Dynamic simulation of simultaneous HVDC contingencies relevant for vulnerability assessment of the Nordic power system

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***Abstract*—Large power-infeed of individual HVDC interconnectors may make the power system vulnerable to contingencies involving multiple HVDC interconnectors. This paper describes and demonstrates an approach to quantitative vulnerability analysis applied to HVDC contingencies. We consider four barriers' ability to mitigate severe frequency drops: inertial response, frequency containment reserves, demand-side response and under-frequency load shedding. Demand-side response, implemented as fast reduction in loads in response to decreasing frequency, is given particular attention. The consequences of an HVDC contingency in the presence or absence of these barriers is analysed to assess the power system vulnerability. Results illustrate how in low-inertia operating states, a) large-scale load shedding may be inevitable after simultaneous outage occurrence of multiple HVDC interconnectors and b) that barriers may significantly reduce the amount of load shed. Demand-side response could be an effective barrier if the response time is low and a sufficiently large amount of load is involved.**

***Index Terms*--Demand response, power system stability**

I. Introduction

Seeking to better utilize available power capacity and energy resources within the European power systems, new HVDC interconnectors are being built. These newer HVDC interconnectors possess maximum power transfer capacities much higher than many existing interconnectors in the Nordic system, e.g. the new NordLink and North Sea Link which each carry up to 1400 MW power [1]. An outage of such an interconnector operating at maximum capacity approaches the current reference incident of the Nordic synchronous area. The reference incident or dimensioning fault in the Nordic synchronous area is loss of the largest generation unit [1]. As the number of HVDC interconnectors with large maximum transfer capacities grows, there is a higher number of infeed units that may be involved in contingencies approaching or exceeding the reference incident. This is a potential vulnerability in the Nordic power system. The potential vulnerability is compounded by increased use of converter-interfaced renewable energy resources and the possibility of high import through HVDC interconnectors, which may lead to low inertia operating states. In such operating states, the system may be especially vulnerable to contingencies involving outage of multiple HVDC interconnectors. Although the probability may be low, such contingencies cannot be ruled out, especially when two or more converter terminals are situated electrically close in the AC transmission grid.

Whereas low-probability contingencies may be entirely neglected in conventional risk and reliability analyses [2], they must be considered in a vulnerability analysis, where the aim is to identify which contingencies can cause critical consequences and how they could be mitigated. Vulnerability associated with HVDC interconnectors was studied in [3] through a qualitative and semi-quantitative vulnerability analysis of the Nordic power system. This study focused on frequency instability following HVDC contingencies in high import, low inertia operating states. It provided a broad overview of relevant aspects of HVDC contingencies in the Nordic power system and a basis for more detailed analysis. The vulnerability analysis in [3] also included the identification of existing and missing barriers that – if operating successfully – could limit the consequences of these contingencies. Identified barriers included System Protection Schemes (SPSs) such as Under-Frequency Load Shedding (UFLS) and new fast-acting sources of active power injection or load reduction.

In this paper we propose to use the qualitative vulnerability analysis in [3] as a starting point for a more detailed quantitative analysis of system consequences: The objective of the paper is to describe and demonstrate an approach to vulnerability analysis focusing on SPSs and the response in system frequency following a simultaneous HVDC contingency in the Nordic power system. A key part of the approach is a consequence analysis able to capture barriers and contingencies not usually considered in conventional risk analysis. Specifically, by combining dynamic simulation and an event

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tree approach, the analysis captures the following barriers and the possibility that barriers fail to operate successfully: inertial response in a future power system with new HVDC interconnectors, generators' primary response, and SPSs such as under-frequency load shedding (UFLS) and Demand-Side Response (DSR). Special emphasis is put on DSR, and we assess how the vulnerability of the system depends on the amount of flexible load and the time-delay for activation.

