Sharing Reserves through HVDC: Potential Cost Savings in the Nordic Countries

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Abstract—During summer 2018, the Nordic system’s kinetic energy dropped below a critical level. As a consequence, Svenska kraftnät, the Swedish transmission system operator (TSO), requested the largest production unit to reduce its power output to guarantee system’s security. This action resulted in a deviation from the generation dispatch determined by the market and in high costs for the Nordic TSOs. In this regard, this paper assesses the economic cost of redispatching the largest generating unit and evaluates potential economic benefits of utilizing the Emergency Power Control (EPC) functionality of HVDC lines for the provision of Fast Frequency Reserve (FFR). Moreover, the analysis is extended to the years 2020 and 2025, using Rate of Change of Frequency (RoCoF) and inertia forecasts from the Nordic TSOs. The findings of the paper suggest that the frequency of redispatching actions will increase in the future and that the cost of security for Nordic TSOs could be reduced by 70% if HVDC links are used for frequency support.

Index Terms—Emergency Power Control, Fast Frequency Reserves, Frequency Containment Reserves, frequency stability, HVDC transmission lines, low inertia, N-1 security, RG Nordic, power redispatch.

I. INTRODUCTION

As governments across the world are planning to limit greenhouse gas emissions, the penetration of renewable energy sources has significantly increased in the last decade. During the last 7 years, offshore wind energy has increased from 4.1 to 18.8 GW on a global level. In 2017, Denmark alone installed 1.27 GW of offshore wind power and forecasts show that investments will not stop here [1]. On the one hand, this process represents the first step towards cleaner electricity systems; on the other hand, it causes a shift from synchronous to inverter-based non-synchronous generation, resulting in lower system kinetic energy and reduced power systems robustness to grid disturbances.

Electrical systems are built to continuously match the supply of electricity to customer demand: any mismatch results in a deviation from the frequency from its nominal value (50 Hz in Europe). Small frequency deviations are common during normal operation, mainly caused by load volatility and intermittent renewable generation. To distinguish between normal frequency fluctuation and deviations caused by large imbalances, Transmission System Operators (TSOs) define security thresholds and activate different balancing resources depending on the size of the power deviation.

In the Regional Group Nordic (RG Nordic), normal system operation has a standard range of ±100 mHz and Frequency Containment Reserves for Normal operation (FCR-N) are deployed to keep frequency within the normal band [2]. When frequency drops below 49.9 Hz, FCR for Disturbances (FCR-D) are activated to mitigate the impact of the disturbance and stabilize the frequency, while Frequency Restoration Reserves (FRR) are used to restore the frequency back to the nominal value. The maximum acceptable Instantaneous Frequency Deviation (IFD) is 1000 mHz and, in case frequency drops below 48.8 Hz, loads are shed to avoid total system blackout [3].

The IFD that follows a disturbance depends on the size of the power deviation, on the activation speed of reserves and on the kinetic energy of the system (system inertia). Indeed, kinetic energy stored in the rotating mass of the system opposes changes in frequency after a disturbance and represents the first inherent containment reserve. Due to the replacement of conventional generation with RES, the system’s kinetic energy is decreasing, leaving the system more prone to high Rate of Change of Frequency (RoCoF) and larger IFD [4].

The methodology for calculating the FCR-D requirement consists in a probabilistic approach which aims at reducing the probability of insufficient reserves, based on different generation, load and inertia patterns [5]. The considered dimensioning incidents are the loss of critical components of the system, such as large generators, demand facilities and transmission lines. On the one hand, a probabilistic approach ensures that reserves are procured in a cost-efficient way by weighting different system conditions with the related probabilities; on the other hand, the dependence of this calculation on system’s inertia might result in insufficient FCR-D dynamic response during low inertia periods. Given the ongoing displacement of synchronous generation, this is raising concerns among TSOs.

