable for demand loads over the seasons of the year -- the monthly loads are driven by exogenously changing climatic Nordic conditions. For this reason, the monthly demand is almost purely driven by temperatures in the Nordic region. For example, LV 2016 estimate that, on average, one degree Celsius decline in the monthly mean temperature, increases the monthly demand by .63 TWh.

WIND is insensitive to market conditions: wind generators produce when it is windy, not necessarily when prices are high. NUCLEAR is similarly taken as a must-run capacity. Through our data-cleaning process explained just above, we define CHP as temperature dependent capacity: the price sensitive part of CHP is included in THERMAL. Thus, effectively, the only capacities that can actively consider when and how much to produce are THERMAL and HYDRO.

Using econometric analysis, we estimate how the historical monthly generation patterns of HYDRO depend on the following market fundamentals: storage levels, inflows, temperatures, and the seasons of the year. It is obvious that the hydroelectricity generation depends on the availability of the resource, as captured by the storage level and also by the inflow to the reserves. Note that we consider these measures as aggregates for the Nordic region: the reservoir size is measured as TWh of energy in any given month. LV 2016 estimate that a 10 TWh increase in the reservoir size per month increases generation by 1.6 TWh per month, indicating that a large fraction of any given addition to the resource is saved for future use.

The hydroelectricity generation depends also on temperatures. For example, a colder than average month calls for more demand for hydroelectricity.

The thermal power generation patterns over the months follow from the hydroelectricity generation patterns. Namely, from the equation above, THERMAL=DEMAND-HYDRO-WIND-CHP-NUCLEAR so that the thermal power is a residual. Thus, our approach is simply to estimate the dependence of HYDRO on the natural fundamentals (reservoirs, inflows, temperatures), and take THERMAL as the residual that is left over from the demand.

It is useful to illustrate how well this method can explain the past generation patterns. Fig. 1, reproduced from LV 2016, shows the historical hydro and thermal generation patterns, and the prediction from our econometric model that uses only information about the natural fundamentals, that is, reservoirs, inflows, and temperatures.

