Innovation in the Power Systems industry

Engineers and specialists worldwide exchange information and state-of-the-art world practices to enhance knowledge related to power systems in CIGRE’s latest publication.

Best papers from the Aalborg Symposium
B4 TF-77 paper on "AC Fault response options for VSC HVDC Converters"
"Study of Harmonics Created by a Power Flow Controller in a Meshed Multi-Terminal High Voltage Direct Current Grid"
Dear readers,

This is the last issue of CIGRE Science & Engineering for this year and is, I believe, in number of published papers one of the largest if not the largest. This shows that the interest of our community to submit the outcome of their scientific research or their engineering applications is continuously increasing. This might be because of our high standards of acceptance, or because of our scrutinizing but fair reviews, or because we offer probably the best qualified and mostly interested readership in the industry. In any case we from the editorial board are very happy about this positive development, thankful to our authors, reviewers and readers and we can assure you that we will do our best to keep up the high quality and information standards we have established over the years for our Journal.

In this sense I am pleased to briefly introduce to you the contents of this issue:

The first eight papers are the best papers per Study Committee participating in the very successful Aalborg Symposium, which was hosted by the CIGRE Danish National Committee from June, 4-7, 2019 in Aalborg Culture and Congress Centre, Aalborg, Denmark.

The two-day Symposium attracted over 325 delegates from more than 30 countries. More than 110 papers were accepted and presented during the 24 sessions. Papers originating from Young Members were also displayed as posters in addition to being presented. In total there were 18 Young Member papers. There were eight tutorials, presented the day before the Symposium by all the supporting Study Committees. The Symposium was supported by Study Committees B1, B2, B4, C1, C2, C4, C3, and C6 with SC C4 leading it.

The Symposium papers are followed by regularly submitted papers, distributed over different Study Committees as follows: One paper from A2, four papers from B4, from papers from C4 and one paper from C6. From these I would like to highlight paper "AC Fault response options for VSC HVDC Converters" by B4 TF-77, paper "Study of Harmonics Created by a Power Flow Controller in a Meshed Multi-Terminal High Voltage Direct Current Grid" by B. Zolett and Y. Li, this being the winning paper of the yearly competition of the French CIGRE National Committee for papers by engineering students.

Conclusively, I believe, that we again are offering you a wide spectrum of useful information, which you will hopefully enjoy reading.

Happy New Year (isn't this too early? 😊)

Prof. Dr. Konstantin O. Papailiou
Chief Editor
konstantin@papailiou.ch
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Importance of mechanical design and testing of cable systems for floating offshore wind

A TYRBERG*, E ERIKSSON, A PERSBERG,
NKT HV Cables AB, Sweden

Summary
Floating wind park installations have become the topic of research and prototyping with the goal to enable development of offshore wind parks at larger water depths where fixed foundation installation not will be feasible. Cables connecting to the floating turbines and floating transformer stations will be dynamic since they will experience re-occurring bending and tension loads during operation.

Within the oil & gas industry, dynamic cable systems have been put in service and some years of experience have been gathered. Analysis and testing methodology has been established which also can be used for export and inter array cables for the floating wind application. This paper provides an overview of the special analysis and testing activities that are required to verify that a dynamic cable design is suitable for its intended application. This is done from the perspective of experience gathered from some of the latest dynamic cable projects that have been qualified and installed.

To verify the suitability of a dynamic cable design for a specific application a number of interconnected analysis and testing activities needs to be performed. This paper includes descriptions of each of these activities and important aspects to be considered have been highlighted. The final step of the qualification of a dynamic cable is the full-scale fatigue test which is part of the type test regime for dynamic cables according to CIGRE TB623. The full-scale fatigue test uses input from all preceding analysis and testing activities and combines it into a test that simulates the expected fatigue loads that the cable will experience during service life. The full-scale fatigue test functions as an important robustness test of the cable and can contribute to finding un-expected failure modes resulting from fatigue loading. This paper gives a more detailed description of the full-scale fatigue test and aspects that should be consider when designing the block program.

1. Introduction
The concept of offshore wind has been widely introduced with huge geographical focus to Northern Europe. One of the contributing success factors is the moderately water depths at the wind park locations, enabling fixed foundation turbines and transformers. Not all regions have that benefit and may face larger water depths where offshore wind parks potentially can be constructed. Yet another reason is that it is expected that the wind power density, and therefore the wind park efficiency, is increased at locations further away from the coast line. In many cases this often means increased water depths [1].

Standard fixed wind turbine constructions for large depths become unfeasible or too expensive. Floating wind park installations have therefore become the topic of research and prototyping [2]. This has of course consequences for several components involved as for instance the submarine cables. The inter array cables, connecting the wind turbines to a transformer or converter platform, must be able to withstand the motions induced by the floating device during its service life. In case the platform itself also is floating – which in many cases can be true – also the export cable must be able to withstand these forces and motions. Such cable systems, designed for dynamic loads during the operational life, are called dynamic cable systems.

Within the oil & gas industry, dynamic cable systems have been put in service and some years of experience have been gathered. This type of technology, or at least

KEYWORDS
Dynamic cables, fatigue analysis, fatigue testing, floating wind

*andreas.tyrberg@nkt.com
parts of it, can also be used for export and inter array cables in the floating wind applications.

This paper will highlight the principle design steps and more heavy engineering steps that must be executed to arrive at a suitable cable system design. The necessary analysis steps will be described and discussed. From here on the testing and qualification steps are described. This is done both from the perspective of the experience of some of the latest dynamic cable projects (Gjøa [3], Goliat and Martin Linge [4]) as well as from the perspective as from the perspective of CIGRE TB623 which also has dealt with this matter [5].

2. Dynamic cables, general

A dynamic cable is a cable that is designed and tested to sustain the dynamic loads induced on the cable from platform motions and hydrodynamic loads induced by waves and current during the service life of the cable.

Especially important for a dynamic cable is its fatigue endurance, i.e. the ability for the cable to sustain the fatigue loads experienced during its service life. A dynamic cable, connected to a floating platform, will typically experience more than 100 million wave induced bending cycles during 30 years of operation. These bending cycles, most often in combination with a tensile load, results in repeated stress and strain variations in the internal cable components. If the magnitude and number of cycles is too large this can result in fatigue damage in the form of crack initiation and eventually failure of the metallic components inside the cable. Component displacement during bending also results in abrasion which potentially can result in damage to the internal layers.

Compared to a static cable, a dynamic cable for floating wind needs to include materials with good fatigue properties, low friction and good abrasion resistance. The design of the dynamic cable must also be made in such a way that the stress/strain in the cable components during cable bending is minimized as far as possible.

In addition to fatigue loads, the dynamic cable must also sustain the loads induced during the most severe weather conditions that will be experienced during the service life of the cable, the so called extreme loads. An important part of the engineering of the dynamic cable system is to find a configuration of the cable, using ancillary items such as buoyancy modules and bend stiffener, that ensures that the loads onto the cable are acceptable. To ensure that the configuration and cable design are suitable for the intended application several design and testing activities are performed which will be further described below.

3. Previous experience with dynamic cables for oil&gas

The latest years, several dynamic cables have been put into service within the oil and gas industry and this section provides an overview of some of these projects and the qualification testing that was performed.

The power cable connecting the O&G platform Gjøa [3] in the North Sea, with the Norwegian power grid at shore, has been in operation since 2010. The cable system comprises of a static cable of almost 100 km of length and a dynamic cable with a length of approx. 1.5km. The cable system enables power from shore, which enables a significant reduction of CO₂ emissions by eliminating the need for locally generated power using gas turbines. The water depth at the Gjøa platform area is approx. 380m and a dynamic cable connects the platform with the static cable. The cable configuration is of ‘lazy wave’ to account for the movements of the platform. The cable is of so-called dry design as the design voltage level is 123 kV. The radial water barrier protecting the insulations system consists of a corrugated copper sheath. Component fatigue testing of critical cable components was performed to establish S-N curves. This enables, together with the global and local analysis, the possibility to verify that the fatigue life of the cable was sufficient for the intended service life of the dynamic cable. Aside from standard electrical and mechanical type testing, the dynamic cable was subjected to a 2 000 000-cycle full-scale flex test, simulating the fatigue loads the cable will experience during its service life. The full-scale fatigue test set-up included cable, bend stiffener and hang-off to include all relevant accessories at the interface to the platform.

The second 123 kV cable of dry design is the Goliat cable project which was installed in 2013. The Goliat cable system consists of 105 km of static cable and 1.5 km dynamic cable and provides power from shore
that the system can withstand the mechanical loads experienced through its service life. A high-level overview, based on CIGRE TB623 [5], of the different activities is presented below:

1. Dynamic analysis: To establish the extreme and fatigue loads onto the dynamic cable system during its service life.

2. Local Analysis: A model of the cross section that is used to calculate the resulting stress/strain in each cable component as a function of the global loads imparted on the cable.

3. Fatigue testing: Fatigue properties of the metallic components incorporated in the cross section is characterised by fatigue testing. A curve showing the stress amplitude to number of cycles to failures (S-N curve) is established by testing the component in blocks with different stress levels and count the number of cycles to failure.

4. Fatigue Analysis: Having the fatigue stress history and the component fatigue data available, the expected fatigue life of the dynamic cable can be calculated through linear damage accumulation.

5. Full scale fatigue test: The final validation that the cable can withstand the expected fatigue loads experienced during service life is through a full-scale fatigue test. The fatigue test is designed such that the total accumulated fatigue damage in the test is equal or greater than the fatigue damage experienced during service life. Important input to the design of the fatigue test are the component fatigue data S-N data, the local model and the global fatigue loads.

4. Overview of analysis and testing activities

An important part of the analysis and test program for qualifying a dynamic cable system is to validate from the Norwegian power grid at shore. The water depth at the platform location is approx. 370 m and the dynamic cable configuration is a ‘reversedpliant wave’, i.e. including a tether anchor in addition to buoyancy modules. The Goliath cable design is in many aspects similar to the above Gjøa design and qualification testing followed the same principals as for the Gjøa project. A project specific full-scale fatigue test was performed as part of the qualification program of the Goliath cable.

Within the Martin Linge project [4] a 4 km long 17.5 kV in-field cable, providing power from the Martin Linge platform to a floating, storage and offloading unit (FSO) was installed 2016 and connected to FSO vessel 2018. The cable is divided in two sections, one static section with a length of approximately 3.5 km and one dynamic section with a length of approximately 500 m between the seabed and the FSO vessel. The combination of harsh North Sea environmental conditions, large FSO dynamic motions and relatively shallow water depth of 120 m meant very high dynamic loads will be imparted onto the cable system. A special cable design was therefore developed, and the suitability of the design was verified through a comprehensive qualification program including electrical and mechanical type tests, component fatigue testing, bend stiffness test and a 2000000-cycle full scale fatigue test.
A schematic overview of this process is presented in Figure 1.

More details on the different activities is provided in detail in the following chapters.

5. Dynamic analysis and cable configuration

The objectives of a dynamic analysis are typically twofold; firstly, to secure that maximum loads as tensile force and curvatures on the dynamic system during extreme environmental conditions are not violated, secondly, to determine the fatigue loads onto the dynamic cable and to verify that they are acceptable. Both the extreme and fatigue loads are induced by environmental loads, i.e. waves, current and host platform motions. The configuration of the dynamic cable, i.e. how the dynamic cable is positioned in the water column, is optimized to secure that design constraints of the dynamic cable system are not violated, including maximum tensile force, curvature, fatigue buffer and to avoid interference (clashing) with any neighbouring infrastructure. The most normal configuration for dynamic cables are a Lazy wave configuration or a Tethered wave (also named Reversed pliant wave configuration).

Figure 2: Dynamic cable in a tethered wave configuration

For this type of configuration, a tether anchor is connected to the cable above the touch down point thereby controlling the movement and tension in the touch down region. Buoyancy modules are used to achieve a hog bend, which both allows larger heave motions of the platform motions and takes up platform offset. A Lazy wave configuration is similar but without the tether anchor. Several different configuration types exist, and the selection of configuration type needs to be made based on the project specific characteristics such as the water depth, interference, platform offsets and dynamics. For floating wind, the specific challenges related to finding a feasible configuration is often the relative shallow water depth, especially when in combination with large platform offsets. The platform offset in relation to the water depth and how this affects the feasibility of the cable configuration is important to consider early in the concept section of the project.

In addition to buoyancy modules and tether system, a bend stiffener is also often installed at the platform interface. The main purpose of the bend stiffener is to provide a gradually increase of stiffness at the connection point to the platform. The bend stiffener is designed to limit the curvature response during extreme events and to limit the fatigue load at the most exposed region of the system. The bend stiffener is also a thermal insulator why detailed analysis of temperature distribution inside the bend stiffener should be carried out to ensure that the thermal constraints of the system are not violated.

The modelling approach for the global analysis is typically performed with time-domain finite element methods, where the model takes hydrodynamic loads from the environment and the host platform motions into account. Characteristics of the cable systems, such as weight, diameter, stiffnesses and drag are also accounted for. The modelling methodology is well developed and several commercial software’s for this type of modelling exists on the market.

The dynamic analysis is performed with regards to the extreme loads which consist of the worst combinations
of waves and current that are expected during the service life of the cable. This could for instance be a 100-year wave condition in combination with a 10-year current condition. Several different combinations of weather conditions, weather directions and platform offset needs to be analysed to ensure that the combination resulting in the worst loads onto the cable are identified and verified acceptable.

The fatigue loads acting on the dynamic cable system is assessed by analysing the system during environmental conditions representative for “normal operation” of the system. A wave scatter diagram, showing the statistical distribution of wave heights and periods, normally provides the basis for the fatigue analysis which consist of a large number of load cases for different combinations of wave height, period and direction. For each load case the curvature and tension response in the cable is analysed and this serves as input for the local analysis and the subsequent fatigue analysis, see below. Since the load cases are based on the statistical weather distribution the probability for each load case is known and this is included in the fatigue damage accumulation.

6. Local analysis

For the local analysis, a model of the cable cross section is used to calculate the resulting stress/strain in each cable component as a function of the cable bending radius and tension. Predicting component stress during bending is more complex than during tension due to the non-linear effects resulting from stick-slip mechanisms of the helical components such as the three cores or the armour wires. The stick-slip behaviour of the components and the resulting friction stress can have a large impact on the fatigue life of the dynamic cable and it is therefore important that component stress induced by friction effects during bending are included in the local analysis. The mechanics of helical components during bending has been extensively studied in the literature, see for instance [6, 7, 8]. By assuming that the helical elements follow a loxodromic curve, i.e. slips in the axial direction of the component, analytical expressions have been developed that allows prediction of stress induced by local bending of the component as well as the friction stress due to stick-slip of the components. The validity of the loxodromic expressions for a dynamic AC cable has been investigated through 3D finite element (FE) modelling [9]. Of especial importance was the stick-slip behaviour of the three power cores. It was found that slippage of the cores also followed a loxodromic curve and good agreement was found between the prediction of the analytical expressions and the result of the 3D FE simulations. The validity of the loxodromic expressions has also been experimentally investigated for a typical umbilical in [10].

To illustrate the effect of friction stress, Figure 3 shows an example of the calculated stress on a position in an armour wire in a dynamic cable when a tensile force of 100 kN is applied and the cable is bend to a bend radius of ±10 m (corresponding to a curvature of ±0.11/m). Initially, at zero curvature the tensile force on the cable, for this example, results in an armour stress of approximately 15 MPa (position 1 in Figure 3). When cable bending starts there is a first region of ‘stick’, where there is no relative sliding between the armour wire and adjacent layers (position 1 to 2) and then, as the curvature increases, there is a transition to ‘slip’ where increasing amount of relative sliding occurs between the wire and adjacent layers (position 2 to 3). The curvature at which sticking breaks down and sliding initiates is determined by both the friction coefficient and the normal contact force onto

![Figure 3: Example of component stress as a function of cable curvature](image)
Fatigue testing is performed by applying a cyclic varying stress/strain (S) on a sample of the component where the number of cycles required to reach fatigue failure (N) are registered. To develop a fatigue curve several samples needs to be tested at different strain ranges. DNV-RP-F401 [11] specifies the number of samples to be tested and the methods to be used to establish the fatigue design curve.

A dynamic cable can include components where special consideration needs to be made in order to assess the fatigue performance. A stranded conductor for instance, is a complex structure built up of individual strands which have undergone a compacting process where the wires in the different layers undergo varying degrees of plastic deformation and resulting eccentricities along each wire. The fatigue properties of stranded copper conductors exposed to bending and tensile loads has been studied in detail experimentally and by finite element analysis in [12, 13, 14]. It was found that friction within the conductor, between the different layers of the conductor strands, also is important to account for in the fatigue analysis.

In addition to component fatigue data, internal friction coefficients in-between the different cable layers are also necessary input to the local model to correctly assess the friction stress induced during cable bending. Friction testing therefore needs to be performed for the various material combinations with the cable for which relative sliding occurs. For some material combinations the friction coefficient will depend on the contact force and applying realistic contact forces when measuring the friction coefficients is therefore important.

8. Full-scale fatigue test

CIGRE TB623 provides recommendation on how a dynamic cable shall be type tested. Special for the
dynamic cable is the full-scale fatigue test that is performed to simulate the entire service life of the cable in an accelerated manner. The full-scale fatigue test functions as an important robustness test of the cable and can contribute to finding unexpected failure modes resulting from fatigue loading. The test also functions as a robustness test of the interface accessories, such as hang-off, when applicable.

The full-scale fatigue test is part of the type test regime according to CIGRE TB623. The main purpose of the test is to verify that the dynamic cable can withstand the expected fatigue loads experienced during service life. The test sequence for the full-scale fatigue test, according to TB623, is shown in Figure 4.

The flex test is performed by applying tension in combination with cyclic bending and the test should consist of at least 1.5 million bending cycles to achieve an accumulated fatigue damage equal to or larger than the expected fatigue damage during operation. The fatigue test will normally take 3-5 months to complete. Applying a realistic tension during the full-scale fatigue test is important to ensure that friction effects, such as stick-slip of the helical components and abrasion, are included in a realistic manner.

The test is designed such that the total accumulated fatigue damage equal or greater than the fatigue damage during service life. The accumulated fatigue damage in the test should be calculated employing the same local models and fatigue data as applied for the evaluation of fatigue damage during service life.

The fatigue test is divided into several load blocks, each with different curvature range and varying number of cycles. The number of blocks should be 5-7 according to CIGRE TB623. The purpose of dividing the test into different blocks is to achieve a realistic distribution of the curvature ranges; with a large number of small curvature cycles and a smaller number of cycles with large curvature range. Different phenomena driving the fatigue damage will be present depending on the curvature range. For instance, at small curvatures friction effects and stick-slip of the components can contribute significantly to the fatigue damage. For large curvatures the fatigue damage might instead be dominated by bending-induced strain and friction has a smaller influence.

Below is an example of a load program that has been constructed to achieve an accumulated fatigue damage of 0.083, in the most fatigue susceptible component, over five load blocks consisting in total of slightly more than 1.5 million cycles. The fatigue damage from each block would be assessed by calculating the induced component strain/stress with the local model and then calculating the accumulated fatigue damage based on the developed S-N curves and the number of cycles in each block.

<table>
<thead>
<tr>
<th>Curvature amplitude (m⁻¹)</th>
<th>Number of cycles</th>
<th>Fatigue damage per block</th>
<th>Accumulated fatigue damage</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.025</td>
<td>1 400 000</td>
<td>0.0132</td>
<td>0.0132</td>
</tr>
<tr>
<td>0.045</td>
<td>140 000</td>
<td>0.0233</td>
<td>0.0366</td>
</tr>
<tr>
<td>0.07</td>
<td>14 000</td>
<td>0.0282</td>
<td>0.0648</td>
</tr>
<tr>
<td>0.1</td>
<td>1 500</td>
<td>0.0157</td>
<td>0.0805</td>
</tr>
<tr>
<td>0.135</td>
<td>150</td>
<td>0.0025</td>
<td>0.083</td>
</tr>
<tr>
<td>TOTAL</td>
<td>1 555 650</td>
<td></td>
<td>0.083</td>
</tr>
</tbody>
</table>

The curvature and number of cycles for each block has been chosen to achieve a similar distribution of fatigue damage between small and large cycles as experienced during service life. Figure 5 shows a typical distribution of cumulative fatigue damage vs. curvature during service life of the cable. This result would be based on the fatigue analysis performed as part of the global analysis where the cable experiences a large number of waves resulting in various curvature response and fatigue damage. The figure also includes the corresponding block program from Table 1, resulting in the same accumulated fatigue damage as for the cable during service life and with a similar distribution of fatigue damage with regards to small and large curvatures.

9. Conclusion and discussion

Cables connected to floating wind turbines and floating transformer stations must be dynamic to be able to withstand the loads resulting from waves, current and the floating platform motions. A dynamic cable is designed and tested to sustain the dynamic loads induced on the
Similar accelerated fatigue test methodology has been employed for several years within the Oil&Gas sector with regards to for instance Umbilicals and Flexible pipes [15, 16].

10. Bibliography


Summary
HVDC transmission systems using voltage sourced converter (VSC) technology are increasingly being applied to transmit renewable wind power through existing AC systems via long transmission circuits. The power ratings of VSC systems can be in excess of 2000MW and are comparable to rating values that are possible using conventional line commutated HVDC technology. Due to difficulties in obtaining new line rights of way, there is a natural tendency to co-locate the HVDC lines on the same right of way or in some cases on the same towers as existing AC lines using suitably re-designed modified towers. Thus, HVDC transmission systems may be constructed within the same corridor together with existing AC transmission systems and may even be installed on the same towers as the AC lines or in some cases two HVDC bipoles may be carried on the same tower.

The AC systems within the common corridor could include 110kV and 380kV electrical power transmission systems as well as railway electrical systems operating at 110kV, 16.7Hz. to establish the extent of possible interference between AC and DC facilities, AC/DC coupling studies and EMF studies have been carried out to investigate and document the environmental and potential interaction impacts between proposed HVDC transmission systems and existing AC transmission systems. It was assumed that the HVDC links would be constructed as full-bridge VSC HVDC systems with either one or two HVDC lines in close proximity with the AC facilities.

When several HVDC systems are located on the same tower, the electrical effects may also change compared to single HVDC lines. The EMF environment in the vicinity of the lines has been calculated for two-bipole HVDC lines on the same tower and compared with a one-bipole dc line.

This paper presents and summarizes the key results of an illustrative AC/DC coupling study and EMF calculations for a two bipole line and provides a discussion of a number of design considerations in event that multiple AC and DC lines are located on the same towers or on separate towers within the same right-of-way.

1. Introduction
HVDC transmission systems using voltage sourced converter (VSC) technology are increasingly being applied to transmit renewable wind power through existing AC systems via long transmission circuits. The power ratings of VSC systems can be in excess of 2000MW and are comparable to rating values that are possible using conventional line commutated HVDC technology.

Due to difficulties in obtaining new line rights of way, there is a natural tendency to with co-locate the HVDC lines on the same right of way or in some cases on the same towers as existing AC lines using suitably designed modified towers. Thus, HVDC transmission systems may be constructed together with existing AC transmission systems and may remain within the same corridor or may be installed on the same towers as the AC lines. The adjacent AC systems could include 110kV and 380kV electrical power transmission systems as well as railway electrical systems operating at 110kV, 16.7Hz. The HVDC line configuration may include two bipole circuits on the same tower.

The potential coupling between the HVDC transmission systems and adjacent AC transmission systems was

* j.hu@rbjengineering.com

KEYWORDS
VSC HVDC, AC/DC Coupling, EMF, Full-bridge, Right-of-way.
Electric field profiles were calculated for a two-bipolar HVDC line tower configuration under normal service conditions with no pole outages. As the ion production and flow of ions is coming under greater scrutiny and environmental concern, electric field lines were also plotted to indicate the expected trajectories of the ion flows under the influence of the electric field under low-wind conditions. Dimensions of the proposed single and two-bipole towers and assumed conductor sags at the midpoint between towers are indicated in Figure 2 and Figure 1. For this analysis, new DC tower configurations are assumed rather than conversion of existing AC line towers.

Typical static electric field and the field as enhanced by space charge for the two-bipole 500 kV line are shown in Figure 1 were calculated assuming the apparent corona onset gradient corresponding to the worst-case fair-weather conditions. The electric field direction is indicated by red arrows.

In the example, the maximum static electric field under the two-bipole ±500kV DC line, due to the charge on the conductors alone, is about 3.0 kV/m and the maximum total field including the contribution from the space charge, is about 15 kV/m. This is much lower than the maximum value of space charge enhanced static electric field of 25kV/m quoted in Cigré TB 583 [14] and Cigré TB 388 [16]. As only the magnitude of the field is of interest, the electric field from the negative conductors is plotted in the positive direction. As there would always some corona-generated space charge, even in fair weather conditions, the actual electric field in a profile perpendicular to the line corridor would be somewhere between the violet and green curves in Figure 1.

For the tower configuration shown in Figure 1, the polarity of the pole conductors was selected so that the two upper pole conductors will be positive and the two lower pole conductors will be negative. Other conductor arrangements would also be possible and would influence...
The terrestrial magnetic field varies from about 30 μT in equatorial regions to about 70 μT near the poles with typically 50 μT in Europe. The net magnetic field profile across the two-bipole HVDC line right of way considering the impact of the current in the line conductors plus the terrestrial magnetic field is shown in Figure 3. Assuming the line is in Europe, the net magnetic field from the overhead lines measured at one meter above ground level would fall within the range of natural variation the terrestrial magnetic field even with DC currents up to 2000A. Larger variations would occur during pole outages but the net magnetic field would still fall within the natural range of the terrestrial magnetic field. The impact due to the two bipole is even lower than that of a single bipole HVDC line which is shown for comparison in Figure 4. Thus, the magnetic field would be seen as a local perturbation of the natural terrestrial magnetic field. For interest, the ICNIRP guideline [15] states that static magnetic field exposures for the general public should be limited to 400mT which is much higher than the ground level magnetic fields in the proximity of an HVDC line.

Figure 2- Electrical Effects from Single Bipole HVDC Line

Figure 3 – Two-Bipole HVDC Line Magnetic Field Both Positive Poles on Top
The coupling effect between the two HVDC transmission systems and existing AC transmission systems within the same corridor or installed on the same towers as the DC lines was evaluated using Electromagnetic Transient Program (PSCAD/EMTDC) taking into account all significant influencing factors. The AC systems evaluate included 110kV and 380kV 50Hz electrical power systems as well as 110kV, 16.7Hz railway electrical systems. The level of coupling was evaluated for a total of eight scenarios corresponding to several AC/DC system configurations as described in Table 1. The details of AC and DC line tower configurations and separation distance between DC and AC transmission systems are shown in Figure A-1 and Figure A-2 in Appendix A.

