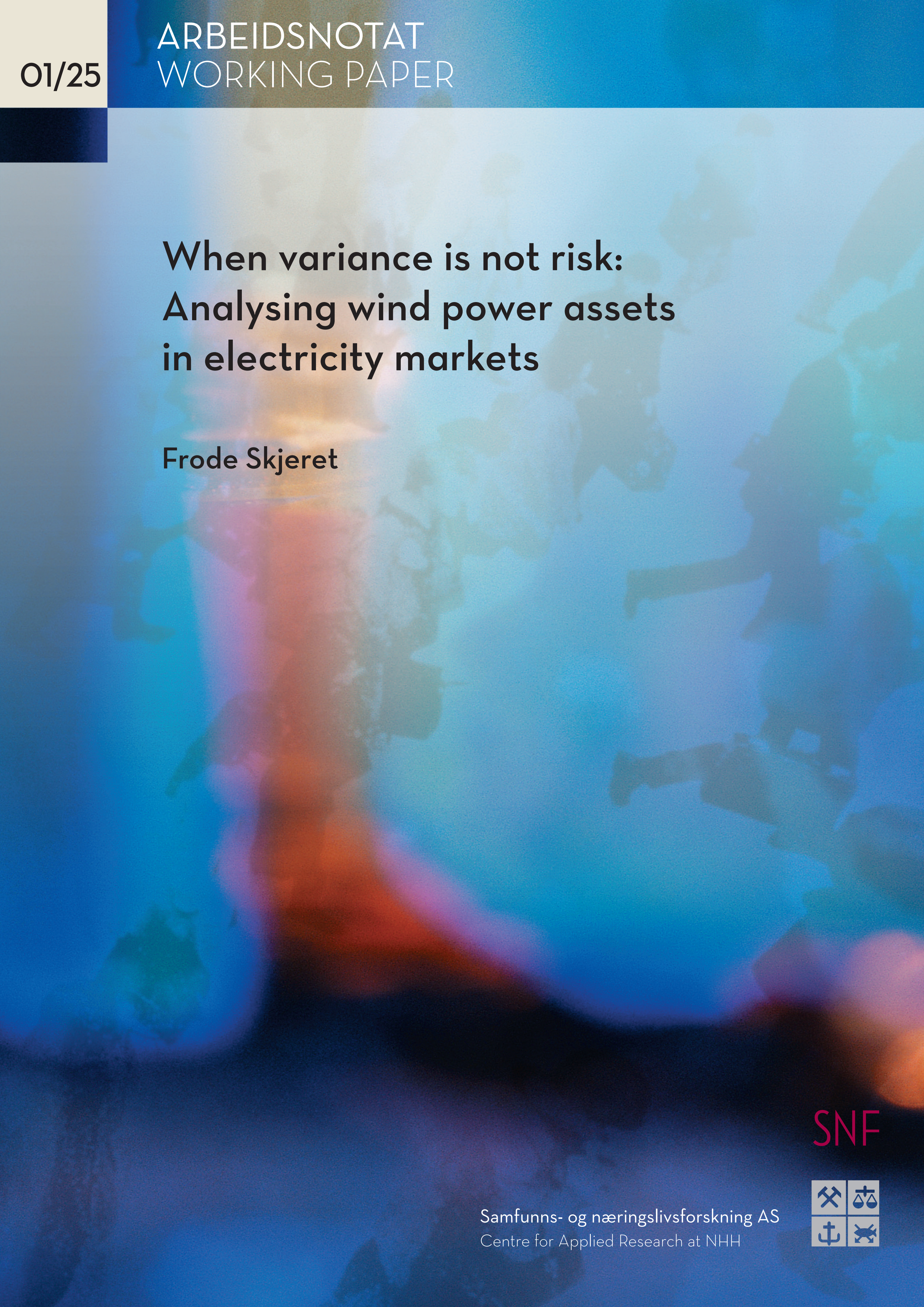

01/25
ARBEIDSNOTAT
WORKING PAPER

# When variance is not risk: Analysing wind power assets in electricity markets

Frode Skjeret

SNF

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SNF Working Paper No. 01/25

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# Analysing wind power assets in electricity markets

Frode Skjeret

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## PREFACE

This paper discusses how to analyse deployment of non-predictable electricity production capacities, using wind power production assets as the case of study. We use data from the Nordic electricity markets for illustrations throughout the paper. First, we propose alternative measures of risk relevant to regulatory bodies like system operators, two measures relating to the day-ahead electricity market, and two measures focusing on the redispatch electricity market. While the existing literature to a large extent focus on variation in production, we argue that the relevant risks for system operators relates to excess demand, thus the measures of risk applies various modifications of excess demand when measuring risk. Finally, the current paper proposes two alternative methods for measuring risk, the use of measures as ‘Value at Risk’ and ‘Expected Shortfall’ is more suited for evaluating the risks facing system operators.