Currently, the dimensioning incident in the RG Nordic is the loss of Oskarshamn 3, a 1450 MW nuclear power plant in Sweden (located in the bidding zone SE3) [6]. The method and the results presented in [7] show that, with the current FCR-D requirement, the maximum IFD is exceeded when the Nordic kinetic energy drops below 150 GWs, unless mitigation measures are taken. This has already happened three times in 2018 (June 23-25, July 6-9 and August 11-12) [8]. During these three periods, the loss of Oskarshamn 3 would have caused an IFD greater than 1000 mHz, violating
the N-1 stability criterion. To avoid this risk, the Swedish TSO (Svenska kraftnät) ordered Oskarshamn 3 to reduce its power output by 100 MW. TSOs are responsible for safe operation of power systems and can give orders to market participants at any market stage (real-time, intra-day, day-1, day-2, day-x) if the system security is in danger. However, this operation comes with high cost, since the affected producers should be compensated for the incurred costs and the substitute power must be procured outside the market operation [11]. This mitigation strategy falls in the category of preventive actions, which aim at eliminating causes of potential dangerous situations before these happen [12]. The following question arises: are there more cost-efficient options which guarantee safe operation while avoiding expensive redispatching actions?

Besides conventional generators, frequency support can be provided by other components capable of injecting active power into the grid, e.g. High-Voltage Direct-Current (HVDC) lines. According to [13], the control scheme of all HVDC converters must be capable of operating in frequency sensitive mode, i.e. the transmitted power is adjusted in response to a frequency deviation. For this reason, an HVDC link connecting asynchronous areas can be used as a vehicle for Fast Frequency Reserves (FFR): to limit the IFD in case of disturbance, the necessary active power can be imported from the neighboring system in the form of Emergency Power Control (EPC). Given the high number of interconnections formed by HVDC lines between RG Nordic and the neighboring groups (see Fig. 1) and the introduction in the Nordic market of a new FFR product expected by summer 2020, this corrective action could represent a valid alternative to expensive preventive redispatching. The current EPC activation method is based on step-wise triggers: when the frequency drops below a certain threshold, a constant amount of power is injected through the HVDC link, depending on the level of inertia. Although already implemented [11], HVDC EPC is currently not in use.

The utilization of HVDC interconnectors for frequency support has been largely investigated from a technical point of view [14]–[19]; however, limited work has been done on the evaluation of the related economic benefits. The goal of this paper is to investigate what is the cost of using HVDC interconnectors for the provision of frequency support, and to perform a cost saving analysis comparing this alternative to the current paradigm, which is the preventive redischatch of Oskarshamn 3. The analysis is carried out for three scenarios (2018, 2020, 2025), using historical data from Nord Pool (2018), RoCoF estimations from market simulations (2020) and inertia forecasts from the Nordic TSOs (2025). The cost of the remedial actions are calculated based on two pricing cases considering different combinations of HVDC capacity reservation and frequency reserve pricing.

The rest of the paper is organized as follows. Section II explains how the calculation of the redispatched energy is performed for the three different scenarios, based on the hours when the kinetic energy is below the requirement, and Section III describes in detail the current paradigm and the alternative remedial action. Section IV introduces the market considerations and pricing scenarios used for the calculation of the related costs. Section V presents the cost saving analyses and Section VI concludes.

II. DESCRIPTION OF SCENARIOS 2018, 2020 AND 2025

The ongoing decrease of system inertia is classified as one of the major future challenges for the Nordic Power System [20]. For this reason, the cost saving analysis presented in this paper starts with the events of 2018, and continues with two future scenarios for the years 2020 and 2025. The methodology for the calculation of the necessary reduction of the dimensioning incident (DI) varies across scenarios based on the availability of data. The three scenarios and the corresponding methodologies are further described in this section.

A. Summer 2018

During Summer 2018, the inertia of the Nordic System dropped below 150 GWs three times. The length of the periods and the limitations on the largest unit, Oskarshamn 3, have been communicated by Svenska kraftnät through Urgent Market Messages (UMM) in the Nord Pool Online Platform [8]. The three periods are:

- June 23-25: duration 50 hours, dimensioning incident reduced by 100 MW;
- July 6-9: duration 75 hours, dimensioning incident reduced by 100 MW;
- August 11-12: duration 41 hours, dimensioning incident reduced by 100 MW.

During these periods, the kinetic energy of the system was not always below 150 GWs; however, for security reasons
and technical limitations (ramping limits and costs), the output of Oskarshamn 3 was reduced for the entire length of these periods. The corresponding redisspatched energy, \( E_{\text{res}} \), is calculated as:

\[
E_{\text{res}} = \Delta P_{\text{res}} t
\]

with \( \Delta P_{\text{res}} \) the DI reduction and \( t \) the length of the period.