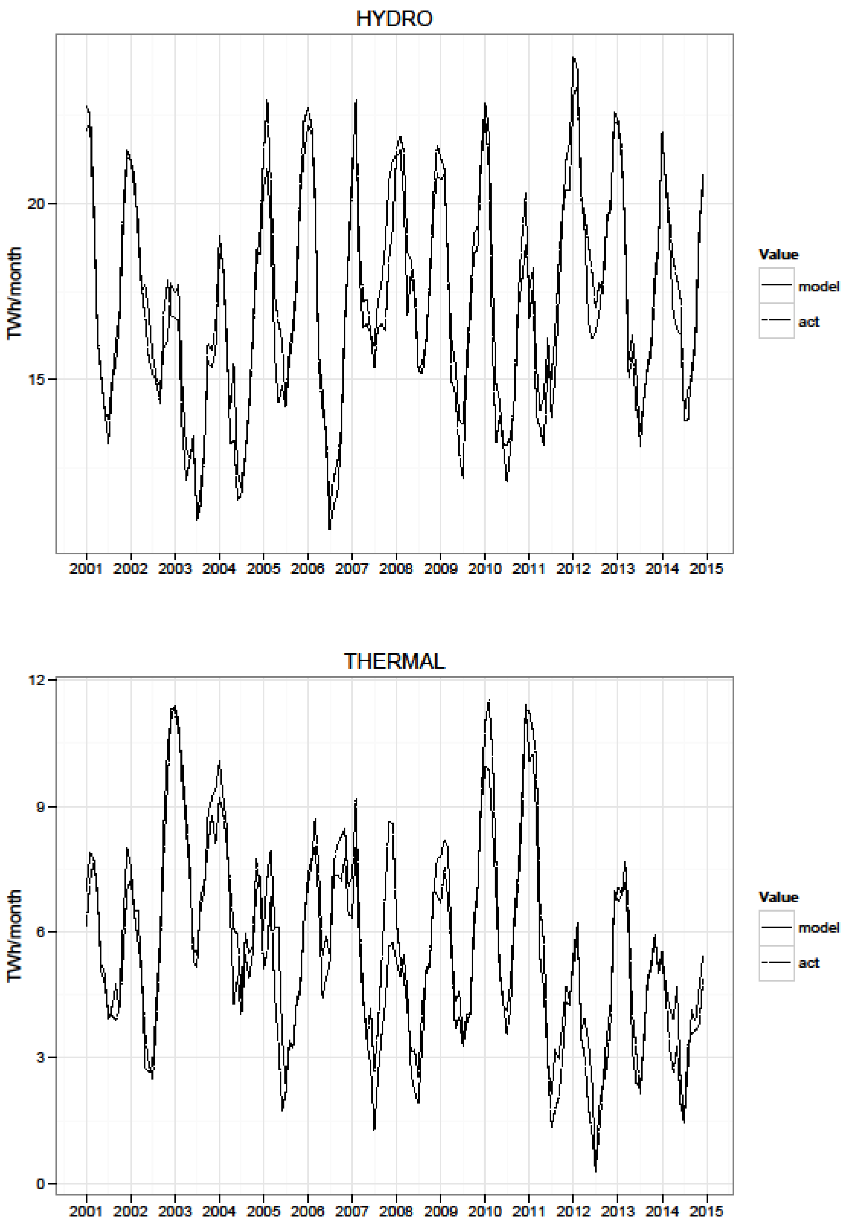

Figure 1 Actual (act) and the estimated (model) HYDRO and THERMAL polices (TWh/month) in years 2001-2014.

There is no information about money-metric variables in the above analysis; it may seem surprising that most of the variation in productions can be explained without them. However, we must also recover prices to able to discuss the revenues generated for each technology, the consumer side expenditures for each country, and also the impact of increases in the wind power generation on the revenues and expenditures.

To recover the monetary values, we assume a cost function for the thermal power, incorporating the dependence on input prices and emission allowances. This cost function is fitted to the data following the idea that the output price must cover the marginal costs of the active thermal units. For example, LV 2016 find that a 1 TWh increase in output per month, that is, a change corresponding to a nuclear power unit, must be associated with a 10 per cent increase in the output price for the price to cover the cost of the additional thermal power output. Fig. 2, reproduced from LV 2016, depicts the historical monthly prices and the predicted prices from the fitted cost function.

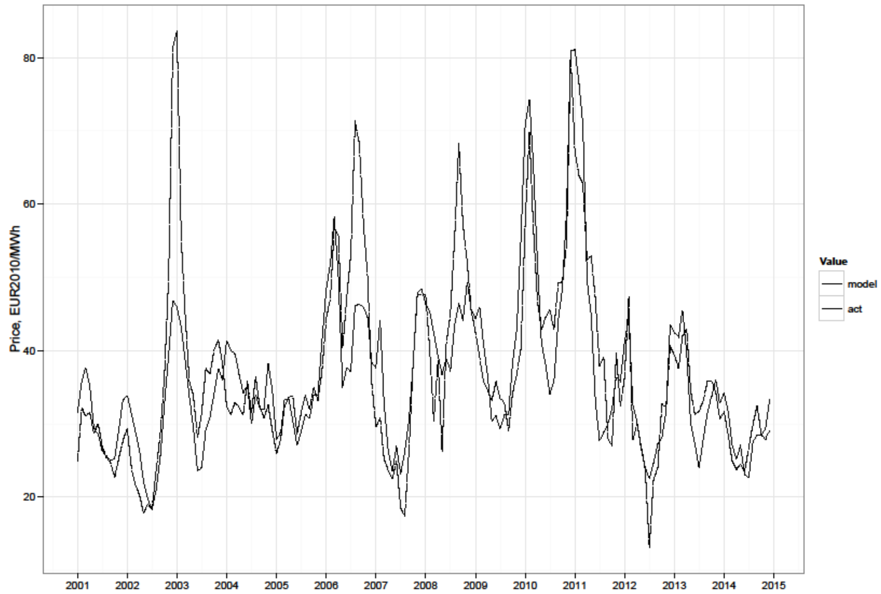

Figure 2 The historical (act) and fitted prices (model), measured in 2010 € MWh.

2.2 THE IMPACT OF WIND POWER ON REVENUES AND EXPENDITURES IN THE NORDIC REGION

As seen from Figs. 1 and 2, the natural fundamentals are a source of great variation in the Nordic market. This makes it difficult to identify, for example, the change in the recent price attributable to the entry of new wind generation; the recent years have also been relatively warm and the hydro resource has been characterized by good availability.[5] Our approach is to consider an average year for the hydro resource and temperatures: for such a typical year, we can obtain the output levels and output prices from our analysis described in the previous Section. This way, the analysis captures the excepted equilibrium generation patterns and prices for any given future year, say, 2018. We have no reason think that year 2018 will be colder or warmer than the average. A similar reasoning holds for the rainfalls that determine the hydro availability.