# CONTENT

# 1 INTRODUCTION

In September 2012 wind power production capacity exceeded 100.000 MW in the European Union, and there were plans to increase wind production to meet a target of 20% renewable production by 2020, see *EU Directive2009/28/EC*. Similar targets were found in other regions of the world. And since then, there has been a large increase in non-controllable production capacities in most electricity markets. Intermittent production sources, such as wind and solar, are at times highly variable and may reduce security of supply in electricity markets.[1] Denmark has the highest penetration rate of wind power in the world (almost 60% of electricity production in 2024).

During a winter storm in Denmark on January 8th, wind gusts increased to a level higher than what windmills can produce at, causing a sudden drop in electricity production. In the morning, output from wind farms in Western Denmark started to drop and by afternoon total wind power production was close to zero. The current paper discusses how to define and measure risks potentially arising when deploying a large fraction of non-controllable energy sources in electricity markets.

Electricity is uneconomical to store in large quantities and supply must always meet demand. If production drops relative to consumption, power outages or blackouts may occur. Moreover, when a sufficiently large fraction of total production is uncontrollable and only partially predictable, risks for blackouts increases. Therefore, there is a growing concern that large deployments of wind power sources may reduce reliability and security of supply. The larger the share of intermittent production capacities, the more adverse will the effects of sudden drops in production from intermittent sources be. The experiences from Denmark will most likely be of value also for other markets as penetration rates of renewable production capacities increases. One important problem in regional electricity markets with wind power production capacities is its inherent intermittency, and its lack of predictability (Fogelberg & Lazarczyk,

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[1] Intermittent energy is oftentimes used as a synonym for non-controllable or uncertain production technologies, like wind power. However, the term intermittency refers to variability, or variable production technologies, however, a highly predictable energy source as tidal power is also intermittent. Therefore, the term intermittency will not be used in this paper, rather terms like uncertain production or risk of production reductions is used.

2017). They argue that the intermittent nature of wind power is challenging in day-ahead markets, and second, that the lack of predictability of wind power production is challenging for intraday markets. With this work, we will analyse several relevant aspects of these types of risks.

This paper aims to add to the understanding of how to analyse deployment of renewable energy assets keeping reliability and security of supply at an adequate level. Before answering this question, we define and the objective for the agent under consideration and discuss how to optimally measure risks. My results are both theoretical and empirical:

First, we discuss how to transform the objectives of a public body - as a system operator or regulator – set to oversee security and reliability of supply into measures of risk. This paper applies four measures of risks relating to different types of risks facing regulators of electricity markets with a substantial share of non-controllable electricity production capacities. Second, we propose two alternative methods for measuring risks from unpredictable power production assets should pay more attention to extreme situations, rather than long-run averages, the measures applied in financial economics are referred to as ‘Value at Risk’ and ‘Expected shortfall’. Finally, and for illustrative purposes, we apply a dataset from the Nordic electricity market – including the Danish electricity market, the market in the world with the highest share of wind power production capacity compared to demand.

One may overcome the problem of non-controllable in several ways. First, geographical distribution of wind power assets will reduce the overall variability of wind power production, Holttinen (2011) shows that increasing transmission capacities between regional markets and/or connecting formerly independent markets may reduce overall variability. Second, introducing highly flexible production technologies able to ramp up and down efficiently when wind power production varies greatly. Bueno and Carta (2006) demonstrate that connecting wind power resources to hydropower facilities increases the potential share of wind power share. In the Gran Canarias the penetration rate may potentially increase from 4,7% to 6,7%. Third, introducing two-way consumption metering for a larger fraction of consumption entities may also reduce the cost of wind power variability.

Recently, insights from financial economics have been used to illustrate how intermittency from introducing wind power production capacities may be reduced by localising plants covering large regions. This rests on the fact that correlation of output from wind farms increases with geographical distance between wind farms. Thus, deploying wind farms over large areas will, using financial jargon, diversify the risks.

The main results from existing literature are that wind power production correlates imperfectly regionally, and that correlation falls with distance between farms, see e.g. Holttinen (2011).

Also using a portfolio approach, Roques et al (2010) analysed how to either minimise wind power production variability or maximise wind power output, where the assets considered were Austria, Denmark, France, Germany and Spain. They find that optimal portfolios of wind power differ greatly depending on whether maximum output or minimum variance is the objective.

Drake and Hubacek (2007) analyse how the difference in production variability and production level when either deploying 2,7 GW of wind power production capacities at one location or dispersing the same 2,7 GW at four different locations in the UK. They find that one may reduce wind power variability “in the order of 36%.”

Illinois, USA, expects a rapid increase in renewable energy production in general, and wind power electricity production in particular, therefore, Chupp et al (2012) analyse how intermittency can be overcome by dispersing wind farms regionally. They also discuss the order in which to build various wind farms for keeping overall production variability at a low level.

Other papers introduce constraints in the Mean-Variance analysis. Degeilh and Singh (2011) propose a method to minimise the variance of wind power production by distributing a given number of windmills at a given number of wind farm sites, they also discuss how to incorporate transmission constraints between regional electricity markets.

