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EVALUATION OF REACTIVE POWER COMPENSATION AND GRID LOSSES IN THE NORDIC TRANSMISSION GRID

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Abstract

Existing publicly available models of future energy systems neglect power system stability. However, to ensure the reliability of future electricity systems, mapping stability and ancillary service needs is crucial. One key stability aspect is voltage stability. As a first step towards the modelling of future voltage stability-related ancillary services, we analyse the required reactive power compensation of the current grid. This work improves an existing grid model of the Nordic High-Voltage transmission grid based on open-source data with around 400 buses and performs power flow analyses for each hour in the reference year 2022. We evaluate the reactive power demands per bus to find the required reactive power compensation capacity for steady-state operation. We also analyse the available dynamic reactive power compensation from generation. For this, we use current grid code requirements for reactive power capabilities for generators. We also consider a scenario where STATCOM operation is required from all converter-connected generation. We further validate the model by analysing system losses and compare them with reported TSO losses. The work serves as a foundation for modelling voltage stability in the case of N-1 contingencies for future scenarios.

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1 Introduction

The share of the electricity demand supplied by wind and solar power has increased drastically in the past decade. This integration of wind and solar power is substantially changing the structure of the electricity system. There is a decreased share of synchronous generation and an increasing share of inverter-based generation. Furthermore, since the location of renewable power generation is dictated by the availability of renewable energy sources, the location of generators is also changing. Additionally, wind and solar power generation is weather dependent. At the same time, electricity consumption is expected to increase drastically as industry and transport move away from fossil fuels, also leading to stark increases in electricity transmission. All of these aspects will lead to an increased and more varied loading of transmission lines.

Throughout these sweeping changes, it is crucial to ensure grid stability. One key grid stability aspect is voltage stability. As generators provide the large majority of dynamic voltage support required for voltage stability, it is important to analyse how a shift in generation technology, including changes in location and generation pattern, impacts the voltage stability. Investigating voltage stability needs and supply can then also show potential needs for additional reactive compensation devices to support the grid, the impact of different grid codes, and impacts from adjusting load or generation locations.

Energy systems models can be used to analyse how future energy needs can be met. However, current publicly available modelling frameworks do not consider voltage stability and in general lack accurate representations of other forms of stability [1]. In this work, we further develop a power flow model of the Nordic synchronous system based on open data with the aim to include it in an energy system modelling framework to address stability aspects of future power systems.

In our reference case, the Nordic system, we begin investigating future stability needs by mapping the reactive power situation of the current transmission grid. We expand on an existing grid model by Hodel et al. [2], validating the system's losses, analysing the steady-state reactive power needs, and estimating the available dynamic reactive power from generation.

2 Methodology

We expand on the Nordic transmission grid model by Hodel et al. [2]. The model includes the lines and transmission-to-transmission transformers of the Nordic transmission grid (voltages 220 kV and up). It also includes load and generation

profiles for each transmission grid bus, separated by generation types, for the year 2022. An AC power flow simulation is run for each hour of the year using PowerModels.jl [3]. We assume that all voltages are held at 1 p.u. (a dimensionless ratio between actual and nominal voltage) in normal operation.
We correct the line types presented in Hodel et al. [2], and the updated line type selection in the model follows Table 1.

2.1 Transmission losses

While Hodel et al. [2] present losses of 12 TWh/year for their reference year of 2022, after reanalysis of their model, losses are only 5 TWh/year (see a breakdown of losses in Section 3.1). The difference is caused by the negligence of the bundle in the resistance calculation. Compared to the losses reported by the TSOs for 2022 of 9.3 TWh/year, the updated model losses of 5 TWh/year are significantly lower.
This discrepancy between reported losses and modelled losses can be caused by several different aspects of the assumptions made:

- Voltages are assumed to be uniform, with very low reactive power transport. This reduces line currents, which reduces losses,
- Line type assumptions are too optimistic (see Table 1 for the assumptions of Hodel et al. [2]).
- Transformers are assumed to be lossless.
- All lines are always assumed to be in operation with no maintenance or other downtime.
- The losses reported by the TSO have a different scope, i.e., they go beyond transmission lines and transmission-to-transmission transformers or outside of a 220-400 kV range.