Table 1 - Study Scenarios for AC/DC Coupling Effect

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1). Two ±500kV Bipole DC System and 110 kV AC System (50 Hz)</td>
<td></td>
</tr>
<tr>
<td>1A</td>
<td>Sharing same tower - 100 km (Double circuit 110 kV system, single conductor)</td>
</tr>
<tr>
<td>1AA</td>
<td>Sharing same tower - 100 km (Double circuit 110 kV system, 2-bundle conductor)</td>
</tr>
<tr>
<td>1B</td>
<td>Same ROW 70m apart - 100 km (Double circuit 110 kV system, single conductor)</td>
</tr>
<tr>
<td>1BB</td>
<td>Same ROW 70m apart - 100 km (Double circuit 110 kV system, 2-bundle conductor)</td>
</tr>
<tr>
<td>(2). Two ±500kV Bipole DC System and 110 kV AC System (16.7 Hz)</td>
<td></td>
</tr>
<tr>
<td>2A</td>
<td>Sharing same tower - 100 km (Double circuit 110 kV system)</td>
</tr>
<tr>
<td>2B</td>
<td>Same ROW 70m apart - 100 km (Double circuit 110 kV system)</td>
</tr>
<tr>
<td>(3). Two ±500kV Bipole DC System and 380 kV AC System (50 Hz)</td>
<td></td>
</tr>
<tr>
<td>3A</td>
<td>Sharing same tower - 100 km (Double circuit 380 kV system)</td>
</tr>
<tr>
<td>3B</td>
<td>Same ROW 70m apart - 100 km (Double circuit 380 kV system)</td>
</tr>
</tbody>
</table>

The coupling effect between the two HVDC transmission systems and existing AC transmission systems within the same corridor or installed on the same towers as the DC lines was evaluated using Electromagnetic Transient Program (PSCAD/EMTDC) taking into account all significant influencing factors. The AC systems evaluate included 110kV and 380kV 50Hz electrical power systems as well as 110kV, 16.7Hz railway electrical systems. The level of coupling was evaluated for a total of eight scenarios corresponding to several AC/DC system configurations as described in Table 1. The details of AC and DC line tower configurations and separation distance between DC and AC transmission systems are shown in Figure A-1 and Figure A-2 in Appendix A.

Summary of EMF from Overhead Lines

The criteria for maximum electric field below an HVDC line are normally selected at or below the threshold of perception for humans. Generally, it is impractical to reduce electric field effects to levels similar to the terrestrial ambient levels within the line right of way corridor. However, the calculations indicate it is possible to reduce the electric field effects of the two-bipole line by selecting the conductor polarities to favourably influence the field lines and the ion current flow.

Magnetic fields from the HVDC one or two-bipole lines are generally low compared with the terrestrial magnetic field. For the tested two bipole and one-bipole configurations the net magnetic field can be viewed as a slight local perturbation of the natural magnetic field of the earth.

3. AC/DC coupling

When AC and DC lines are built in close proximity or on the same right of way either on the same tower or on the same right of way, a fundamental frequency voltage component will be induced on the DC line conductors by inductive and capacitive coupling from the AC lines. The major concerns associated with the fundamental frequency AC current flow in the DC line are possible core instability in the converter transformers due to DC offset [17] and increased DC equipment ratings due to superimposed fundamental frequency voltage and current on the DC voltage and current. The primary coupling mode is inductive.

Similarly, faults and transient events on the DC system can induce transient quasi-DC currents into the parallel AC circuits. This could adversely impact the AC line protections if the DC current is large enough to saturate the CTs. This aspect would need to be considered when selecting the CTs and protection equipment for the parallel AC lines.
Coupling from AC Lines to DC lines in Steady State

When AC lines are located close to the DC line, they can induce significant levels of AC voltage and current into the DC circuits. The main results from the investigations are described below:

(a) The maximum induced AC voltages and currents from the 50 Hz and 16.7 Hz AC lines to DC lines under steady state are shown in Figure 6 and Figure 7. The highest induced voltage is 40.3kV in Scenario 3A in which the double circuit 380 kV AC line is on the same tower as the DC circuits. Coupled voltages and currents on the DC lines are significantly lower when the AC lines are further away from the DC lines on separate towers in the same right-of-way.

(b) Induced fundamental frequency voltages on the DC lines are directly proportional to the length of the coupled line section and the magnitude of the AC line currents for a given conductor configuration on a common tower or separate tower within the right of way under the steady state operation.

(c) Due to the long DC lines being considered, the AC voltage coupled onto the DC line can undergo significant amplification due to the Ferranti effect. The degree of Ferranti amplification is a non-linear function of the length of DC line between the coupled line section and the remote converter station, with longer lines producing greater amplification. In the worst case of Scenario 3A with DC System and 380 kV AC systems located on the same tower, the longitudinal voltage coupled to the DC line on the100km coupled line length is about 25kV while the total longitudinal voltage on 700 km DC lines after Ferranti amplification is about 40kV. Thus, the final voltage is 160% of the voltage coupled onto the line.
voltages are reduced by a factor of about 5 times as compared with the induced voltage levels for circuits on the same tower.

(f) Although the AC voltage and current flows in the DC line are relatively large (up to 40 kV and 70A), the DC currents observed on the secondary side of converter transformer due to AC currents on the DC lines are very small (<0.5A). This is due to two inherent features of full-bridge VSC converters:

i). Decoupled control of AC and DC voltages without modulation index limitations.

ii). The VSC converter provides a relatively low impedance path for AC currents to flow between pole and DMR conductors without passing though the converter transformers.

This is different than LCC converters. In an LCC system, the converters have high impedance to the AC circuit and the coupled sections is a very effective means to reduce the magnitude of induced voltage and current on the DC lines. One full rotation of 50 Hz AC lines was found to reduce induced current on DC lines by a factor of about 10 in the configuration that was studied. However, additional transpositions beyond one full rotation do not result in further large decreases in the induced current. Transpositions of the AC circuits are also effective in reducing the induced voltage on the DC line even when the AC circuits are on separate towers with 70 m separation in same right of way.

(e) Increasing the separation between AC and DC conductors would reduce coupling between the circuits. For AC and DC lines that are located on separate tower with 70 m separation, the coupled voltages are reduced by a factor of about 5 times as compared with the induced voltage levels for circuits on the same tower.

(d) Transposition of AC line conductors within each AC circuit and the coupled sections is a very effective means to reduce the magnitude of induced voltage and current on the DC lines. One full rotation of 50 Hz AC lines was found to reduce induced current on DC lines by a factor of about 10 in the configuration that was studied. However, additional transpositions beyond one full rotation do not result in further large decreases in the induced current. Transpositions of the AC circuits are also effective in reducing the induced voltage on the DC line even when the AC circuits are on separate towers with 70 m separation in same right of way.
flow of AC currents through the valve but current can flow in two windings of the transformer only when the converter valves are turned on. The fundamental frequency component of the current is converted by the converter bridge into a DC component as well as a second harmonic component flowing in the secondary windings of the converter transformer.

In a VSC half-bridge converter, the AC current can flow into the MMC module capacitors in one direction but is blocked in the other direction by the free-wheeling diodes. This is different than a full-bridge VSC converter but this was not investigated in these studies.

The low levels of DC current flow observed in the converter transformers with the full-bridge converter are achieved by the normal control algorithms of the converters without any special control feature to reduce the DC current in the converter transformers and without taking any steps to reduce the amount of AC current in the DC circuit. Because of the decoupling of the AC and DC voltages, it would be possible to tolerate an AC ripple voltage of almost any waveshape on the DC side even a composite waveshape containing multiple simultaneous frequencies such as 50 Hz or 16.7 Hz without influencing the AC transmission and without introducing any harmonics on the AC side.

(g) Stable operation of the full-bridge VSC DC systems was demonstrated up to the rated power of 2000MW delivered to the inverter. There do not appear to be any operational or performance concerns in spite of the significant AC voltages and currents that can be induced onto the DC lines. The circulating AC currents on the DC lines do not result in harmonic generation on the AC side nor is there any significant DC current flow in the converter transformers.

**Coupling from DC Lines to AC Lines**

The AC system operation is not affected by the DC system under normal steady state operation because the steady DC current does not induce voltages or currents on the AC circuits. Coupling would be limited to the time varying components of the DC current which could include harmonics, ripple and high frequency currents which are normally very small.

However, coupling of a quasi-DC current into the AC circuits can occur during some events such as run-back or run-up when there is a large and fast change in the DC current. The effect of coupling from DC to AC lines during disturbances in the parallel DC lines was investigated by simulating faults on the DC lines from pole to ground or from Pole to dedicated metallic return (DMR) to ground. The faults are applied along DC BIPOLE I within the three coupled locations with two coupled lengths, 20km and 100km. If the coupled line length is 100 km, the faults are applied at ten locations from 10km to 100km in steps of 10 km. If the coupled length is 20 km, the faults are applied at two locations, 10 km and 20 km. A total of eleven types of faults were simulated at each fault location including pole to ground or DMR, pole to pole, pole to pole to ground or DMR.

The magnitude of induced DC voltage and current on the AC lines associated with DC line faults varies with the type of fault. Large DC currents are induced in the AC lines during the faults when one pole and both ground and DMR are involved in the fault. This is due to the smaller zero sequence impedance that is provided through the ground between the fault location and the neutral of AC system. For other faults, the magnitude of the induced DC currents is general lower (<40A) and are not very sensitive to the location of the faults. The induced currents are less than 0.26 kA in all the fault cases and scenarios.

The magnitude of induced DC current due to DC line faults is not significantly sensitive to the AC and DC lines coupled location. For 380 kV AC system, the induced DC currents on AC lines are highest when AC and DC lines are coupled close to the sending end of DC system while it is about the same when coupled at middle and receiving end of DC system. For 110 kV AC system, both 16.7 Hz or 50 Hz, the induced current is about the same when coupled at sending and receiving end and it is slightly lower when coupled at middle of the DC system.

The maximum induced DC currents observed on AC CIRCUIT are summarized in Table 2 The highest DC currents occur during both positive pole-to-ground and negative pole-to-ground fault especially when the fault is close to the receiving end of AC lines. The highest DC currents occur during both positive pole-to-ground and
ripple voltages on the DC side without passing them through the converter transformers to the AC side as DC currents or complementary harmonics, the induced voltage and current can cause following undesirable consequences which must be taken into account in the detailed design.

- Increased energy losses in the DC line and DMR.
- Increased losses in the freewheeling diodes of the valves.
- Increased ratings are needed in the valve DC module capacitors.
- Increased numbers of series MMC modules may be needed if the ripple voltage is high enough.
- Increased rating and insulation level of overhead transmission lines and cables.

(b) When considering AC and DC lines on the same right of way, it is recommended to reduce the coupled voltages and currents by passive design measures to the extent that it is practical as follows:

i. Whenever possible, install the AC and DC circuits on separate towers to increase the separation distances between AC and DC line. Apply transpositions on the AC line conductors within the coupled sections to further reduce coupled voltages. These measures are also applicable if the DC is implemented as a buried cable system.

ii. If it is not possible to avoid placing AC and DC circuits on the same tower, then apply AC conductor transpositions on all circuits within the coupled section.

(c) The DC system should be specified to be capable of operation in the symmetric monopole mode during faults or other events which may cause the DMR to become unavailable. Alternatively, an emergency

4. Summary of AC/DC Coupling Investigation and Recommendations

These studies have identified issues that need to be considered in event that AC and DC lines are located on the same towers as well as on the same right-of-way. Some of the studies should be repeated when the specific configurations, coupled line lengths and connection points of the AC and DC lines have been finalized. The following recommendations are made based on the study results.

(a) Although the studies indicate full-bridge VSC converters can inherently tolerate relatively large negative pole-to-ground fault especially when the fault is close to the receiving end of AC lines.

The maximum DC currents on 110kV 50 Hz, 110 kV 16.7 Hz and 380 kV 50 Hz are about 240 A, 165 A, and 270 A during negative pole to DMR to ground fault at 100 km away from sending end. In the worst case of Scenario 3A, the corresponding DC current in the neutral of AC CIRCUIT at sending end is 574 A. These values of DC current are high enough to be of concern and could lead to protection mis-operation in the AC line protections unless mitigative measures such as gapped CT cores or special protection algorithms are applied on affected AC circuits. Affected AC circuits may not be confined to those within the coupled zones as the DC current must flow to ground via grounded transformers at the AC substations. Coupling of DC into the AC circuits would be of short duration and is unlikely to cause equipment damage but any protection mis-operation issues would need to be remedied.

(b) When considering AC and DC lines on the same right of way, it is recommended to reduce the coupled voltages and currents by passive design measures to the extent that it is practical as follows:

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Coupled Location</th>
<th>Sending End</th>
<th>Receiving End</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Phase A or Outer Phase</td>
<td>Phase B or Inner Phase</td>
<td>Phase C</td>
</tr>
<tr>
<td>Scenario1AA</td>
<td>Sending</td>
<td>238.0</td>
<td>211.2</td>
</tr>
<tr>
<td></td>
<td>Middle</td>
<td>231.8</td>
<td>202.5</td>
</tr>
<tr>
<td></td>
<td>Receiving</td>
<td>236.3</td>
<td>204.0</td>
</tr>
<tr>
<td>Scenario2A</td>
<td>Sending</td>
<td>163.9</td>
<td>133.3</td>
</tr>
<tr>
<td></td>
<td>Middle</td>
<td>129.4</td>
<td>134.7</td>
</tr>
<tr>
<td></td>
<td>Receiving</td>
<td>160.0</td>
<td>130.2</td>
</tr>
<tr>
<td>Scenario3A</td>
<td>Sending</td>
<td>268.1</td>
<td>157.9</td>
</tr>
<tr>
<td></td>
<td>Middle</td>
<td>232.2</td>
<td>160.4</td>
</tr>
<tr>
<td></td>
<td>Receiving</td>
<td>230.6</td>
<td>159.9</td>
</tr>
</tbody>
</table>

Table 2 - Maximum Induced DC Current on AC CIRCUIT Due to DC Faults
ground electrode or earth connection shall be provided at or near the ungrounded converter terminal to allow bipolar operation during outage of the DMR.

(d) The switching impulse withstand level (SIWL) of the DMR of both bipoles should be selected to withstand the maximum observed overvoltages during faults plus some margin. In the case of the studied configurations the observed switching overvoltages were about 550 kV.

(e) The tower dimensions for all hybrid configurations would be sufficient to accommodate insulators needed to avoid flashovers for steady state, and switching overvoltages. The shield wires of the DC should be located to provide complete protection for the outside DC pole conductors of the DC line which could be vulnerable to lightning strikes and shielding failure flashovers.

4. Conclusions

Electrical and magnetic fields for two-bipole HVDC lines are comparable to the values for single bipolar overhead HVDC lines. Some configurations of pole conductor polarity may result in reduced electric field and ion current flow outside the line right of way. This should be considered before finalizing the tower head design of a two-bipole line.

The results of an AC/DC coupling study for VSC full-bridge show that although the AC voltage and current flows induced in the DC line are relatively large, the DC currents observed on the secondary side of converter transformer due to AC currents on the DC lines are very small. This is due to two inherent features of the full-bridge VSC converter:

- decoupled control of AC and DC voltages without modulation index limitations, and
- the VSC converter provides a relatively low impedance path for AC currents to flow between pole and DMR conductors without passing though the converter transformers.

5. Bibliography

Figure A-1 - 500 kV DC and 380 kV and 110 kV AC Tower and Conductor Configuration
Figure A-2 – Separation Distance and Conductor Phasing of Parallel DC and AC Lines
Summary
Multi-terminal HVDC systems based on Modular Multilevel Converters (MMCs) are envisaged for the large scale integration of renewable energy sources worldwide. There are several system designs in discussion for these future grids. Two of the discussed realisation aspects being the HVDC system configuration and the protection system. Existing point-to-point systems are built using the symmetrical monopole configuration. For future multi-terminal systems, bipolar configurations are in discussion as they provide redundancy in case of pole-to-ground faults. Due to the different grounding schemes associated with the system configurations, the steady state fault currents differ significantly for pole-to-ground faults. The proposed protection systems for multi-terminal systems, however, may have to identify, locate, and clear faults based on the first travelling waves within a few milliseconds. This paper therefore compares the system behaviour of a high impedance grounded monopole with a bipolar configuration with dedicated metallic return regarding a selective HVDC protection system applying HVDC circuit breakers. Based on the analysis, the differences in requirements on the protection system for the two system configurations are evaluated.

The analysis is carried out in a cable-based HVDC system in an electromagnetic transients program, with parameters similar to existing offshore connections employing MMCs with half-bridge submodules. The results show that the used system configuration leads to little difference in the current and voltage profiles in the time period relevant for the detection of line faults in multi-terminal grids as the behaviour is predominantly defined by the travelling wave effects. The same applies for the current breaking requirements on the HVDC circuit breakers. Special care must be taken only at the grounded terminal of the bipolar configuration, as higher currents occur in case of a pole-to-ground fault in comparison to the symmetric monopole configuration.

1. Introduction
Voltage source converter based high-voltage direct current (VSC HVDC) transmission has been identified as one of the key means to integrate large-scale offshore wind power generation into the power system [1]. While existing point-to-point connections employing modern Modular Multilevel Converters (MMCs) are based on the symmetrical monopole configuration, bipolar configurations are in discussion for future multi-terminal systems due to higher achievable power ratings and inbuilt redundancy among other factors. For both configurations, the design of a fast and reliable protection system is still considered one of the key challenges for multi-terminal HVDC (MTDC) systems [2].

Previous studies have identified the symmetric monopole configuration to have less stringent requirements on the fault separation devices, e.g. HVDC circuit breakers (DC CB), due to no “steady state” fault current in case of pole-to-ground faults [2]. In this context, steady state refers to the fault current after all transient effects have subsided. In bipolar configurations, the same fault type results in a high steady state current. The different grounding strategies in the two configurations lead to this difference: Symmetrical monopole systems are commonly built with a high impedance grounding on the AC side resulting in minimal steady state fault current, but a voltage rise on the healthy pole. Bipolar systems, which are commonly grounded on the DC side with a low impedance grounding, exhibit a high steady state fault current, but no voltage asymmetry after fault clearing [2].
shows these configurations and the respective grounding. Several variations of the grounding scheme are generally possible. The existing symmetric monopole systems are grounded with a high impedance on the AC side, featuring a star point reactor. The grounding in this paper is adapted accordingly. The investigated bipolar system is effectively grounded at the midpoint connected to the metallic return at one converter station to avoid ground currents in normal operation.

3. Faults and protection in MTDC systems

Line faults in HVDC systems lead to the initiation of travelling waves from the fault location to the line ends, where they are partly reflected and partly transmitted depending on the respective surge impedances of the subsequent converters and lines [4]. The arrival of the travelling waves can be measured as a voltage decrease and current increase. Due to the steep increase of the current resulting from the discharge of the capacitances in the system and the limited overcurrent capability of the power electronics in the converter protective actions must be initiated within a few milliseconds. To protect the IGBTs in the converter, a converter-internal overcurrent protection based on the arm currents is commonly applied, which blocks the IGBTs in case the overcurrent threshold is exceeded [5]. When considering MTDC systems with a protection concept applying DC CB at each line end, the limited current breaking capabilities of the breakers must be taken into account as well. Different DC CB concepts have been proposed, which can be roughly summarised with regard to the elements in the main current path: Solid state circuit breakers, hybrid circuit breakers featuring mechanical and solid state elements and mechanical circuit breakers. The concepts differ with regard to the opening time of the breaker, the maximum current interruption capability and the on-state losses among other factors. Solid state circuit breakers are capable of breaking currents within a µs time frame. However, due to the limited overcurrent capability of the power electronic devices within the converters, the proposed DC CB types and the overall stability of the DC grid, the protection system may have to identify, locate and clear faults based on the first travelling waves within a few milliseconds before steady state is reached. To this end, several different detection algorithms, protection philosophies and fault clearing technologies have been proposed for MTDC systems in recent years with most underlying studies focussing on just one of the system configurations. This paper therefore analyses and compares the impact of the applied system configuration on the characteristic system behaviour shortly after fault occurrence, with a focus on the relevant period for the protection system to detect and clear the fault. For this purpose the typical HVDC system configurations and proposed selective HVDC protection systems are summarised. The HVDC system configurations are then modelled in an electromagnetic transient simulations program, capable of calculating the system behaviour under DC faults. The analysis starts from a prospective analysis in a point-to-point connection that is in a second step included in a four-terminal system to take into account the effect of multi-terminal grids on the protection. Based on the analysis, the applicability of the proposed protection systems is evaluated and compared for the system configurations.

2. HVDC system configurations

There are three main HVDC system configurations: The symmetric monopole, the asymmetric monopole and the bipolar configuration which consists of two asymmetric monopoles with opposing polarity connected in parallel. The bipolar configuration can either have a dedicated metallic return conductor, use ground return or can be configured as a so called rigid bipole with no metallic return and only one grounded converter station [3].

This paper focuses on two topologies: the symmetric monopole, as it is used for most existing MMC systems in operation today and the bipolar configuration with metallic return conductor as it offers additional redundancy in case of a pole-to-ground fault. Figure 1 shows these configurations and the respective grounding. Several variations of the grounding scheme are generally possible. The existing symmetric monopole systems are grounded with a high impedance on the AC side, featuring a star point reactor. The grounding in this paper is adapted accordingly. The investigated bipolar system is effectively grounded at the midpoint connected to the metallic return at one converter station to avoid ground currents in normal operation.

Figure 1: HVDC System Configurations, (a) Symmetric monopole with high impedance grounding on the AC side, (b) Bipolar configuration with dedicated metallic return grounded on the DC side
4. Investigation framework

The comparison of the monopole and bipolar configuration are carried out in a point-to-point and in a four-terminal HVDC system specified in the Horizon 2020 project PROMOTioN, as shown in the single line diagram in Figure 2a. The busbar configuration including the inductors, DC CB and the measurement system is shown exemplarily for the busbar at C_2 in Figure 2b. The investigation in the point-to-point system is based on the indicated connection between converter C_2 and C_4, as this is a highly loaded line, which will later be connected in the loop of the MTDC system. The system is assumed to be an offshore system based on XLPE cables connecting the converter stations with the line lengths given in Figure 2.

In the bipolar configuration the metallic return is effectively grounded at converter C_2. For comparison purposes the grounding is shifted to converter C_1 along with the V_{DC}-control mode in one investigation. The converter control is based on the cascaded vector control from Cigré WG B4.57 [9]. The control modes of the converters are given in Figure 2. All converters in P-control either import or export P = 1.2 GW as indicated by the arrows in Figure 2. The converters are in V_{AC}-control mode with V_{AC} = V_{n,AC} = 400 kV.

The symmetrical monopole and bipolar half-bridge MMCs have the same electrical design parameters apart from the necessary changes due to the difference in configuration. The main design parameters for each configuration are summarised in Table I.

The applied converter model is a Type 4 Detailed Equivalent Circuit Model, which enables an accurate representation of the converter’s behaviour during faults [9]. The cables are modelled using a frequency dependent phase model for accurate representation of travelling wave phenomena [9]. The submodule parameters are based on an INFINEON IGBT commercially available with a continuous DC collector current of I_{CDC} = 1.5 kA and a collector-emitter voltage of V_{CES} = 3.3 kV [10].

![Figure 2: (a) System layout, (b) Busbar configuration with measurement system](image)
The AC systems are represented by ideal sources with respective short circuit impedances ($S_k = 30 \text{ GVA}$). The simulations are carried out with a simulation time step of $t_{sim} = 10 \mu\text{s}$.

### Table I: Converter station parametrisation

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Rating Monopole</th>
<th>Rating Bipole</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rated station power</td>
<td>1256 MVA</td>
<td>632.5 MVA</td>
</tr>
<tr>
<td>Rated active station power Rated</td>
<td>1200 MW</td>
<td>600 MW</td>
</tr>
<tr>
<td>DC pole voltage Rated AC</td>
<td>±320 kV</td>
<td>320 kV</td>
</tr>
<tr>
<td>voltage at MMC Rated DC pole</td>
<td>350 kV</td>
<td>166 kV</td>
</tr>
<tr>
<td>current</td>
<td>1.875 kA</td>
<td>1.875 kA</td>
</tr>
<tr>
<td>Number of submodules per arm</td>
<td>350</td>
<td>175</td>
</tr>
<tr>
<td>Rated submodule voltage</td>
<td>1.9 kV</td>
<td>1.9 kV</td>
</tr>
<tr>
<td>Submodule capacitance Arm</td>
<td>8.8 mF</td>
<td>8.8 mF</td>
</tr>
<tr>
<td>resistance</td>
<td>80 mΩ</td>
<td>80 mΩ</td>
</tr>
<tr>
<td>Arm inductance</td>
<td>42 mH</td>
<td>42 mH</td>
</tr>
<tr>
<td>Converter output inductance</td>
<td>10 mH</td>
<td>10 mH</td>
</tr>
<tr>
<td>Star point reactor</td>
<td>5000 H, 5 kΩ</td>
<td>-</td>
</tr>
</tbody>
</table>

Exemplifying faults are simulated in the middle of line L24. This paper focuses on faults that can occur in both monopole and bipolar systems: pole-to-ground faults and pole-to-pole-to-ground (P-N-GND) faults. Pole-to-ground faults are the most common fault type in cable systems [2]. For symmetry reasons only positive pole-to-ground (P-GND) faults are shown in this paper. P-N-GND faults are very unlikely in cable systems, however, are referred to as a worst case scenario with regard to fault currents. The simulated fault resistance for both fault types is $R_f = 0.01 \Omega$. The converters have an internal overcurrent protection which blocks the IGBTs when the arm current exceeds 0.9 pu of the repetitive peak current of the IGBTs (here, $I_{arm,max} = 2.7 \text{kA}$).

Within the point-to-point system, the prospective behaviour of the two configurations is analysed for both fault types. Only the converter internal protection is activated. In the multi-terminal system DC CB are additionally placed at each line end. They are modelled as ideal breakers in parallel to a surge arrester with a rated voltage of $v_{arrester} = 1.2 \text{ pu}$. For the analysis an idealised selective protection is used which separates the faulty line 10 ms after the travelling wave reached the line end. This timeframe allows to analyse the system behaviour and current rise including the opening time of slower DCCB. To limit the fault current’s rate of rise due to the fast cable discharge, inductors are installed at each line end with $L_{Line} = 50 \text{ mH}$.