**B. Future Scenario: 2020**

Svenska kraftnät has performed a large number of market simulations using a dataset of historical meteorological data for the past 30 years. There is a strong correlation between weather and system inertia, e.g., in dry periods with low rainfall the production of hydro power plants is replaced by HVDC imports leading to low inertia levels [20]. Based on available data from market simulations and future forecasts [21], frequency stability can be assessed for 2020 with a resolution of 3 hours. In the following, the relation between system inertia and IFD is presented.

As mentioned above, IFD depends on power deviation, system inertia and activation speed of reserves. Assuming that generators swing coherently and neglecting the frequency dependency of the load, the system dynamics can be modeled by a single machine equivalent and its behavior can be expressed using the normalized swing equation [22]:

\[
2H \frac{d\omega_r}{dt} = P_m - P_e
\]

where \( H \) is the inertia constant of the system (s), \( \omega_r \) is the generator speed (p.u.) and \( P_m, P_e \) are respectively the mechanical and electrical power of the system (p.u.). The kinetic energy of the system, \( E_k \), can be computed as follows:

\[
E_k = \sum_{i=1}^{N} H_i S_i
\]

where \( N \) is the number of synchronous machines in the system, \( H_i \) is the inertia constant of the \( i \)th synchronous machine and \( S_i \) its rated power. The aggregate system inertia \( H \) can be related to the kinetic energy \( E_k \) with the following expression:

\[
H = \frac{E_k}{S_n}
\]

where \( S_n \) is the system’s base power. In such a reduced system, the rotor speed \( \omega_r \) of the single machine equivalent is directly related to the system frequency \( f \):

\[
\omega_r = \frac{2\pi f}{2\pi f_0}
\]

where \( f_0 \) is the nominal system frequency. RoCoF can be obtained by plugging Eq. (4) and (5) into Eq. (2):

\[
\frac{df}{dt} = \frac{f_0}{2E_k} \Delta P
\]

where \( \Delta P = (P_m - P_e) S_n \) is the mismatch between mechanical and electrical power (in actual units, e.g., MW, GW, etc.). An expression of the IFD, \( \Delta f \), can be derived by taking the Laplace transform of Eq. (5):

\[
\Delta f = \frac{f_0}{2s} \frac{\Delta P}{E_k}.
\]

The single machine equivalent described above can be extended including primary frequency reserves. The IFD is then expressed as in [7]:

\[
\Delta f = \frac{f_0}{s + \frac{R F(s)f_0}{2E_k}} \frac{\Delta P}{E_k}
\]

with \( F(s) \) the transfer function of primary reserves, describing the dynamics of governor and turbine, and \( R \) the regulating strength in MW/Hz.

Eq. (8) shows the strong correlation between RoCoF and IFD. With the assumption that the ratio between regulating strength and kinetic energy is constant for a system with high regulating strength, the authors in [7] approximate Eq. (8) using a linear regression model. The regressions are expressed as:

\[
\Delta f_{\text{over}} \approx \alpha_{\text{over}} \frac{\Delta P}{E_k} + \beta_{\text{over}}
\]

\[
\Delta f_{\text{under}} \approx \alpha_{\text{under}} \frac{\Delta P}{E_k} + \beta_{\text{under}}
\]

with the assumption that the transfer function of primary reserves is not the same for under and over frequency events. The regression model was determined using respectively 19 and 26 disturbance events (occurred in the period between October 2015 and September 2016 in the Nordic system) for under and over frequency deviation, under the assumption that FCR-N were fully activated (frequency deviations start at 49.9 Hz) and provided similar response during each disturbance. The resulting model was validated using historical disturbances from October 2016 to September 2017, with the resulting standard deviation equal to 0.035 Hz and 0.048 Hz for under and over frequency response.

The regression model is used in this work to determine the IFD for the 2020 scenario, using the RoCoF estimations based on market simulations [21]. The following assumptions are made in accordance to current TSOs practice:

- A safety margin of 0.05 Hz is kept and the maximum allowed instantaneous frequency deviation is 950 mHz;
- The dimensioning incident is reduced by blocks of 50 MW;
- The redispactch is performed 3h before and 3h after the event (3h resolution of the data);
- If the frequency limits are exceeded twice (or more) within 36 hours, the dimensioning incident is reduced for the whole period (the maximum reduction is applied).