We want to verify that the model has an acceptable level of accuracy despite these loss discrepancies. Therefore, we apply the following modifications to better mimic real-world conditions:

1. Applying conductors with higher resistances as a result of fewer or thinner subconductors. We change from the line type assumptions made by Hodel et al. [2] (see Table 1) to more conservative assumptions (see Table 2).
2. Applying a more accurate transformer model that includes transformer losses.
3. Change voltages to be non-uniform: Buses with higher load than generation have their voltage set-point reduced to 0.985 p.u. This voltage set-point reduction intends to mimic some of the real voltage variation in the transmission grid.

We combine these modifications into two scenarios with increased losses and compare both against the base case:
Scenario 1: Modifications 1 and 2, but the voltages remain uniform. Scenario 2: All modifications.

2.2 Steady-state reactive power demand

After running the power flow simulations, we find the required reactive power to keep the voltage at 1 p.u. for each bus at each hour. We use the extremes of the required hourly reactive power compensation at each bus to find the required installed capacities of reactive power compensation at that bus. In practice this steady-state compensation is primarily provided by shunt compensation (shunt capacitors and shunt reactors).
The approach of keeping the voltage at 1 p.u. overestimates reactive power needs, as it does not allow for aggregation of nearby opposite reactive power needs. However, due to the meshed nature of the grid, if a line is under high/ low load, nearby lines are likely also under high/ low load. In that case, aggregation does not reduce the required reactive power compensation.

Table 1 Line type assumptions made by Hodel et al. [2].

Line type	Voltage [kV]	Conductors per phase	R [Ω/km]	X [Ω/km]	C [nF/km]	I_{rated} [A]
774-AL59	220	2	0.019	0.31	11.7	1960
910-AL59	400	3	0.012	0.27	13.3	3240
606-AL1[a]	300	1	0.049	0.42	8.5	870
606-AL1[a]	300/400	2	0.025	0.31	11.6	1730

[a] Only for Norway. For Norway, conductor type is chosen based on available conductor count data.

Table 2 Line type assumptions for increased losses. Changed assumptions are in bold.

Line type	Voltage [kV]	Conductors per phase	R [Ω/km]	X [Ω/km]	C [nF/km]	I_{rated} [A]
774-AL59	**220**	**1**	**0.038**	**0.42**	**8.6**	**980**
593-AL59	**400**	**3**	**0.017**	**0.27**	**13.1**	**2480**
606-AL1[a]	300	1	0.049	0.42	8.5	870
606-AL1[a]	300/400	2	0.025	0.31	11.6	1730

[a] Only for Norway. For Norway, conductor type is chosen based on available conductor count data.

2.3 Dynamic reactive power availability

Dynamic reactive power is required to keep voltages stable in the event of a disturbance. Dynamic reactive power is supplied primarily by generators. A first step to assess voltage stability in the case of a disturbance is thus to quantify the available dynamic reactive power that can be supplied by the generators. We only consider the reactive power requirements according to the currently active grid codes for generators of type C and D (generators with more than 10 MW of capacity). See Table 3 for a simplified overview of national grid code requirements for generators.

2.3.1 Assumptions for energised generation: The Nordic grid codes specify requirements on the reactive power capabilities on generators at the point of connection. However, these requirements generally only apply if the generator is energised (producing active power). As the generation data are not at an

Table 3 Current grid code requirements for generators of type C or D on reactive power at the connection point.