### 5. System analysis

#### 5.1 Faults in the point-to-point system

Figure 3 shows the prospective system behaviour of the monopole and bipolar point-to-point system at converter $C_2$ over a time frame of 35 ms after a P-GND fault has been initiated at $t_f = 0 \text{ ms}$. The voltage of the faulted positive pole breaks down steeply in both configurations. In the first 5 ms the behaviour is dominated by the travelling wave reflections between the converter and the fault. These also affect the healthy conductors. After the travelling waves have been damped, the voltage on the positive pole falls to $v_{C2,P} \approx 0 \text{kV}$. In the monopole configuration, the healthy pole is subjected to a voltage offset, such that the voltage increases over its nominal voltage. In the bipolar configuration, the voltage of the healthy pole and the metallic return conductor remain at approximately nominal voltage. The current shows the characteristic behaviour of the different configurations considering the grounding strategies. In the monopole configuration, the current increases to a maximum value of $i_{C2,max} = 3.5 \text{kA}$ at $t = 0.9 \text{ ms}$ due to the discharge of the submodule capacitors in the MMC and then decays to $i_{C2} \approx 0 \text{kA}$ after the blocking of the IGBTs due to the internal overcurrent protection. The current on both poles is symmetrical. In contrast, the current on the healthy pole stays in the same range in the bipolar configuration, while the fault current loop is closed via the metallic return conductor reaching a steady state fault current of approximately $i_{C2,P} = -9 \text{kA}$.

In case of a P-N-GND fault (cf. Figure 4), a similar system behaviour can be found: The travelling wave arrival leads to a steep voltage breakdown before the voltage on both poles subsequently decays to $v_{C4} = 0 \text{kV}$. The current rises rapidly and reaches a maximum value of $i_{C4,max} = 21.5 \text{kA}$ in the monopole and $i_{C4,max} = 19.4 \text{kA}$ in the bipolar configuration.
5.2 Faults in the MTDC system

Figure 5 shows the voltage and current profiles for a P-GND fault in the middle of line \( L_{24} \) at the busbar of converter \( C_4 \) for the time frame of 15 ms after fault inception, as this would be the relevant time frame for fault detection and fault clearing applying the discussed DC CBs. For both configurations, the voltage and current profiles on the faulted line are very similar. There is a steep voltage breakdown at the line end when the travelling wave arrives to \( v_{L42,P} = -200 \) kV, followed by reflections at the fault location. The voltage profiles at the adjacent line \( L_{14} \) and the converter \( C_4 \) result from their corresponding surge impedances and the used inductors. In comparison to the faulted line, \( v_{L41} \) reduces very slowly reaching \( v_{L42} = 0 \) kV at \( t = 5.5 \) ms. The voltage at the converter is subjected to a voltage profile similar to the faulted line with a reduced amplitude. There are fault current contributions both from the adjacent cable and the converter. While the fault current contribution from the converter is reduced in comparison to the point-to-point connection due to the reduced voltage breakdown at the converter terminal, the adjacent cable leads to an additional current contribution. The total current at the end of the faulted line rises to a maximum amplitude of \( i_{L24,P} = 9.16 \) kA in the monopole and \( i_{L24,P} = 9.83 \) kA in the bipolar configuration. For the monopole configuration, this amounts to more than twice the current amplitude measured in the point-to-point connection. Overall, the system behaviour in the analysed time period is mainly dominated by the travelling waves initiated by the fault and their reflection and transmission at the line ends.
An analysis of the currents and voltages at the grounded terminal of converter \( C_2 \) shows a slightly different behaviour (cf. Figure 6). The voltage profiles on the faulted positive pole are again the same in both configurations and dominated by the travelling wave reflections. The current on the faulted pole increases at the same rate of change for the first millisecond. Afterwards, the current in the bipolar configuration increases further to a maximum amplitude of \( i_{L42,P} = 11.8 \) kA at \( t = 10 \) ms in comparison to a maximum current of \( i_{L42,P} = 6.4 \) kA at \( t = 6 \) ms in the monopole configuration. The current in the monopole configuration reduces in the analysed time period after this given peak value. This difference in current at the faulted line end mainly originates from the increased fault current from converter \( C_2 \) in the bipolar configuration, while the fault current contribution from the adjacent line is slightly lower due to a lower voltage profile at the line end.

To give a complete picture, Figure 7 shows the voltage and current profiles at the line end of line \( L_{24} \) for a grounding of the bipolar system at converter \( C_1 \). In this case the current and voltage profiles in the monopole and bipolar configuration are again identical.
In case of P-N-GND faults the same behaviour can be observed regardless of the system configuration or the grounding location. Figure 8 exemplary shows the voltage and current at the line ends L24 at converter C2 for a P-N-GND fault on this line. The travelling wave arrival leads to a steep voltage break down and corresponding reflections. The current rises fast and reaches a maximum value of $i_{L24,\text{max}} = 15.6\, \text{kA}$ in the monopole configuration and $i_{L24,\text{max}} = 13.2\, \text{kA}$ in the bipolar configuration.

5.3 Evaluation of the proposed protection systems

Based on the preceding analysis, it can be concluded that the system behaviour in the first 10 ms after fault occurrence for a given load flow and grid topology is mainly dominated by the travelling wave behaviour of the system, i.e. the combination of inductors and the surge impedances of connected components at each line end irrespective of the system configuration and its grounding scheme.

Consequently, the evaluation of the proposed detection criteria would yield the same result in both system configurations. Due to the decoupling of the voltage profile of the faulted line and the adjacent connections by the inductors at each line end, the use of ROCOV criteria appears to be suitable for selective fault detection. The ROCOV criterion could also allow the differentiation between the faulted and the healthy pole in the bipolar configuration.

The resulting maximum current amplitudes for pole-to-ground faults and thus the required fault current interruption capabilities of the DC CB are also the same at most busbars in the grid, with one exception: The busbar at which the metallic return of the bipolar configuration is grounded. At this busbar the current contribution from the bipolar converter is higher, leading to higher current amplitudes on the faulted line in comparison to the monopole configuration. In the analysed example the difference in the maximum current amplitudes between the system configurations amounts to $\Delta i_{L42,\text{p}} = 5.4\, \text{kA}$.

When accounting for the (highly unlikely) event of a P-N-GND cable fault in the design of the DC CB, the required fault current interruption capabilities for both systems exceed the values for the P-GND faults, such that no extra care must be taken with regard to the grounding location of the bipolar configuration.

6. Conclusions

In this paper, two of the mostly discussed system configurations for future MTDC systems – the symmetric monopole and bipole with metallic return – have been analysed with regard to fault detection and fault clearing using DC CB. As pointed out in previous works, the requirements on the DC CB differ greatly when considering the steady state fault current after P-GND faults. However, to avoid the loss of stability in an MTDC grid, the detection and clearing of a fault using DC CB must be achieved within a few milliseconds, especially if converter blocking should be avoided, hence before steady state is reached. Considering the first 10 ms after travelling wave arrival at the line ends, the analysis shows that the voltage and current profiles at the line ends of the faulted pole are almost identical as they are mainly influenced by the travelling waves initiated by the fault and their reflection and transmission. Consequently, the use of typically proposed protection criteria for MTDC systems is not restricted by the transient behaviour of the two system configurations.

The requirements for the used DC CB are also similar in both configurations at most line ends. Special care must be taken at the grounding location of the metallic return for the bipolar configuration. At the ungrounded busbars, the current amplitudes after occurrence of a P-GND fault are the same in the monopole and bipolar configuration. At the grounded busbar, however, the fault current contribution from the converter in the bipole configuration is higher leading to a higher current on the faulted line. This must be accounted for when designing the system and circuit breakers. In the unlikely event of a P-N-GND fault, the system behaviour is similar for both configurations. In the short term as the travelling waves determine the behaviour and in the long term as the fault current loop is closed via the conductors and converter arms and not via the grounding. In comparison to P-GND faults, the requirements on the current breaking capability of the DC CB are significantly higher.
While the requirements for fault detection and fault clearing are very similar for both configurations the system recovery after fault separation still poses some challenges in either configuration in case of single pole-to-ground faults. In the symmetric monopole, the voltage asymmetry persists after fault clearing. Suitable measures to discharge the healthy pole must be applied to rebalance the system and recover normal operation after fault clearing. The impact of these measures on the protection system is to be investigated. In the bipolar configuration, the selective disconnection of the faulted pole leads to an asymmetric grid operation. For both cases, there is still research needed to identify the path towards a fast system and power flow recovery.

7. Acknowledgement

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System frequency variations and the effect of wind power: Analysis based on an Irish transmission system test model

S. HELLMUTH*, M. KUSCHKE¹, K. STRUNZ¹, M. VAL ESCUDERO²
¹Technische Universität Berlin, Germany
²EirGrid, Ireland

Summary

European transmission systems face the challenge of integrating a rising share of wind power and other renewable energy sources (RES) and this trend will proceed in the future. Wind power plants are characterised by a varying feed-in of active power due to the fluctuating wind speed. Since active power variations lead to frequency variations in the system, wind power plants can deteriorate the power quality in a grid. Furthermore, many types of wind energy conversion systems (WECS), but also other RES, comprise power electronics (PE). With directly coupled synchronous machines being replaced by PE devices, the system inertia and primary control reserve decrease. A lower system inertia and primary control reserve, again, lead to higher variations of the system frequency. In this paper, system frequency variations caused by variable wind power generation are investigated. For that purpose, two use cases are simulated, which are characterised by PE penetration levels of 60 % and 80 %, respectively. The grid model used for this study is based on the Irish transmission system and has been adapted according to a future energy scenario of 2040. The simulation results are analysed in order to evaluate the quality and quantity of frequency variations. First, the minimum and maximum deviation from the nominal frequency are determined and compared to the limits for normal operation. In a next step, the distribution of the sample values is described by means of the standard deviation. From the results of the analysis, it can be shown that frequency variations increase with a higher PE penetration level, primarily because of higher active power variations and a lower system inertia as well as a lower primary control reserve in the system.

1. Introduction

One of the key priorities for the European Union (EU) is to mitigate climate change and achieve net-zero greenhouse gas emissions by 2050 [1]. In order to reach this goal, the European Commission foresees a rising share of renewable energy sources (RES) in the European energy mix [2], [3]. Currently, wind power has the highest installed capacity among RES. In 2017, the installed wind power capacity accounted for 169 GW, which corresponds to 18 % of the total installed generation capacity in the EU [4]. Typical for wind energy conversion systems (WECS) is the varying feed-in of active power into the grid due to the fluctuating nature of the wind speed [5]. In turn, these power variations influence the system frequency resulting in frequency deviations [6]. Furthermore, most WECS and many other types of RES are connected to the grid with a power electronic (PE) interface [7], [8]. With the extensive use of PE new challenges arise. One important aspect with implications for the system frequency is the decoupling of the inertia of the connected generator from the AC grid [9]. Given that PE-connected generators of RES replace directly coupled synchronous generators, which are the prime contributors to the system inertia, the total system inertia decreases. In addition, the involvement of PE-interfaced generation units in the balancing energy market is still at an early stage [10]–[12]. Therefore, ancillary services such as primary frequency control usually are not provided by PE-interfaced generation units today. A lower system inertia and primary control reserve in combination with power variations caused by RES, however, lead to higher variations of the system frequency [13]. These frequency variations appear even during normal grid operation making it a power quality issue [14].

*simon.hellmuth@tu-berlin.de

KEYWORDS

Frequency variations, power quality, wind power
Frequency variations in transmission systems have been studied in power systems worldwide. Examples for studies based on present-day transmission systems can be found in [15] and [16]. While [15] analyses time series of frequency measurements of recent years from synchronous areas in North America, Japan and Europe, the study in [16] focuses on the Nordic Power System. Both studies determine that the appearance of larger frequency deviations in the range of up to ±100 mHz correlates to the schedule of trading intervals in the electric energy market. Thus, the authors identify energy trading as today’s prime cause for frequency deviations in normal operation. The results conform with earlier studies for different synchronous areas in Europe [17]–[19]. However, it is also stated that frequency variations generally tend to increase with a higher share of RES in the power system regardless of the influence of trading intervals [15].

What is missing is an investigation which estimates the extent of frequency variations under the influence of RES in the future. This work is carried out as part of the research project Massive InteGRATion of power Electronic devices (MIGRATE), funded by the European Union under the framework of the European Union’s Horizon 2020. In the context of MIGRATE, a large-scale model based on the Irish transmission grid is implemented in DIgSILENT PowerFactory. The model is developed for a scenario for the year 2040 and includes a high installed capacity of wind power plants and other PE-interfaced devices. With this grid model, the system frequency is studied for different levels of PE penetration. Frequency variations caused by variable wind power generation are simulated over a period of ten minutes, analysed and compared to each other.

This paper introduces two selected study cases carried out within the MIGRATE project. Following this introduction, the power system model is described in Section 2. In Section 3, the study cases with their analysed simulation results are presented. A conclusion is drawn in Section 4.

2. Power system model

The study object is a nonlinear dynamic grid model suitable for phasor-type simulation. It is based on the transmission system of Ireland for 2016 as shown in Figure 1 and has been adjusted to the specifications of a future scenario for 2040. The model is not supposed to reflect a true representation of the Irish power system for the present or any future scenario since simplifications are applied in order to reduce the modelling and computational effort. Simplifications include generic models for load elements and generation units as well as merging wind farms into fewer but larger units. Furthermore, the grid model of Northern Ireland is excluded. With the test system, qualitative statements can be made instead. These are true for power systems of similar size and configuration as the Irish system.

The test system is a large-scale transmission system model and comprises several thousands of nodes. As can be seen from Figure 1, the grid model includes voltage levels of 110 kV, 220 kV and 400 kV. To a large part, the high-
The 110 kV network connects areas with lower load, which are usually also sparsely populated. At the same time, a large share of PE-interfaced generation units are situated in these remote areas and, therefore, connected at a voltage level of 110 kV. Most of these units consist of wind farms, which are especially concentrated along the west coast of Ireland as shown in Figure 1. In the test system, the total installed capacity of wind power amounts to 5,360 MW as it is also listed in Table 1.

The test system based on the present-day grid of Ireland is described in detail in [22] and has been amended for this study merely in terms of generation capacity. Thus, only a short overview will be given regarding the applied models for load elements, synchronous generators and wind farms.

The grid model is implemented in DIgSILENT PowerFactory and is suitable for phasor-type dynamic simulation. For the transmission lines, a lumped parameter model is chosen since all OHL are shorter than 200 km and all cables are shorter than 60 km [13]. Load elements in the modelled system are connected at the low voltage side of transformers connecting the transmission and distribution system. Lower voltage levels include 10 kV, 20 kV and 38 kV. The load consists of 86% conventional load elements and 14% PE-interfaced load (PEIL) elements. In the test system, conventional voltage alternating current (HVAC) transmission lines in the test system are realised as overhead lines (OHL). Exceptions are lines in parts of the network representing densely populated areas like Cork and Dublin where they are realised as underground cables. As listed in Table 1, high-voltage direct current (HVDC) interconnectors with a combined power transmission capacity of 1,200 MW are also modelled in the test system. This includes the East West HVDC Interconnector between Ireland and Great Britain and a second HVDC interconnector linking Ireland to France. The latter interconnector does not exist today but is included in the model based on its description in the Ten Year Network Development Plan (TYNDP) 2018 published by the European Network of Transmission System Operators for Electricity (ENTSO-E) [21]. In the test system, the 220 kV and 400 kV AC systems represent the core network for power transmission and connect load centres like Dublin, Cork and the Shannon Estuary as shown in Figure 1. Thermal generation units with an installed capacity larger than 100 MW are connected to voltage levels of 220 kV and 400 kV and are located close to the load centres. When regarding Table 1, it becomes clear that the largest share of thermal generation units are gas-fired power plants with an installed capacity of 5,430 MW in total.

Coal- or oil-fired power plants are decommissioned completely as it is foreseen by the implemented future energy scenario. The 110 kV network connects areas with lower load, which are usually also sparsely populated. At the same time, a large share of PE-interfaced generation units are situated in these remote areas and, therefore, connected at a voltage level of 110 kV. Most of these units consist of wind farms, which are especially concentrated along the west coast of Ireland as shown in Figure 1. In the test system, the total installed capacity of wind power amounts to 5,360 MW as it is also listed in Table 1.

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<table>
<thead>
<tr>
<th>Category</th>
<th>Installed capacity P [MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fossil fuel</td>
<td></td>
</tr>
<tr>
<td>Gas</td>
<td>5,430</td>
</tr>
<tr>
<td>Waste</td>
<td>50</td>
</tr>
<tr>
<td>Renewable</td>
<td></td>
</tr>
<tr>
<td>Wind</td>
<td>5,360</td>
</tr>
<tr>
<td>Hydro</td>
<td>240</td>
</tr>
<tr>
<td>Solar</td>
<td>400</td>
</tr>
<tr>
<td>Wave / tidal</td>
<td>40</td>
</tr>
<tr>
<td>Waste and biomass</td>
<td>460</td>
</tr>
<tr>
<td>Storage and interconnection</td>
<td></td>
</tr>
<tr>
<td>capacity</td>
<td></td>
</tr>
<tr>
<td>Pumped hydro storage</td>
<td>290</td>
</tr>
<tr>
<td>Battery storage</td>
<td>300</td>
</tr>
<tr>
<td>DC interconnection</td>
<td>1,200</td>
</tr>
<tr>
<td>Other</td>
<td>650</td>
</tr>
<tr>
<td>Total</td>
<td>14,420</td>
</tr>
</tbody>
</table>
load is assumed as a combination of 50% dynamic load represented by a non-linear model [23] and 50% static load with a constant impedance. The PEIL model is a generic model suitable for phasor-type simulation developed in the MIGRATE project. It mimics the typical behaviour of a full converter-interfaced load, which leaves the load-side with a reduced dependence on the grid-side frequency and voltage. Power plants that are equipped with a synchronous generator directly coupled to the grid are modelled according to a generic plant model with predefined models from the PowerFactory library. It consists of a 6th order synchronous generator model described in [24], a standard IEEE Type 1 Excitation System Model (IEEEEX1) [25] for the automatic voltage regulator (AVR) and a turbine governor. For the latter, the IEEE Type 2 Speed-Governing Model (IEEEG2) is assigned to steam and gas turbines, whereas the hydro turbine governor model HYGOV is chosen for hydro power plants [26]. For the representation of wind farms, a generic nonlinear WECS model with a type 4 wind turbine is chosen as described in [27]. The single WECS in a wind farm are simuated separately in order to allow for individual wind speed profiles for each wind turbine. The wind speed serving as an input for the WECS is modelled as described in [5]. It considers wind turbulences, which dominate the shape of the wind speed profile for a period below ten minutes. The coupling of the wind farm to the grid is realised with a converter, of which the control scheme is based on [7].

3. Case study

In this section, two study cases and their operating points are introduced. Case 1 includes a PE penetration level of 60%, whereas Case 2 comprises a corresponding level of 80%. Following that description, the simulation results for each study case are presented and analysed. The simulation time is ten minutes and simulation results include time series of the feed-in of active power by synchronous generators and PE-interfaced generation units, the balancing energy provided by synchronous generators and the electrical system frequency. The system frequency $f_{sys}$ is plotted and compared to the limits for normal operation. According to the Irish grid code, the limits are set to 50 ± 0.2 Hz [28]. In order to evaluate the frequency variations further, the standard deviation of the samples is determined.

3.1 Study case description

The operating points for two study cases are defined and summarised in Table 2. The aggregated active power demand $P_L$ of 5.9 GW is the same for each case and represents a winter peak situation. Case 1 comprises a PE penetration level of 60% and corresponds to a present-day scenario in Ireland where 65% is the maximum limit for PE penetration [29]. Since there is no installed capacity for wave and tidal power stations or battery storage in the present-day Irish transmission grid [22], the respective units in the grid model are inactive. Thus, the active power feed-in by PE devices is limited to the contribution by wind farms and the HVDC interconnector between Ireland and Great Britain. With 80% PE penetration, Case 2 represents a future use case. As can be seen from Table 2, PE-interfaced wave and tidal power stations as well as battery storage units are active. Together with wind farms and HVDC interconnectors, they account for 4,932 MW of PE-interfaced generation. Solar power plants are inactive because winter peak demand in Ireland usually occurs after sunset [30].

Table 2 also states the entries for the equivalent system inertia constant $H_{eq}$ and the inverse of the equivalent speed droop $1/R_{eq}$ of the synchronous generators in the system. The latter determines the primary control reserve and the network power frequency characteristic. As can be seen, $H_{eq}$ and $1/R_{eq}$ decrease with a higher level of PE penetration. The impact of $H_{eq}$ and $1/R_{eq}$ on the system frequency shall be illustrated with a one-area power system, which is expressed as an equivalent plant model in the per unit (p.u.) system. When neglecting turbine and governor dynamics, changes in system frequency after a load change $\Delta P_L$ can be described with the transfer function in (1) [13].

$$\Delta f_{sys} = \frac{-\Delta P_L}{2H_{eq}s + D_{eq} + \frac{1}{R_{eq}}}$$

Here, $D_{eq}$ is the load-damping constant in p.u. Based on (1), frequency deviations become larger for a smaller $H_{eq}$ and smaller $1/R_{eq}$, all else being equal.

For the simulations of the study cases covered in this paper, all wind turbines within a wind farm are active. Further, it is assumed that all turbines operate in maximum power point tracking (MPPT) mode. This operating
mode maximises the power output of the WECS based on the incoming wind speed [5]. Consequently, the MPPT mode leads to active power variations in contrast to operation above rated wind speed when blade pitch control regulates the power output to its nominal value [5]. Therefore, the study cases describe situations with high active power variations caused by wind farms.

### 3.2 Case 1: 60 % PE penetration

The aggregated feed-in of active power by PE-interfaced power sources is depicted in Figure 2a). The active power fluctuates over a span of 133 MW between the minimum and maximum value because of the non-stationary wind speed that serves as input for the wind farm models. It can be seen from Figure 2b) that the active power feed-in by synchronous generators acts in the opposite direction of the varying power feed-in by PE devices in order to keep the power balance in the system. Integrating the curve for active power provided by synchronous generators reveals the resulting balancing energy deployed by synchronous generators in Figure 2c). The balancing energy for the ten minutes simulation time is represented by the area between the active power curve and the height of active power feed-in at the initial operating point. Here, the positive balancing energy is marked in blue and is determined as 1.47 MWh. The negative balancing energy is marked in red and amounts to 1.43 MWh. In order to describe the implications of the delivered balancing energy for synchronous generators, the balancing energy is stated in proportion to the installed capacity of active synchronous generators in a next step so it can be compared to Case 2 later. Adding up the absolute values of energy and dividing the sum by the installed capacity of 3,735 MVA for active synchronous generators results in 2.80 MWs/MVA.

In Figure 2d), the frequency measured at the synchronous generator terminals is shown for Case 1. It is visible that the frequency is subject to variations due to the changes in active power. The maximum frequency reaches 50.04 Hz, whereas the minimum lies at 49.95 Hz. Thus, the deviations from the nominal frequency of 50 Hz are within the acceptable limits of 49.80 Hz and 50.20 Hz for normal operation. Furthermore, the distribution of the frequency samples reveals a mean of 50.00 Hz and a standard deviation $\sigma$ of 16.8 mHz.

### Table 2: Operating points for the study cases

<table>
<thead>
<tr>
<th>Description</th>
<th>Variable</th>
<th>Unit</th>
<th>Case 1</th>
<th>Case 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Level of PE penetration</td>
<td>-</td>
<td>[%]</td>
<td>60</td>
<td>80</td>
</tr>
<tr>
<td>Active power demand</td>
<td>$P_L$</td>
<td>[MW]</td>
<td>5,894</td>
<td>5,894</td>
</tr>
<tr>
<td>Active power loss</td>
<td>$P_{losses}$</td>
<td>[MW]</td>
<td>270</td>
<td>271</td>
</tr>
<tr>
<td>Active power feed-in of wave and tidal power stations</td>
<td>$P_{ocean}$</td>
<td>[MW]</td>
<td>0</td>
<td>40</td>
</tr>
<tr>
<td>Active power feed-in of battery storage units</td>
<td>$P_{battery}$</td>
<td>[MW]</td>
<td>0</td>
<td>200</td>
</tr>
<tr>
<td>Active power feed-in of HVDC interconnectors</td>
<td>$P_{HVDC}$</td>
<td>[MW]</td>
<td>350</td>
<td>800</td>
</tr>
<tr>
<td>Active power feed-in of wind farms</td>
<td>$P_{wind}$</td>
<td>[MW]</td>
<td>3,348</td>
<td>3,892</td>
</tr>
<tr>
<td>Active power feed-in of synchronous generators</td>
<td>$P_{SG}$</td>
<td>[MW]</td>
<td>2,466</td>
<td>1,233</td>
</tr>
<tr>
<td>Equivalent system inertia constant</td>
<td>$H_{eq}$</td>
<td>[s]</td>
<td>3.01</td>
<td>1.77</td>
</tr>
<tr>
<td>Network power frequency characteristic</td>
<td>$1/R_{eq}$</td>
<td>[MW/Hz]</td>
<td>1,665</td>
<td>871</td>
</tr>
<tr>
<td>Installed capacity of synchronous generators in operation</td>
<td>$S_{SG}$</td>
<td>[MVA]</td>
<td>3,735</td>
<td>1,946</td>
</tr>
</tbody>
</table>
3.3 Case 2: 80 % PE penetration

The representation of aggregated active power feed-in from PE-interfaced power sources is shown in Figure 3a). As can be seen, the absolute power variations increase compared to Case 1 and reach a span of 160 MW between the minimum and maximum value. The active power feed-in from synchronous generators is depicted in Figure 3b). As for Case 1, also the balancing energy provided by synchronous generators is visualised and shown in Figure 3c). It is composed of 1.45 MWh of positive balancing energy, marked blue, and 1.42 MWh of negative balancing energy, marked red. The sum of the two absolute values for energy amounts to 2.87 MWh. This results in 5.30 MWs per MVA of installed capacity of active synchronous generators and constitutes an increase by 89 % compared to Case 1.

The system frequency for Case 2 is shown in Figure 3d). The maximum frequency reaches 50.09 Hz, whereas the minimum lies at 49.90 Hz. The deviations are thus within the accepted boundaries of 49.80 Hz and 50.20 Hz. However, it can be seen that the variations are more intense than in Case 1. For Case 2, the standard deviation is 34.4 mHz. Compared to Case 1, the standard deviation has thus increased by 105 %. The higher variations are due to the decrease in system inertia and primary control reserves of the remaining synchronous generators while, at the same time, active power variations caused by wind farms are higher. These active power variations occur with low rates of change as can be seen from Figure 3a). Therefore, the impact of the lower primary control reserve on system frequency variations is more severe than that of the lower system inertia.