These studies illustrate how wind power production correlates regionally. However, we argue that agents in the electricity sector rarely have preferences on long-term averages of risk and reward as prescribed by modern portfolio theory. Rather, it is the probability of extreme events, and negative impact of the extreme events that er most relevant for agents overseeing electricity markets. Therefore, we propose to use alternative theories when analysing risks in deregulated electricity markets.

## 2 RELEVANT RISKS

Public bodies set to oversee electricity markets are concerned about large deviations between production and consumption, *e.g.* excess demand (positive and negative), and large deviations in excess demand between short time intervals. When analysing risks facing system operators one must first differentiate between various electricity markets. Several markets play a role for securing a stable electricity market, from forward and futures market, via day-ahead and intraday markets, to command and control of market participants. The current paper only discusses how increased share of intermittent electricity production affect day-ahead and intraday electricity markets. We first outline risks related to day-ahead markets and then intraday electricity markets.

A Day-ahead market is oftentimes referred to as the main trading spot for electricity. In day-ahead markets, agreements for producing and consuming electricity on the following day is settled. Bids for consuming and producing electricity in day-ahead markets are made on expectations about future levels of production and consumption.

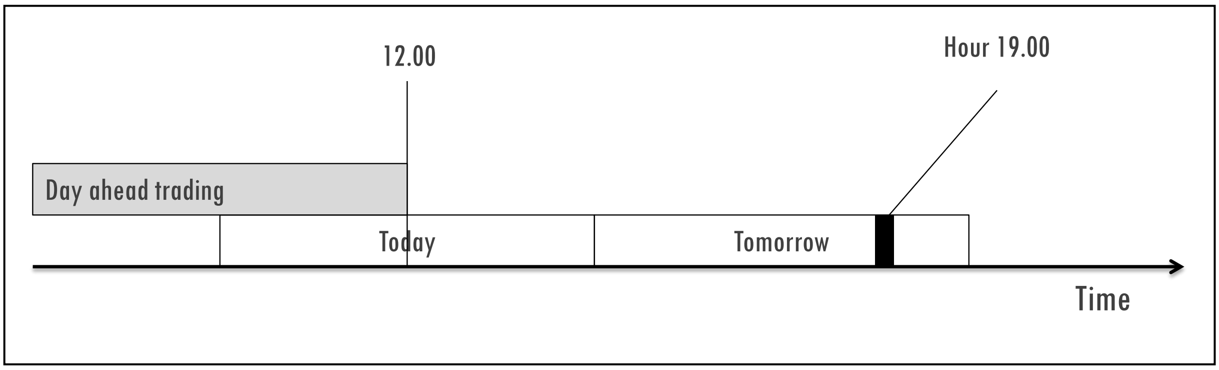

*Figure 1: Illustration of day-ahead electricity trading for hour 19 for tomorrow's market.*

The day-ahead market arranges contracts for each hour of the following day (tomorrow in figure 2), and quantities and prices are communicated to market participants after the closure of the market. In the NordPool market, all agents must submit bids for spot market operations to the system operator before 12.00 day ahead (today in the figure) of physical delivery of electricity. Prices and quantities are announced at about 12.30 for all hours lasting from 00.00 to 23.59 the next day.

The relevant risk for system operators in this market refers to the system operator's ability to – via the market mechanism – create incentives for production and consumption entities to clear the market. That is, eliminate excess demand in all hours of the next day. In the literature mentioned above, relevant risk relates to expected production and the covariation between expected production bids from various production entities. When analysing how wind power production affects security of supply in day-ahead electricity markets, the literature has regarded how wind power production varies across the day, and between different regions (location of wind farms). The measure for analysis use is therefore:

$$\left(q_{t,n}^{B},\ q_{t,m}^{B}\right) \tag{3.1}$$

$q_{t,n}^{B}$ denotes production from wind power entities during hour $t$ in region $n$. Topscript $B$ indicates that it is a bid into the day-ahead market.[2] Herein, it is argued that one must also consider how wind power production correlates with demand for electricity. The rationale for this is that a system operator is not concerned with production variation *per se*, rather deviations between supply and demand bids concerns the system operator, and in particular, hours where supply bids are unable to meet demand bids. Observed wind power production exhibit significant diurnal and seasonal variations. Wind power production is significantly higher during daytime than during the night, and significantly higher during the wintertime than during the summer. Thus, there is positive correlation between electricity demand and supply of wind power output. One relevant risk for a system operator is the extent of wind power production entities require additional (or less) ramping from other production sources to equilibrate supply and demand day ahead of production and consumption taking place. A natural candidate for a measure of risk is related to excess demand, hereafter referred to as the "*excess demand risk*" measure:

$$\left(x_{t,n}^{B} - q_{t,n}^{B}\right) \tag{3.2}$$

Since wind power production displays significant diurnal and seasonal effects, one expects to observe a lower correlation between excess demand (equation 3.2) than production (equation 3.1). Thus, the positive correlation between wind

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[2] More correctly, $q_{t,n}^{B}$ denotes a bid from a production entity accepted by the system operator. Thus, production levels are the values contracted to be dispatched.

power production and consumption implies that wind power has some load following.