Country	Synch. generator		Power park module	
	Q_{cap}	Q_{ind}	Q_{cap}	Q_{ind}
Sweden [4]	$1/3P$	$1/6P$	$1/3P$	$1/3P$
Norway [5]	$0.46P_{\text{max}}$	$0.46P_{\text{max}}$	$1/3P_{\text{max}}$	$1/3P_{\text{max}}$
Finland [6]	$1/3P_{\text{max}}$	$1/3P_{\text{max}}$	$1/3P_{\text{max}}$	$1/3P_{\text{max}}$
Denmark [7]	$0.4P_{\text{max}}$	$0.2P_{\text{max}}$	$1/3P_{\text{max}}$	$1/3P_{\text{max}}$

individual generator level and instead aggregated to each transmission bus by generation type, assumptions are made on how much generation is energised. Then we apply the grid code requirements on the energised generation.

We make different assumptions for each generation type, as different generation types are differently energised over time in relation to their output power production. energised generation (P_{end}) is estimated for each bus, time step, and generation type based on instantaneous generation (P) and annual peak generation (P_{peak}).

For hydropower, we assume a constant 80 % load factor based on Persson et al. [8]: $P_{\text{end}} = P/0.8$. For wind and solar, if the relative generation (P/P_{peak}) is above 20 %, we assume the generators are fully energised: $P_{\text{end}} = P_{\text{peak}}$. If P/P_{peak} is less than 20 %, we assume a 50 % load factor: $P_{\text{end}} = P/0.5$. For HVDC, nuclear, gas and other thermal generation: If generation is non-zero ($P > 0$), we assume that the generators are fully energised: $P_{\text{end}} = P_{\text{peak}}$.

2.3.2 Future grid codes: Sweden is the only country with a grid code that requires only reactive power compensation capability proportional to active power P rather than energised power capacity P_{max}. However, the Swedish TSO, Svenska Kraftnät, has suggested a new grid code [9]. The new grid code would change the reactive power requirements to be proportional to the energised power capacity (P_{max}). Additionally, it would require converter-connected generation to remain energised even if no active power is being produced. This requirement, also called STATCOM operation, could enhance the available dynamic reactive power capacity, especially in future inverter-dominated systems.

To analyse the differences in a grid code with a requirement of keeping converter-connected generation energised, we compare the available dynamic reactive power compensation following current grid codes, to a potential future where Sweden adopts the proposed grid code and the other TSOs follow suit in requiring STATCOM operation for all converter-connected generation.

In this alternative scenario, we assume that the Swedish grid code also uses reactive power requirements proportional to P_{max} and the energisation assumptions shown in Section 2.3.1 are $P_{\text{end}} = P_{\text{peak}}$ for wind and solar independent of P.

3 Results

3.1 Grid losses

Table 4 shows the losses as reported by the TSOs, and from our model as produced by the base case and by Scenario 1 (increased resistances) and Scenario 2 (increased resistances with non-uniform voltages).

Table 4 Comparison of transmission grid losses between the base case and the two scenarios for Year 2022. Scenarios 1 and 2 are defined in Section 2.1.

Country	Reported [TWh]	Base case [TWh]	Scenario 1 [TWh]	Scenario 2 [TWh]
Sweden	5 [10]	2.7	3.8	4.0
Norway	2.7 [11]	1.8	1.9	2.0
Finland	1.6 [12]	0.44	0.61	0.65
Denmark	-[a]	0.0301	0.04	0.06
Total	9.3[a]	5.02	6.4	6.7

[a] To our knowledge, the Danish TSO Energinet does not report transmission losses publicly.

There is a clear increase in losses between the base case and Scenarios 1 and 2. Still, the total losses in scenario 2 are below the reported figures. A key reason for this could be that some of the TSOs have a different scope in which losses they include, as we only include losses within the transmission lines and from transmission-to-transmission transformers.

Additionally, our line type assumptions with increased losses (see Table 2) are still too optimistic for some lines. For example, we always assume a triplex bundle for 400 kV lines outside of Norway. However, this is not always the case, as some 400 kV lines are only duplex. Furthermore, the switching of lines and maintenance have not been considered in our model, also reducing the resulting modelled losses.