4. Conclusion

In this paper, frequency variations are investigated for a test system based on the transmission system of Ireland for the year 2040. The grid model comprises a high share of PE devices, mainly due to wind farms. Two study cases are presented and analysed with regard to frequency variations. The first case represents a present-day scenario with a PE penetration level of 60 %. It also serves as the base for comparison with the second study case, which introduces a PE penetration level of 80 %. The simulation results reveal that the frequency remains within the normal operating range of 49.80 Hz to 50.20 Hz for both cases. However, there is a clear correlation between the level of PE penetration and frequency variations. One indicator for that observation is the standard deviation, which increases by 105 % from Case 1 to Case 2. The cause for the frequency variations are active power variations that are induced by the wind farms in the modelled system. With a higher share of wind power in the system, the active power variations in Case 2 increase as well. At the same time, the inertia and the primary control reserve are reduced with a higher PE penetration level because synchronous generators are replaced by PE-interfaced power sources. Both factors have a negative effect on the system frequency in terms of power quality. It is also shown that the remaining synchronous generators increase their share in load-
frequency control. This is pointed out by showing that the amount of provided balancing energy per MVA of installed capacity of operating synchronous generators grows with a rising level of PE penetration. It becomes clear that under such an operating condition also the wear and tear of synchronous generators increases.

It has to be noted that higher frequency variations are not an inevitable consequence of high PE penetration in transmission grids. As it is shown in this paper, system frequency variations primarily depend on active power variations on one side and on the system inertia and the available primary control reserve on the other side. It is observed that the active power variations in the system are characterised by low change rates. Therefore, the influence of primary control on the intensity of frequency variations is higher than that of the system inertia. For the presented study cases, the primary control reserve declines for a higher PE penetration level because PE-interfaced generation and storage units do not contribute to primary frequency control. This setting corresponds to today’s general practice where synchronous generators deliver most of the balancing energy. However, some TSOs already allow other power sources like batteries to contribute to frequency control. Therefore, it is recommended to include further generation units for the support of primary frequency control in normal operation. As wind farms play an increasingly important role in the power system, they should be involved in frequency control in the future.

Figure 3: Time series of a) active power feed-in by PE-interfaced generation units, b) active power feed-in by synchronous generators, c) balancing energy provided by synchronous generators and d) the system frequency for Case 2

5. Acknowledgements

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6. Bibliography


Stakeholder consultation and nature inclusive design of the offshore grid

S.A. JAARSMA 1*
TenneT TSO B.V., The Netherlands

Summary
In this paper, TenneT will elaborate on the ideas related to offshore grid eco-design: cooperation with environmental organisations, the value of offshore data gathering, and the re-assessment of the offshore grid concept from a nature inclusive design perspective.

For TenneT, since the start of the offshore grid development in 2013, the cooperation with external stakeholders like government, offshore wind sector and environmental organisations was key. Through several consultation sessions suggestions and requirements were gathered and applied during the design and (spatial) planning/licensing phase of the offshore grid concept. At the time (2014-2016), cost reduction was the leading factor. Amongst others, a cooperation with Rijkswaterstaat was initiated, to create the so-called Maritime Information Services Point for offshore data gathering. Services with a societal benefit are coordinated and data will become publicly available, e.g. meteo data and bird & bat monitoring.

Since 2013, TenneT has gathered insights from several project specific Environmental Impact Assessments, resulting in requirements for the permits and licenses of the offshore grid projects. Based on the experiences so far, TenneT is now re-assessing the standardised offshore grid concept in terms of opportunities for nature enhancement and further ecological monitoring. Whereas cost reduction is still an important driver, additionally the idea of using the offshore grid infrastructure to realise opportunities to increase nature diversity and to achieve additional societal benefits has evolved. Nature inclusive design measures have been identified for the topside (bird deck), jacket (biocages) and along the cable route and within the safety zone of the platform (hard substrate structures). The expectation is that if such measures are integrated in an early stage, they can be added against very limited cost and risk compared to the project investment. The ultimate objective is to enhance nature inclusive design as an incremental part of the technical design and (spatial) planning/licensing phase of the offshore grid.

1. Introduction
By means of the National Energy Agreement (2013), the Dutch government wants to achieve a substantial increase in the share of wind energy in the Netherlands’ energy mix. To increase offshore wind energy capacity, the government has designated three zones in the North

Figure 1 - Principle of 700 MW AC offshore grid concept

* Saskia.Jaarsma@tennet.eu

KEYWORDS
During the consultation process, transparency was key. TenneT published position papers about technical, legal and planning matters. Representatives of the wind energy industry were given an opportunity to respond to these papers via the Internet and during expert meetings. At these (monthly) meetings, matters were explained and discussed in accordance with an agenda published in advance. Additional investigations were performed where necessary, for instance to determine the feasibility of opting for a supply voltage of 66 kV for the offshore wind farms. Findings and conclusions from each expert meeting were reported on and a two-week period was scheduled for participants and all stakeholders to provide feedback. The final versions of the position papers set out the positions reached on each topic, as well as the underlying considerations. Via newsletters, interested parties were kept up-to-date on the plans and activities. In this way TenneT collected the necessary information to meet the requirements of wind farm developers or to propose well-considered alternative solutions. Results of the consultation process include:

- Decision to select 66 kV as the supply voltage;
- Coordinated access to platforms;
- No helicopter landing platform or permanent diesel generator;
- Optimisation of electricity connections.

TenneT also actively sought alignment with existing bodies in order to inform and involve the relevant stakeholders. As the Ministry of Economic Affairs organised public meetings on the development of offshore wind energy in the Netherlands, TenneT provided regular updates. TenneT also pro-actively provided updates at informal meetings of the Electricity and Gas Grid Users Platform (GEN), with a view to future changes to the Dutch Codes.

Another characteristic of the consultation process was the clear definition of roles and responsibilities in the decision-making process from the outset. The Ministry of Economic Affairs and the Authority for Consumers & Markets (ACM) were invited to attend the expert meetings as observers. As soon as a topic was discussed to the participants’ satisfaction, the outcome was submitted to the Ministry for decision-making purposes. Fundamental decisions that affect both TenneT and the wind farm developers have been laid down by the
Various (semi-) government organizations have indicated that they are interested in placing such information systems and in the data of these systems. Currently, some parties have placed their sensors on oil and gas platforms or wind farms off the Dutch coast. In the future, however, the number of oil and gas platforms will decrease. The TenneT platforms then offer a welcome replacement option. In other cases they can be an extension to the existing sensor networks. The intended locations and existing offshore facilities form a good starting point and deliver significant (cost) advantages compared to existing sites. Parties like port companies, pilotage, knowledge and research institutions, Coast Guard, wind farms, telecommunication companies and the government have shown interest.

As the information needs of these interested parties partially overlap, placement of one sensor can serve several stakeholders. This resulted in a cooperation with Rijkswaterstaat, to create the so-called “Maritime Information Services Point” (MISP). Aim is to coordinate the services with a societal benefit and make data publicly available. Rijkswaterstaat designs, realises, operates and maintains centrally the sensors and communication systems that are installed on TenneT’s platforms and ensures that the data of these systems are made available to interested parties. The principle is illustrated in figure 2. For example, meteo data and bird & bat monitoring will be organised through this cooperation. Both the government and knowledge and research institutions, Coast Guard, wind farms, telecommunication companies and the government have shown interest.

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### 3. Offshore (ecological) data gathering and monitoring

TenneT will develop five standardised 700 MW AC platforms until 2023. In addition to the main task of connecting the offshore wind farms and housing of the high-voltage equipment, these offshore platforms may also be considered as a base station for placing sensors and communication systems.

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counts and the above mentioned Maritime Information Services Point which includes sensors for gaining ecological data.

Another specific example worth mentioning is a permit requirement related to EMF emitted by TenneT’s offshore 220 kV AC cables. As the government’s intention is to increase knowledge in this matter, TenneT will develop a monitoring plan for EMF and assure the gathered data will become publicly available.

4.2 Nature Inclusive Design

In meetings with the governmental stakeholders and NGO's on the Offshore Wind Roadmap 2030, it became more and more clear that ecological aspects are a limiting factor for the continued increase of offshore wind. With the ongoing offshore grid expansion, consisting of platforms and cables offshore, TenneT also has an increasing ecological impact during the realisation and operation of the offshore grid.

The internal driver for TenneT to prevent its ecological impact can be found in the Corporate Social Responsibility policy: “We strive to enhance the energy transition in a sustainable manner, leading the way in maximising our societal contribution and minimizing our impact as a TSO.” [5] Several ambition areas are defined with targets. With regards to the ambition area “nature”, the CSR target is described as: “Our commitment to nature is to take our responsibility to minimise our impact and

<table>
<thead>
<tr>
<th>System</th>
<th>Description</th>
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<tbody>
<tr>
<td>Meteo</td>
<td>Weather station</td>
</tr>
<tr>
<td>LiDAR</td>
<td>Advanced wind measurement</td>
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<tr>
<td>Hydro</td>
<td>Wave height and water temperature</td>
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<tr>
<td>Vleermuisdetectie</td>
<td>Monitoring of bat migration</td>
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<tr>
<td>Vogelradar</td>
<td>Knowledge building on bird migration and input for permit requirements offshore wind farm</td>
</tr>
<tr>
<td>VHF (Very High Frequency)</td>
<td>Radiocommunications, including Radio over IP and DSC (Digital Selective Calling)</td>
</tr>
<tr>
<td>AIS Base Station</td>
<td>Automatic identification system for shipping</td>
</tr>
<tr>
<td>Radio Direction Finder (RDF)</td>
<td>For ‘search and rescue’ activities performed by the Coast Guard</td>
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<tr>
<td>Maritime radar</td>
<td>Radar for monitoring of ship movements</td>
</tr>
<tr>
<td>Closed Circuit TV</td>
<td>Local images for camera surveillance for the Coast Guard</td>
</tr>
<tr>
<td>LoRaWan</td>
<td>IT network for ‘Internet of Things’; long distance wifi</td>
</tr>
<tr>
<td>NetPos</td>
<td>Reference point for accurate position determination for Kadaster</td>
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</tbody>
</table>
At the topside, a bird deck can be attached. As practice shows birds will come and use the platform for resting, the expectation is birds can be guided to a sheltered place at the platform where the electrical operation of the platform is not disturbed. Feeding facilities are not foreseen. Depending on local species, the bird deck shall be designed in detail. For the black-legged kittiwake that resides in the area Hollandse Kust Noord for example, a cabinet divided in smaller shoebox sized boxes would be attractive.

Within the jacket, fish-friendly structures like biocages could be attached on three levels in height underneath the waterline to provide shelter for multiple species. A biocage is an open structure of mesh filled half with oyster shells or quarry stone and half open space but protected from predators. In total nine of these bio huts with a size of approximately 1m x 1m x 0,5m and a maximum weight of 250 kg could be mounted to the jacket. For installation purposes, two attachment points per biocage in the form of a flange connection are foreseen, on sufficient distance from the jacket to prevent interference with structural integrity and conservation.

Along the cable trajectory and within the safety zone around the platform, hard substrate could be added. Maintenance operations should not interfere with the structures and therefore a certain distance to the offshore grid assets should be observed. The hard substrate may consist of different types of structures to target specific species, for example: layered build-up reef balls of 1 – 1,5 m height, hexagon shaped objects and lobster boxes (preferably different sizes for different age classes), and
cages or baskets with oyster shells. The expectation is the reefs will start to grow towards each other after some years.

Further experiences should come from actual pilots in practice. This is currently under investigation. It should be noted actual application of nature inclusive design is still in its early stages and monitoring of the nature inclusive design measures is required to gather data on impact and effectiveness in practice.

Involvement of external stakeholders like government, NGO’s and the offshore wind developers will add to the success and the ultimate objective: nature inclusive design as an incremental part of the technical design of the offshore grid.

5. Bibliography


Challenges of harmonic distortion limit allocation to multiple customers in a meshed network using IEC TR 61000-3-6

D.H. MILLS¹, Z. EMIN¹, D. O’BRIEN², M. VAL ESCUDERO²
¹PSC, ²EirGrid
¹UK, ²IRELAND

Summary
Transmission and distribution system operators are responsible for maintaining harmonic voltage distortion within statutory limits in their own networks. To achieve this, most system operators impose a limitation on the harmonic emissions allowed for new connections. Various standards and technical recommendations exist worldwide (e.g. IEEE 519, ENA ER G5/4, IEC TR 61000-3-6, etc) with different approaches and, thus, different outcomes on the allocation of emission limits. This paper concentrates on the application of IEC TR 61000-3-6 to multiple connections under high levels of uncertainty.

For a new distorting customer to connect to the system, they are given harmonic voltage distortion limits in accordance with IEC 61000-3-6. For a single customer connecting on a system with a well-established network development plan, this may be reasonable. However, the rapid growth in new technologies and renewable generation suggests that the modern network is undergoing significant development to accommodate a growing number of customer connection applications. In many circumstances the network operator is simultaneously receiving connection applications from multiple distorting customers. Furthermore, the network expansion plans required to accommodate the increased power transfers associated with new renewable generation connections are sometimes uncertain, subject to optimisation and stakeholder engagement.

In a meshed system, harmonic impedances exhibit multiple parallel and series resonances which can result in high harmonic transfer coefficients between nodes. In other words, these new customer connections will all have an impact on each other and the surrounding network. As a result, no single customer can be provided with a harmonic distortion limit without considering the connection and harmonic distortion of the other customers.

This paper demonstrates that direct implementation of the IEC TR 61000-3-6 methodology on a modern transmission system can result in very restrictive harmonic emission limits being provided to all customers. These limits are often too small to measure, and so customers may be required to install some form of harmonic filtering equipment to comply with their connection requirements.

Each customer’s harmonic filtering equipment has an impact on any resonances and existing harmonic distortion on the system. Since all of the customers are connected to such a strongly meshed network the harmonic limits and associated impedance loci previously provided to all the customers would need to be re-accessed to take into consideration each customers’ harmonic mitigation approach.

1. Background
Currently, transmission and distribution system operators are responsible for maintaining harmonic voltage distortion within statutory limits in their own networks. To achieve this, most system operators impose a limitation on the harmonic emissions allowed for new connections. Various national and international standards

* david.mills@PSCConsulting.com

KEYWORDS
Power quality, harmonic emissions, harmonic assessment, emission limit allocation, voltage gain
and/or technical recommendations exist worldwide (e.g. IEEE 519, ENA ER G5/4, IEC TR 61000-3-6, etc). Each of these take different approaches and thus result in different outcomes on allocation of emission limits. This paper concentrates on the application of IEC TR 61000-3-6 and in particular, when considering multiple connections under high levels of uncertainty [1].

When a new distorting customer applies to connect to the system they are given harmonic voltage distortion limits in accordance with IEC 61000-3-6. The principle of these limits is that when all distorting installations are injecting levels of harmonic distortion equal to their emission limits, the total distortion level anywhere in the system should not exceed the planning level [1]. For example, using Figure 1 as a reference, if nodes B2, B3 and B4 all contain distorting installations the resultant distortion at every node (including B1) should remain within the associated Planning Levels (PL).

\[ E_{\text{em}}^i \] is the emission level for each installation \( i \) connected at node \( B_m \)
\[ L_{h_{\text{EHV}}} \] is the PL being considered at node \( B_m \)
\( \alpha \) is the IEC summation exponent for harmonics (Table 1)

<table>
<thead>
<tr>
<th>Harmonic Order</th>
<th>( \alpha )</th>
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<tbody>
<tr>
<td>( h &lt; 5 )</td>
<td>1</td>
</tr>
<tr>
<td>( 5 \leq h \leq 10 )</td>
<td>1.4</td>
</tr>
<tr>
<td>( h &gt; 10 )</td>
<td>2</td>
</tr>
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</table>

The influence coefficient \( k_{h_{B_n-B_m}}^g \) is used to determine the harmonic voltage distortion seen at node \( B_m \) as a result of voltage distortion applied at node \( B_n \). This can be determined either through a harmonic propagation study or via voltage magnification calculations using impedance frequency scans and applying Equation 2 [2, 3].

\[ k_{h_{B_n-B_m}}^g = \left( \frac{Z_{h_{B_n-B_m}}}{Z_{h_{B_n}}} \right)^\alpha \] \hspace{1cm} \text{Equation 2}

Where:
\( Z_{h_{B_n-B_m}} \) is mutual-impedance between node \( B_n \) and \( B_m \) at harmonic order \( h \)
\( Z_{h_{B_n}} \) is the self-impedance of node \( B_n \) harmonic order \( h \)

In some cases, a series resonance may exist at \( B_n \) resulting in a very large influence factor on \( B_m \). The recommendation in IEC TR 61000-3-6 is to multiply the influence coefficient by a reduction factor (Equation 3).

\[ F_{h_{B_n}} = \frac{Z_{h_{B_n}}}{h \cdot Z_{1_{B_n}}} \] \hspace{1cm} \text{Equation 3}

Where:
\( Z_{1_{B_n}} \) is self-impedance at node \( B_n \) at fundamental frequency \((h = 1)\)

This is achieved through satisfying Equation 1 for every substation in the system under consideration, and not just those for which new connections are being considered.

Where:
\( k_{h_{B_n-B_m}}^g \) is the influence factor of node \( B_n \) on node \( B_m \) at harmonic order \( h \)

\[ \sqrt{ \left( \sum_{i \in \bar{B}_1} E_{U_{B_1}}^i \right)^{\alpha} + \left( \sum_{i \in \bar{B}_2} E_{U_{B_2}}^i \right)^{\alpha} + \cdots + \left( \sum_{i \in \bar{B}_m} E_{U_{B_m}}^i \right)^{\alpha} } \leq L_{h_{\text{EHV}}} \] \hspace{1cm} \text{Equation 1}
Additionally, when multiple customers are being considered the available harmonic distortion needs to be allocated to them appropriately. Various methods have been adopted and typically either a first come, first served approach (ENA ER G5/4) or sharing by connection capacity (IEC 61000-3-6) is applied [1, 4, 5]. This paper is dealing with the latter whereby the available headroom is shared between multiple customers connecting simultaneously in a meshed transmission system.

Therefore, the following IEC methodology for sharing based on the connection capacity through application of the following equation must apply:

\[
G_{h_{B_m}} \leq \sqrt{ \left( k_{h_{B_1-B_m}}^a \cdot S_{t_{B_1}} \right) \left( k_{h_{B_2-B_m}}^a \cdot S_{t_{B_2}} \right) + \cdots + \left( k_{h_{n-B_m}}^a \cdot S_{t_{B_n}} \right) } \cdot L_{hEHV}
\]

Equation 4

Where:

- \( S_{t_{B_m}} \) is total power of the new connection(s) at node \( B_m \)
- \( G_{h_{B_m}} \) is the maximum global contribution of all the distorting installations that can be supplied from node \( B_m \) at harmonic order \( h \)

When considering multiple customers, the \( k_{h_{B_m-B_m}}^a \cdot S_{t_{B_m}} \) are added for every customer under consideration until they are no longer significant. In a meshed network the influence between nodes, particularly at low order harmonics can be strong, resulting in lots of customer interactions that need to be considered [1, 2]. As a result, the apportioning of the available headroom must be done for every node on the system and not just those nodes at which new customers are connecting. Therefore, the limitation on a customer’s contribution to the systems harmonic distortion can be limited by the available harmonic headroom at a remote node rather than just its own.

Using Figure 1, the following provides a theoretical example of apportioning the available headroom at node \( B_1 \) to new customers that are connecting at nodes \( B_2, B_3, \) and \( B_4 \).

For node \( B_1 \) in the example above, the apportioning of \( AHDH_{h_{B_1}} \) (Available Harmonic Distortion Headroom) between customers \( B_2, B_3, \) and \( B_4 \) will result in an Allocated Harmonic Voltage Distortion Limit \( (AHVDL)_{h_{B_1}} \) for those customers as shown in the following equations.

Apportioning of available headroom at Node \( B_1 \):

\( \text{AHVDL}_{h_{B_2}}(x) = \frac{k_{h_{B_2-B_1}}^a \cdot MW_{B_2}}{k_{h_{B_2-B_1}}^a \cdot MW_{B_2} + k_{h_{B_3-B_1}}^a \cdot MW_{B_3} + k_{h_{B_4-B_1}}^a \cdot MW_{B_4} \cdot AHDH_{h_{B_1}}} \)  

Equation 5

\( \text{AHVDL}_{h_{B_3}}(x) = \frac{k_{h_{B_3-B_1}}^a \cdot MW_{B_3}}{k_{h_{B_2-B_1}}^a \cdot MW_{B_2} + k_{h_{B_3-B_1}}^a \cdot MW_{B_3} + k_{h_{B_4-B_1}}^a \cdot MW_{B_4} \cdot AHDH_{h_{B_1}}} \)  

Equation 6

\( \text{AHVDL}_{h_{B_4}}(x) = \frac{k_{h_{B_4-B_1}}^a \cdot MW_{B_4}}{k_{h_{B_2-B_1}}^a \cdot MW_{B_2} + k_{h_{B_3-B_1}}^a \cdot MW_{B_3} + k_{h_{B_4-B_1}}^a \cdot MW_{B_4} \cdot AHDH_{h_{B_1}}} \)  

Equation 7
2. Results from a real system example

A recent study on the EirGrid network required harmonic limits to be issued to multiple distorting customers, all applying to connect within short timeframes to the heavily meshed Dublin region (Figure 2). In order to accommodate all of these connections the impact of several planned transmission system developments also had to be considered. Due to the number of new connections and the associated number of transmission system developments, there was a significant level of uncertainty that had to be taken into consideration.

In a meshed system, harmonic impedances exhibit multiple parallel and series resonances which can result in high harmonic transfer coefficients between nodes (Equation 2). In other words, these new customer connections would all have an impact on each other and the surrounding network. As a result, no single customer can be provided with a harmonic distortion limit without considering the harmonic distortion of the other customers.

The following tables present an abridged example from the above study completed on the EirGrid network where 21 new connections were being considered simultaneously. In carrying out the assessment, it was important to ensure customers were issued with limits in a timely and accurate way and therefore EirGrid have adopted the IEC TR 61000-3-6 methodology [4, 1]. As detailed above, the principle of IEC TR 61000-3-6 is to share the available harmonic distortion between all customers based on their MW connection capacity such that no customer exceeds the IEC planning levels.

Where:

- \( AHVDL_{hB_n} \) is the Allocated Harmonic Voltage Distortion Limit at the new customer’s node Bn that ensures the IEC planning level at node B1 is not exceeded.
- \( k_{B-A} \) is the influence coefficient from node B to node A taking into consideration the reduction factor (Equation 3).
- \( MW_{Bn} \) is the contractual power level of the new customer(s) connecting at node Bn.
- \( AHDH_{B1} \) is the Available Harmonic Distortion Headroom at node B1.

The same process is followed to apportion the available headroom at each transmission node (m) resulting in a series of “m” values of Allocated Harmonic Voltage Distortion Limits (\( AHVDL_{h} \)) for each new customer connection at each scenario and operating condition.

For each customer the minimum \( AHVDL_{h} \) at each harmonic order establishes their harmonic limits. This ensures that the new customer connections will not result in any node exceeding the IEC planning levels.

Additionally, the frequency response of the system can vary significantly with different generation dispatch and outage (N-1) conditions, and therefore this uncertainty also has to be taken into consideration. The apportioning of the available headroom is calculated for a range of credible generation / demand scenarios and operating conditions (i.e. summer minimum, winter peak, N and N-1 conditions) or per utility specific operational security standards.
In both cases, the shown customer allocation has been based on the 3rd harmonic order (150 Hz) and assumes that there is no existing background harmonic distortion (i.e. the full planning level of 2.0% is available). This demonstrates that regardless of the existence of any existing harmonic distortion on the system the sharing of headroom in a heavily meshed region of the network results in a very small allocation which is potentially below a reasonably measurable level [7]. In the actual study the approach described was applied to every harmonic order and took into consideration the existing harmonic distortion along with the limits that have been issued to customers that have not yet connected. This further reduced the available headroom that could be shared between the new customers under consideration.

As shown in Table 2, the existence of a meshed and heavily interconnected network at node A means that all the customers have a reasonable influence on the harmonic distortion at this node. As a result, the available harmonic headroom must be equally shared between them as per Equation 4 and therefore each customer ends up with a small share. This ensures that the combined distortion from all customers does not result in the harmonic distortion at node A exceeding the PL.

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\[ \text{Weighting}_{hCn}(x) = \sqrt{\frac{k_{hCn-A}^a \cdot MW_{Cn}}{\sum_{l=1}^{21} k_{hCn-A}^a \cdot MW_{Cn}}} \]  

Equation 8
As shown in Table 3, where the transmission network is relatively weakly connected (node B), the majority of the customers have significantly reduced influence on the node. Only those customers which are electrically close (1 and 21) have a strong influence on the distortion at this node (B). However, since the weighting factor (Equation 8) takes into consideration the capacity of the connection requested these customers do not receive the largest share of the available headroom which is instead allocated to customer 8.
breached. The result is shown in Table 4, and it is clear that 12 of the customers would get a limit of less than 0.1% which may not be reliably measurable [7]. Of the remaining customers, 7 receive a limit of between 0.1 and 0.2% and only 2 receive a limit in excess of 0.2% (customer 5 and 8).

Table 3 - Share of available headroom at node B based on Equation 4

<table>
<thead>
<tr>
<th>Customer (Ca)</th>
<th>New Capacity (MW)</th>
<th>Influence on Node B ( (k_{Bn-B}) )</th>
<th>( k_{Bn-B} \cdot MW_{Cn} )</th>
<th>Weighting (Equation 8)</th>
<th>Customer Allocation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>50</td>
<td>0.58</td>
<td>28.94</td>
<td>0.06</td>
<td>0.19</td>
</tr>
<tr>
<td>2</td>
<td>80</td>
<td>0.21</td>
<td>16.54</td>
<td>0.03</td>
<td>0.31</td>
</tr>
<tr>
<td>3</td>
<td>100</td>
<td>0.23</td>
<td>22.78</td>
<td>0.04</td>
<td>0.38</td>
</tr>
<tr>
<td>4</td>
<td>100</td>
<td>0.17</td>
<td>17.09</td>
<td>0.03</td>
<td>0.38</td>
</tr>
<tr>
<td>5</td>
<td>142</td>
<td>0.25</td>
<td>35.94</td>
<td>0.07</td>
<td>0.54</td>
</tr>
<tr>
<td>6</td>
<td>119</td>
<td>0.57</td>
<td>68.41</td>
<td>0.13</td>
<td>0.46</td>
</tr>
<tr>
<td>7</td>
<td>61</td>
<td>0.57</td>
<td>35.07</td>
<td>0.07</td>
<td>0.23</td>
</tr>
<tr>
<td>8</td>
<td>267</td>
<td>0.50</td>
<td>132.93</td>
<td>0.25</td>
<td>1.02</td>
</tr>
<tr>
<td>9</td>
<td>50</td>
<td>0.19</td>
<td>9.61</td>
<td>0.02</td>
<td>0.19</td>
</tr>
<tr>
<td>10</td>
<td>85</td>
<td>0.22</td>
<td>18.72</td>
<td>0.04</td>
<td>0.33</td>
</tr>
<tr>
<td>11</td>
<td>95</td>
<td>0.22</td>
<td>20.92</td>
<td>0.04</td>
<td>0.36</td>
</tr>
<tr>
<td>12</td>
<td>25</td>
<td>0.24</td>
<td>5.98</td>
<td>0.01</td>
<td>0.10</td>
</tr>
<tr>
<td>13</td>
<td>42.3</td>
<td>0.18</td>
<td>7.47</td>
<td>0.01</td>
<td>0.16</td>
</tr>
<tr>
<td>14</td>
<td>50</td>
<td>0.22</td>
<td>10.76</td>
<td>0.02</td>
<td>0.19</td>
</tr>
<tr>
<td>15</td>
<td>45</td>
<td>0.54</td>
<td>24.33</td>
<td>0.05</td>
<td>0.17</td>
</tr>
<tr>
<td>16</td>
<td>49</td>
<td>0.24</td>
<td>11.91</td>
<td>0.02</td>
<td>0.19</td>
</tr>
<tr>
<td>17</td>
<td>15</td>
<td>0.24</td>
<td>3.65</td>
<td>0.01</td>
<td>0.06</td>
</tr>
<tr>
<td>18</td>
<td>34</td>
<td>0.22</td>
<td>7.49</td>
<td>0.01</td>
<td>0.13</td>
</tr>
<tr>
<td>19</td>
<td>16</td>
<td>0.21</td>
<td>3.44</td>
<td>0.01</td>
<td>0.06</td>
</tr>
<tr>
<td>20</td>
<td>70</td>
<td>0.19</td>
<td>12.98</td>
<td>0.02</td>
<td>0.27</td>
</tr>
<tr>
<td>21</td>
<td>40</td>
<td>0.69</td>
<td>27.51</td>
<td>0.05</td>
<td>0.15</td>
</tr>
</tbody>
</table>
but not yet connected to the system. Additionally, this existing background distortion could become amplified due to changes in system resonances due to the new customers installation. This would further reduce the harmonic headroom available and therefore the limit that is given to each customer.