However, this is not the only concern for system operators. Since wind power output varies to a great extent across an average day, there is a concern that the production side may change between adjacent hours of the day. When production entities submit bids for all hours of the following day in day-ahead markets, they must take into account physical production restrictions relating to both maximum production and maximum production increases between hours of the day. Refer to this measure as "*supply ramp-rate risk*":

$$\left(x_{t+1,n}^{B} - q_{t+1,n}^{B}\right) - \left(x_{t,n}^{B} - q_{t,n}^{B}\right) \tag{3.3}$$

The term $\left(x_{t+1,n}^{B} - q_{t+1,n}^{B}\right) - \left(x_{t,n}^{B} - q_{t,n}^{B}\right)$ measures how excess demand varies between hour, say, 19.00 and 20.00 for region $n$. If one expects large variations in excess demand between two hours, other production entities must counteract this change. The availability of flexible production technologies easily ramped up (or down) determines how easy these variations can be met.

Intraday market

The two alternative measures for relevant risks proposed above concerned the ability of system operators to close the day-ahead market, that is, to incentivise sufficient production to meet demand for all hours of the day. With regard to wind power, there are also risks for not being able to ramp up (down) production during the operations of the intraday market. Intraday markets open after the closure of the day-ahead market, trading electricity in intraday markets until, say, 1 hour before production/consumption takes place.

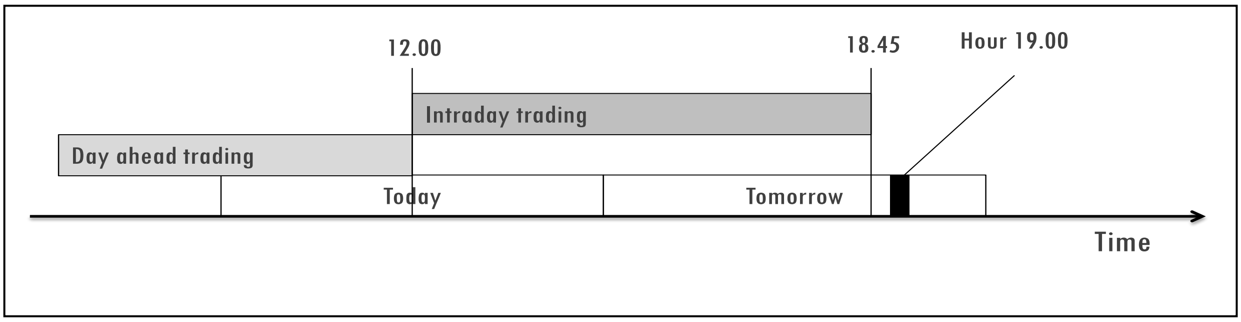

*Figure 2: Operations of intraday electricity market*

While using the notion of supply and demand when discussing day-ahead markets, we use the terms production and consumption when discussing intraday markets. This is to stress the difference between bids day-ahead markets that are based on expected consumption and production 12 to 36 hours ahead and bids in intraday markets are accepted during the hours leading up to physical delivery of electricity. In the example of figure 2, agents submit bids 32 hours ahead of delivery.

A proper measure of risk relevant for intraday markets must therefore relate to how wind power production close to the time of physical delivery differs from wind power supply bids submitted to the day-ahead market closing at noon one day earlier. Moreover, since one may expect that consumption and wind power production correlate, one should also consider consumption deviations. As intraday trading takes place, realised wind power production most likely deviates to some degree with what was expected at the time of day-ahead market operations. One risky situation for a system operator is an hour requiring large ramping capacities from non-wind production resources (or consumption entities) when realised wind production and/or realised consumption deviates from the expected level, refer to this measure as "*excess consumption risk*":

$$\left(\left(x_{t,n}^{B}-x_{t,n}^{R}\right)-\left(q_{t,n}^{B}-q_{t,n}^{R}\right)\right) \tag{3.4}$$

The term $x_{t,n}^{B}-x_{t,n}^{R}$ measures how demand bids ($x_{t,n}^{B}$) deviate from realised consumption ($x_{t,n}^{R}$), and the term $q_{t,n}^{B}-q_{t,n}^{R}$ indicates how supply bids ($q_{t,n}^{B}$) deviate from realised production from wind power farms ($q_{t,n}^{R}$). A negative number indicates that whether realised consumption is higher than expected and/or realised production is lower than what was expected when the day-ahead market closed. Imperfect correlation between regions reduces the need for additional production entities to enter the market.