The numbers below describe the average year, as just explained. Our quantification considers how such an average year changes when we introduce more wind to the market. This counterfactual analysis builds on the following premises:

[5] In addition, the fuel prices relevant for thermal power costs have reached historically low levels.

A. Installed capacity, other than wind, remains in the market. This the key assumption that will be relaxed shortly when we consider the phase-out of the nuclear.

B. The thermal output responds, on average, one-to-one to *permanent* increases in the wind generation. For if there is a permanent reduction in demand for the incumbent capacities, the annual hydro output cannot response by permanently saving inflows.[6] Thus, the margin that adjusts to the wind forced to the system is the thermal power.

C. The wind generation in all scenarios follows a monthly pattern that we can estimate from the data. We allocate any given increase in annual wind according to the estimated monthly profile.

D. We consider wind scenarios with 0-50TWh of annual generation. The benchmark is the capacity in year 2014 that implies 20 TWh of expected generation per year. In the experiments, we adjust the annual wind output to reflect the change of capacity underway. We take 50 TWh as the upper bound for the WIND increase.[7] We vary the level of the annual generation between 0-50 TWh to capture six scenarios. The permanent price reduction implied by the current 20 TWh is the main case; 0 TWh provides a benchmark for evaluating the change in the market that has already taken place. Scenarios 30-50 TWh are for the forthcoming projects in the pipeline. A sufficient increase in its share can make the counterfactual analysis unsound if the estimated current price-setting capacity is fully replaced. 50 TWh of annual wind generation comes close that limit.

E. The input prices are set equal to the historical averages in the data period.

Following steps A-F and considering 20 TWh annual wind generation, LV 2016 estimate that the revenues for producers (expenditures for consumers) in the Nordic countries are 15.57 billion euros annually on the wholesale electricity (Table 1). This estimate is obtained from the annual total electricity production profile and the monthly price estimate for 20 TWh of wind added to the market; the confidence interval [10.924, 22.195] reflects to a large extent the variation in the potential monthly prices.[8]

[6] The total availability of hydro over time can be reduced only by spilling of water which is regulated activity in the Nordic countries; see Kauppi (2009).

[7] TEM (2012) has compiled, from various sources, the estimated increase for the total wind generation in the Nordic countries: 29 TWh in 2015 and 48 TWh in 2020.

[8] The annual consumptions are relatively stable.

Table 1

	TWh WIND	low estimate	Mean	high estimate
1	0	13,126	18,732	26,729
2	10	11,974	17,077	24,350
3	20	10,924	15,570	22,195
4	30	9,963	14,203	20,246
5	40	9,089	12,960	18,485
6	50	8,288	11,830	16,881

The table reports the total annual invariant electricity market revenues in the Nordic countries in millions of 2010 euros for TWh wind power generated. Low and high estimates from the 95 per cent confidence interval.

We can see that the revenues have declined by more than 3 billion euros per year: without the wind output, the estimated number would be 18.732 billion euros annually. Recall that this number applies to an average year; the actual realized revenue can and is expected to take very low and high values in all scenarios depending on temperatures and rainfalls. Yet, the reduction in expected revenues is permanent. Of course, the opposite side of the coin is that the consumer side saves exactly the same amount in expenditures.

The breakdown of the revenues between countries is in Table 2. The revenues are shared between the countries in proportion to consumptions.

Table 2

TWh Wind	0	10	20	30	40	50
DEN	1,533	1,398	1,275	1,163	1,061	968
FIN	4,851	4,423	4,032	3,678	3,357	3,064
NOR	5,469	4,986	4,546	4,147	3,784	3,454
SWE	6,878	6,270	5,717	5,215	4,758	4,344
Total	18,731	17,077	15,570	14,203	12,960	11,830

The table reports the annual invariant electricity market expenditures by country in millions of 2010 euros for TWh wind power generated. Mean values reported.