3. Conclusions

This paper demonstrates the implementation of IEC TR 61000-3-6 applied to the EirGrid transmission system in the meshed Dublin region receiving a significant number of new connections for distorting installations. The result is that this can lead to very restrictive harmonic emission limits to all customers since they all have a strong influence on each other and the majority of nodes in the region. These limits are often too small to

Additionally, in order to reduce the complexity of this analysis the following assumptions were made:

- No allowance was made for the existing background harmonic distortion which would further reduce the harmonic distortion headroom available to customers.
- Only the intact system was considered, the assessment should be made for all credible operating scenarios.
- Only 2 nodes have been considered rather than all nodes that the new customer connections would have a material impact on including the customer nodes.

In reality, there would already be some level of background harmonic distortion which would reduce the available headroom that can be shared between the customers. In addition to the measured background distortion it would also be necessary to take into consideration any other customers that have been issued with harmonic limits

<table>
<thead>
<tr>
<th>Customer</th>
<th>New Capacity (MVA)</th>
<th>Node A Allocation (%)</th>
<th>Node B Allocation (%)</th>
<th>Customers Limit (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>50</td>
<td>0.07</td>
<td>0.19</td>
<td>0.07</td>
</tr>
<tr>
<td>2</td>
<td>80</td>
<td>0.12</td>
<td>0.31</td>
<td>0.12</td>
</tr>
<tr>
<td>3</td>
<td>100</td>
<td>0.14</td>
<td>0.38</td>
<td>0.14</td>
</tr>
<tr>
<td>4</td>
<td>100</td>
<td>0.14</td>
<td>0.38</td>
<td>0.14</td>
</tr>
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<td>0.20</td>
<td>0.54</td>
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<td>6</td>
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<td>0.17</td>
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<td>0.09</td>
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<tr>
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<td>85</td>
<td>0.12</td>
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<tr>
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<td>95</td>
<td>0.14</td>
<td>0.36</td>
<td>0.14</td>
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<tr>
<td>12</td>
<td>25</td>
<td>0.04</td>
<td>0.10</td>
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</tr>
<tr>
<td>13</td>
<td>42.3</td>
<td>0.06</td>
<td>0.16</td>
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</tr>
<tr>
<td>14</td>
<td>50</td>
<td>0.07</td>
<td>0.19</td>
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<tr>
<td>15</td>
<td>45</td>
<td>0.06</td>
<td>0.17</td>
<td>0.06</td>
</tr>
<tr>
<td>16</td>
<td>49</td>
<td>0.07</td>
<td>0.19</td>
<td>0.07</td>
</tr>
<tr>
<td>17</td>
<td>15</td>
<td>0.02</td>
<td>0.06</td>
<td>0.02</td>
</tr>
<tr>
<td>18</td>
<td>34</td>
<td>0.05</td>
<td>0.13</td>
<td>0.05</td>
</tr>
<tr>
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<td>0.02</td>
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<td>0.27</td>
<td>0.10</td>
</tr>
<tr>
<td>21</td>
<td>40</td>
<td>0.06</td>
<td>0.15</td>
<td>0.06</td>
</tr>
</tbody>
</table>
Additionally, it may be worthwhile considering alternative approaches to mitigation solutions that prevent unnecessary and costly installation of mitigation equipment by individual customers. A transmission system operator led optimised mitigation may allow for a better understanding of the system impact and appropriate location of a mitigation solution for multiple customer connections.

4. Bibliography


A geometrical approach to improve the accuracy of determining average oil temperature rise of oil-immersed power transformers

A. GAMIL1*, A. AL-ABADI1, M. FLISS1, A. LINGAUER1, E. SCHLUECKER2
1SGB Power Transformers, (SGB-SMIT Group), Regensburg, Germany
2Institute of Process Machinery and Systems Engineering, Friedrich-Alexander-University, Erlangen, Germany

Abstract
The way of determining average oil temperature rise of oil immersed power transformers has been kept over years in standards as the average value of the top and bottom oil temperature rises without considering the effect of thermometer pockets location on the deviation of temperature measured over the whole oil volume. The accuracy of the average oil temperature rise is important as it is the base on which the winding gradients and hot spots are determined. In this study, both temperature and position of the thermometer pockets on the cover of transformer are considered and formulated in a geometrical approach (G-Approach) to increase the accuracy of determining the average oil temperature rise. Results of the G-Approach are validated by analyzing the cooling curves (CC) and using fiber optic sensors (FOS). Although results show a higher accuracy within ±3 K compared to standard method described in IEC 60076-2 (deviation offset is higher than 5 K in average), nevertheless, the approach is kept simple and applicable for the factory acceptance test (FAT).

1. Introduction
According to standard IEC 60076-2:2011, the calculation of winding gradients and hotspots, which affect to a high extend the estimation of the lifetime of transformer, is described by using the measurements of top and bottom oil temperature rises. The gradient is the difference between winding temperature rise, which is determined using the cooling curves (CC), and the average oil temperature rise, which is the arithmetic average of all top and bottom temperature rises. Theoretically this method could work if the top and bottom oil temperatures of the oil flowing directly through the windings are available. This is possible by using fiber optic sensors (FOS), which cannot be always installed for each transformer. Practically the top and bottom oil temperature rises are measured through the available thermometer pockets temperatures and an average of all presents the average oil temperature rise of the transformer, figure 1 [1].

This simple way of determining the average oil temperature rise has been kept for decades in IEC without changing the base. With increasing the rating, size and complexity of transformers and entering the technology of FOS and computational fluid dynamics (CFD), it has become clear that the deviation between designed and measured values increases and lots of correction factors must be used to match the IEC straight line between top and bottom temperatures. Although, the recommended position of top pockets is described roughly in IEC 60076-2 to reflect the most reasonable top-oil temperature on the tank cover, the arithmetic averaging of top oil temperature is not taking into account the effect of pockets positions on determining of the average oil temperature with respect to the whole oil volume.

Comparing average oil temperature of windings using FOS, located on the main oil inlet and outlet of the winding, and average oil temperature of six transformers using IEC showed a deviation up to 8 K, which indicates that average oil result based on IEC is not presenting the real average oil temperature of the winding [2].

A deep look on Fig. 1 would raise the following questions:
• How far and where can this linearity be applied on oil temperature distribution in transformers?
• Does the average top-oil present the mixing of winding oil temperature at the top?

* ahmed.gamil@sgb-smit.group

KEYWORDS
Average oil temperature rise, Cooling Curves, Fiber Optic Sensors, Geometrical Approach, Power Transformers.
Using least-square-regression the measured data should be fitted to the model of equation (1) as shown in figure 2. The used optimization algorithm is a nonlinear Generalized Reduced Gradient Algorithm (GRG) [3], which is based on the idea to minimize a given target function subject to set of constraints as follow, 

\[
\text{minimize } f(X)
\]

subject to 

\[
g_i(X) = 0, \quad i = 1, \ldots, m \] 
\[
b_l \leq X_i \leq b_u, \quad i = 1, \ldots, n
\]

Where, \(X\) is n-vector, \(b_l\) and \(b_u\) are given lower and upper boundaries, \(g_i\) are the constraints functions which can also be inequalities.

In this study, a new approach is presented to determine the average oil temperature rise based on both measured temperature and the geometrical distribution of thermometers pockets (G-Approach). The accuracy of the average oil temperature rise is important as it is the base on which the winding gradients and hot spots are determined. Results are validated by analyzing CC and using FOS measurements.

### 2. Cooling Curves Analysis

The cooling curves (CC) of the average winding temperature rise (\(\Delta \theta_w\)) are presented in different functions in the IEC, the most accurate one is the double exponential function as below,

\[
\Delta \theta_w = a \cdot e^{-\frac{t}{\tau_w}} + b \cdot e^{-\frac{t}{\tau_o}}
\]

where, 

- \(a\) represents the winding gradient [K]
- \(b\) represents the average oil temperature rise per winding [K]
- \(\tau_w\) represents the thermal time constant of the winding [min]
- \(\tau_o\) represents the thermal time constant of the oil [min]

Using least-square-regression the measured data should be fitted to the model of equation (1) as shown in figure 2.

The calculation of the parameters of equation (1), the starting points and the constraints are set as in Table 1. The GRG method is a built-in in the Microsoft Office Excel Solver tool.

### Table 1 - Initial feasible values and constraints for the parameter

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Starting point</th>
<th>Constraints</th>
</tr>
</thead>
<tbody>
<tr>
<td>(a)</td>
<td>15</td>
<td>10 \leq a \leq 20</td>
</tr>
<tr>
<td>(\tau_w)</td>
<td>10</td>
<td>5 \leq \tau_w \leq 15</td>
</tr>
<tr>
<td>(b)</td>
<td>40</td>
<td>20 \leq b \leq 60</td>
</tr>
<tr>
<td>(\tau_o)</td>
<td>200 ONAN</td>
<td>100 \leq \tau_o \leq 300</td>
</tr>
<tr>
<td></td>
<td>100 (ONAF)</td>
<td>0 \leq \tau_o \leq 200</td>
</tr>
</tbody>
</table>

### 3. Case studies comparing FOS and CC data

Six case study units with different rated power, voltage, coolant oil type and cooling type are investigated. For
all case studies the FOS’s are located at the top and the bottom of HV-LV winding system on the main outlet and inlet of oil flowing through the windings respectively, figure 3. The average value from the measured temperatures of the top and bottom sensors was considered as the average oil temperature rise of the winding. For the cooling curves, the average value of the resulting \( b \) of all windings from equation 1 (CC\(_{\text{avg}}\)) is compared to the resulting average oil temperature from the sensors (FOS\(_{\text{avg}}\)). The average oil temperatures are calculated correspondently for HV and LV windings as follows,

\[
\text{FOS}_{\text{avg}} = \frac{\text{FOS}_{\text{HV,top}} + \text{FOS}_{\text{LV,top}} + \text{FOS}_{\text{HV,bot}} + \text{FOS}_{\text{LV,bot}}}{4}
\]

\[
\text{CC}_{\text{avg}} = \frac{\text{CC}_{\text{HV,avg}} + \text{CC}_{\text{LV,avg}}}{2}
\]

Comparison of the average oil temperature rises calculated by using FOS and CC with the average oil temperature using the method in IEC 60076-2 (Average temperature of top and bottom thermometer pockets) is shown in Table 2. The results give the ability to rely on the analysis of CC as a validation tool for the new approach, as it is not always possible to use FOS in each transformer. Figure 4 shows the deviation between FOS and CC on one side and FOS and test bay (IEC) on other side of the same investigated six case study units. It is important to state that the IEC method could still work some scales and dimensions, but this is not a rule.

\textbf{4. G-Approach}

Physically, heat transfer from a certain solid to the surrounding fluid beside the fluid distribution over this solid influence the flow distribution of this fluid. Considering the oil-immersed power transformers, the fluid is enclosed in a certain volume, which is mainly the tank. The radiators with or without fans have the duty of dissipating the heat. However, the heat dissipation occurs already at any point of the whole transformer surface but in different levels. In other words, each location of the oil volume contains to a certain extend a part of information about the thermal status of the fluid. Gathering this information (values and location) would give a clearer picture of the temperature distribution in oil.

The proposed geometrical approach (named as G-Approach) offers an accurate and simple method to predict the average oil temperature rise using not only the measured temperatures of the thermometer pockets
but also the positioning of these pockets in respect to the central axis of the middle phase. The minimum pockets number needed is three, two on the tank cover (top-oil) and one at the bottom of the radiators (bot-oil). The three pockets can be connected to shape a triangle. The surface of this triangle is the area of the G-Approach analysis drawn by the coordinates of the pocket’s positions. The mathematical base to analyze the temperature distribution inside the triangle surface (named as G-Function) is the same used in the FEM for heat transfer analysis [5, 6].

Typically, during FAT two or three thermometer pockets on the cover and one at the bottom of the radiators (depending on the rated power) are used. In case of two pockets on the top, the coordinate systems origin for X and Y is the center of the middle phase and Z is the mid height of the tank. From this reference each pocket has defined (X, Y, Z) coordinates, which only depend on the positioning of the active part in the tank. These coordinates build a triangle in the space of the oil volume. Since, the analysis is limited to the internal region of the triangle, the 3-D coordinates are converted to 2-D coordinates, and hence, the triangle surface area is considered. The average oil temperature rise of the transformer is geometrically located on the line dividing the triangle surface area into two equal areas.

The following steps are conducted to determine the average oil temperature rise using G-Approach:

- Determine the coordinates of top and bottom thermometer pockets and convert them from 3-D to 2-D,
- Note top- and bot-oil temperature rises at the instance of shut down,
- Determine the coefficients of G-Function for the triangle frame (see section 4.3),
- Determine the coordinates of the intersection line dividing the triangle into two equal areas. The line must be parallel to the line that connects the two top pockets (see section 4.3),
- Set the intersection coordinates in G-Function results in two temperature values, from which the arithmetic mean value is calculated, which is the average oil temperature rise (see section 4.4).

4.1. Triangular working area

Basically, the temperature pockets should be selected, so that the triangle surface will construct a cross-section in the tank width plane, as shown in figure 5. In some cases, set of temperature pockets are in one position for different temperature measurement purposes during operation. This pocket array is considered as one position (simply in the center of the array). When using the G-Function, the coordinates are defined as nodes and the temperature rises at the nodes as nodal values.

4.2. Coordinate system

Considering the planar area formed by the triangle, it is convenient to convert the 3-D coordinates in the global Cartesian coordinate system X, Y, Z to the local 2-D coordinate system x, y. The origin is chosen to be located at one of the nodes at the top of the tank as shown in figure 6 by the position of T₁.

4.3. G-Function

G-Function is an analog form of an interpolating model in Finite Elements Method (FEM), applied within a triangular element having the temperature rise as an analyzed physical quantity. Equation 2 represents the first order interpolation, which is used to validate the G-Approach. The function is valid inside the frame of the triangle and assumes a linear distribution of

![Figure 5 - Representation of the triangle side and top view](image)

![Figure 6 - Conversion of 3-D to 2-D coordinate system](image)
temperature over the triangle surface. The general form of G-Function is defined as follows,

\[ T(x,y) = \alpha_0 + \alpha_1 x + \alpha_2 y \]  

(4)

where \( \alpha_i \) with \( i = \{0, 1, 2\} \) are unknown geometric coefficients (also known as generalized coordinates) and \( T(x,y) \) is the temperature rise value at the node \((x,y)\).

To solve equation (4) for \( \alpha \), the nodal values and coordinates are substituted into equation (4) building the equations (5-7),

\[ T_1(x_1,y_1) = \alpha_0 + \alpha_1 x_1 + \alpha_2 y_1 \]  

(5)

\[ T_2(x_2,y_2) = \alpha_0 + \alpha_1 x_2 + \alpha_2 y_2 \]  

(6)

\[ T_3(x_3,y_3) = \alpha_0 + \alpha_1 x_3 + \alpha_2 y_3 \]  

(7)

Which can be presented in a matrix form as shown in equation (8),

\[
\begin{bmatrix}
T_1 \\
T_2 \\
T_3
\end{bmatrix} =
\begin{bmatrix}
1 & x_1 & y_1 \\
1 & x_2 & y_2 \\
1 & x_3 & y_3
\end{bmatrix}
\begin{bmatrix}
\alpha_0 \\
\alpha_1 \\
\alpha_2
\end{bmatrix} = A \cdot \alpha
\]  

(8)

Where \( T_j \) and \( T_k \) are the temperature values at the cover of the tank (top) and \( T_3 \) is the temperature at the bottom of the radiator at the nodes \((x_1, y_1)\), \((x_2, y_2)\), and \((x_3, y_3)\), respectively (see figure 5). These values are also referred to as initial conditions for the equation. Rearranging equation (6) by matrix inversion,

\[
\alpha = A^{-1} \cdot T
\]  

(9)

yields to,

\[
\alpha = \frac{1}{|A|} \begin{bmatrix}
x_2 y_3 - x_3 y_2 \\
x_3 y_1 - x_1 y_3 \\
x_1 y_2 - x_2 y_1
\end{bmatrix} \cdot \begin{bmatrix}
T_1 \\
T_2 \\
T_3
\end{bmatrix}
\]  

(10)

Where \(|A|\) is the determinant of the matrix \( A = \begin{bmatrix}
2 & \text{area of the triangle } (T_1T_2T_3)
\end{bmatrix} \), and then,

\[
a_0 = \frac{1}{|A|} \left[ (x_2 y_3 - x_3 y_2) T_1 + (x_3 y_1 - x_1 y_3) T_2 + (x_1 y_2 - x_2 y_1) T_3 \right]
\]  

(11)

\[
a_1 = \frac{1}{|A|} \left[ (y_2 - y_3) T_1 + (y_3 - y_1) T_2 + (y_1 - y_2) T_3 \right]
\]  

(12)

\[
a_2 = \frac{1}{|A|} \left[ (x_3 - x_2) T_1 + (x_1 - x_3) T_2 + (x_2 - x_1) T_3 \right]
\]  

(13)

Having the coefficients \( a \), the temperature rise can be determined inside the frame of the triangle using G-Function.

**Computation of the average oil temperature rise**

Once the geometrical coefficients \( \alpha \) are known, G-Function can be used to determine temperature rise at any coordinates \((x, y)\) in the frame of the triangle. From a geometrical point of view, the line intersecting the surface area to two equal parts \( A_r1 = A_r2 = \frac{|A|}{4} \) parallel to the top segment \( T_1T_2 \) includes the coordinates from which more than one oil temperature rise along the line can be calculated and the average of all values can be considered.

In the following example, only two nodes \( T_4(x_4,y_4) \) and \( T_5(x_5,y_5) \) as shown in figure 7 are considered, from which the arithmetic mean value is calculated to present the average oil temperature rise of the transformer \( T_{om} \),

\[
T_{om} = \frac{(T_4 + T_5)}{2}
\]  

Figure 7 - Triangle divided into two equal subareas \( A_r1 \) and \( A_r2 \)

In section 5, the validation of G-Approach against FOS and CC has shown that using the mean value of the intersection points \( T_4(x_4,y_4) \) and \( T_5(x_5,y_5) \) is enough to determine an accurate average temperature rise.

**4.4. Limitations**

The G-Function is only solvable, if the matrix \( A \) is nonsingular, i.e. invertible. This condition is satisfied if the nodes do not lie on the same line. However, in real world cases, when the distance between two nodes is very short relative to the distance to the third node or when the three nodes are quasi colinear, the matrix can be numerically singular and thus, the system of equations (5-7) becomes unsolvable. These situations should be consequently avoided. These two cases are illustrated in figure 8. Case (a) represents placing temperature sensors just in pocket array, which is considered as one position. Case (b) could result from gooseneck radiators while the cross distance between top-oil pockets is much bigger than the vertical distance to the bottom pocket (L >> h).
5. Results and discussion

5.1. Validation of G-Approach versus FOS

Table 3 shows the same case studies which are used again to compare FOS vs. CC in section 2. The results of G-Approach meet FOS in a tolerance range of ± 3K, while the standards method results have no representation of the average oil temperature rise. The deviation is shown in figure 9 as FOS results represents the reference for comparison. It could be observed that the G-approach deviations for ON is higher than those for KN, however, it is an early stage with a small amount of case studies to make a sub-category of deviation based on cooling liquid yet. The focus is to limit the deviation within ± 3K.

To have an indication of the advantage of using G-approach on determining the hotspot, case 3 in table 3 is taken as an example. The winding and the top-oil temperatures rises in this case are 48.9 and 46.5 respectively. Considering the hotspot factor to be equal to 1.3 as a reference, the following calculation compares IEC with G-Approach in determining the hotspot [8].

<table>
<thead>
<tr>
<th>method</th>
<th>Gradient [K]</th>
<th>Hot spot [K]</th>
</tr>
</thead>
<tbody>
<tr>
<td>IEC</td>
<td>48.9 – 31.0 = 17.9</td>
<td>46.5 + 1.3 x 17.9 = 69.8</td>
</tr>
<tr>
<td>G-Approach</td>
<td>48.9 – 37.4 = 11.5</td>
<td>46.5 + 1.3 x 11.5 = 61.5</td>
</tr>
</tbody>
</table>

Increasing the accuracy of the average oil temperature will have a positive effect on the accuracy of hotspot, which leads to more possibility of thermal design optimization by using the margin up to the guarantee value without affecting the transformer lifetime.

Using these case studies for validating cooling curve analysis and G-Approach results confirms the ability to use the cooling curves as a tool for further and continuous benchmarking of G-Approach against the results of the cooling curve analysis as described in section 2. The advantage of using the cooling curve as a validation tools saves cost and time needed to install FOS. However, a precise recording of the cooling curve with high quality, accuracy and a sufficient duration of measurements is necessary to obtain reasonable results.
5.2. Validation against CC

Figure 10 shows the benchmark made for over 150 transformers with different ratings (between 16 MVA and 187 MVA) and cooling combinations of ONAN and ONAF. Focusing on a deviation in the range of ±3K, the probability to be out of this range lies by 5%. These exceeding deviations can be avoided by choosing the right positions of the pockets, so that the triangle shape will not be too close to the limitations described in section 4.5. A correlation between the resulting deviation out of ±3K and the top pocket distance to the center of the middle phase was observed.

Investigating other types of cooling like OF and OD is kept for the next step. The reason of that is not the difficulty of analyzing these cooling by measurements rather than the lack of information of the available units with FOS. Besides, the analysis using CC shows that the oil time constant for OF is quite different to that for ON. However, a comparison between CC and G-approach has been initially done over 5 units with OF and OD cooling with ratings between 50 and 100 MVA, as shown in figure 11.

6. Conclusions

The current study presents a new approach that offers the possibility to include the effect of the position of the cover mounted temperature pockets in determining the average oil temperature rise. This effect is represented by the shape and surface area of a triangle enclosed by the pocket positions in connection to bottom temperature pocket. The determination of the average oil temperature as a function of triangle area instead of the approximated straight line (in the current standards), provides the necessary offset, which increases the
accuracy in calculating the average oil and in turn the hotspot temperatures. Besides, considering a surface section of oil temperature gives the chance to calculate more than one average oil temperature, which each has a different coordinate in the oil volume. Physically, in certain limits as described in section 4.5, the change of temperature pockets location result in changing the shape of the triangle with the corresponding top- and bottom-oil temperatures which results to only one mid-point on that surface, which is the real average temperature rise.

The G-Approach offers a solution for the well-known problem by experts, which is the gap between winding top-oil and tank top-oil temperatures. It gives the ability to determine the average oil temperature during the factory acceptance test FAT more accurately compared to IEC method, which results in more accuracy in winding gradients and hotspots. This leads to a better control on the safety margin to the guaranteed hot spot, and therefore, the transformer lifetime.

The investigation in this work highlights the effect of the positioning of the temperature pockets on the accuracy of the resulting average oil temperature rise. It allows to describe these limitations not only in a general way but also in a clear mathematical description to avoid undesirable deviations (higher than ± 3K).

This work has additionally introduced the advantage of using the cooling curve analysis to replace the fiber optic sensors (FOS) in the range of measuring the average oil temperature rise of the oil flow inside the winding. After validation against FOS using case studies, the cooling curve analysis gives the ability to validate the G-Approach. To have reasonable results from the cooling curves a cooling duration must be of at least 30 min with measurement intervals of 15 seconds is recommended.

**Acknowledgment**

Authors gratefully acknowledge the continuous support of Mr. Franz Schatzl (the technical director at SGB Power Transformers). His know-how and experience have been the main guidance to reach this stage of work in the best way.

**References**


**Biographies**

Ahmed Gamil received his B.Sc. degree from Zagazig University, Egypt in 1999 (Electric Machines) and his M.Sc. degree from RWTH Aachen, Germany in 2004 (High Voltage Technology). Ahmed worked previously in development of differential protection system and battery technology before joining SGB. In 2010 he joint SGB with the target of building R&D department from technology and management point of view. In the last years as a head of R&D he added contributions in transformer design optimization through improvements in losses, noise and thermal behavior of power transformers. His new approach to determine the average oil temperature rise (G-Approach) was one of the reasons to nominate him in “IEC Call for Experts” as a member of MT 60076-2 for the revision of IEC 60076-2:2011.

Ali Al-Abadi graduated from the University of Baghdad, Iraq in 1997 for B.Sc. and in 2000 for M.Sc. He
received his Dr.-Ing. degree from Friedrich-Alexander-University, Erlangen, Germany. From 2010 to 2015 he worked as research assistant and research associate at the same University. He was responsible for industrial projects. Ali joined SGB Power Transformers (SGB-SMIT Group) located in Regensburg, Germany in 2015. Since then, he has been working as a Senior Expert and Team Leader of R&D Projects. His main experiences are vibro-acoustics, thermo-fluids, losses and magnetic-field calculations of power transformers. Ali is an active member of IEEE, DAGMA and ASME, and a participant member in the CIGRE working groups. He has been publishing, presenting and reviewing many scientific and technical papers in the international conferences and peer review journals. Ali is an active contributor in power transformers and wind energy sectors.