As in the case of day-ahead markets, deviations in excess consumption between neighbouring hours may cause problems system operators. The ability of system operators to counteract a sudden unexpected drop in wind power production depends on how i) demand changes in this hour and ii) the ramp-rate abilities for other production entities. In contrast to the supply ramp-rate risk measure in (3.3), this measure can be referred to as a measure of "*production ramp-rate risk*":

$$\begin{aligned}&\left[\left(x_{t+1,n}^{B}-x_{t+1,n}^{R}\right)-\left(q_{t+1,n}^{B}-q_{t+1,n}^{R}\right)\right]\\&\qquad-\left[\left(x_{t,n}^{B}-x_{t,n}^{R}\right)-\left(q_{t,n}^{B}-q_{t,n}^{R}\right)\right]\end{aligned} \tag{3.5}$$

This measure is probably the most widely discussed topic for risk when introducing wind power production on a large scale, the risk that wind power production suddenly – and unexpectedly – drops from a high level to a very low level. It is the difference between excess consumption risk for hour $t$ and excess consumption risk for hour $t+1$. The term $\left(x_{t+1,n}^{B}-x_{t+1,n}^{R}\right)-\left(q_{t+1,n}^{B}-q_{t+1,n}^{R}\right)$ measures how consumption and production deviates from supply and demand bids in day-ahead markets during hour, say 20 in region $n$. The term $\left(x_{t,n}^{B}-x_{t,n}^{R}\right)-\left(q_{t,n}^{B}-q_{t,n}^{R}\right)$ for one hour earlier describes the same deviations. A negative number indicates that there is a need for ramping up production at other production entities between hour 19 and 20. During the winter storm in Denmark on January 8th, 2005, large deviations in excess consumption and moderate changes in excess consumption were observed. The measure in (3.5) captures these types of incidents.

Assuming that day-ahead market was closed on the expectations of rather strong wind gusts during the wintertime in a market with a large share of wind power production capacity. One would expect that consumption of electricity also was higher due to the chill-effect. If during the operations of the system operator observes a sudden – and unexpected – drop in production taking place at the same time as a sudden drop in consumption, production entities must ramp up production at a fast rate. If this is not sufficient, both production and consumption entities may have to change their planned use and production of electricity by command.

This measure of risk captures the most relevant risk from introducing large amount of wind power production entities in deregulated electricity markets. The low predictability of wind gusts, and therefore wind power production even at a short time horizon, may cause stressful situations in electricity markets. To sum up the discussion from above, we have four measures of risks, analysed using two methods. Herein, we focus on the measures of ramp-rate risks. The first row illustrates risks in the day-ahead market, while the second row relates to risks in the intraday market.

*Table 1: Measures of risks in day-ahead and intraday market.**

| | **Level risk** | **Ramp-rate risk** |
|---|---|---|
| **Day-ahead market** | Excess demand risk<br>$(x_{t,n}^B - q_{t,n}^B)$ | Supply ramp-rate risk<br>$(x_{t+1,n}^B - q_{t+1,n}^B) - (x_{t,n}^B - q_{t,n}^B)$ |
| **Intraday market** | Excess consumption risk<br>$(x_{t,n}^B - x_{t,n}^R) - (q_{t,n}^B - q_{t,n}^R)$ | Production ramp-rate risk<br>$(x_{t+1,n}^B - x_{t+1,n}^R) - (q_{t+1,n}^B - q_{t+1,n}^R)$ |

*$x_{t,n}^B$ denotes demand for electricity $(x)$ bid into the day-ahead market for hour $t$ in region $n$. $q_{t,n}^R$ denotes production $(q)$ realised $(R)$ in hour $t$ in region $n$, hence superscript $R$ indicates realised levels and $B$ indicates bids into day-ahead market. We differentiate between the terms demand/supply relating to bids into day-ahead market, and production/consumption relating to realised levels of production/consumption in intraday markets.

## 3 MEASURING RELEVANT RISKS

In this section, we argue that average measures, *e.g.* using the Mean-Variance approach are inappropriate for quantifying risks facing system operators in deregulated electricity markets. Rather, one would want a measure able to illustrate the worst-case scenarios from deploying wind power assets on a grand scale.

The literature has predominantly used averages from historical observations of factual production and/or wind transformed into wind power production. This may not give a proper measurement of the relevant risks for system operators. Rather, system operators would want a measure of the worst cases that may take place within a certain time horizon, for the analysis in this paper the relevant time horizon ranges from about a day to some minutes ahead. If using Mean-Variance analysis, one estimates a number capturing the normal situation.

This argument resembles the “flaw of averages,” Savage (2002). Consider the use of averages for analysing risks in intraday electricity markets, where the average correlation between windpower assets is 0.8. This highlights only the normal conditions in the market, however, hours best described as ‘normal’ conditions do not describe risky situations. Although average correlation is 0.8, there may be hours during the operations of intraday markets where production levels move in opposite direction. Thus, when analysing risky situations, one should pay more attention to non-normal situations rather than describing normality. Simply speaking, a market arrangement based upon ‘normal conditions’, normally goes wrong. That is, system operators cannot build an electricity market able to handle only average situations. Rather, electricity systems must also handle worst-case scenarios in an effective manner. This section of the paper will propose two alternative methods for measuring relevant risks for system operators. This paper differentiates between measures in day-ahead and intraday electricity markets in the following manner. Measures of risk related to the day-ahead market are associated with expected variations in wind power supply and electricity demand. On the contrary, measures of risks associated with the intraday market relates to unexpected variations in wind power production and electricity consumption.