The sequence diagram of the algorithm is depicted in Fig. 2. For each instance, the RoCoF is given as an input to the linear regression model (Eq. (10), with \( \alpha_{\text{under}} = 0.0769 \) and \( \beta_{\text{under}} = -0.02 \)), which returns the corresponding IFD. The IFD is then compared to the maximum allowed IFD (Triggering Frequency Level - TFL), which is 950 mHz. If the IFD is below this value, then the N-1 criterion is satisfied and no redispactch is necessary, so the algorithm moves to the next instance. When the IFD is greater than 950 mHz, the algorithm calculates how much the dimensioning incident must be reduced to meet the maximum allowed IFD. The duration of the event is determined according to the aforementioned
assumptions. The redispatched energy is then calculated using Eq. (1).

C. Future Scenario: 2025

Nordic TSOs have an online tool for inertia estimation in their SCADA systems [11]. Since the decrease of system inertia is becoming a concern, a lot of work is done to forecast what could be the future situation. In 2016, Nordic TSOs published a collaborative report with the expected future level of inertia in the Nordic system for different scenarios [20]. The presented results are based on market simulations with historical generation data and future load forecasts. Average inertia constants for nuclear, thermal and hydro power plants are used to estimate the kinetic energy level of the system. Using estimations on future wind power installed capacity and information on synchronous generation plants decommission, the report provides the occurrence of low kinetic energy situations in hours per year. Two different scenarios for 2025 are considered, based on different system conditions:

1) Full nuclear (FN): market simulations based on the current situation, with nuclear power plants fully dispatched.
2) Half nuclear (HN): market simulations with half of the nuclear production replaced by wind and solar production and HVDC imports (all inverter-based generation).

The scenarios are further described in a previous report from ENTSO-E [23]. The comparison of the two scenarios gives an idea of how synchronous generation replacement contributes to low inertia periods, moving from 7.7% to 22% occurrence.

The results presented in [20] are used in this work to determine the necessary redispatched energy for the 2025 scenario (FN and HN). It is assumed that Oskarshamn 3 is fully dispatched during low kinetic energy periods, i.e. the dimensioning incident is equal to 1450 MW. Moreover, the loss of inertia corresponding to the loss of Oskarshamn 3 is also considered. Based on the number of hours per year when the estimated inertia is below the requirement, the redispatched energy was calculated using (1).

III. REMEDIAL ACTIONS

Remedial actions are defined as the set of measures applied by TSOs to maintain operational security and relieve congestions. According to the Network Code on System Operation [12], remedial actions can be divided into:

- Preventive actions: measures applied in operational planning or scheduling stage to prevent dangerous situations and maintain system security in the coming operational situation.
- Corrective actions: measures implemented immediately or relatively soon after an occurrence of a contingency.

In this paper we consider remedial actions taken to meet the maximum allowed IFD during low inertia periods, fulfilling the N-1 security criterion. This section starts with the explanation of the current paradigm, the preventive reduction of Oskarshamn 3 followed by upward regulation of reserves. We then investigate an alternative corrective action where HVDC contributes to frequency stability. Technical considerations are out of the scope of this paper; remedial actions are considered only from an economic point of view, and their costs are compared in Section V.

A. Current Paradigm - DI Reduction

The current practice in case of low inertia periods is the preventive reduction of the dimensioning incident, i.e. the largest production unit, Oskarshamn 3. For example, if the maximum disconnected power the system can handle is 1300 MW, the power output of Oskarshamn is reduced by 150 MW. Fig. 3 shows the power limitation on Oskarshamn (orange plot) depending on the level of inertia.

When this measure is used, the producer should receive market compensation for the costs associated with the power limitation. First, by decreasing its power output, the producer incurs opportunity costs that are equal to what they would have received for producing an amount of power equal to the power reduction. Second, by moving away from the nominal power output, extra costs are incurred due to lower efficiency (as a rule of thumb, for nuclear power plants, one can say that half of the fuel which is not used during the power reduction is wasted) [11]. Third, the decrease of power production of nuclear power plants results in a temperature transient, inducing a cumulative aging of the unit and increasing the risk of failure [11]. Finally, depending on the length of the reduction period, nuclear units might take from 6 to 72 hours to get back to their nominal power output (for example, if the limitation is performed for up to 80% of the operational period, the output cannot be increased for the remaining time) [11].