Andreas Lingauer was born 1985 in Germany and has a successfully completed vocational training at industrial mechatronics. In 2012 he received his Dipl.-Ing. degree from Technical University in Munich in the discipline of power engineering. Till 2016 he has worked as a scientific assistant at the institute of high voltage engineering and switchgear technology in the field of optimization of the stator insulation system of low voltage rotating electrical machines for electric road vehicles. Since 2017 he is working at SGB Power Transformers in Regensburg on different multidisciplinary optimization projects in relation to quality and planning processes for the high voltage test bay department.

Eberhard Schlücker studied mechanical engineering at the University of Applied Sciences in Heilbronn. After having worked at company LEWA for several years he received his doctor’s degree in chemical and bioengineering from the University of Erlangen-Nuremberg. Two years later he again joined company LEWA as a member of the executive board. In 2000 he became head of the Institute of Process Machinery and Systems Engineering at the University of Erlangen-Nuremberg, which he has been holding up to now. His main areas of research are high pressure- and process engineering, fluid system dynamics and acoustics as well as chemical and biological process technology. Professor Schlücker is the editor of various technical journals and the Chairman of the EFCE Working Party for High Pressure Technology.
Summary

Power transmission line inspection enables early detection of faults and defects on power lines and their associated electric equipment thus plays a vital role in the electric equipment management process. The total length of power transmission lines in China has been as long as hundreds of thousands of kilometers, so both helicopters and drones have been utilized to help take inspection images. A tremendous amount of manpower thereby is currently employed for the analysis of massive inspection images.

To reduce the labor force investment, researchers have been studying automatic recognition techniques for years for detecting faults and defects of electric line and equipment in inspection images. Traditional image recognition algorithms generally have two parts, namely feature design and classifier construction but are seldom used in real-world power line inspection scenarios for two reasons. First, considering the tremendous types of electric equipment and their faults/defects, manually designing appropriate feature sets for all cases would be a huge project. Second, designing an almost perfect feature set to characterize a single case (i.e., to interpret the visual characteristics for a case) is even a challenge.

However, in the 2012 ImageNet Large Scale Visual Recognition Competition, a deep learning algorithm was adopted for the first time and achieved the best results. Since then, the advantages of deep learning in image recognition have been widely recognized. Deep learning not only has complex model structures that are suitable for large-scale data training but also is capable to automatically extract features. Though deep learning has been applied in different fields, its applicability in the real-world power line inspection scenario is not yet known.

In this paper, automatic recognition models of totally eight categories of faults/defects (e.g., tiny fittings and insulators’ defects) have been implemented based on state-of-the-art deep learning object detection algorithms. Additionally, online hard example mining, multi-scale training, sample balancing, soft non-maximum suppression and more mechanisms have also been involved in order to optimize these models’ performances. As a consequence, the final overall recognition precision is as high as 92%. On the basis of these models, an intelligent power line inspection image (video) analysis system is further developed. And this system is highly applicable in the power transmission line inspection scenario, i.e., it is able to handle both videos and images from various sources (e.g., taken by helicopters, drones and robotics and cameras installed at fixed locations) and to process inspection images in near real-time (i.e., it processes a single 10 megapixel HD photo in less than 200 milliseconds).

1. Introduction

Electric power transmission networks constitute the main backbone for continuous electric power supply from generators to consumers. The inspection of a power transmission network (hereafter referred to as power line inspection) aims at identifying all unexpected dynamic changes that affects this network, so appropriate maintenance actions could be taken accordingly.

Various factors may threaten the health status of both power lines and their associated devices in a power network. These components’ lifetime could be significantly shorten by extreme weather conditions, e.g., storm, flood, snow, thunder and others. Besides, accidents could lead to even more serious damages,
for example, wildlife may cause ground short, towers and their fundamentals could be got hit by agricultural machinery, short circuit between phases may happen due to falling kites, power lines which are in touch with plants may be damaged. Various types of faults and defects thereby can happen everywhere along power lines. Furthermore, even an initially insignificant fault holds a chance to take a turn for the worse then eventually to result in varying degrees of economic losses if it cannot be identified and handled in the first place. As can be seen, effective power line inspection is a premise to reliable system operations.

Power line inspection has two categories of targets including electric devices and passway environment, where electric devices are further divided into ontology (e.g., towers, fundamental of towers, insulators, fillings and others) and accessories (e.g., protection devices from lightning and birds), and typical targets of passway environment inspection include power line crosses, nearby construction operations and more.

Manual inspection that is thought as the most typical power line inspection mechanism needs inspectors to enter into a power line passway and pass through it to observe the status for the previously discussed targets with telescopes, infrared detection instruments and naked eyes. This even demands inspectors to climb towers to make test for insulators and other devices’ conditions. However, manual inspection has no longer been adequate since power lines have become longer and longer year by year. For example, by 2017, the total length of power transmission lines of 220 kilovolt and above in China has been about 0.688 million kilometres, and a much bigger number in the near future is foreseen to happen. Taking all of these challenging situations into considerations, more efficient inspection mechanisms have thus been employed as complementary or replacements. Power line inspections with helicopters or Unmanned Aerial Vehicles (UAVs) have been widely utilized in recent years for their features of higher efficiency, accuracy and safety such that both helicopters and UAVs can use their embedded cameras to take images for all those previously discussed targets at various locations which humans cannot reach. Images taken by helicopters and UAVs are first stored locally during flying then are highly likely moved into a server after landing. Experienced engineers can thus analyze these images one after another to check if there exists any abnormality like broken devices. However, at present a tremendous amount of manpower has been employed for the analysis of inspection images but is still far from enough as is known. Therefore, researchers have already tried to develop computer vision techniques to assist or replace those engineers. These computer vision applications which can help find all potential targets out from an image are called object detection. In the scenario of power line inspection, the so called objects are referred to as specific devices, devices with faults/defects and other previously discussed inspection targets of interests which are visually recognizable. Actually, related researches have been conducted for years.

Typical computer vision techniques often follow four steps (i.e., feature extraction, image segmentation, target locating, and fault classification) to process an image, in order to identify potential faulty electric devices. In [1] a framework that is able to identify and classify different towers in an image is proposed, where both Histograms of Oriented Gradients (HOG) and Multi-layer Perception (MLP) neural network are utilized for feature extraction and target classification respectively. In [2] broken strands are detected by a similar framework but with Support Vector Machine (SVM) as the classifier. In [3] a method which can recognize obstacles along power lines (i.e., insulator strings, counterweights and suspension clamps) is proposed to facilitate mobile robot to move along power lines more smoothly. In [4] the segmentation of insulators out from images is realized. In [5, 6] power line components (e.g., towers, suspension and strain type insulator strings) and faulty insulators are identified respectively. However, these traditional computer vision techniques’ performances are sensitive to targets’ backgrounds, sizes, materials, shapes and other factors because their extracted features are insufficient to interpret targets’ real characteristics. This is also the reason why they are seldom applied in real-world power line inspection scenarios.

Nevertheless, the advantage of deep learning algorithms in computer vision has been widely recognized since 2012 when the deep neural network Alexnet achieved the best result in the ImageNet Large Scale Visual Recognition Competition [7]. Both the complex network
and can handle most of the concerned inspection targets.

This paper is structured as follows. Section 2 formulates the inspection image analysis problem. Section 3 introduces all those algorithms and optimization mechanisms involved in this work for model training. Section 4 details the architecture of the intelligent power line inspection image (video) analysis system.

Section 5 summarizes the experimental results. The final section concludes this paper.

2. Problem formulation

Both helicopters and UAVs take photos or even videos for those critical locations during the power line inspection process. All these image data are first stored locally then transferred to a server where image analysis could be conducted to determine whether any inspection target with abnormal conditions exists. In order to figure out the most concerned power line inspection targets and build corresponding models, a full survey of both helicopter and UAV inspectors has been carried out, in addition to which a certain number of image instances for each type of target is harvested during this survey.

As seen in Table 1, column 1 lists the targets of interests in power line inspection that are mainly about electric components. Column 2 details the exact concerned issues of these components. The total count of all structure and the involved convolution mechanism facilitate deep learning algorithms to automatically extract a target’s features that can better describe this target. A few researchers thus have tried to explore the potential of deep learning for power line inspection image analysis. For example, in [8] a random forest classifier was constructed to classify images of insulators, transformers and other devices where Alexnet is taken as the feature extractor. In [9-12], Faster Region-based Convolutional Neural Networks (Faster R-CNN) is applied for the detection of insulator faults, bird nests and other abnormalities, which can not only locate a target but also identify the exact type of it. In [13] the Faster R-CNN deep learning framework is used to detect dead end body components. As could be seen, the above have only studied the potential of deep learning in power line inspection, but each of them can only handle one or a few targets. Therefore, they are still not applicable to the real-world power line inspection scenario concerning various targets and situations.

In this work, an intelligent power line inspection image (video) analysis system is constructed based on state-of-the-art deep learning algorithms (i.e., Faster R-CNN and Region-based Fully Convolutional Network (R-FCN)) and various optimization mechanisms. As far as is known, this is the first automatic image analysis system that is applicable to the real-world power line inspection scenario and can handle most of the concerned inspection targets.

![Table 1 - The list of most concerned power line inspection targets and defects](image)

<table>
<thead>
<tr>
<th>Targets</th>
<th>Concerned Fault/Defect Issues</th>
<th>Image Count</th>
<th>Ranks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Fitting</td>
<td>Missing peg</td>
<td>20388</td>
<td>1</td>
</tr>
<tr>
<td>Insulator</td>
<td>Damaged or self-exploded</td>
<td>4401</td>
<td>2</td>
</tr>
<tr>
<td>Vibration Damper</td>
<td>Moved or damaged</td>
<td>3187</td>
<td>3</td>
</tr>
<tr>
<td>Foreign Matters</td>
<td>Bird nest</td>
<td>793</td>
<td>4</td>
</tr>
<tr>
<td>Discharge Gap</td>
<td>Loosen</td>
<td>595</td>
<td>5</td>
</tr>
<tr>
<td>Grading Rings</td>
<td>Tilting or damaged</td>
<td>540</td>
<td>6</td>
</tr>
<tr>
<td>Tower Foundation</td>
<td>Sink, buried or surrounded by high plants</td>
<td>436</td>
<td>7</td>
</tr>
<tr>
<td>Warning Sign Board</td>
<td>Fallen off or damaged</td>
<td>421</td>
<td>8</td>
</tr>
<tr>
<td>Earth Wire</td>
<td>Untwisted or broken strand</td>
<td>303</td>
<td>9</td>
</tr>
<tr>
<td>Clamp</td>
<td>Tilting or damaged</td>
<td>288</td>
<td>10</td>
</tr>
<tr>
<td>Tower Materials</td>
<td>Corrosion, missing, out of shape or fallen off</td>
<td>271</td>
<td>11</td>
</tr>
<tr>
<td>Spacer</td>
<td>Damaged, disconnection or foreign matter</td>
<td>259</td>
<td>12</td>
</tr>
<tr>
<td>Pathway Environment</td>
<td>Over-high plants, illegal building and construction</td>
<td>248</td>
<td>13</td>
</tr>
<tr>
<td>Monitoring Devices</td>
<td>Disconnected line, line droop or damaged</td>
<td>27</td>
<td>14</td>
</tr>
<tr>
<td>Lightning Arrester</td>
<td>Connection box issue or disconnected line</td>
<td>7</td>
<td>15</td>
</tr>
</tbody>
</table>
collected images for each kind of target with either fault or defect is shown in column 3. Actually, the portion for one target could reflect how likely an issue of this target can happen relative to the others in real-world scenarios. Column 4 shows the ranks for each target. Figure 1 shows the examples for all these device issues.

Identifying targets with faults and defects in a power line inspection image is actually an object detection task. As this term indicated, object detection can process an image to identify where an object is and to classify what it is. Traditionally a deep learning-based object detection model could be trained based on hundreds of images or more to handle one or multiple objects. The more images are provided, the higher the performance of the corresponding object detection model could be. Oppositely, a model may not be trained sufficiently if the provided data is not enough. Consequently in this work object detection models are only developed for the top eight targets in Table 1. Figure 2 shows a general process of deep learning-based object detection. Provided a certain number of images, experienced inspectors first enclose those regions of interest for each image and labels them to indicate their belonging classes. These annotation information is then fed into a deep learning-based object detection framework together with the original images for model training. Finally, one can use the generated model to detect objects.

3. Methodology

Faster R-CNN is one of the most widely used deep learning-based object detection frameworks [14]. It consists of four components, including a list of convolutional layers, a Region Proposal Network (RPN), a Region of Interest (ROI) pooling layer, and a classification layer. Given that an image is fed into this framework, these four components would behave one after another in order to detect objects of interest. The convolutional layer list first extracts feature maps from this image. The RPN then proposes several possible regions in the image that may contain objects. For each region proposal, the ROI pooling layer is responsible to generate its corresponding proposal feature maps based on previously extracted feature maps. Because proposal
Given an image, an object detection framework under the training phase first proposes a certain number of regions in this image. It then makes judgements on all of these regions and utilizes a loss function to determine the overall correctness. These judgements may include whether a region is about foreground objects or background, whether the classification of a region is correct or not, and how well the forecast location of a region could match with an actual object’s real location.

Minimizing the overall function errors guides the framework to iteratively optimize parameters. However, during training, thousands of regions or even more may be proposed for an image, and they are extremely unbalanced. The portion of positive regions may be as low as 0.1%. Besides, the difficulties to detect different objects may be varied. All these make difficulties to model training. It is reasonable to consider that the detection accuracies for the regions of background and easily reorganized objects are relatively higher, so the corresponding loss errors should be lower as well. OHEM simply sets 0 weights for these regions, which subsequently forces the framework to pay more attentions on those hardly recognized regions when parameters are updated in the training phase.

R-FCN is an optimized framework on the basis of Faster R-CNN. Figure 3 shows the different network structures of both Faster R-CNN and R-FPN. Their main difference lies in the way to make pooling for proposal feature maps. In R-FCN an optimized pooling mechanism that is called Position Sensitive ROI pooling (PSROI pooling) is proposed, which better handles the object location information missing issue caused by ROI pooling. Furthermore, the new mechanism could significantly reduce the computational cost than Faster R-CNN because it is not necessary to conduct fully connection computing for a region’s complete features. For more details of R-FCN see [15].

Additionally, the following three mechanisms are utilized in order to further optimize the performances of Faster R-CNN and R-FPN, namely Online Hard Example Mining (OHEM) [16], soft Non-maximum suppression (NMS) [17], and image instance optimization.

feature maps of different region proposals are in different sizes, the ROI pooling layer also needs to convert them into a standard size. The classification layer identifies a region’s exact class and adjust its pixel location. For more details of Faster R-CNN see [14].

For more details of R-FCN see [15].
these separate components could be implemented or even operated individually, which on the one hand reduces the system’s complexity and on the other hand improves the robustness. The system architecture is illustrated in Figure 4, which has three layers and different modules.

The platform layer provides all necessary hardware (i.e., both data storage resources and GPU and CPU computational resources) and software environments (i.e., operation systems, docker services and deep learning frameworks) for the system to operate safely, reliably and efficiently. Because all these are off-the-shelf products and services, this paper will not go into their details.

The supporting layer is responsible to provide file system, computing and database services. Services of the file system includes the storage of videos, images and other files, the downloading of directories and files, the file searching and modification function, and the function of compressing and decompressing and more. The computing service could load different pre-trained deep learning models and at the same time invoke either CPU or GPU computation resources to conduct intelligent analysis. The initial inputs to this service are original images, and the outputs are initially detected results. Each of the models owns a specified pipeline which can conduct image pre-process (e.g., image resizing, image quality improving) and result after-processing (e.g., multi-results comparison and filtering). The database service supports all necessary data management fundamentals that it store user information, authority information, task related information, detection results and manual validation results.

The application layer is responsible to verify a user’s identity information, to validate the correctness of a request, to resolve and process external HTTP requests (i.e., data import and export, task management, authority management, manual validation and report generation) and to communicate with all supporting layer services. Moreover, essential technologies that enables the system implementation are listed in Figure 5.
First, the information middleware technology is applied to realize real-time communication between the intelligent analysis application and the computing module. Second, a concurrent and parallel computing framework involving multi-thread and multi-process techniques is utilized to accelerate computing. The multi-thread technique enables time consuming tasks to be executed by different threads, like file upload, data packing and report generation, in order to facilitate the main thread to respond to user requests. The multi-process technique allocates the computation burdens into different processes for the module with multi models and GPUs to avoid the competition for computing resources. Third, the docker technique is applied to pack the database and the analysis application and service all together, so only the operating system, essential hardware and their driver software and the packed docker service are necessary when deploying the system, and all other dependencies and software that are previously essential for each of the elements in the docker are not necessary to install any more. Finally, the computing module may be taken as the kernel of this system. Recall that totally eight categories of defect issues are concerned in this paper, so eight separate models are generated and integrated into this module subsequently. Because all of these models are generated by a same process, the following briefly describes the process to train one single model with the data described in Table 1.

First, all defect image instances are converted to 800×1200 then divided into three potions for training, validation and testing respectively with a fixed ratio equaling 7:2:1. Second, both Faster R-CNN and R-FPN are applied to train different models on the basis of the training data where Residual Network 101 (ResNet101) is chosen as the basement feature extraction convolutional networks for both of them and Stochastic Gradient Descent (SGD) is taken as the optimization algorithm. Actually, other widely known deep learning-based object detection frameworks like You Only Look Once Version 3 (YOLOv3) have also been evaluated beforehand but are found not as competitive for the power line inspection scenario, for which only Faster R-CNN and R-FPN are used for model generation in this work. Because the main intension of the paper is to introduce the system as a whole, so the comparison among these frameworks will not be presented. In the third step, a trial and error process is utilized to iteratively modify the model parameters for both Faster R-CNN and R-FPN and check detection results on the basis of the validation data in order to determine the better one of these two for the specific task. Fourth, another trial and error process is taken in order to iteratively involve each of the previously discussed optimization mechanisms (e.g., OHEM) or a random combination of them into the previously chosen framework, to retain models, to modify parameters and to validate performances. The model that has the best performance is finally embedded into the computing module of this system.

5. Experiments

The experimental results of this system, especially those regarding the system’s detection precision, are illustrated in this section. For each of the target, the detection performance of this system is tested based on the corresponding testing data. Recall that 10% images of Table 1 were left for testing. In this work, the criteria chosen to evaluate a model’s object detection performance is Average Precision (AP) which is calculated by averaging the Precision values at different Recall settings. The next will first intuitively show the system’s capability by presenting multiple power line inspection images returned by the system. Statistic results will then be shown to describe this system’s performance more precisely.

Recall that Figure 1 has shown 12 images about those typical defects of different targets. Figure 6 shows the detected results after feeding these images into the system. Note that all of these 12 images are from the testing data such that none of these were involved in the model training phase. Given an image, once the system identifies a potential defect, it encloses the defect area.
with a rectangle box of a specific color where different colors denote different defects. As seen, for most of these targets, their involved defects are successfully identified and tightly enclosed by bounding boxes, while exceptions still occur on two of these targets, namely tower foundation and tiny fitting. For the former case, this system fails to find the case when the tower foundation is hidden under the water. And this is due to the extreme unbalance among different defect issues in the images. It is found most of the images which were used to train the tower foundation model are about those buried or plant surrounded towers, and only tens of images are about the case when the tower foundation sinks in water. Because the model is purely data driven without any manually coded prior knowledge, the only way to optimize the model is to add more training image instances of various different defect types. For tiny fitting, though the system correctly identifies the peg missing issue, it also misidentifies another normal tiny fitting as one of the same issue. This is because that such target is much smaller than the others, and it is even difficult for a human to visualize. Actually, all those images shown in Figure 1 have been clipped for demonstration purposes, so the original images are of much bigger sizes. In the last of this section, Figure 7 shows the actual look of an image in initial size.

Table 2 gives the experimental statistic results regarding this system’s performances on object detection. The overall AP value on all these eight kinds of defect issues is as high as 92.45%. Even the lowest AP which occurs on Grading Rings is higher than 85%. For peg missing which is commonly considered to be the most concerned yet most challenging power line inspection task, this system achieves an 89.93% AP.

In addition to the high detection precision, this system could process a single 10 megapixel HD picture in less than 200 milliseconds, as a result of which real-time detection could be nearly achieved. Both the high accuracy and efficiency performances enable this system to be applied in all power line inspection processes with fixed cameras, helicopters, drones or robotics.
And even for the peg missing issue which is commonly thought as the most concerned yet most difficult task, the achieved AP nearly approaches 90%. Additionally, both the constructed hardware and software environments enable the system to carry out image detection in a rapid fashion. Therefore, this system can potentially be used in real-world power line inspection processes to improve efficiency.

6. Conclusions

This paper has introduced an intelligent power line inspection image (video) analysis system both about its algorithm mechanisms and the internal architecture. This system is able to identify as many as eight main categories of defects. Experimental results about this system’s precision have also been presented such that the mean AP for all eight targets is as high as 92%.

<table>
<thead>
<tr>
<th>Targets</th>
<th>Concerned Fault/Defect Issues</th>
<th>Image Count</th>
<th>AP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small Fitting</td>
<td>Missing peg</td>
<td>20388</td>
<td>89.93%</td>
</tr>
<tr>
<td>Insulator</td>
<td>Damaged and self-exploded</td>
<td>4401</td>
<td>98.23%</td>
</tr>
<tr>
<td>Vibration Damper</td>
<td>Moved and damaged</td>
<td>3187</td>
<td>92.35%</td>
</tr>
<tr>
<td>Foreign Matters</td>
<td>Bird nest</td>
<td>793</td>
<td>95.50%</td>
</tr>
<tr>
<td>Discharge Gap</td>
<td>Loosen</td>
<td>595</td>
<td>94.07%</td>
</tr>
<tr>
<td>Grading Rings</td>
<td>Tilting and damaged</td>
<td>540</td>
<td>85.16%</td>
</tr>
<tr>
<td>Tower Foundation</td>
<td>Sink and buried</td>
<td>436</td>
<td>91%</td>
</tr>
<tr>
<td>Warning Sign Board</td>
<td>Fallen off and damaged</td>
<td>421</td>
<td>95.36%</td>
</tr>
<tr>
<td><strong>Overall Result</strong></td>
<td></td>
<td></td>
<td>92.45%</td>
</tr>
</tbody>
</table>

Figure 7 - the actual sized detection result by the system. To better exhibit the detection results, all of those defect pixel areas are enlarged in this figure.
7. Bibliography


Summary
The energy scenario is experiencing substantial change due to increasing displacement of conventional forms of generation at transmission network level by renewable energy sources (RES) at distribution level. At the same time, consumers have started to participate in the electricity market as prosumers (both producer and consumer) or demand side response (DSR) entities. These partly fluctuating RES and DSR units at distribution level will change the behaviour of entire system, challenging the balance of load and generation in the grid at all time. Obviously, each distribution/transmission system operator is responsible for its own grid only, but to operate the grid properly in the new emerging scenario, it is important to know what is happening in part of the surrounding grids too. The Transmission system operator (TSO) has the primary responsibility of grid balance but it has no direct control over RES and DSR at distribution grid as of today. In general, TSOs also do not have the desired observability levels of relevant components of the distribution network such as medium voltage lines, substations etc. In future, TSOs using traditional observability analysis approach, as a fundamental tool to ensure system security, might be at risk. From a DSO (distribution system operator) perspective, the use of transmission system’s observability information has always been very limited and unnecessary until now. However, in the new scenario, the information exchange between TSOs and DSOs allows them to utilize the increasing penetration of DERs and DSRs more effectively providing ancillary service and local control. This trend is expected to grow more in future so it demands revision of the traditional way of TSO - DSO interaction. This work will explore the current practice of interaction between TSOs and DSOs, investigate the specific grid operation challenges, and identify the possible future ways of cooperation in smart grid. The analytical analysis in European perspective considering Denmark as an example is presented.

1. Introduction
The European Union (EU) is targeting for a 100% renewable based energy system by 2050 and 20% by 2020 [1], [2]. To support this EU initiative, all countries in EU have setup their respective milestones. As an example, Denmark has an ambitious milestones to meet 50% of electricity production from wind by 2020 and 100% energy consumption (heating, electricity including transport) to be meet from RES by 2050 [3]. The International Renewable Energy Agency (IRENA) have evaluated EU energy prospectus in its latest RE map (Renewable energy map) report. REmap program determines the potential for individual countries and regions to scale up renewables. Summary of renewable energy prospects for the EU is given in Fig. 1 [2].

Fig. 1 shows the percentage of renewable energy in total energy generation in the countries in EU in 2010 and compare it with REmap 2030. The fundamental way of power system planning and operation is changing due to this new strategy to move towards a more sustainable energy system, in which REs and electricity consumer’s role is kept in center [4], [5]. In this regard, an efficient exchange of power between individual countries becomes even more important in systems with high penetrations
of variable renewables. The capacity to export and import power is a key source of flexibility to the power system, allowing the integration of larger volumes of RES by attenuating their inherent variability into a larger power system. The EU can double the share of RES from 17% in 2015 to 34% in 2030 in its total energy mix [2] if the right frameworks are put in place to allow more RES [6], [7]. In fact, the traditional distribution network managed by DSO is mostly passive, demand is nonflexible and Distributed Generation (DG) is operated with a fit-and-forget approach. However, in the changing situation, DSOs are expected to manage active networks. In addition, other anticipated activities are to support local balancing; active interaction with Transmission System Operators (TSOs), optimum utilization of available distributed energy resources (DER) and controllable network assets; and preserve system integrity and stability. Therefore, new operational options to ensure a required flexibility seen in relation to also an increased TSO/DSO/market coordination have to be investigated. It will enhance the Active Distribution System Management (ADSM) for preventive actions rather than corrective actions.

More specifically, the electricity scenario is experiencing a significant change due to emerging trend of increasing penetration of renewable based distributed generation (DG) at distribution grid level replacing conventional generators at transmission grid level. This is supported by the behavioural change of the customer, because they have started to participate in the market either by becoming prosumers (consumer as well as producer) or by engaging in DSR activities. Challenges due to change in the electricity scenario can be categorized in to three groups: (i). Availability and application of huge data due to presence of new actors (smart meters, aggregators, retailers, BRP: balance responsible parties etc.) in the system, (ii). Commercial interaction of these actors that leads to the new market framework and (iii). Technical challenge in the grid management due to an active distribution network with more fluctuation generations (E.g.: Congestion, voltage/frequency fluctuation, grid balance, protection/control, islanding etc.). These challenges are not only for distribution grids but also for the whole electricity network operation. It will change the behaviour of the whole system making it more challenging for the TSO not only for balancing generation and load but also for grid control and protection at all time. Key criteria to handle these challenges are optimal use of resources, vibrant rules for competition, ensured customer confidentiality and reasonable and reliable allocation of price [8]. This work focuses on greater operational interaction between TSO – DSO in future grid considering above-mentioned challenges. This paper will describe the emerging scenario of stakeholders interaction in the electricity system and investigate the current practice and problems in TSO-DSO interaction. Then it will describe the key issues like data handling, the dimension of markets, network planning and system operations during TSO – DSO interaction in Denmark as a case study. An analytical method will be used to discuss aforementioned issues and define the observability areas of both TSOs and DSOs to identify which points of the distribution and transmission grids will be considered in the process of exchanging information. As an example, findings of this study can be beneficial to TSO and DSO to address technical problems like congestion management and exchange of ancillary services in their respective grids in future. Finally, it will formulate the guidelines and recommendations that can serve as a foundation for discussion between the stakeholders in this domain.