The rest of the paper is structured as follows. Section II summarizes related work on power system vulnerability analysis that forms the foundation for the present analysis. Sec. III describes the proposed approach for analysing consequences of simultaneous HVDC contingency as part of a power system vulnerability assessment. To illustrate some fundamental principles relevant for assessing the vulnerability of the power system, a case study considering a specific HVDC contingency is presented in Sec. IV. In Sec. V the paper is summarized and some suggestions for further work are made.

II. Vulnerability analysis

The work presented in this paper builds upon a general framework for vulnerability analysis of high-impact low-probability (HILP) events in power systems [4] and a specific application of this framework for analysing the vulnerability associated with HVDC contingencies in the Nordic power system [3]. Vulnerability analysis allows for consideration of HILP events that may be deemed too unlikely and thus entirely neglected in traditional risk analyses. By first identifying critical consequences that may occur in the power system, we may try to understand *how* these critical consequences could occur and how they could be mitigated.

In the general vulnerability framework [4], a barrier is understood as something that either can prevent an event from taking place or protect against its consequences. As depicted in Fig. 1, barriers are associated with either the power system's susceptibility to threats or its coping capacity with respect to contingencies caused by a threat. A vulnerability can be associated with a barrier that is either missing or ineffective. In the present paper, the scope is limited to the right half of the bow-tie model in Fig. 1. We thus consider how barriers may improve the coping capacity of the system with respect to contingencies involving the simultaneous outage of multiple HVDC interconnectors, given that such contingencies occur.

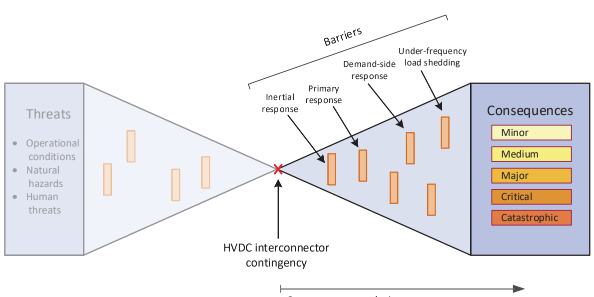

Figure 1. Bow-tie model schematically illustrating the vulnerability analysis and the scope of the dynamic simulations carried out for this paper.

Related work also includes [2], which presented a risk and vulnerability analysis methodology and applied it to a real transmission system. This methodology was based on fault trees for the cause analysis and event trees combined with static power flow simulations and expert judgement for the consequence analysis. In contrast to [2], the present paper focuses on the consequence analysis part of the vulnerability analysis and employs more detailed dynamic simulations. Event trees are also proposed for modelling failure of corrective actions (including SPSs) in [5], which highlights the importance of considering such failures. It has previously been demonstrated in [6] that modelling of corrective actions greatly affects the estimated consequence of contingencies. Although that work considered a reliability analysis, it clearly showed the importance of modelling the barriers relevant for the system's coping capacity. However, also in the context of HILP events (specifically so-called cascading outages), the importance of SPS modelling has been highlighted [7] [8].

III. Methodology

This section describes the proposed approach for analysing consequences of a simultaneous HVDC contingency as part of a power system vulnerability assessment. The approach includes using a dynamic power system simulation model (Sec. III.A), appropriately tuning the model to represent operating states with high HVDC import and low inertia (Sec. III.B), and modelling SPSs and other barriers that are relevant for the response in system frequency (Sec. III.C). Finally, Sec. III.D explains how an event tree approach is considered to employ the consequence analysis in a vulnerability analysis context.

A. Dynamic power system simulation model

The Nordic 44 (N44) model, described in [9], is an aggregated dynamic power system simulation model designed for analysis of system frequency response in the Nordic power system. It consists of 44 buses, 43 loads, 67 branches and 61 generators, many fewer than the thousands of buses and generators in detailed models of the real Nordic power system. The model is implemented in both Siemens PSS/E and DIgSILENT PowerFactory. The reference to *Nordic* in this model means Norway, Sweden and Finland, where East-Denmark is very simplified represented as being part of the load in the south of Sweden. The N44 model is intended for research and educational purposes in the absence of publicly available detailed grid models. Data sets together with a description of the background of the model are available at [10]. In load-flow terms, existing HVDC interconnectors are modelled as PQ-buses and PV-buses.