All these costs are shared by Nordic TSOs, together with the cost of procuring the substitute power in the regulating market.

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Fig. 2. Sequence diagram of the algorithm calculating the redispatched energy in the 2020 scenario (IFD = instantaneous frequency deviation, TFL = triggering frequency level).
B. HVDC Emergency Power Control

This remedial action relies on the fact that HVDC converters, equipped with fast frequency controllers, can adjust the power flow in response to frequency deviations. This control mode is referred to as Emergency Power Control (EPC). This measure falls in the category of corrective actions: even if the loss of Oskarshamn would lead to an IFD greater than 1000 Hz with the expected inertia level of the system, the output of Oskarshamn 3 is not reduced in advance. In case the dimensioning incident occurs (e.g. because of an outage), the EPC is immediately activated and the necessary power to keep the frequency within the limits is injected through HVDC.

Different control strategies can be used to define the response of HVDC converters. The currently implemented strategy is based on step-wise triggers: depending on the size of the power deviation and the corresponding frequency variation, a constant amount of power is injected to improve the frequency response of the system. Authors in [14] presented a new approach based on droop control, where the power injection varies taking into consideration the actual frequency response of the system (instead of injecting a fixed amount of power) to achieve a faster response compared to the current strategy. However, technical aspects, such as control strategies or ramping limits, are outside the scope of this paper. For our analysis, the injected power is calculated based on the reduction of the dimensioning incident with an efficiency of 0.87, as it can be seen in Fig. 3 (blue plot). Indeed, from a frequency point of view, injecting a certain amount of power through HVDC is not as effective as decreasing the disturbance inertia.

With this action, the possible costs for Nordic TSOs would only be the reservation of HVDC capacity and the procurement of primary reserves in the neighboring countries. This control method is used only to contain the frequency within the limit; the frequency restoration is assumed to use local reserves: since primary reserves are not paid for the energy they produce, there are no extra costs for the activation of reserves in case of contingency. In addition, the reservation of HVDC capacity and the procurement of reserves for HVDC EPC are only needed for those hours when the frequency can fall below 49.05 Hz whereas the reduction of the dimensioning incident would be prolonged for more hours due to technical limitations. The analysis focuses on four interconnectors - Baltic Cable, Kontek, SwePol and NorNed - and the injected power is equally shared by the four links.

IV. MARKET CONSIDERATIONS

In this section, the market considerations and pricing cases for the cost saving analyses are presented.

A. Pricing Cases

Two different pricing cases are considered for the calculation of the costs of the remedial action using HVDC:

1) NoCosts (NC): there is no need for procuring primary reserves and there is available capacity on the HVDC links, so Nordic TSOs do not bear any cost.

2) Reserves&HVDC (RH): Nordic TSOs pay for the procurement of primary reserves and for reserving capacity on the HVDC links;

The first case, NoCosts, is based on the consideration that UCTE is a large system with more than 3 GW of reserves. It is reasonable to assume that there might be, in the future, an agreement between Nordic TSOs and TSOs in RG Continental Europe and RG Baltic for the exchange of reserves in situations where operational security is in danger (or at any time in order to increase the level of security). This can be something similar to the International Grid Control Cooperation (IGCC) [24], an agreement between 27 TSOs in RG Continental Europe. The goal of the project is to avoid the simultaneous activation of reserves in opposite directions by considering the availability of cross-border transmission capacity. The result is that TSOs use less balancing energy while increasing system security. Regarding HVDC capacity, this case considers a certain availability of capacity (given that there are 100 MW of available capacity on the considered lines for 70% of the time on a yearly average [25]) or the possibility to overload HVDC lines for a short amount of time (in the range of minutes) when HVDC lines are operated at their maximum capacity. In this way, there is no need to reserve HVDC capacity in advance, thus avoiding these costs.