3.2 Steady-state reactive power compensation

Figure 1 shows the required steady-state reactive power compensation capacities to keep the voltages at 1 p.u. at each bus. For example, in bidding zone SE3, a total of around of 3,600 MVar of installed steady-state capacitive reactive power is required (primarily in the form of shunt capacitors), as well as 3,500 MVar of steady-state inductive reactive power (primarily in the form of shunt reactors).

The steady-state reactive power compensation is primarily provided by shunt reactors and shunt capacitors. We expect the results presented in Figure 1 to be in the range of the actual current installed capacities of shunt capacitors and shunt reactors in the Nordic system.

3.3 Availability of dynamic reactive power compensation

Figure 2 shows the temporal distribution of available dynamic reactive power compensation capacity as required by grid codes for generators for 2022, while Figure 3 shows the same but assuming that all countries adopted the updated grid code

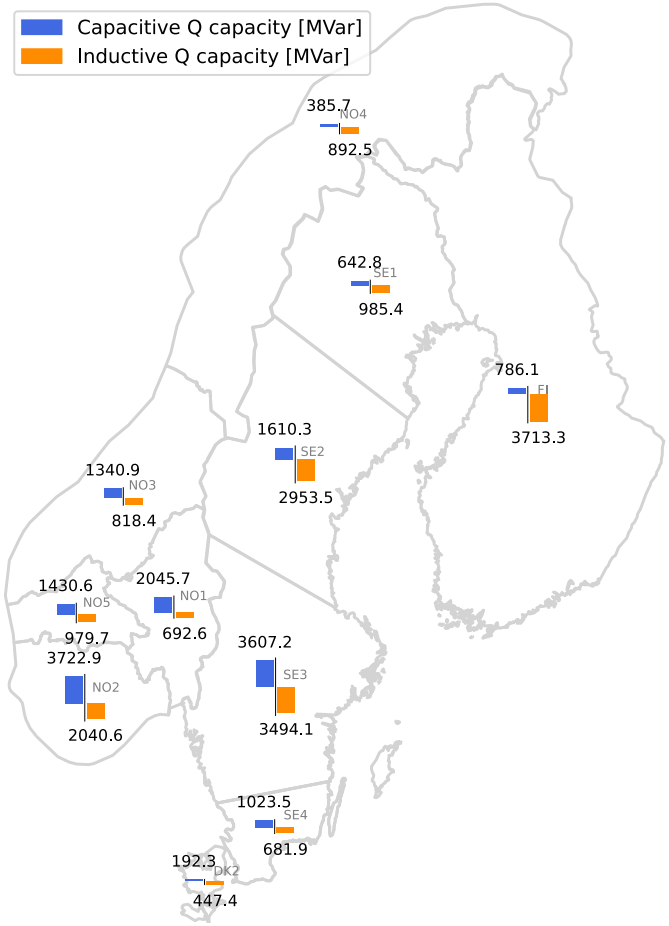

Fig. 1 Required steady-state reactive power capacities in the Nordics for the current system (2022). Capacities are grouped together by bidding zone.