B. Tuning of aggregated grid model and operating state

To study the response in system frequency following a simultaneous HVDC contingency in the future power system, the N44 model and the operating state (generation and load demand distribution) must be tuned appropriately. Tuning is challenging as there is no historical data publicly available for response in system frequency which we may utilize in tuning for a simultaneous HVDC contingency. Further, there are large uncertainties in future power system developments, making the future system response less predictable. To consider response in system frequency following a simultaneous contingency of HVDC interconnectors importing power near rated capacity in both high and low inertia scenarios, the following procedures are followed: 1) tune the N44 model using currently available

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data on large frequency excursions in the Nordic power system to create a base case, 2) represent an operating state with high HVDC power import, 3) represent an operating state with reduced inertia.

1) Tuning of aggregated grid model

The N44 model frequency response is in [11] tuned to the measured frequency response of the Nordic system frequency following the large, scheduled outage of the Ringhals nuclear power plant in Sweden at the 5th of March 2015, at 11:00 – 12:00 hours. The operating state has a total load of 49 238 MW and is considered the base case in our analyses.

2) Modelling of HVDC interconnectors

To study large losses of power infeed, the interconnectors that will be involved in the contingency in the simulations must be set to import power. The load buses corresponding to these HVDC interconnectors thus have their load demand set to $-P_{\text{export}}$, where $-P_{\text{export}}$ is the import of the HVDC interconnector before the contingency occurs. Changing the power infeed at HVDC interconnectors in N44 causes power flows to change and lines to be overloaded. As dynamic simulations in PSS/E are initialized from static power flows, overloads must be alleviated to avoid unpredictable behavior in dynamic simulations. We thus reduce active power generation at generators in the power system to compensate for increased active power import. Primarily the generation of generators in proximity to the HVDC import-adjusted interconnectors is reduced, to try to retain system-wide power flows as in the non-overloaded base case.

The simultaneous outage of HVDC interconnectors is modelled by a step load change at each of the considered HVDC buses in the N44 model from $-P_{\text{export}}$ to 0. The load steps occur at the start of the dynamic simulations in PSS/E and represent loss of power import.

3) Reducing inertia of the Nordic synchronous area

To study the effects of low inertia, the inertia of the base case must be reduced. First, the system load and generation are reduced by an amount α (%) at each load and each generator in the power system. Second, it is checked if there are superfluous generators online; that is, if there are N generators online at a generator bus prior to reduction of active power generation, it is checked whether the rated capacity of fewer than N generators is sufficient to provide the desired amount of active power generation, which has now been reduced by α. If more generators are online than required, excessive generators are disconnected to reduce inertia and the active power generation is distributed equally amongst remaining online generators. The inertia decrease is measured using the Centre of Inertia (COI) frequency [12]. These heuristics for reducing inertia may not accurately represent realistic power system operation, but we only wish to compare results from high and low inertia cases, and this approach is sufficient for our purposes.

C. Modelling of barriers

This section describes how barriers intended to reduce the consequences of an HVDC contingency are implemented in the vulnerability analysis. An overview of implemented barriers is shown in Fig. 2.

Figure 2. Overview of how barriers are implemented in the simulations

1) Inertial response

The inertial response refers to the ability of the rotating masses, in the power system, to absorb or release energy in response to frequency changes. Power is released or absorbed proportional to the inertia of the rotating masses, and the inertial response is included in the dynamic simulations through PSS/E generator models.

2) Primary response

Primary reserves (or Frequency Containment Reserves for Disturbances, FCR-D) allow generators to increase active power generation in response to frequency dips. This is the primary response and occurs a few seconds after a disturbance as the frequency drops and is implemented using PSS/E turbine governor models. Primary response failure occurs when primary reserves are saturated, which is modelled as no primary response following the HVDC contingency.