Value at Risk is primarily used for analysing financial portfolios, but the theoretical construct is also used for analysing firms potentially facing liquidity constraints in their operations (referred to as “cash flow at risk”). Portfolio managers must ask the question: “What is the maximum loss from a particular asset portfolio, for a given level of significance (say 99,5%) and a given time horizon (say, next month or year)? Similarly, system operators must ask the question, what is the maximum excess demand for an hour the next day with a given level of significance during hour 19? The Value at Risk with a probability level of $\alpha$ is the $\alpha$-quantile of the largest negative observations from the dataseries. For a detailed discussion about this, and the method used in this paper, see Braverock.com (a). This measure enables us to say something about how large the extreme situations are.

Expected shortfall also measures the risk of observing data points at the tail of the distribution of the population of observations. However, in contrast to Value at Risk, Expected Shortfall also incorporates the shape of the distribution of observed parameters. A thorough discussion about expected shortfall, and the method of analyses used in this paper, see Braverock.com (b). This measure enables us to say something about how large the extreme situations are. Expected shortfall is an alternative to VaR, it is considered more sensitive to the shape of the tail of the distribution of the time-series analysed.

For small values of the time-series, e.g. ramp-rate requirements, it focuses on the worst losses. The measured expected shortfall does not only take into account the most extreme outcome.

To illustrate the measures of risks – and the estimation of these risks – we have gathered data from ENTSO-E, for the electricity price regions in Norway (NO2, NO3, and NO4), Sweden (SE1, SE2, SE3 and SE4), Denmark (DK1 and DK2), and Finland (1 price region). The data-series are hourly observation of 4 relevant electricity market data, Expected Load data, Realised Load data, Expected wind power data, and Realised wind power data. When single missing data were wound, we replaced missing values with the average of the hour before and after. In addition, 26 observations were removed, since the value of these observations were clearly wrong. Data used ranged over the time period, 01.01.2020 to 31.12.2024.

Illustration of risks in day-ahead market

Observing figure 3 below, excess demand risk exhibit to a large extent positive values, and only to a small extent negative values. This illustrates that wind power production deployment is still small compared to overall consumption. However, some hours during the year are characterised by having higher production from wind power sources than total consumption in this region. The largest negative values were observed during the wintertime (February 8th) during the night. Production was expected to be very high (above 2.600 MWh for some hours), while demand was expected to be relatively low (about 1.500 MWh). Thus, Denmark 1 was expected to export electricity during these hours.

When production is higher than consumption and transmission is very high, prices for electricity may drop to zero, and even turn negative; this is observed in the Nordic electricity market regularly, in particular so, in Denmark. The difference between these measures highlights the importance of using one measure for each appropriate risk relevant to the system operator. While covariation of production entities may augment a market's ability to accommodate wind power resources, one should also consider how consumption correlates between regions, and how consumption and wind power production correlates.