2. Stakeholders interaction in electricity system

General interaction within the major stakeholders in the electricity system for traditional and emerging electricity systems are shown in Fig. 2 and Fig. 3
respectively. As shown in Fig. 2, TSO has a major role and control in the traditional system for grid operation. It has required flexibility in its own grid due to connection of big consumers and most of the generation placed at transmission network level. Also, in most of the cases the TSO have the dominant role in market operation. Wholesalers and Generation companies are the only major market participants and retail market for consumers exists in Europe from 2011 [9]. Distribution grids are mostly passive and have no flexible resources in their grid. So, there used to be very limited interaction between TSO and DSO in the traditional system. However, this will not be true in the emerging scenario. As shown in Fig. 3 flexibility available at transmission grid is shifting to distribution grid and new actors are participating in the market. The value of a specific flexibility service is also not the same at TSO level and at DSO level respectively. Therefore, it is not straightforward for the TSO to balance its grid and coordinate with market. So a clear procedure and a strong coordination is needed [7].

As we can observe from Fig. 3, TSO-DSO cooperation and interoperation ability is one of the frameworks, which has to be upgraded and enabled for efficient operation in future because not only flexible resources are increasing at distribution level but also participating in the market too. In this transformation, two important actors in facilitating the transition to cleaner and secure energy have been the TSOs and DSOs. To achieve the energy target in the emerging scenario, TSOs and DSOs contribution is expected to be crucial due to new challenges they may face such as high penetration of renewable based DGs. This will enhance their responsibilities more demanding to fulfil. Apart from the unbundling cases where TSOs and DSOs operate at national level, it is likely to expect TSOs and DSOs handling new responsibilities and roles in different ways throughout the region in future [10].
3. Specific grid operation challenges in emerging electricity system

Emerging trend of increasing volume of partly fluctuating generations at distribution grid replacing less fluctuating conventional generators at transmission grid is challenging network operators to balance generation and demand at all time. Challenges that are related to TSO-DSO interaction are handling of huge data, interaction of stakeholders in new market setup, and handling of technical issues (E.g.: congestion of interfacing transformer and line, voltage support, balancing the grid, islanding etc.) [11]. These may be different for different network configuration and operation scenarios. Description of some generic grid operation challenges and the concerns in TSO-DSO interface are described in Table 1.

Table 1 - General grid operation challenges that concern TSO-DSO interface

<table>
<thead>
<tr>
<th>Grid operation challenges</th>
<th>Description</th>
<th>Concern in TSO-DSO interface</th>
</tr>
</thead>
</table>
| Data security and handling | • Huge data will be available due to smart meters, RTUs/PMUs, load/generation forecasting of distributed consumers and producers etc. | i. Who will take ownership of these data?  
ii. How individual’s privacy can be guaranteed?  
iii. Are there any guidelines for data exchange between TSO and DSO?  
iv. How to identify which data are beneficial for each other (TSO and DSO)? |
| Operation in new market setup | • Market should be fully liberalized to host increasing DG/RES/flexible loads at distribution grid. Due to this, new participants like aggregators, prosumers, BRPs, retailers are emerging in the new scenario. | i. What is the best market structure in new scenario? Is the market fully liberalized?  
ii. If yes, how each market participants are interacting with each other and how they are linked with TSO and DSO?  
iii. What commercial information is exchanged between TSO and DSO?  
iv. Is both transmission and distribution capacity limitation considered between market zones? |
| Congestion of TSO-DSO interfacing transformer and transmission line respectively | • Interfacing transformer is more likely to be overloaded due to increasing DG/RES/loads at distribution grid. If this transformer is not owned by DSO, they have to communicate to TSO in this situation.  
• Overloading of transmission line, which can happen due to overloading of many interfacing transformer and TSO’s own customers. | i. Who owns this transformer? TSO or DSO  
ii. If owned by TSO, and in case of congestion, how communication happens? Manually by phone or automatically? Does TSO sends signals directly to feeders for disconnection?  
iii. Does TSO communicate to the DSO before disconnecting interfacing transformer to avoid transmission line congestion?  
iv. Is possible congestion avoided in planning phase and later it never happens? Example: applying n-1 criteria?  
v. Is TSO-DSO interfacing area fully observable using network state estimation and forecasting of loads/generations?  
vi. Are there any control measures at TSO-DSO interfacing area to utilize the flexibility available there? |
| Challenges in Power balancing | Difficulties in balancing the grid due to fast fluctuating generation and consumption. | i. Are generators and loads from DSO network participating in balancing market?  
ii. Is DSO involved in prequalification processes related to ancillary service from the loads and generation at distribution network?  
iii. Real time balancing platform exists or not?  
iv. Are smart meter data measured by DSO used for flexibility assessment and communicated to TSO?  
v. There is possibility for TSO to balance its grid by having bilateral contract for flexibility from generator or loads. Is DSO involved somewhere or not? |
| Voltage support on both transmission and distribution network | Using flexibility on distribution grid and tap setting of interfacing transformer both DSO and TSO can support the voltage at each other’s network respectively. | i. Voltage control on Transmission network: Does DSO support voltage at TSO lines by activating flexibility on distribution grid. If yes, how it is communicated?  
ii. Voltage control on Distribution network: Does DSO control voltage level with TSO-DSO transformer tap setting at distribution grid? If yes, and transformer is owned by TSO how communication happen? |
| Interoperability Challenges for coordinated protection | In case of faults in transmission grid, alarms can be seen in the distribution system and even force to trip the distribution grid component and vice versa. | i. Are there any interaction between DSO and TSO for coordinated protection?  
ii. If yes, are there real time data exchange for this?  
iii. Do DSO’s protection system receive any settings from TSO or vice versa?  
iv. Are there any guidelines or protection policy available and implemented as of today for TSO-DSO data exchange in particular area? |
| Challenges during Islanding at TSO-DSO interfacing area, re-synchronization and black start | Islanding: Technically zero power flow from TSO-DSO interfacing transformer; detection of such situation, re-synchronization and balancing after that. | i. Are there regular exercise with participation from both DSO and TSO?  
ii. If yes, what type of data are exchanged (human interaction or automatic?) for island detection, re-synchronization and balancing |
4. Current practice of TSO-DSO interaction

General status of TSO – DSO interaction in Europe and specifically in Denmark has been identified. It is evaluated based on the literature review, survey of network operators, and interaction during project meetings with project partners Energinet.dk (the Danish TSO), Eniig and SE (Danish DSOs), Kenergy (Energy consultant) and ABB [11], [12], [13], [14], [4], [7], [15], [16], [17]. The main objective here is to identify how network operators are handling grid operation challenges that are discussed in section III and to made necessary recommendation for future smart grid operation scenario. To have efficient operation and planning, TSO-DSO can share specific information (E.g.: operation schedule, forecasted load/generation, grid data, flexibility data etc.) with each other via data exchange platforms (DEP). In most of the countries in Europe, DEPs are in operation except in Germany [18]. But their ownership and operation is not in similar manner. In countries like Denmark, Estonia, Norway it is owned and operated by the TSO (operated by subsidiary company of TSO in Norway). Where as in Belgium and Ireland, DEP is owned by DSO and in Italy it is owned by both TSO and DSO but is operated by a third party in all these three countries [18]. Market structure is not country specific like data handling, mostly it is regional (E.g.: Epexspot, Nord Pool, etc. in Europe). Epexspot covers France, UK, Germany, Netherlands, Belgium, Luxembourg, Austria and Switzerland [19]. Denmark is a participating in Nord Pool electricity market; it not only covers Scandinavian countries but also Baltic countries and UK too. This is the world’s first electricity market to liberalize both generation and retail [20]. These electricity markets consists of both day ahead market settlement and balancing mechanism and provide intraday trading in the European region. Due to inherent regional characteristics of these markets, only transmission capacity limitations are considered during the settlement [20]. Generally, fluctuating REs like wind are participating on day ahead market based on fixed price for generation (i.e. feed-in-tariffs). However, increasing high share of fluctuating REs are putting pressure to downstream wholesale price due to their low marginal cost. In Denmark, to minimize the impact and accommodate more REs two price based imbalance settlement is used [20]. In this case only the generators who is contributing to the system imbalance is subject to pay the penalty but if it’s over production can be utilized due to increased load at that particular time then it will not be penalized and get same price as agreed before. As of today, only TSO is involved in this market clearing process. After the settlement of market, hourly operation schedule is shared to TSO only and commercial information exchange between TSO-DSO is very limited.

Regarding technical issues, in most of the countries, interfacing transformer and transmission line congestion are avoided in planning phase by the n-1 criteria and cooperation is made during planning phase [11]. In most of the cases the TSO is responsible for control of supply and demand. Disconnecting of feeders and load is performed manually or automatically, it depends on the situation. Generally, DSOs are not seen involved in grid balancing activities, TSO takes care of it but in some cases distribution customer are taking part in balancing with partial involvement of the DSO. For voltage support, TSO is supporting the DSO by tap changing in the interfacing transformer and reversely capacitor banks installed in the distribution grid are supporting TSO [11]. In some cases DGs can be found supporting voltage due to grid code for Volt-Var control [11]. If islanding of the network is detected by a defined algorithm, the DG is disconnected and black start is carried out in close cooperation. However, coordination in protection is still seen limited in most of the cases. Summary of current TSO-DSO interaction in Denmark (Energinet.dk and Eniig) is given in Table 2.
stakeholders in the new market set up is grouped as a non-technical dimension. Whereas TSO-DSO interface and coordination required during network planning phase as well as in system operation and control is grouped as a technical dimension. These dimensions are interlinked to each other for example data collection and handling can be either from planning perspective or from real time system operation perspective [21]. Brief description of these dimensions are given in Table 3 below.

<table>
<thead>
<tr>
<th>TSO-DSO Interaction for</th>
<th>Current practice in Danish case</th>
</tr>
</thead>
</table>
| Data Handling           | • TSO operates the Data hub and owns it in accordance with the applicable legislation under Danish act under the processing of personal data.  
• Any grid company/DSO can access the data under certain terms and condition and are obliged with market regulations. |
| Operation in new market structure | • Denmark is participating in Nord pool market. Only transmission capacity limitations are considered in the market settlement.  
• Only TSO is involved in market clearing process and get the hourly operating schedule from the market.  
• New stakeholders like BRPs, aggregators and retailers are emerging mostly at DSO level. |
| Congestion of TSO-DSO interfacing transformer | • Interfacing transformer is 150/60 kV and is owned by TSO but 60 kV circuit breaker at this transformer station is controlled by DSO. In case of congestion, communication (regarding frequency) are automatic.  
• Mostly n-1 contingency analysis is carried out in planning phase. |
| Transmission line congestion | • TSO communicates to the DSO before disconnecting interface with DSO to handle the line congestion.  
• Although some level of analysis is carried out during planning phase still transmission lines are overloaded in many situation. |
| Grid balancing | • Generators and loads in DSO networks are participating in balancing market and are controlled by TSO.  
• DSO is not involved in prequalification, TSO takes care of this.  
• Consumer flexibility is not assessed by real metering data measured by DSO. It is done by data hub.  
• DSO is not involved in the bilateral contract between TSO and generators or loads at distribution grid. TSO is balancing its grid based on this contract. |
| Voltage support on both TSO-DSO side | • DSO helps TSO for voltage support by reducing its load at the step of 10%.  
• TSO helps DSO for voltage support by changing the taps in the interfacing transformer. It is communicated via SCADA system of TSO. |
| Interoperability for real time control and coordinated protection | • Some level of communication and real time data exchange is carried out via SCADA.  
• Communication standards and protocols for this data exchange are available. |
| During islanding, re-synchronization and black start | • Regular exercise to avoid possible hazard due to islanding have been carried out by TSO with the participation of DSO. |

5. New dimensions of TSO-DSO interface

Based on the above presented scenario and discussion, the dimensions of TSO-DSO interface and interoperability can be broadly categorized in to non-technical and technical clusters. Here, handling of huge data available in the emerging scenario and interlink of commercial
<table>
<thead>
<tr>
<th>Cluster</th>
<th>Dimension of TSO-DSO interface</th>
<th>Descriptions</th>
<th>Remark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-technical</td>
<td>Data handling</td>
<td>• More data will be required in the emerging scenario for enhanced operation that enables consumers participation (i.e. entry of aggregators and DSR activities), improve network observability and real time control.</td>
<td>• Collection of real time data from each small scale RES/DG/DSR for TSO and DSO will be difficult or more costly.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• These data can be available from smart meters and new stakeholders in the market (Aggregators, BRP etc.)</td>
<td>• Framework to identify required data type, its quality and ownership has to be put in place by TSO and DSO jointly. It should also guarantee the security and privacy of data. It will simplify the processing of huge data and help to maintain fair market competition.</td>
</tr>
<tr>
<td></td>
<td>Market framework</td>
<td>• In the traditional market set up TSOs are not involved in retail market. In the new set up TSO’s involvement in retail market is necessary because prosumers or DSR entity at DSO network are participating in market and are also providing system services like balancing, frequency response etc. which are needed by TSO.</td>
<td>Based on individual stakeholders’ coordination pattern some conceptual market framework that can be used in emerging scenarios are identified as:</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Therefore, clear and defined roles and responsibility of TSO and DSO are now important whatever the market framework be.</td>
<td>• Improved traditional framework: One TSO operated ancillary service market for resources available at both TSO and DSO network. Here, DSO is not involved in market settlement process and its constraints are not considered too.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Separate market framework: DSO operates separate market for resources connected to its own network and can offer the aggregated bids to TSO operated market only after solving the local grid constraints at DSO level.</td>
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<td></td>
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<td></td>
<td>• Shared framework for balancing: TSO and DSO share the responsibility of network balancing. However, they balance their respective network using own resources only in their respective market where their respective constraints are considered.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• One flexibility market framework: One market for all resources in the system (both TSO and DSO). Operation could be single or integration of TSO operated market and DSO operated market in real time. Both DSO and TSO constraints are considered.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• Combined flexibility market framework: Single common flexibility market but operated by separate independent operator (not TSO and DSO). Resources allocation based on price. DSO constraints are considered.</td>
</tr>
<tr>
<td>Technical</td>
<td>Network planning</td>
<td>• Traditional planning approach may not enable the potential of prosumers/DSR/RES connected to distribution grid for system services (congestion management, voltage support etc.). Provision of only grid connection facility for DGs at DSO network may not be sufficient in future.</td>
<td>• Integrated planning approach where TSO and DSO should interact from planning phase is necessary.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• DSO’s knowledge in local and regional level demand and generation harnessing will be crucial information for system expansion planning in new scenario, which demand regular interaction and exchange of information between TSO and DSO for system planning purpose.</td>
</tr>
<tr>
<td></td>
<td>System operation and control</td>
<td>• Increasing RE based generation at DSO network replacing conventional generators at TSO network.</td>
<td>• To utilize the DG/DSR’s capability for ancillary service, proper operational setup is required to minimize the scarcity of system service at TSO network.</td>
</tr>
<tr>
<td></td>
<td></td>
<td>• Even in new scenario, TSO will have main responsibility for balancing, frequency control and system restoration whereas DSO will manage its own network congestion and voltage management.</td>
<td>• Enhanced observability of DG/DSR connected to the DSO operated network and defined observability reach of both TSO and DSO with sufficient overlap as shown in Fig. 4 is required.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>• It will improve the security of supply, minimize the impact of forecast error also help to limit the reserve margin due to uncertainty.</td>
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</tbody>
</table>
6. Observability of TSO/DSO interfaces

Each network operator is responsible for its own network so in general they can observe only its own area. However, to operate grid properly in emerging scenario observability of its own grid will not be sufficient. It will be crucial to know what is happening in the nearby network. By defining the observability area, grid operators’ observability reach can be significantly enhanced beyond their own network. Responsible area consisting of own grid as well as part neighbouring grid is known as observability area [4]. The concept of observability area in a Danish scenario is illustrated in Fig. 4.

Common observability area is more important in TSO-DSO interface where it may be required for them to exchange more intense data related to their own network as well as significant grid users in that area. Here, intense data is referred as estimated or measured network state, forecasted profile of load and generation etc. that can be embedded to advanced distribution management system (ADMS) and also communicated to TSO-SCADA. For the network outside the common observability area, the exchange of only limited information may be sufficient for example, information about amount of flexibility available at distribution network may be sufficient for TSO. It can be collected from aggregators. In this case, TSO may not need network data from the distribution grid.

7. Recommendations for smart TSO-DSO interactions

From above discussion and scenarios presented, though some trend of interaction between TSO and DSO are evolving they are not sufficient for future energy landscape. This gap can be fulfilled by extending present interaction and implementing some new strategies. These are described in Table 4 below. It is seen that DSO roles and responsibility will be magnified compared to TSO as it has to carry out two-way communication with TSO, DSR entities at distribution network as well as data and flexibility management. On top of it, DSO should also put in place the real time grid monitoring mechanism via ADMS and has to interface it with the TSO-SCADA system.
8. Conclusions

In this paper the current practice of network interaction are discussed, specifically TSO-DSO interaction. Three aspects of challenges are categorised, namely data handling, market setup and technical issues for the emerging scenarios in power systems (increasing RE penetration at distribution level and decreasing conventional generators at transmission level). Due to the replacement of conventional generators at TSO grid by RE based generators at DSO, grid challenges are emerging not only for ancillary service management but also for system operation. It is discussed and recommended that these challenges can be converted to opportunities to certain extent by redefining data management, proper exchange of data between TSO-DSO (not only technical but also commercial), restructure of market setup and by revising the strategy to handle technical problems.

9. Bibliography


Table 4 - Recommendation for TSO-DSO interaction in smart grid operation

<table>
<thead>
<tr>
<th>S.N.</th>
<th>Interaction for</th>
<th>Recommended strategy for future</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Data handling</td>
<td>• Security of data (e.g.: customer consumption history data recorded via smart meter) can be guaranteed by an independent Data hub center under the owner ship of public entities not within TSO or DSO. • DSO can share the estimated/measured network status from the selected interfacing area to TSO and vice versa.</td>
</tr>
<tr>
<td>2</td>
<td>Market strategy</td>
<td>• Since the distribution grid is becoming more active, considering distribution system limitation too in market settlement will increase the system operation reliability. • In addition, DSO involvement in market clearing process can help DSO to balance its network locally and reduce the stress on TSO. For this, either TSO should share the operation schedule received from market to DSO or market should also have direct communication with DSO. • More liberalized local market is another possibility where power can be utilized locally in DSO responsible area by operating DSO operated local market. In this case, resources can be traded locally and they can contact upper market (regional market) only for excess load or excess generation or for balancing purpose.</td>
</tr>
<tr>
<td>3</td>
<td>Congestion management (interfacing transformer and transmission line)</td>
<td>• More relevant and detailed data exchange within the common observability area that will increase the flexibility use and reduce the transformer loading. • DSO can send the flexibility information collected from aggregator to TSO. • TSO can analyse and use flexibility available at distribution network to minimize transmission line congestion. Prioritization technique can be used to select the flexibility available in transmission and distribution network respectively.</td>
</tr>
<tr>
<td>4</td>
<td>Network balancing</td>
<td>• DSO can take part in grid balancing via aggregator • DSO can take the role of local network balancing • Overlapping should be avoided between flexibility trading signals (commercial signals) with network operation signals using flexibility otherwise it will miss lead the operation.</td>
</tr>
<tr>
<td>5</td>
<td>Voltage support</td>
<td>• Reactive power from DG can be used for TSO voltage support in a coordinated manner. • Existing capacitor banks at DSO network can be used for TSO voltage support. • TSO-DSO can agree on specific set points for reactive power/power factor/voltage at interfacing point.</td>
</tr>
<tr>
<td>6</td>
<td>Coordination in real time control and protection</td>
<td>• Exchange the measured/estimated network data for protection for quick localization of fault.</td>
</tr>
<tr>
<td>7</td>
<td>Islanding detection and black start</td>
<td>• Share the DG/RES production forecasted so that TSO can use these units for grid restoration</td>
</tr>
</tbody>
</table>


Feasibility of direct measurement of HVDC converter station loss

A. BERGMAN, RISE, Sweden, G. RIETVELD, VSL, The Netherlands

Abstract
Losses of HVDC converter stations need to be accurately quantified to support evaluation of bids for such systems and to underpin efforts to reduce greenhouse gas emissions. At present, these losses are estimated, based on loss calculations for individual converter components, and no reliable method exists to measure the actual HVDC converter station loss as difference between power on the AC- and DC-side of the station. The necessary requirements for such a measurement are investigated in this study, and a tentative design of a suitable loss measuring setup is explored. This approach is a useful alternative for those cases where a direct measurement of losses via a temporary connection with two converters operating in back-to-back mode cannot be made.

1. Introduction
The energy losses in our electricity transmission and distribution systems represent a significant cost that must be covered by sales of energy, driving prices. The losses also have to be generated, requiring production that is not used for salient purposes and leading to extra CO2 emissions. These losses are significant, around 8.2% over the total power transported by the electricity grids [1]. A major part, around 30%, of these losses are generated in power transformers [2] which led the European Union to issue a directive that per 1 July 2015 puts efficiency requirements on medium-size and large power transformers [3]. The significance of power transformer losses, despite the relatively small number of power transformers in the grid, lies in the fact that large amounts of energy are transported by them. A similar situation holds for high-voltage direct current (HVDC) transmission: even though the number of HVDC lines is limited, the amount of energy transported by these lines is very significant. So even relatively small loss reductions in the HVDC transmission system translate into large energy savings. This becomes ever more important since the number of HVDC interconnections is rapidly increasing, for example to connect different grids to enlarge stability and connect energy markets [NorNed and BritNed], to connect offshore windfarms [Borwin1, DolWin1], and for transmission of bulk energy over large distances [Itaipu, Rio Madeira, Irkutsk-Beijing, Jinsha River II] [4]. So, both for power transformers and HVDC transmission, mitigation of losses is an important task for grid operators and this, among other things, requires that these losses can be reliably measured and quantified. Accurately determined losses are crucial to unequivocally verify loss predictions, to allow equitable bid comparison and to perform an objective verification after delivery of the performance requirements guaranteed by the supplier.

HVDC transmission losses can roughly be divided into line loss and converter station loss. The former is reasonably straightforward to estimate since a DC transmission line (or cable) causes loss that is calculable from current magnitude and circuit DC resistance. However, for the determination of converter station loss no similar simple solution exists. The present state of the art for measurement of converter loss is reflected in two main IEC standards related to HVDC converter losses, namely IEC 61803 for line-commutated or current source converters (CSC) [5] and IEC 62751-1 for voltage source converters (VSC) [6]. Both standards describe a standardised method of calculating the HVDC converter station losses by summing the losses calculated for each item of equipment. The accuracy of this method relies on the availability and quality of experimental data obtained from measurements on individual equipment and components under conditions.
2. Direct HVDC converter loss measurement

2.1 General approach

The basic formula for the direct measurement of HVDC converter station loss power $P_{\text{loss}}$ is

$$P_{\text{loss}} = |P_{\text{AC}} - P_{\text{DC}}|,$$  \hspace{1cm} (1)

with $P_{\text{AC}}$ and $P_{\text{DC}}$ the high-voltage (HV) AC and DC power respectively transmitted by the converter station.

To achieve an overall target of 3% expanded uncertainty for an estimated converter loss of 1%, the gross power must be measured with 0.03% relative expanded uncertainty. Reasonably assuming that the AC-side and DC-side power measurements $P_{\text{AC}}$ and $P_{\text{DC}}$ contribute equally to the final uncertainty, and that a third equally large contribution stems from unavoidable variation in readings during the measurements, we see that an uncertainty of $0.03/\sqrt{3} \approx 0.017\%$ should be the target for each of the three uncertainty contributions. Grid type measuring equipment is not intended for metering purposes at this accuracy level. Even the best guaranteed accuracy class of 0.1% of metering equipment by far is not sufficient for the determination of converter station loss. In the following, we first detail the requirements for the accurate measurement of $P_{\text{AC}}$ and $P_{\text{DC}}$ respectively, and subsequently discuss what other experimental factors add to the total measurement uncertainty.

2.2 AC power measurement

2.2.1 Basic approach

The suggested approach for the accurate measurement of AC power $P_{\text{AC}}$ follows the standard practice used in grid metering setups: the high voltage and current are scaled using precise voltage and current transformers, and their outputs are measured with a precise power meter. So, for each phase, the AC power is determined via:

$$P_{\text{AC}} = \frac{1}{T} \int_0^T V_{\text{HV},\text{rms}}(t) \cdot I_{\text{HV},\text{rms}}(t) \cos \varphi dt,$$  \hspace{1cm} (2)

with $V_{\text{HV},\text{rms}}$ and $I_{\text{HV},\text{rms}}$ the root-mean-square (rms) values of the high voltage and high current respectively, and $\varphi$ the phase between these two signals. Eq. (2) assumes (for ease of discussion) sinusoidal voltage and current signals; the effect of inevitably present distortion is discussed in chapter 3.2.
If we introduce the nominal voltage transformer (VT) and current transformer (CT) scaling factors $k_{VN}$ and $k_{CN}$ respectively, Eq. (2) becomes:

$$P_{AC} = k_{VN} \cdot k_{CN} \cdot P_W,$$

(3)

with $P_W = V_{\text{rms}} \cdot I_{\text{rms}} \cdot \cos(\varphi)$ for the AC power measured by the reference power meter connected to the outputs of the instrument transformers.

**2.2.2 Uncertainty budget**

To evaluate the uncertainty in the AC power measurement, the non-perfect behaviour of the instrument transformers must be included into Eq. (3). This results in the following equation for $P_{AC}$, which is adapted from Eq. (4) in IEC 60076-19 [8]:

$$P_{AC} = k_{CN} \cdot \frac{1}{1 + \frac{\epsilon_C}{100}} \cdot k_{VN} \cdot \frac{1}{1 + \frac{\epsilon_V}{100}} \cdot \left( P_W \left( 1 - (\Delta \varphi_C - \Delta \varphi_V) \tan \varphi \right) \right)$$

(4)

where

- $\epsilon_C$ Actual ratio error of the current transformer (%), calibrated with an uncertainty $u_C$
- $\epsilon_V$ Actual ratio error of the voltage transformer (%), calibrated with an uncertainty $u_V$
- $\Delta \varphi_C$ Actual phase displacement of the current transformer (rad), calibrated with an uncertainty $u_{\Delta \varphi_C}$
- $\Delta \varphi_V$ Actual phase displacement of the voltage transformer (rad), calibrated with an uncertainty $u_{\Delta \varphi_V}$

Table 1 gives an overview of the different uncertainty contributions to the overall uncertainty in $P_{AC}$.