3) Demand-side response

Demand-side response describes the ability of loads to reduce load demand in difficult grid situations [13]. While typically associated with reducing peak load, this type of flexible resource could also be utilized to respond to off-nominal system frequency. This form of DSR can be referred to as an emergency demand response or curtailable load program [13]. Such contracted load shedding can be considered as a SPS and it can be considered as a load-based frequency response reserve [14], [15]. The effectiveness of DSR as a barrier to an HVDC contingency will depend on the amount of DSR-enabled load available, the reliability of of the DSR-enabled load to respond when called for, and the time-delay of the response to changes in system frequency. For example, to fully compensate a loss of 2100 MW power infeed due to an HVDC contingency, only 4.3% of the total load of 49 238 MW is needed for the operating state mentioned in section III.B.1). However, the response must also occur sufficiently fast.

DSR is implemented as a simple proportional response-based mechanism where frequency is measured at each load in the system, and the load is decreased proportionally to the bus frequency over a given frequency interval $f_{\text{lower}} \leq f \leq f_{\text{upper}}$, where f is the frequency at the load, f_{upper} is the upper frequency activation threshold for which the demand starts responding and f_{lower} is the lower threshold at which all DSR-enabled load is utilized. The DSR is modelled as:

$$\frac{dP_{\text{DSR}}}{df} = \frac{\delta \sum_{i=1}^{K} P_{\text{L},i}}{\Delta f} \tag{1}$$

$$\Delta f = f_{\text{upper}} - f_{\text{lower}} \tag{2}$$

where P_{DSR} is the total active power response of the DSR in the system, δ is the percentage of the load in the system that is DSR-enabled, Δf is the width of the frequency interval in which DSR responds, K is the number of loads and $P_{\text{L},i}$ is the load i in the power system at the start of simulation. The frequency bias of DSR is thus given by dP_{DSR}/df.

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4) Under-frequency load shedding

UFLS is a SPS through which load is automatically and progressively reduced in a controlled manner as the frequency drops beneath certain pre-defined thresholds. This is considered a last-resort barrier against system blackout. UFLS is implemented using the PSS/E protection relay model DLSHBL. Load shedding thresholds are specified for three distinct frequency values as described in more detail in [16].

D. Consequence analysis

To evaluate the performance of different barriers and the effect of their absence or failure to operate, the frequency nadir is used as a performance indicator. Following e.g. [2], [5], an event tree can be constructed showing possible combinations of barriers that may or may not operate successfully following an HVDC contingency, as shown in Fig. 3. The event tree may then be used to select a subset of possible sequences of events considering failure of barriers. In the context of vulnerability analysis, this allows inspection of possible consequences that would normally be neglected due to low estimated probabilities of the events occurring.

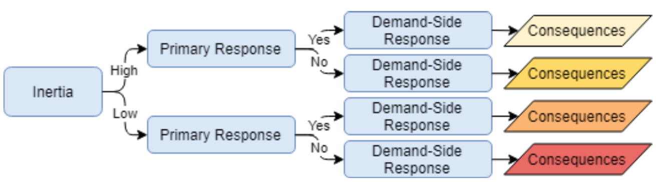

Figure 3. Event tree for a subset of the barriers modelled, where weakened, absent or failed barriers lead to the most severe consequences.

IV. Case Study

In this section a case study is considered to illustrate the principles captured by the proposed methodology and how the barriers that are modelled may affect the vulnerability of the power system. The scenario for the case study is described in Sec. IV.A before results are shown in the form of time-domain plots for system frequency in Sec. IV.B.1) and a sensitivity analysis focusing on the DSR barrier in Sec. IV.B.2).

A. Case set-up

Using the heuristics described in section III.B.3), α is set to 30% and the system inertia is successfully reduced by approximately 30% from 290 GWs in the base case operating state to approximately 200 GWs in the lower inertia operating case. The value 30% is arbitrarily chosen to be able to compare high and low inertia cases. In this paper we focus on the consequences in these two operating states for a specific contingency: the simultaneous outage of two HVDC interconnectors in Norway corresponding to a 2100 MW loss of imported power. It must be stressed that ascertaining the consequences that would occur in the real power system is not our intention, but rather to illustrate how barriers may in principle affect the response in system frequency.