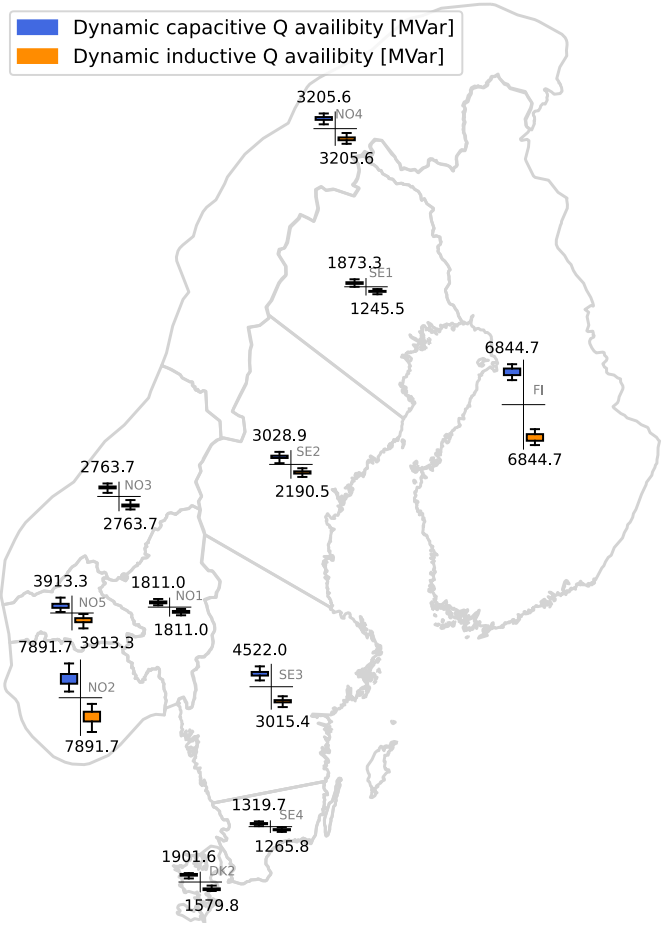

Fig. 2 Distributions of hourly available dynamic reactive power compensation in the Nordics from generators in the current system (2022). Availability is grouped by bidding zone and annual maximum availability is labelled.

proposed by Svenska Kraftnät (see Section 2.3.2). For example, in the SE3 bidding zone, the maximum availability of capacitive dynamic reactive power increases from 4,522 MVar to 5,292 MVar. when applying the updated grid code Additionally, the box-plots in SE3 are narrower for the updated grid code than for the current grid code case, showing that the variability of available dynamic reactive power compensation is lower.

It is clear that the grid code impacts the availability of dynamic reactive power compensation. In many bidding zones, the maximum availability of dynamic reactive power compensation increases with the proposed Swedish grid code formulation. More importantly, however, the variability of available dynamic reactive power compensation decreases while the minimum available compensation increases. The changes are largest in bidding zones with significant shares of converter-connected generation (e.g., SE3), while some bidding zones with little or no converter-connected generation (e.g., NO5) show no significant differences between the current and updated grid code.

It should be noted that, while maximum availability of dynamic reactive power compensation capabilities are higher than required steady-state reactive power installed capacities, this does not mean that dynamic reactive power compensation capabilities are sufficient for N-1 contingency scenarios. The dynamic reactive power required during a contingency is more local than the bidding zone level and can fall outside of the normal operating needs of steady-state reactive power. Additionally, while maximum availability of dynamic reactive power compensation capabilities is generally higher than steady-state installed needs, minimum availability is significantly lower in some bidding zones.

4 Discussion

Some general limitations apply to the grid model: 1. Line types are assumed based on voltage and country (thickness + subconductors/bundle). This assumption is less likely to impact reactive power, as impedance and inductance do not heavily depend on subconductor type and bundle arrangement. 2. Only the transmission grid is considered, and loads and generators are connected to the geographically closest transmission grid bus (rather than connected to the distribution grid, which distributes load and generation between nearby transmission grid