Wind power entry implies losses for the existing producers; they are depicted in Table 3.[9] The hydro output presents about 50 per cent of output on average, with over 9 billion annual average revenue. The current wind power in the market has lowered prices by about 20 per cent, leading to a direct hydro technology loss of the same magnitude. Since this technology has very low out-of-pocket marginal costs, the loss is a direct loss of rents. The near-term wind projects in the pipeline (30-50TWh of wind) imply another 2 billion annual loss of hydro rents. Nuclear power is a must-run capacity; it loses revenue in the same proportions as the hydro

[9] There is a slight difference in the producer and consumer side numbers due to trade with Germany and Russia.

technology. Thermal power units are almost idle after 50 TWh of annual wind power generation: they lose 75% of their annual revenue.[10]

Table 3

	0	10	20	30	40	50
HYDRO	9,259	8,447	7,708	7,036	6,426	5,870
NUCLEAR	3,655	3,337	3,047	2,783	2,543	2,325
CHP	2,085	1,896	1,725	1,570	1,428	1,300
THERMAL	3,616	2,892	2,268	1,732	1,275	884
WIND	0	398	727	994	1,208	1,375
Total	18,615	16,970	15,475	14,115	12,880	11,754

Annual invariant electricity market revenue losses by technology in millions of 2010 euros for Terawatt-hours WIND generated. Mean values reported.

[10] Our analysis cannot shed light on the potential reserve capacity value of the thermal units for emergency situations -- the analysis shows that these units lose most of their compensation in the wholesale market.

3 The nuclear phase-down

3.1 THE PHASE-DOWN SCENARIOS

In Table 4, we list the Nordic nuclear units and their estimated annual productions together with the estimated or announced closure dates. There is no hard data on the closure dates; we used the company reports and the industry journals for the estimated closure dates reported. From this list, we construct the following scenarios for the decline in the nuclear generation:

1. 0TWh: Closure of R1,R2,O1,O2 and the start of OL3. The reduction of total generation is close to 4 TWh annually, rounded to 0TWh.
2. 10TWh: Additional closure of R3.
3. 20TWh: Additional closure of R4.
4. 35TWh: Additional closure of F1,F2.
5. 45TWh: Additional closure of F3.
6. 55TWh: Additional closure of O3.

Table 4

	abbr.	TWh/year	closure: technical	closure: announced / estimated
Forsmark-1	F1	7.23	2040	2020
Forsmark-2	F2	8.11	2041	2020
Forsmark-3	F3	8.72	2045	2020
Oskarshamn-1	O1	2.55	2022	2017
Oskarshamn-2	O2	4.16	2024	2015
Oskarshamn-3	O3	9.92	2035	2035
Ringhals-1	R1	5.33	2026	2020
Ringhals-2	R2	4.78	2025	2019
Ringhals-3	R3	7.29	2041	2020
Ringhals-4	R4	8.18	2043	2020
Loviisa-1	L1	3.81	2027	2027
Loviisa-2	L2	3.88	2030	2030
Olkiluoto-1	O1	7.15	2038	2038
Olkiluoto-2	O2	7.21	2040	2040
Olkiluoto-3	O3	12.61	2079	2079
Fennovoima	FE	9.46	2084	2084

The table lists the Nordic nuclear units and their announced/estimate closure dates. The energy produced is obtained from the plant capacity and historical availability factors. Closure dates from Energiauutiset 3/2016 for the Swedish units, from Fortum for Loviisa; the remaining are our estimates.

The current wind generation is on average 31 TWh annually; the actual wind generation was 35.6 TWh in 2015 which was an exceptionally windy year. We evaluate that the average wind generation reaches 40 TWh per year by 2020. The quantification presented below can be seen present year 2020 situation for wind (40

TWh) and for the above six possible scenarios of the nuclear phase down (0-55TWh). The production of both technologies is assumed to follow their respective historical production patterns over the months of the year.

3.2 THE PRICE RECOVERY IN THE NUCLEAR PHASE-DOWN SCENARIOS

Table 5

	TWh phase down	Low	Mean	High
1	0	21.1	30.9	45.4
2	10	23.3	34.1	50.1
3	20	25.7	37.7	55.3
4	35	29.8	43.7	64.1
5	45	32.8	48.2	70.8
6	55	36.2	53.2	78.3

The table shows the mean annual electricity wholesale prices \euro/MWh for the nuclear phase-down scenarios 1-6, with 95 percent confidence intervals. Annual wind generation is 40 TWh in all scenarios.