Using event trees as illustrated in Fig. 3 we define cases with combinations of barriers to be included (operating successfully) or are absent (failing to operate) in the simulations. The UFLS time-delay for load shedding is set to 1.0 seconds. Primary reserves are 1800MW and the frequency bias is 8400 MW/Hz. For brevity, primary reserves will in the results be referred to as FCR. For DSR, f_{upper} is set to 49.9 Hz and f_{lower} is set to 49.0 Hz. Thus, when the frequency is 49.9 Hz, no DSR has been activated, but will be linearly activated until it reaches maximum activation (specified by δ) at 49.0 Hz. In the time-domain plots, δ is set to 10% and the DSR time-delay is set to 1.0 seconds. With δ at 10%, there is up to 4923.8 MW of reserves for the base case. For the low inertia case (with lower load) there is 3446.7 MW. In sensitivity analyses, δ is varied along with the time-delay.

B. Results

1) Time-domain response in system frequency

We simulate the consequences of the contingency for the cases defined in Sec. IV.A and show the results for the operating state with higher inertia (abbreviated HI) in Fig. 4. In the case including all considered barriers (HI, FCR, DSR) we may avoid load shedding and the frequency drops to approximately 49.6 Hz. Using DSR (HI, DSR), the frequency reaches a steady-state value of approximately 49.2 Hz, showing a significant decrease in the absence of FCR. If DSR is absent and FCR operates successfully (HI, FCR), reaches a steady-state frequency of approximately 49.0 Hz, which is worse than when using DSR. This is due to a larger amount of DSR-enabled load available than FCR (4923.8 MW of DSR reserves versus 1800 MW for FCR). With the absence or failure of both FCR and DSR (HI), the frequency drop is large and load is shed within 6–7 seconds of the disturbance.

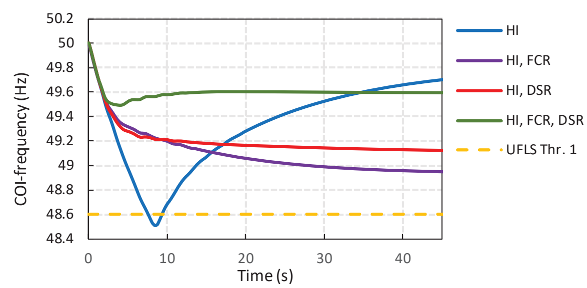

Figure 4. Time-domain plot of response in system frequency with higher system inertia.

For the operating state with low inertia, abbreviated LI, Fig. 5 shows that in all cases load is shed approximately 5–15 seconds after the simultaneous HVDC contingency. When both the FCR and DSR are present and operate successfully (LI, FCR, DSR), there is sufficient load shed at the first UFLS threshold to arrest the drop in system frequency. Assuming only FCR or DSR, load shedding also occurs at the second threshold as there is insufficient load shed at the first threshold to stop the decrease in frequency. For only FCR (LI, FCR), load shedding occurs slightly later than for DSR (LI, DSR), implying that FCR may be marginally more effective in attempting to arrest the frequency for lower system inertia. This contrasts with (HI, FCR) and (HI, DSR) where DSR was more effective than FCR. The difference may result from lower amounts of controllable load in the lower inertia operating state due to proportional reduction of load demand and active power generation. In the absence of these barriers (LI), the frequency drop is even larger. Furthermore, a rapid decrease in frequency leads to larger amount of shed load due to the time-delay of UFLS and is

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evident from the frequency rise after (especially) the 2nd load shedding threshold. In the (LI, FCR, DSR) case, the frequency decreases more slowly, leading to a lower amount of load shed and to the lowest steady-state frequency in Fig. 5. In contrast, large amounts of load shed for the (LI) case lead to a large generation surplus in the system after load shedding and thus a very rapid frequency rise and high steady-state frequency. This behavior might be mitigated if frequency thresholds were specified in more steps, as in the real power system. Load shedding would then occur progressively instead of through large steps, and the sudden frequency rise may be reduced.