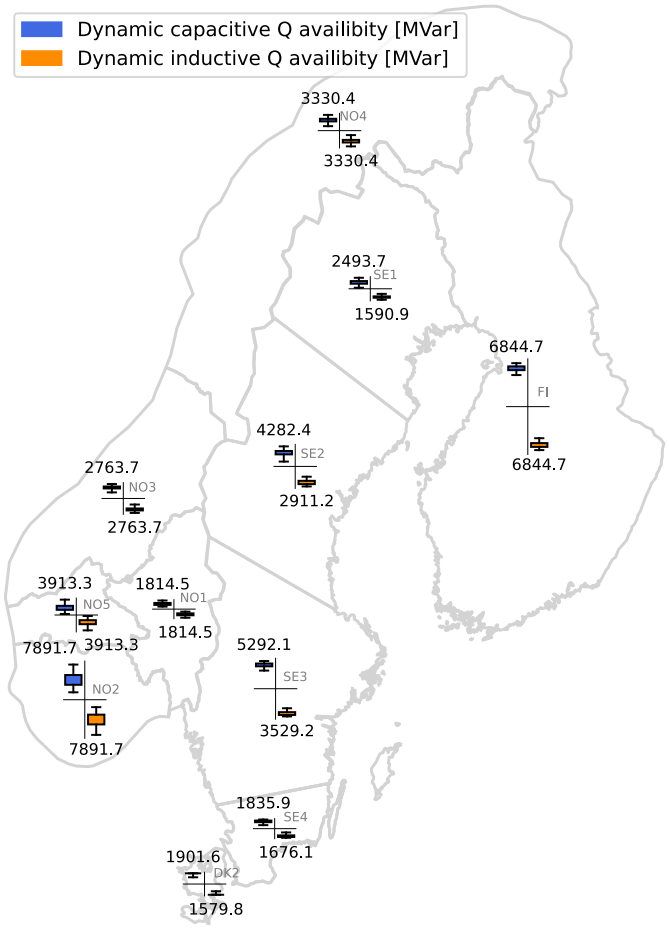

Fig. 3 Distributions of hourly available dynamic reactive power compensation in the Nordics from generation in the current system (2022) assuming changed grid codes requiring STATCOM operation (see Section 2.3.2). Availability is grouped by bidding zone and annual maximum availability is labelled.

buses. 3. The grid topology is based on the ENTSO-E grid map [13], which adjusts the positions of lines for topological clarity. This distorts the lengths of the lines, slightly changing the electrical parameters. Despite these limitations and the discrepancies in losses described in Section 3.1 we believe that the grid model is a sufficient basis to analyse reactive power demands in the transmission grid.

4.1 Losses

It is not clear what causes the remaining discrepancies between the reported losses and the modelled losses shown in Table 4. We believe that the factors outlined in Section 2.1, account for the main differences. However, more detailed information from TSOs about their line types and a breakdown of their transmission losses could clarify the discrepancy.
The discrepancies in the losses indicate inaccurate assumptions in line type. For line-type assumptions, the subconductor thickness and bundle configuration are the most uncertain. These two parameters primarily impact losses and thermal capacity but have a more limited impact on reactance and capacitance, and therefore on reactive power which is the focus of this work. Nevertheless, accurate modelling of thermal ratings and resistances is still important when applying the model to study other phenomena such as modelling of future systems when accurate thermal ratings are required. Also, accurate resistances are crucial when analysing the damping of high-frequency converter harmonics.

4.2 Steady-state reactive power compensation

Although we expect installed capacities of shunt compensation to be in the range of our modelling results, different factors may lead to over- or underestimation. The assumption of uniform voltages leads to an overestimation of required compensation. Furthermore, transmission line switching could reduce the required inductive reactive power compensation capacity under light load conditions. Currently, some steady-state reactive power is also provided by dynamic sources such as power generators. However, according to a representative from Svenska Kraftnät, this use of dynamic resources is undesirable for future operation and is being actively phased out.
Despite potential inaccuracy in the required installed compensation capacities, this approach can be used to compare current results against an eventual future scenario.