The second case, Reserves&HVDC, considers a possible future situation where there is a European market for reserves, and Nordic TSOs are requested to procure the necessary primary reserves through this platform. This seems to be the direction that European countries are taking, as described in [26] for automatic activated FRR. Moreover, the reservation of HVDC capacity is assumed to come with a cost. This is considered also in [11], where they assume there might be a reservation cost for HVDC in the future.

The choice of these cases has been made to give a possible range of costs, since they represent the upper and lower bounds on the cost of this remedial action. Whether Nordic TSOs will pay for reserves or HVDC capacity, or both of them, the costs calculated based on the second case, Reserves&HVDC, will represent the maximum costs they will bear. Similarly, considering NoCosts for the utilization of HVDC gives an indication of the maximum cost savings that could be achieved.
B. Redispatching Costs and Regulating Prices

The downregulation of Oskarshamn 3 is considered as a redispatching action. Normally, redispatch happens after the day-ahead and intra-day markets have been cleared: this is done to avoid the distortion of the market outcome. Generators and consumers have to submit their final dispatch 45 minutes before real time operation; in this time frame, TSOs check if the actual dispatch violates grid constraints. If this happens, they downregulate and upregulate some units. This can be done in two ways: market- or cost-based [27]. In the first approach, generators and consumers submit their bids for up/down regulation, the real-time market is cleared and the prices for up/down regulation are defined. With a cost-based approach, downregulated units return an amount equal to their cost of production and keep their revenue, while upregulated generators are only compensated for their costs of production.

However, low inertia periods are considered extraordinary events where the security of the system is in danger. For this reason, Svenska kraftnät can communicate the limitation on Oskarshamn 3 at any market stage. In 2018, low-inertia events were forecast after the day-ahead market was cleared, and thus the reduction of Oskarshamn 3 was performed similarly to normal redispatching:
- Oskarshamn 3 was compensated for the opportunity cost of not producing 100 MW (the compensation was equal to 49 SEK/MWh - approx. 4.64 €/MWh);
- Oskarshamn 3 was compensated for reduced efficiency and other costs associated with the power limitation (fixed amount equal to 50’000 SEK - approx. 4’740 €);
- the substitute power was procured from other generators in the regulating market (Nord Pool regulating price €/MWh [25]).

All three low-inertia events in 2018 happened during summer (June to August). Therefore, in all our scenarios we assume that the redispatching will most probably occur in the summer period. As a result, we calculate the average regulating price during summer weekends (low-load periods). The average Nord Pool regulating price during summer weekends in 2018 was equal to 50.18 €/MWh [25]. Since market forecasts for the year 2020 or 2025 are out of scope of this work, all the prices considered in this paper are based on 2018 market data. This assumption is reasonable considering the almost flat evolution of prices forecasted in [28].

C. Reserve Procurement Prices

To make the analysis as realistic as possible, the necessary power is injected through four different HVDC links - Baltic Cable, Kontek, SwePol and NorNed. The power injection of each link is considered to be 25% of the total injection. For this reason, the procurement of primary reserves is done in the three countries connected by these links - Germany, Poland and the Netherlands.

The prices for reserves are taken from ENTSO-E Transparency Platform [29], and the cost analyses are based on the average price during summer weekends in 2018. The average price in Germany was 10.17 €/MWh, in Poland 5 €/MWh and in the Netherlands 17.16 €/MWh. As for regulating prices, we assume reserve prices are the same for the 2020 and 2025 scenarios.

D. HVDC Capacity Reservation Price

For those interconnectors whose capacity can be reserved, prices are determined through auctions which are usually not publicly accessible. However, Energinet has published in their online database, Energi Data Service, the auction prices for Kontek [30], the link between Germany and Denmark (DK2). Since no other data is available, in our analysis we consider prices for the all the HVDC links to be equal to the prices for Kontek.

In 2017, the auction price was 26’185.10 Eur/MW/year or 2.99 Eur/MW/h on average. For the scenario 2018, the exact dates of the redispatch periods are available, thus HVDC reservation prices are determined using the reservation prices for those exact periods from [30]. On the contrary, the dates for the redispatch events taking place in 2020 and 2025 are unknown, thus, we use the 2017 average capacity reservation price, i.e. 2.99 Eur/MW/h.