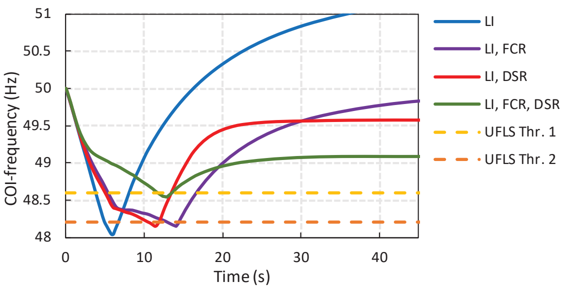

Figure 5. Time-domain plot of response in system frequency with lower system inertia.

2) Sensitivity analysis for DSR

We now focus on the DSR barrier and analyse how sensitive its effectiveness is to the DSR time-delay and the amount of DSR-enabled load. Note that a similar approach could be used for any barrier. Below, steps in time-delay of 0.5 seconds and steps in DSR-enabled load (δ) of 5% are considered.

For high system inertia and in the absence of FCR, we can consider the effectiveness of DSR in stopping the frequency drop. Fig. 6 shows that increasing the amount of DSR-enabled load improves the nadir of the system frequency. Below 10% of DSR-enabled load there is a steep decline in the frequency nadir. The frequency decline is steeper when DSR has a short time-delay, as short time-delays allow DSR to reduce the load several seconds before nadir. The frequency nadir is similar for 0% and 5% due to UFLS hindering frequency drops below approximately 48.6 Hz. Furthermore, it is evident that increasing the amount of DSR-enabled load has an almost negligible effect on the frequency nadir when the amount is sufficiently large, while a shorter time-delay will significantly improve the response if the amount of DSR-enabled load is higher than approximately 10–15%.

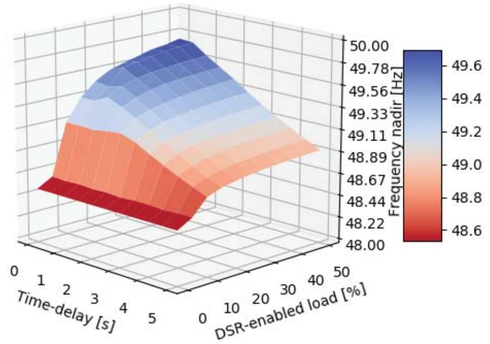

Figure 6. Frequency nadir as a function of DSR time-delay and the amount of DSR-enabled load for higher system inertia, UFLS and DSR.

For lower system inertia and with FCR enabled, the response is similar. The 1st and 2nd UFLS thresholds lead to two relatively flat parts of the surface in Fig. 7, as load shedding stops the frequency drop. Furthermore, it can be seen that shorter time-delay is most effective if the amount of DSR-enabled load exceeds 15–20%. Note that, even with FCR enabled, there is 1st and 2nd stage load shedding for all cases below 20% of DSR-enabled load. In Fig. 6, even without FCR, there was only 1st stage load shedding below 10% DSR-enabled load.

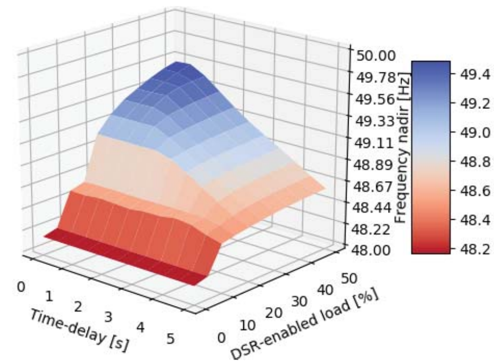

Figure 7. Frequency nadir as a function of DSR time-delay and the amount of DSR-enabled load for lower system inertia, UFLS, FCR and DSR.