4.3 Availability of dynamic reactive power compensation

We assume that all generation is of type C or D (10 MW or larger) for the requirements defined by the grid code. This slightly overestimates the available reactive power compensation, as less strict requirements apply to generation of type A and B. We present dynamic reactive power compensation aggregated to the transmission grid level. However, a significant amount of generation is still not directly connected to the transmission grid, and its capability for reactive power compensation would not be fully available at the transmission grid level. At the same time, we currently only consider the dynamic reactive power requirements specified by the grid code, rather than based on the actual PQ capability curve of the generators. Furthermore, we make assumptions about energised generation (P_{end}) as a function of P and P_{peak}. While the constant loading factor of 80 % for hydropower is based on [8], we make assumptions for wind and solar: We assume that if generation (P) is above 20 % compared to P_{peak}, the generation is fully energised ($P_{\text{end}} = P_{\text{peak}}$) , while below 20 % we assume a 50 % load factor ($P_{\text{end}} = P/0.5$). All of these assumptions bring uncertainty into our results. However, we believe that the results give a reasonable indication regarding the order of magnitude of available compensation and regarding the trends between the grid codes.
When comparing the two cases of available dynamic reactive power compensation, differences are not large for every bidding zone. This would likely change with increasing shares of converter-connected generation, as the STATCOM operation requirement only applies to converter-connected generation. According to projections from the Nordic TSOs [14],

converter-connected generation may amount to more than 75 % of all Nordic generation capacity in 2050. In such a scenario, the differences in availability in dynamic reactive power compensation depending on grid codes that require or do not require STATCOM operation would be very significant. While STATCOM operation incurs internal grid and inverter losses to owners of inverter-based generation during times of no production, it should still be considered due to its significant impact in available dynamic reactive power compensation capacity.
This modelling of dynamic reactive power compensation availability is important for N-1 voltage stability analyses, as it quantifies the ability of the system to keep voltages within allowed ranges dynamically in the case of a disturbance.

5 Conclusions

In this work we further improved a model of the Nordic transmission grid including load and generation for the year 2022 with the aim of eventually analysing voltage stability. We found that losses as provided by the model are significantly lower than losses as given by the TSO which indicates that the grid data still needs to be improved. Assumptions on bundle configuration and subconductor type are identified as weak parts and real world data on this would improve the accuracy of thermal ratings and resistances.
We analysed both the steady-state reactive power compensation need and the available dynamic reactive power compensation capacity. The steady-state compensation used to balance the reactive power consumption and production from transmission lines, and reactive power consumption from transformers during normal operation. The dynamic reactive power compensation is estimated from both synchronous generators and converter-interfaced generators, which can be used to provide fast reactive power support during contingency events.
The Nordic grid codes are not equal in their requirement for available dynamic reactive power compensation. Sweden's current grid code puts very weak requirements on the available reactive power compensation of generators. However, a currently suggested update to the Swedish grid code by the Swedish TSO, Svenska Kraftnät, would change this significantly, by putting more demanding requirements on the dynamic reactive power supply from converter-connected generation. Their grid code suggestion requires STATCOM operation for converter-connected generation when not producing active power.
We compared the availability of dynamic reactive power compensation capacity according to currently active grid codes and if the Swedish grid code suggestion were implemented with other Nordic countries following the STATCOM operation requirements. We show the new grid code significantly reduces the variability of available dynamic reactive power compensation capacity while also increasing the minimum available capacity. These changes in variability and minimum availability happen, as all converter-connected generation will have to provide their reactive power compensation capacities at all times. Especially for a future system with very high shares of converter-connected generation, requiring STATCOM operation would considerably improve available dynamic reactive power compensation capacity variation. However, losses for owners of inverter-based generation would increase if STATCOM operation were required.

6 Future work

This work serves as a basis for the analysis of future systems, leading to analyses of dynamic voltage stability and reactive power support in the case of N-1 contingencies. An evaluation of the cost and value of STATCOM operation can be done to compare the losses incurred to owners of inverter-based generation with the value of dynamic reactive power compensation capability. Analysis of other stability aspects is also desired, for example the damping of converter harmonics, the availability of short circuit current, and the oscillations caused by control interactions of converters in weak grid conditions.

Acknowledgments

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