V. COST SAVING ANALYSES

In this section, the results of the cost saving analyses are presented. TABLE I presents the results of the calculation described in Section IV with the hours when the kinetic energy is below the requirement and the corresponding redispatched energy. The average length of three low-inertia periods in 2018 was 55 hours. In order to estimate the number of events in 2020 for the fixed-cost compensation, the same average length was considered, while we assume it increases to 80 hours in 2025 for the full nuclear scenario and to 90 hours for the half nuclear scenario (this is done in order to not overestimate fixed costs).

The cost of reducing the dimensioning incident is provided in TABLE I. In summer 2018, the cost of downregulating Oskarshamn 3 is calculated to be around 83 thousand euros, while the procurement of the substitute power about 724 thousand euros, resulting in a total cost of around 0.8 million euros. The future projections suggest that there will be more low-inertia periods in 2020 and the redispatch costs will be doubled, reaching 1.6 million euros. Depending on the generation mix considered in the full nuclear or half nuclear scenarios, the cost of reduction of the dimensioning incident will range between 12.36 and 47.27 million euros per year by 2025.

While estimating the cost of using HVDC for frequency support, two pricing scenarios were considered - Reserves&HVDC and NoCosts. This gives a possible range of costs, considering all the possible costs in one scenario and

| Scenario | Events | Hours (h) | Energy (GWh) |
|----------|--------|-----------|--------------|
| 2018     | 3      | 166       | 16.60        |
| 2020     | 5      | 294       | 33.12        |
| 2025 FN  | 9      | 673       | 257.88       |
| 2025 HN  | 22     | 1901      | 987.52       |
no costs in the other. In 2018, under the assumption of the Reserves & HVDC scenario, the costs of using HVDC can be divided into 50 thousand euros for reserving HVDC capacity and 176 thousand euros for procuring primary reserves in the three neighboring countries, for a total cost of 226 thousand euros. Similar to the preventive reduction of Oskarshamn, these costs are expected to double in 2020, reaching 451 thousand euros. Then, depending on the generation mix (full vs. half nuclear), these costs will range between 3.51 and 13.45 million euros per year by 2025. The costs based on the Reserves & HVDC scenario are reported in detail in TABLE III. On the contrary, if the assumptions of scenario NoCosts take place, then there are no costs associated with this remedial action.

The cost saving comparison between DI reduction and HVDC EPC is provided in Fig. 4 for all the considered scenarios. The cost of the current paradigm is used as reference, and the savings from HVDC EPC based on the two pricing cases are compared. Clearly, the economic benefit from using HVDC for frequency support during low-inertia periods can be seen even today, where potential cost savings in 2018 are between 0.58 and 0.8 million euros depending on the generation mix (full vs. half nuclear), or in the range of 33.80-47.20 million euros per year if the capacity of nuclear power plants is halved (half nuclear).

VI. CONCLUSION

During summer 2018, the inertia level of the Nordic System dropped below 150 GWs three times, jeopardizing the N-1 security of the system. To deal with these situations, Svenska kraftnät ordered the reduction of the power output of Oskarshamn 3, a nuclear power plant in Sweden, which is the most critical generating unit of the Nordic system. The costs associated with this power limitation for the three instances in 2018 have been calculated in this paper and amount to 0.8 million euros. Given that more and more low-inertia periods are expected in the coming years, this calls for a reassessment of whether there exist more cost-efficient options which guarantee safe operation while avoiding expensive redispatching actions.

In this paper, we investigate what is the cost of using HVDC interconnectors for the provision of frequency support, and we perform a cost savings analysis comparing this alternative to the current paradigm. The analysis is carried out for three scenarios (2018, 2020, 2025), using historical data from Nord Pool, RoCoF estimations from market simulations and inertia forecasts from Nordic TSOs. The cost of the remedial actions are calculated based on two pricing cases considering different combinations of HVDC capacity reservation and frequency reserve pricing. Our results show that, if HVDC was used in the form of Emergency Power Control, the costs in 2018 could be reduced to 0.25 million euro (or cancelled out). The extension of the analysis to year 2020 and 2025 confirms that many more low-inertia periods can be expected in the future, calling for more redispatching actions. In this regard, the method proposed in this paper would reduce the costs by 70%, resulting in cost savings in the range of 8.84-47.2 million euros per year by 2025.

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