C. Discussion

This case study captures several features of the Nordic power system, such as future HVDC interconnectors, power system inertia, generators' primary response and SPS. To capture these features, we have taken advantage of the computational tractability of an aggregated power system simulation model to perform hundreds of dynamic simulations for the Nordic power system. In a similar manner, simulation of other contingencies than the one considered above can be carried out with relative ease [16]. As the model represents an extended geographical area, the power system simulation model may also give insight into the dependence on the geographical location of contingencies. For instance, as described in more detail in [16], simulations of an HVDC contingency in another part of the Nordic power system resulted in voltage collapse, reduction in power transfer capacity between different areas, loss of synchronism and ultimately system separation.

Uncertainties in the modelling originate primarily from two categories. The first is the aggregated nature of the N44 model. Due to the aggregation of generators and simplifications of grid and load models, the simulations are not expected to represent real system behaviour with similar accuracy as a more detailed grid model. For instance, the analysis is not able to capture cascading transmission line outages, which would require a higher detail level. The models would also need to be tuned for system properties other than frequency, e.g. voltage control. Second, it is difficult to assess if the model is appropriately tuned and the response in system frequency is realistic due to uncertainties resulting from the heuristics applied to the model, as described in Sec. III.B. The heuristics were necessary to obtain the desired operating states for our case study, but the tuning in [11] may no longer be valid.

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While acknowledging the uncertainties, we still believe that the results obtained serve as input to a vulnerability assessment. For instance, the results indicate that low-inertia operating states may lead to frequency excursions that bring about severe consequences in the form of large amounts of load shed, even with the implementation of DSR and successful operation of barriers. In addition, DSR shows considerable promise in mitigating large frequency drops if the time-delay for activation is low. However, the DSR may be less effective as a barrier in operating states with lower total load, as seen in the lower-inertia cases. Using DSR to contain frequency may then be less effective for operating states where low inertia results from low system load instead of large amounts of converter-interfaced renewable energy resources (where load may still be high). Further, it must be noted that it is preferable to use DSR for reduction of load demand: one key difference between UFLS and DSR is that DSR may be implemented to reduce load demand in a more discriminatory manner that minimizes the consequences and inconvenience felt by end-users of electric energy.

V. CONCLUSIONS AND FURTHER WORK

In this paper we have described and demonstrated an approach to analysing consequences of simultaneous HVDC contingencies as part of a power system vulnerability assessment. Using an aggregated power system simulation model, we can capture barriers and contingencies not easily captured in conventional risk analysis. Furthermore, we simulate the response of system frequency following a simultaneous HVDC contingency, and we use an event tree to consider possible sequences of events with regards to the absence or failure of barriers. Applying this approach in a case study, we have illustrated how after simultaneous outage occurrence of multiple HVDC interconnectors, a) load shedding is almost inevitable for a power system with lower inertia but b) load shedding may be avoided for higher-inertia operating states through the successful operation of barriers. We note that we cannot use the results from the presented analysis to infer the consequences of such contingencies in the actual Nordic power system. We have nevertheless demonstrated how the effectiveness of a barrier can be analysed. This is exemplified in the case study, which shows how DSR may be an effective barrier that reduces the vulnerability of the system if the time-delay for activation is sufficiently low and amount of DSR-enabled load is sufficiently high.

This paper has focused on presenting illustrative results for a single contingency and only a few operating states. The approach proposed is well suited for screening multiple contingencies and multiple operating states. Other suggestions for further work include using more detailed dynamic power system simulation models to study the effects of HVDC contingencies on the grid near the interconnectors. A detailed power system model could reveal problems that the N44 model is unable to capture due to the aggregated nature of the model. Moreover, modelling DSR in higher detail may allow us to capture aspects that affect its effectiveness as a barrier. For instance, the fraction of DSR-enabled load may be different at different loads in the transmission system, there may be different time-delays for activation both within the system and within each load, and some of the load may fail entirely to respond when activated. Finally, barriers such as HVDC emergency power or synthetic inertia may be implemented to ascertain the impact of these barriers on the vulnerability of the power system.

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