It is instructive to start with the impact on the mean annual prices. Looking at scenario 0, one should bear in mind that in this starting situation there are four closures on the Swedish side and one compensating startup on the Finnish side. Since the wind generation is 40 TWh annually, there is a significant addition to the total generating capacity, in contrast with years 2000-2010. Therefore, the mean price of €30.9 /MWh is lower than the historical average prices: according to the industry specialists this price comes close to the running costs of the Swedish plants. The closure of Ringhals 3 and 4 is estimated to increase the Nordic price level permanently by more than 20% (cf. scenarios 1 vs. 3). Note this closure scenario leads to a price increase that is enough to compensate the effect of the nuclear tax on the operating profits of the remaining Swedish plants. Taking Forsmark 1 and 2 offline, increases the wholesale price level by more than 40% (cf. scenarios 1 vs. 4); closing Forsmark 3, brings the number to 56%. The last closure, Oskarshamn 3, is more speculative since the estimated closure date is quite late to be comparable with other closures. Yet, if this plant closes unexpectedly early, the total price recovery becomes 72% (cf. scenario 1 vs. 6).

We transform these price level estimates now into revenues for the producers (expenditures for the consumers) in the Nordic region. The numbers are reported in Table 6 and are obtained as in LV 2016 from the monthly Nordic consumption profile multiplied with the estimated monthly prices. The total turnover changes quite closely in the same proportions as the price level in Table 5. The nuclear capacity has a significant impact on the region: the nuclear phase-downs bring the total electricity market expenditures well above 1% of the Nordic GDP.

Table 7 reports the breakdown of the revenue (expenditure) by country. Sweden as the largest consumer bears the largest absolute increase in the expenditures.

Table 6

	TWh phase down	Low	Mean	High
1	0	9,367	13,736	20,142
2	10	10,351	15,180	22,260
3	20	11,438	16,775	24,609
4	35	13,279	19,499	28,632
5	45	14,663	21,557	31,688
6	55	16,192	23,834	35,086

The table reports the total annual electricity market turnover in the Nordic region in millions of 2010 euros for the nuclear phase-down scenarios 1-6, with 95 percent confidence intervals.

Let us now turn to look at the revenue change per technology. In Table 8, we provide the breakdown of the revenues by technology.[11] Interestingly, the technology whose revenues recovers most, relatively, from the nuclear capacity change is thermal. Recall that we defined thermal power in our analysis such that includes also the trade with the neighboring regions so that not all of the increased revenues accrue to the Nordic producers. On reflection, however, the thermal power is adjusting margin that not only receives higher prices but also must expand its output. When combined, the higher prices and the better utilization lead to revenues increasing by multiple factors over the scenarios. In contrast, the hydro and CHP capacities see their annual revenues developing more or less in lock-step with the output prices.[12] In the most extreme outcome, the hydro revenues increase by 70%, reflecting a pure increase in the hydro technology rents since the out-of-pocket cost from using the hydro capacity does not increase over the scenarios; for the thermal power, the bulk of the revenue increase is absorbed by increasing marginal costs.

Table 7

TWh phase-down	0	10	20	35	45	55
DEN	1,125	1,243	1,374	1,597	1,756	1,952
FIN	3,547	3,920	4,332	5,035	5,567	6,155
NOR	4,029	4,453	4,921	5,720	6,324	6,992
SWE	5,035	5,564	6,148	7,147	7,901	8,736
Total	13,736	15,180	16,775	19,499	21,557	23,835

The table reports the mean annual electricity market turnover in the Nordic countries in millions of 2010 euros for the nuclear phase-down scenarios 1-6. The mean values reported.

[11] Note that the trade with the neighboring regions causes some departure with the total revenue estimates reported in Table 6.

[12] The hydroelectricity is not must-run capacity but the total output from this source is fixed in the following sense: the hydro resource cannot be borrowed from the future so that the hydro producers cannot expand their annual generation in respond to the nuclear exit.

Table 8

TWh phase-down	0	10	20	35	45	55
HYDRO	6,929	7,654	8,456	9,820	10,852	11,990
WIND	1,287	1,422	1,572	1,827	2,019	2,233
CHP	1,510	1,670	1,848	2,155	2,383	2,643
THERMAL	1,665	2,191	2,811	3,942	4,855	5,918
NUCLEAR	2,676	2,608	2,496	2,229	1,968	1,631
Total	14,067	15,545	17,183	19,973	22,077	24,415

The table reports the mean annual electricity market revenues by technology in millions of 2010 euros for the nuclear phase-down scenarios 1-6. The mean values reported.