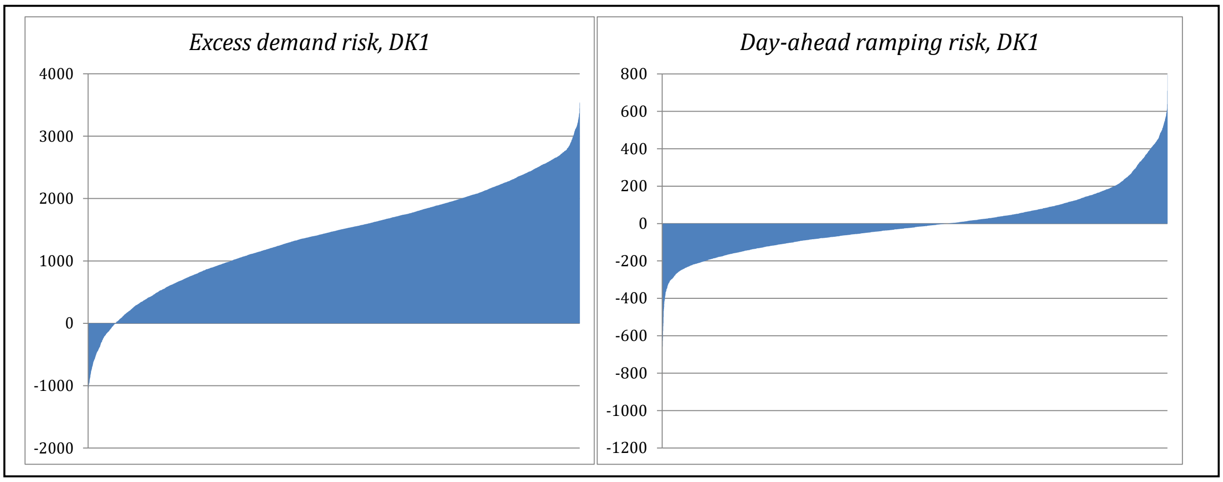

*Figure 3: a) Excess demand risk and b) supply ramp-rate risk for Denmark 1.*

Day-ahead ramping risk, the risk for sudden changes in excess demand exhibits considerably lower changes in absolute values. However, these changes highlight the need for ramping between hours required for clearing the market each hour the following day. In hydrobased electricity markets, production entities are highly flexible, while some thermal markets have stricter ramp-rate limitations potentially causing larger problems for equalising demand and supply when wind power supply and demand changes in an unfavourable way. The largest negative values are hours late at night where demand drops while expected wind power production increases. Positive values are observed when demand increases in the morning while production from wind power entities is expected to fall.

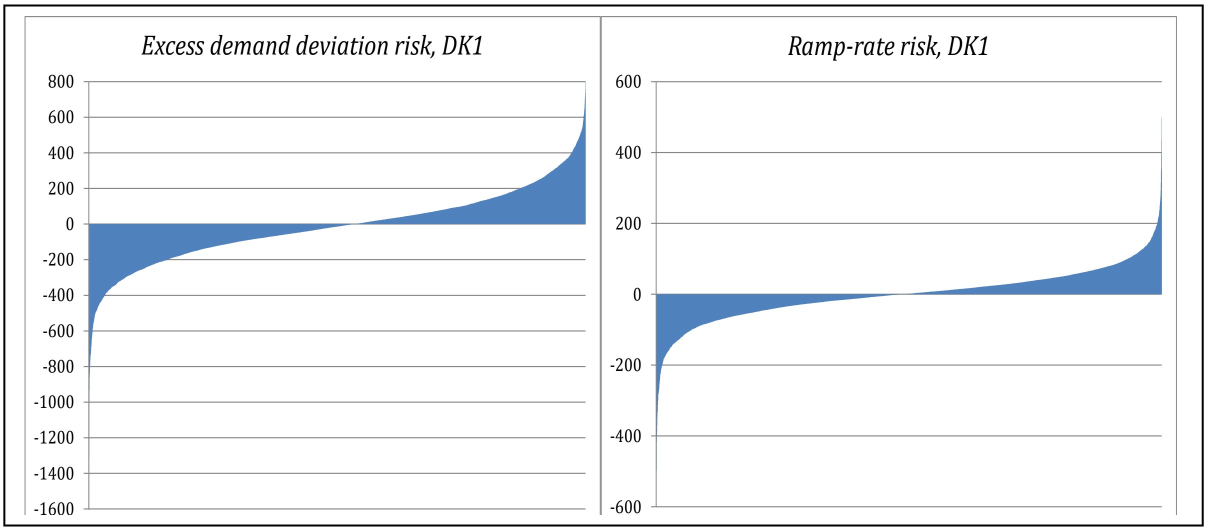

*Figure 4: Production risk to the left (4a) and ramp-rate risk to the right (4b) in Denmark 1.*

Large negative values are typically those hours where production is much lower than what was expected when the day-ahead market closed, and where realised consumption were higher than what was bid into markets day ahead. Thus, other production entities must start up producing electricity during these hours.

The final measure of risk captures the incident that took place in Denmark in 2005. Sudden and unexpected drop in wind power production requires that other production entities must ramp up production. As in the case from 2005 discussed above, the larger share of wind power deployed a larger share of production may unexpectedly stop producing electricity at a short notice. Most of the large negative values are those hours characterised by increased consumption during the morning and reduced wind power output. On average wind power production increases during the morning hours due to the diurnal effect, but in some instances this effect is negative and there is a need for ramping up other production resources or importing electricity from neighbouring areas.

## The Nordic market as illustration

We use the data described above to illustrate the proposed measures of risks, focusing on the two measures of ramp-rate risk, Supply ramp-rate risk (SRRR, see equation 3.3) and Production ramp-rate risk (PRRR, see equation 3.5).[3] Table 2 below illustrates the percentage contribution of (Var or ES) for each regional price region to the overall market VaR (or ES).

*Table 2: Supply ramp-rate risk (RSRR) and Production Ramp-rate Risk (PRRR) measured using Value at Risk (Var) and Expected Shortfall for 10 Nordic price regions (DK1, DK2, FI, NO2, NO3, NO4, SE1, SE2, SE3, SE4).*

| | **SRRR** | | **PRRR** | |
|---|---|---|---|---|
| | **VaR** | **ES** | **VaR** | **ES** |
| DK1 | 0,2119 | 0,2193 | 0,3969 | 0,3005 |
| DK2 | 0,0308 | 0,0300 | 0,0290 | 0,0119 |
| FI | 0,2663 | 0,2563 | 0,2164 | 0,2368 |
| NO2 | 0,0256 | 0,0279 | 0,0179 | 0,0561 |
| NO3 | 0,0219 | 0,0263 | 0,0157 | 0,0593 |
| NO4 | 0,0052 | 0,0053 | 0,0025 | 0,0088 |
| SE1 | 0,0227 | 0,0212 | 0,0286 | 0,0210 |
| SE2 | 0,1691 | 0,1723 | 0,2042 | 0,1957 |
| SE3 | 0,2101 | 0,2049 | 0,0778 | 0,0949 |
| SE4 | 0,0363 | 0,0365 | 0,0110 | 0,0149 |

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[3] The software used for analysing the dataseries is R, and the VaR and ES were estimated using the package PerformanceAnalytics.