The reduction in the nuclear capacity implies a considerable increase in the expenditures on the consumer side. Similarly as in the case of feed-in tariffs for renewable energies, the consumers could subsidize the nuclear power generation to prevent the exit from the market. The change in the expenditures defines the consumer-side willingness to pay to prevent the nuclear power exit. How much the consumers could subsidize each MWh generated by nuclear without budgetary implications? To obtain a measure for the consumers' willingness to pay, we take the expenditure increase implied by each plant shutdown scenario 1-6 and divide the increase by the cumulative reduction in the energy generated. The resulting number is the subsidy per MWh that exactly coincides with the consumer side change in the electricity market expenditures: it is the maximum amount that the consumer could pay to avoid the plant shutdown. The results are reported in Table 9, including also the breakdown of the willingness to pay between the Nordic countries.

Table 9

TWh	10	20	35	45	55
DEN	-12	-7	-7	-4	-4
FIN	-37	-21	-23	-13	-12
NOR	-42	-23	-27	-15	-13
SWE	-53	-29	-33	-19	-17
Total	-144	-80	-91	-51	-46

Consumer-side willingness to pay for MWh of nuclear generation: annual expenditure reduction (in 2010 euros) divided by the cumulative decline of the nuclear generation (MWh), starting from zero.

4 Concluding discussion

We conclude by discussing the wider implications of the nuclear capacity change for the Nordic market. One pressing recent issue is that the regional prices have diverged from the system price. The question arises if the system price is a reasonable indicator of the Nordic price level in the near future? We tend to conclude that the capacity change scenarios depicted here imply a relocation of the nuclear capacity towards the area with relatively high regional prices (Finland) from the region with relatively low prices (Sweden). Consider our scenario 0TWh where there is no change in the total supply but a considerable increase of capacity in Finland compensating the phase-down in Sweden. This alone takes partly the edge off the pressure on the current transmission links between Finland and Sweden. In the other scenarios, the nuclear capacity in Sweden further declines, which could, arguably, lead to an imbalance in the opposite direction. Yet, looking beyond 2020, the wind generation in Sweden is likely to exceed the benchmark and this can mitigate the potential trade imbalance problem. Obviously, the shorter-term ramifications of the increased wind power generation require a further elaboration.

As noted just above, the wind will not stop at 40 TWh annual generation in the Nordic countries -- the phase-out of the Swedish nuclear power through its impact on the market prices can make the wind investments profitable even without subsidies. One may therefore vision a market transition where the subsidized wind power that enters the market by 2020 replaces thermal power in the short term, and a fraction of the nuclear in the medium term. The latter part of the transition leads to a price recovery which brings part of the thermal power back to business. In the longer term, the recovered prices attract further investments in the wind capacity, and perhaps to the final replacement of the thermal capacity.

The Nordic market came to existence since there is a natural division of labor between capacities in the participating regions. The winners and losers from trade take turns over the years, which may explain the stability of the trading institution. The market is changing because of the implementation of the national climate and energy policy objectives. It cannot be taken for granted that there is a natural division for labor between the countries also in the future. Yet, one should bear in mind that Nordic electricity market in its current state already represents a role model the future of electricity markets: intermittently available technologies combined with storable sources of energy. The market effectively pools together the available sources of hydroelectricity which, on average, covers 50% of annual consumption, providing a counterbalance for intermittent sources of supply. Thus, the intermittency problem has been mitigated by a collaboration across national borders. The Nordic solutions should build on this concept also in the future.

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THE IMPACT OF RENEWABLE ENERGY ON THE NORDIC ELECTRICITY MARKET

Wind power production in the Nordic region has increased on average at one percent monthly rate over the last 13 years. The Nordic renewable energy expansion path for the coming 5 to 10 years will further speed up the entry of the renewable capacity. The subsidized entry of technologies that operate with zero marginal costs lead to a potentially significant reduction in the final wholesale prices. This presents a serious challenge to the Nordic market design that is based on the idea of marginal cost pricing. The traditional technologies may face a situation where they can no longer cover their running costs in a market-based manner.

In this report, we first quantify the pressure on prices and operating revenues that follows from the current subsidized entry of wind generation. We find that about 20-30 percent of the price reduction in the Nordic market is attributable to the wind generation. We then quantify the impact of the Swedish nuclear power phase-down on the market. We find that the phase-down plan can more or less neutralize the impact of wind on the market prices, although the transition – increasing wind and declining nuclear – creates winning and losing technologies.

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