The first thing to note is that three markets stand out as the largest contributors to risk from three of the price regions, the DK1, SE1, SE2 and FI. The first price region represents the largest part of Denmark with a substantial amount of wind power generation, while the other three regions are all large regional areas. These four regions represent more than 85% of the Expected Shortfall for the supply ramp-rate risk. That is, in these markets one expects changes in excess demand between two hours, and this requires that there are other production entities able to counteract this, or large transmission capacities to other price regions with flexible production. The availability of easily ramped production technologies determines how easy these variations can be met. Note also that there is a large decrease in risk for the SE3 market when comparing the VaR and ES for supply ramp-rate risk measure to the production ramp-rate risk measure.

Next, note that the risks stemming from the region DK1 to the overall market increases substantially when looking at the production ramp-rate risk. Since the day-ahead market already has been closed, this measure asks for large amount of production capacities to operate in the intraday market. If there is a sudden drop in production from wind power accompanied with an increase in consumption – both unexpected day ahead – production entities must ramp up production at a fast rate. This measure illustrates the case from Denmark discussed above, where a large fraction of production (that is, wind power) went down due to a severe storm not expected day ahead of the incident taking place.

Furthermore, there is a large difference between the VaR and ES for the DK1 region when looking at the Production ramp-rate risk, this highlights the importance of considering the tail of the distribution of risks when analysing risks in the electricity intraday market.

There are a range of interesting extensions of the current study. First, one cannot a priori argue that a portfolio of wind power assets distributed according to minimum variance using a mean-variance approach minimises the occurrence of extreme situations (Value at Risk) or level of extreme situations (Expected shortfall). There can be reasons for analysing whether risks during wintertime differ from risks during summertime.

Second, one need not restrict the analysis to expected and realised wind production using historical data. In most countries, there is long time-series of detailed wind data that can be applied to analyses of deployment of wind power production capacities in electricity markets. In this manner, one will be able to analyse the potential impact on regional markets and the overall electricity markets before actual deployment of wind farms. However, the data need to be of high quality. Chupp et al (2012) notes that "data collection should: (1) take into account the purpose of the study, (2) span three or more years, (3) have high frequency observations, and (4) be taken at 80 meters or higher (a typical turbine height)."

Third, analyses of deployment of large wind farms will impact both the need for flexible production capacities and/or transmission to regions with flexible production capacities. Events where wind farms have been employed can be analysed using a Difference-in-difference like approach for studying not only ramping requirements, but also price impacts of wind power production deployment.

## 4 CONCLUSION

The major problem related to regional wind power assets is its inherent intermittency, and its lack of predictability (Fogelberg & Lazarczyk 2017). First, the intermittent nature of wind power poses challenges when clearing day-ahead markets, and second, the lack of predictability will be challenging for intraday markets. Herein, the introduction of wind power production assets in deregulated electricity markets has been analysed using a range of measures for risks and techniques for analysing the relevant measures.

First, we outline a set of risks facing e.g. a regulator or system operator related to how one could describe preferences, that is, how to optimally define measures of risk. We illustrated measures able to capture extreme events in electricity markets.

Second, this paper outlined several measures for quantifying risks related to day-ahead and intraday electricity markets. We argued that long-term averages are not as interesting from a regulatory perspective, rather the quantification of i) the probability of extreme events, and ii) the severity of the extreme events once it takes place is of more interest.

Finally, we propose to use methods from financial economics for measuring risk of intermittency in deregulated electricity markets was introduced. And illustrated these measures using historical data from the Nordic electricity market, we found that both the measures of risk (supply ramp-rate risk and production ramp-rate risk) differs between the techniques use to quantify the risks (VaR and ES) and vice versa.

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This paper discusses how to analyse deployment of non-predictable electricity production capacities, using wind power production assets as the case of study. I use data from the Nordic electricity markets for illustrations throughout the paper. First, I propose alternative measures of risk relevant to regulatory bodies like system operators, two measures relating to the day-ahead electricity market, and two measures focusing on the redispatch electricity market. While the existing literature to a large extent focus on variation in production, I argue that the relevant risks for system operators relates to excess demand, thus the measures of risk applies various modifications of excess demand when measuring risk. Finally, the current paper proposes two alternative methods for measuring risk, the use of measures as 'Value at Risk' and 'Expected Shortfall' is more suited for evaluating the risks facing system operators.

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