**Table 1 - Uncertainty contributions AC power loss measurement**

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Component</th>
<th>Contribution to standard uncertainty [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT ratio error</td>
<td>$\epsilon_C$</td>
<td>$u_C$</td>
</tr>
<tr>
<td>VT ratio error</td>
<td>$\epsilon_V$</td>
<td>$u_V$</td>
</tr>
<tr>
<td>Power meter</td>
<td>$P_W$</td>
<td>$u_{P_W}$</td>
</tr>
<tr>
<td>Phase displacement</td>
<td>$F_D = \frac{1}{1 - (\Delta \varphi_C - \Delta \varphi_V) \tan \varphi}$</td>
<td>$u_{F_D}$</td>
</tr>
</tbody>
</table>

Combined standard uncertainty calculated as: $u_P = \sqrt{u_C^2 + u_V^2}$

The expanded uncertainty is $U_P = 2 \cdot u_P$, which corresponds to a level of confidence of approximately 95%.

The uncertainty $u_{F_D}$ that affects the phase displacement correction $F_D$ depends on various variables but, assuming that the phase displacements of the CT and VT are small, for practical applications it can be estimated by the following simplified relation:

$$u_{F_D} \approx u_{\Delta \varphi} \cdot \tan \varphi$$

(5)

where the standard uncertainty $u_{\Delta \varphi}$ represents the combined standard uncertainty of the difference of the instrument transformer phase displacements.

For three-phase circuits, the power measurement should be performed using three individual single-phase measuring systems, adding the three results. For simplicity in analysis, it is assumed that the connection of instrument transformers is in star configuration. In this case, the criteria for estimating the uncertainties for the power in each phase are the same as given above for a single-phase circuit.

Normally the three measurements of the power are not correlated, and the absolute expanded uncertainty $U_T$ of the total power is obtained by the formula:

$$U_T = \sqrt{\hat{U}_1^2 + \hat{U}_2^2 + \hat{U}_3^2}$$

(6)

where the symbols below the square root represent the absolute expanded uncertainties of the power measurements performed on the individual phases and expressed in watt. The relative expanded uncertainty is:

$$U_T = \frac{\hat{U}_T}{P_{WT}}$$

(7)

where $P_{WT}$ is the sum of the power on all three phases. Absolute uncertainties are identified with a dot above the symbol, whereas relative uncertainties are without. The background is given in Clause 8.1 of IEC 6007619 [8].

An interesting corollary is that if the uncertainties are given as relative uncertainties for each phase, then the relative expanded uncertainty of the total power is reduced by a factor $\sqrt{3}$ – provided that the uncertainties of the individual phases indeed are uncorrelated. This will for example hold true if variability of readings dominates, but not if the calibration uncertainty is dominating and the measurement components of the different phases have been performed by the same reference setup. In the latter case the uncertainty reduction is less than $\sqrt{3}$ and may even be absent.

**2.2.3 Estimate of required component performance**

In section 2.1 above, a suggested performance requirement for the AC-side power measurement
was given as 0.017 % relative expanded uncertainty. Assuming that the uncertainty is uncorrelated between phases, as discussed in the previous section, it is seen that each phase needs an expanded relative uncertainty $U_r < 0.03\%$. A first estimate of required expanded uncertainty of each of the four (assumed equal) uncertainty contributions listed in Table 1 is then 0.03 $\% \sqrt{4} = 0.015 \%$

For the uncertainty contributions $U_c$ and $U_f$ in the CT and VT ratio error determinations, this estimate is straightforward, as well as for the uncertainty $U_{PW}$ in the power meter measurement. The contribution due to uncertainty in phase displacement is somewhat more complex since it depends on the power factor $\cos(\phi)$ of the measured power. The power factor under actual HVDC station operating conditions is expected to be larger than $\cos(\phi) = 0.5$. The uncertainty $U_{FD}$ in power due to phase displacement difference between current and voltage transformers is then roughly multiplied by $\tan(\phi) = \sqrt{3}$, when the phase displacement is expressed in radians. This leads to the overview of the necessary uncertainties of the components in the AC power measurement given in Table 2.

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Expanded relative uncertainty</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>CT ratio error</td>
<td>$U_c$</td>
<td>0.015 %</td>
</tr>
<tr>
<td>VT ratio error</td>
<td>$U_f$</td>
<td>0.015 %</td>
</tr>
<tr>
<td>Power meter</td>
<td>$U_{PW}$</td>
<td>0.015 %</td>
</tr>
<tr>
<td>Phase displacement</td>
<td>$U_{FD}$</td>
<td>0.09 mrad</td>
</tr>
</tbody>
</table>

### 2.2.4 Available technologies

The best available standard instrument transformers have 0.1 % class accuracy [9, 10, 11]. However, the basic technology used in the standard instrumentation can be made much more accurate if larger cores, or higher-quality material, are used. For a VSL reference setup aimed to verify HV grid metering systems in HV substations [12], custom-made high-precision CT and VTs, suitable for on-site outdoor measurements, were made by one of the major instrument transformer manufacturers.

The CTs in the VSL reference setup have two ratios, 2000:1 and 600:1, both with 250 % over-current capability so that currents up to 5000 A can be measured. For the 2000:1 ratio, the ratio errors are less than 5 $\mu$A/A over the full current range, down to 20 A, and without significant burden dependence up to 1 VA. The phase displacement of the CTs shows a similar behaviour, with values less than 40 $\mu$rad over the same current range [13].

The VTs selected for the VSL reference setup have three ratios, 2200:1, 1500:1, and 1100:1, for measurement of grid voltages of 220 kV, 150 kV, and 110 kV respectively. For each ratio setting, the nominal output voltage is $100 \sqrt{3} \approx 57.7$ V. To compensate for ratio errors caused by the inevitable capacitive effects in the 100 000-turn primary winding, a series of windings with 10 turns and 1 turn respectively can be placed in series with the primary winding via switches. Before the final calibration of each VT, the 10-turn switch has been set such that the ratio error at nominal voltage is less than 1 part in $10^4$. For zero burden, the phase displacement of the VTs is around -100 $\mu$rad whereas the ratio error lies between -100 $\mu$V/V and 50 $\mu$V/V depending on the VT and the selected ratio. If required, the ratio error at nominal voltage can be reduced to less than 20 $\mu$V/V by adjusting the 1-turn switch. For voltage changes less than 10 % of nominal voltage, the ratio error does not change by more than 10 $\mu$V/V.

Similar VTs can also be acquired for grid voltages of 380 kV. As an example, a mobile reference transformer has been deployed for in-situ calibration at the prevailing voltage in virtually all 400 kV substations in Sweden [14]. The uncertainty for this transformer is estimated at 0.006 %.

Both the CTs and the VTs can be calibrated with an expanded uncertainty of 20 ppm in ratio and 20 $\mu$rad in phase displacement using high-level reference setups traceable to international standards. The long-term drift of the units is found to be less than 50 ppm / $\mu$rad over 5 years. This makes them ideally suited for the purpose of measuring HVDC converter losses. Temperature dependence is considered negligible as these devices are purely inductive, with the properties of the magnetic core not changing significantly with temperature.

For the power measurement, several commercial three-phase power meters are available on the market that are specified with a specified accuracy of 0.01 %. An extensive evaluation of one of these meters for application
of AC power measurements in HV substations showed that the actual behaviour can be even a factor 2 better, over the full range of relevant currents and voltages [12]. A similar result was found for another power meter, after correction of its measurement errors [15]. There typically is an effect of temperature on the accuracy of commercial AC power meters. This preferably has to be determined and corrected for. For example, for the power meter used in the VSL AC power reference setup, the temperature effect was found to be at most -2 µW/VA [13]. As an alternative, the power meter should be installed in a climate-controlled environment.

Combining the uncertainties of the CTs, VTs, and reference power meter according to Table 2, an overall uncertainty in the AC power measurement of better than 0.01 % is achieved, well below the target of 0.017 %.

2.3 DC power measurement

2.3.1 Basic approach

Power measurement on the DC side of HVDC converter stations follows the same basic approach as on the AC side. It requires accurate DC current transducers and DC voltage dividers. DC power metering can in principle be performed with dedicated DC responsive power meters, but in the case of verification measurements, the use of high-precision multimeters combined with suitable software forms a very good alternative.

Measurement of the HVDC station DC voltage output poses a challenge since the low voltage terminal is normally not at earth potential. Several connection schemes are used, e.g. having an earth electrode at some distance from the converter station or utilising two converters in a bi-pole connection where a common point is at low potential, or the case of metallic return where the low voltage terminal is routed via cable or overhead line to the other end of the intertie. These examples show unequivocally that it is necessary to measure the voltage between the low- and high-voltage terminals of the HVDC station. Connecting the voltage divider between these terminals would be preferable from the point of reducing uncertainty. The problems of arranging the insulation of the instrumentation connected to the low voltage output prohibit solution. Thus a separate voltage divider for measurement of the neutral bus voltage must be considered. The normal operating voltage of a neutral bus is often in the range of less than 5 % of the line voltage, so that even solutions with moderate accuracy can be considered. The insulation level, should however be such that the voltage divider can withstand the voltage that can occur during faults. These voltages will be specific for each installation and determined in system studies. A general estimate however is that short-time stress (e.g. events similar to switching impulse) is not worse than 25 % of the line voltage.

2.3.2 Uncertainty budget

The result of a measuring system for DC power can be written as:

\[ P_{DC} = S_{FC} \cdot V_C \cdot (S_{FV} \cdot V_V - S_{FVN} \cdot V_{VN}) \]  (8)

where

- \( P_{DC} \) Power measured on DC side with a combined absolute standard uncertainty \( u(P_{DC}) \)
- \( S_{FC} \) Actual scale factor of the DC current transducer in V/A, calibrated with a relative standard uncertainty \( u_{SF_{FC}} \)
- \( V_C \) Output voltage of the DC current transducer in V, measured with a relative standard uncertainty \( u_{VC} \)
- \( S_{FV} \) Actual scale factor of the DC line voltage divider in V/V, calibrated with a relative standard uncertainty \( u_{SF_{FV}} \)
- \( V_V \) Output voltage of the DC line voltage divider in V, measured with a relative standard uncertainty \( u_{VV} \)
- \( S_{FVN} \) Actual scale factor of the DC neutral bus voltage divider in V/V, calibrated with a relative standard uncertainty \( u_{SF_{VN}} \)
- \( V_{VN} \) Output voltage of the DC neutral bus voltage divider in V, measured with a relative standard uncertainty \( u_{VVN} \)

Since equation (8) consists of both products and sums, formal development of uncertainty budget must be performed in full accordance with the GUM [16], which estimates the absolute uncertainty, i.e. an uncertainty of the power expressed in Watt. It is however more conventional to express an uncertainty as fraction (i.e. in %). This can be accomplished by dividing the absolute uncertainty with the power. Performing this exercise and considering that line voltage \( S_{FV} \cdot V_V \) is normally at least 10 times larger than neutral bus voltage
we can identify the following simplifications

\[
\frac{SFX \cdot V_{FN}}{SFY \cdot V_Y} < 1.1 \quad \text{and} \quad \frac{SF_{YN} \cdot V_{YN}}{SF_{YN} \cdot V_{YN} - SF_{YN} \cdot V_{YN}} < 0.11
\]

which results in the final uncertainty equation for the relative combined standard uncertainty \(u_c(P_{DC})\) of the power measurement:

\[
u_{c}^2(P_{DC}) < u_{SF^2}^2 + u_{VC^2}^2 + (1.1 \cdot u_{SFY})^2 + (1.1 \cdot u_{VY})^2 + (0.11 \cdot u_{SFYN})^2 + (0.11 \cdot u_{VYN})^2
\]

(9)

Table 3 - Uncertainty contributions in DC power loss measurement

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Component</th>
<th>Contribution to relative standard uncertainty</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current transducer, scale factor</td>
<td>(SF_X)</td>
<td>(u_{SF})</td>
</tr>
<tr>
<td>Instrument for voltage of current transducer</td>
<td>(V_C)</td>
<td>(u_{VC})</td>
</tr>
<tr>
<td>Line voltage divider, scale factor</td>
<td>(SF_Y)</td>
<td>(1.1 \cdot u_{VY})</td>
</tr>
<tr>
<td>Instrument for line voltage of voltage divider</td>
<td>(V_Y)</td>
<td>(1.1 \cdot u_{VY})</td>
</tr>
<tr>
<td>Neutral bus voltage divider, scale factor</td>
<td>(SF_{YN})</td>
<td>(0.11 \cdot u_{SFYN})</td>
</tr>
<tr>
<td>Instrument for neutral bus voltage of voltage divider</td>
<td>(V_{YN})</td>
<td>(0.11 \cdot u_{VYN})</td>
</tr>
</tbody>
</table>

Combined relative standard uncertainty calculated as per equation (9).

The relative expanded uncertainty is \(\hat{u}_e = 2 \cdot u_c\), which corresponds to a level of confidence of approximately 95%.

2.3.4 Available technologies

DC current sensors for high-precision application at high current are often realized using DC Current Transducers utilizing zero-flux technology. This technology was developed already in the 1960ies [17] and developed for use also in HVDC converter stations in the late 1970ies [18, 19]. The performance of these devices has been shown to be on the order of a few parts in 10^5 [20] and is thus eminently suited. Since the zero-flux technology relies on the realisation of zero flux in the measurement core, the temperature dependence is very small. Calibration facilities for these devices are available at several National Measurement Institutes world-wide.

A significant challenge is however the high-voltage insulation required if the measurement is to be performed on the high-voltage bus. Fortunately, this can be circumvented by realizing that the neutral bus will carry the same current, reducing insulation requirements drastically. In fact, at neutral bus voltage levels there is a possibility to use a low voltage measuring head with a piece of high-voltage cable routed through the opening of the toroidal measuring head. Estimated best performance for the DC current sensor is 0.004 %.

DC voltage dividers can be made for voltages up to more than 1000 kV and for use in HVDC stations. Provided they are stable enough, a calibration can be performed to verify the stability. A recent development funded by the European Union, has made available 1000 kV reference dividers with a best uncertainty of 0.002 % [21, 22, 23]. One of these dividers is of modular design and can be used.
directly in an on-site measurement of voltage on an HVDC station busbar. Estimated best performance for the DC line voltage divider is 0.004 %, including compensation for a known temperature coefficient of 0.0009 %/°C.

Performance of state-of-art DC voltmeters can be estimated as 0.001 %. The instruments should preferably be installed in a climate-controlled environment, or alternatively high-end DC voltmeters with temperature coefficient less than 0.0002 %/°C should be used.

Combining the uncertainties of the current and voltage sensors and of the voltmeters, an overall uncertainty in the DC power measurement of better than 0.006 % is achieved, well below the target of 0.017 %.

### 3. Additional experimental factors

#### 3.1 Operating conditions

Extraneous influences need to be mitigated as far as possible during the measurements. Influence of weather is however impossible to eliminate completely. It is of course prudent to avoid measuring during rain, since this can lead to increased interference with the primary sensors for voltage and current, as well as possibly leading to real fluctuations in power. On the other hand, clear sky might mean that sensors drift due to solar heating effects.

The impact of the typically significant temperature variations on-site on the accuracy of the measurements needs to be carefully evaluated. As indicated in the previous chapter, the high-end voltage and current sensors suggested for the present application have negligible temperature coefficient. For the AC power meter and DC voltmeters, used for the AC and DC power measurement respectively, the effects of temperature dependence can be minimised by either putting this instrumentation in a climate-controlled environment or by selecting high-end versions with negligible temperature effects. Loss needs to be quantified at many different power levels, which should be defined in a test program. In order to obtain stable power levels, a recourse to night-time measurements might be necessary. Fluctuations on the power grid tends to be less severe in many grids during night.

Integration time, as well as time instant, should be the synchronized between AC and DC side power measuring systems, so that power meters on AC side integrate energy during the same time span as the DC multimeters do. Guidance on suitable integration time cannot be given accurately but may be as high as several minutes in order to achieve the necessary stability in readings.

### 3.2 Harmonic distortion

The effect of harmonic distortion on the AC side can be viewed several different ways. On one hand, there may be harmonic distortion on the supply voltage on the electrical grid, which should be taken into account. Conversely, a converter station can generate harmonic distortion due to the operation of the HVDC valves. In first approximation, the converter can be viewed as current source for harmonic currents (or alternatively as a voltage source in series with an impedance) [24]. These currents lead to a corresponding harmonic voltage that depends on the impedance of the connected grid. What is important here, is that the harmonic power is fed into the grid. To be clear, this means that the harmonic power is added to the power drawn from the grid, either increasing or decreasing the apparent value of the AC power. One suggestion is to consider only the power at the fundamental frequency. This choice is by no means uncontroversial, and further discussion is required. If the harmonic power is included in the evaluation, the AC power meter should be verified on the accuracy of its harmonic power measurement capabilities. For modern, sampling-based power meters this should not be a significant problem, especially since any harmonic power will only be a fraction of the fundamental power.

On the DC side, any effect of harmonic power will be removed by the integration over time of measured quantities and can thus be disregarded.

### 3.3 Location of high voltage transducers

The intention of the loss determination is to quantify the converter station loss. Therefore, all primary transducers (AC voltage and current transformers, DC dividers and current transducers) should be close to the station inputs and outputs in order to be sure to include the losses of all filters etc. in the loss determination.

A significant boon from this is that the action of filters will relieve some of the concerns for effect of harmonics on the AC-side power measurement, due to the mitigation by the filters.
3.4 Electromagnetic interference and grounding

The HVDC converter station forms a harsh electromagnetic (EM) environment for the precision power measurements, easily negatively affecting the measurement accuracy. Therefore, extensive attention has to be paid to correct shielding and grounding of the AC- and DC-power measurement setups. It is the experience of both authors that effective shielding indeed can be achieved in such on-site conditions amongst others via the use of double-shielded twisted pair cables connecting the instrument transformers with the power meters [14]. The outer shield of these cables is connected to ground at both ends of the cable and used as safety ground. The inner shield serves as a measurement ground and only is connected at one side of the cable, typically at the side of the instrument transformer.

For the grounding, a central ground should be used as much as possible, and ground loops should be prevented in the measurement circuit. For the DC-side power measurement, special care has to be taken to minimise DC offsets in the voltage measurement circuits.

The possible occurrence of both EM interference and ground loops can be significantly reduced by minimising the length of the secondary wiring between the instrument transformers and the power meters, and placement of the AC- and DC-power measurement equipment in shielded racks. Readout of these racks can subsequently be arranged with fiber readout.

3.5 Instrument transformer burden

Since ultimate accuracy is to be achieved in the AC- and DC-power measurements, it is important to consider burden effects on the ratio errors and phase displacements (AC) and scaling factors (DC) of the instrument transformers used. Ideally, the instrument transformers are calibrated with the actual burden, taking into account e.g. actual secondary cable and instruments used in the final HVDC converter station measurements. The use of short secondary cables not only reduces possible effects of EM interference as discussed in the previous section, but also helps to realise low burden values for current transformers. Modern precision AC power meters and DC voltmeters pose a negligible burden to the instrument transformers they are connected to, due to the very high impedances of their voltage inputs and low impedances of their current inputs respectively. The high voltage input impedance furthermore is important to minimise voltage divider effects [14] in the secondary voltage measurement chain.

4. Conclusions

The feasibility has been explored for direct determination of HVDC converter station loss by measuring the difference of station output power and input power. For achieving an overall 3 % uncertainty in a typical 1 % station loss power, the AC- and DC-side power measurements each have to achieve better than around 0.017 % uncertainty. Careful evaluation of the respective AC- and DC-power uncertainty budgets show that such uncertainties indeed appear achievable using state-of-the-art commercially available measurement instrumentation. Particular details of the DC-power measurement are the voltage measurement of both the high-voltage and low-voltage busbar, and the current measurement in the low-voltage busbar.

Spurious effects possibly affecting the overall loss measurement accuracy have been carefully evaluated. These include operating conditions, harmonic distortion, measurement position, EM interference, and instrument transformer burden. Several recommendations result from this evaluation, such as the use of short, double-shielded secondary cables and calibration of the instrument transformers with the burden using in the actual HVDC station loss measurement.

In conclusion, this study has shown that direct measurement of HVDC converter station losses, as the difference measurement of AC- and DC-power, indeed is achievable with 3 % uncertainty for HVDC converter station loss power levels of 1 %. This is a significant step forward with respect to the present state of the art for measurement of converter loss, reflected in the two main IEC standards related to HVDC converter losses, where HVDC converter station losses are estimated by summing the losses calculated for each item of equipment. Our proposed approach achieves much better uncertainty and moreover does not rely on assumptions concerning converter station component behaviour nor on the (inherently imperfect) characterisation of these components. It can however not completely supplant previous methods in estimating losses under all pertinent
operating conditions, in particular since the actual operating conditions may not be equal to the conditions for which the HVDC system losses are guaranteed but will then provide a reliable point of reference for these. Ideally, the proposed direct loss measurement should be applied on the entire converter station as a routine measure after delivery, or at least as a validation of the calculation and estimation methods presently used.

5. Acknowledgements
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6. References
Abstract

The modern power system faces the challenge of maintaining stability in weak grids resulting from renewable generation. This is because renewables connect to the grid using voltage source converters (VSC) which lack the inertia and current handling capabilities of synchronous machines. Given that the future of VSC technologies is the Modular Multilevel Converter (MMC), this paper shows that a properly designed MMC system connected to the weak part of a grid can be used to regulate the voltage and frequency. It is shown that the most important contributing factor for fault recovery is the transient current capabilities of the MMC. Both dynamic reactive current prioritization as well as enough active current margin is necessary. Inclusion of an energy storage mechanism allowed storage and release of energy from the MMC to mimic the energy storage behavior of a synchronous machine during faults. The proposed methodology has been demonstrated using EMT simulations.

1. Introduction

Voltage Source Converters (VSCs) using typical control techniques may not be sufficient to withstand disturbances in a weak grid. Therefore, when integrating renewables from remote locations to the AC network via VSCs, it is important to ensure that the VSC component ratings and controls have been designed properly. Most of the solutions discussed in literature look to the synchronous machine as inspiration for their controls. This is because the synchronous machine is able to remain stable in fault conditions due to its high current handling capability and ability to store and quickly release energy in its rotating mass. This functionality is referred to as “synthetic inertia” in power converters and it is becoming a requirement for some TSOs [1].

Many findings in literature have provided synthetic inertia through the idea of a virtual synchronous machine (VSM) in which the synchronous machine dynamic equations are used in the VSC controls to provide a similar performance to the synchronous machine. These methods in literature have investigated modelling the full dynamics of the synchronous machine introduced as VISMA [2], 2nd order model introduced as Synchronverter [3]-[4], or 1st order model introduced as VSYNC or VSG [5]-[6]. These techniques produce the voltage, current or power reference of the VSC respectively [7]. Furthermore, introducing second order swing equations to the VSC controls may even introduce unwanted oscillations similar to electromechanical oscillations of synchronous machines.

Alternative techniques, such as the Inertia Emulation Control (INEC) or Generator Emulation Control (GEC), have been explored which use the dc-link capacitor to provide the energy needed for the synthetic inertia [8]-[9]. However, in order to keep within stable operating limits of the dc-link voltage, larger dc-link capacitors are necessary to provide the synthetic inertia while maintaining the dc-link voltage [10]. Reference [11] proposes a virtual synchronous control (ViSynC) which synchronizes to the grid using the dynamics of the dc-link capacitor. Note that the proposed techniques mentioned above as well as many others proposed in literature use two level VSCs. Therefore, these techniques may not be effective for the future of VSC technology i.e. Modular-Multi-Level converters (MMC) in which there is no dc-link capacitor, but rather a capacitor within each submodule (SM) in the MMC.

KEYWORDS

Frequency, Inertia, Modular Multilevel Converter (MMC), Voltage Source Converter (VSC), Weak grids
More recently there have been research in the area of MMC operation in weak grids. Reference [12] proposes to control the SM capacitor voltages to store energy in the SM capacitors during changes in commanded power. This method supports frequency by mimicking the inertia effect of synchronous machines. The results for severe faults i.e. Three phase to ground (3ph-g) were not presented. Additionally, this method takes the frequency dip as indication to enable the control. The delay associated with reading the frequency could result in a delayed indication from the actual event.

The authors have proposed a control technique for MMCs in weak grids considering the voltage and frequency support individually [13]. Similar to [12], energy storage in the SM capacitors is utilized to provide the support; however, unlike [12] the proposed technique uses the voltage as input to the control which is a more immediate indicator of the fault than the frequency. The excess energy is stored in the submodule capacitors of the MMC during disturbances such as faults. This energy is released immediately upon fault clearance. Note that this immediate support cannot be achieved by absorbing power from the DC side or from the rectifier terminal. A requirement of VSCs connected to weak grids is the high current handling capability during the transients. In order to recover from the faults, a current injection higher than the rated current of the VSC is required. Specifically, a large amount of reactive current injection is required (1.0 pu in the very weak test system used by the authors) in order to get an acceptable voltage recovery and subsequently a significant active current injection around 0.5 pu for the test system used by the authors is required for the frequency recovery. Furthermore, proper coordination of the controllers is required to obtain the right support at the right time. Note that the rectifier side faults were not considered in this analysis. The proposed control methodology is activated only for inverter side faults and therefore it is expected that the VSC will respond as a regular system for the rectifier side faults.

This paper analyses the capabilities of an MMC to provide frequency and voltage support to a weak grid during disturbances. This paper is organized as follows: Section 2 presents the requirements of MMCs connected to weak grids; Section 3 describes the test system; Section 4 presents the results of the tests that were performed to demonstrate the features of the proposed controls; Section 5 shows the performance of the MMC with the proposed control method when subject to terminal faults; and finally the conclusion is presented in Section 6.

2. Requirements of Modular Multilevel Converter Connected to Weak Grids

The basic dynamic requirements of MMCs connected to weak grids are as follows:

2.1. High Transient Current Injections

Synchronous machines are capable of injecting more than 3pu of rated current during system faults. At the recovery, these high currents help the system voltage and frequency to recover quickly. VSC systems are typically capable of handling up to about 1.1 pu of its steady state rating. Based on the types of loads connected to the weak grid, this current may not be enough for the voltage to recover well. In order to improve this, the reactive current prioritization mechanisms are adapted in most of the grid codes. However, this may lead to frequency instability due to less active current support. Therefore, it may be necessary to consider the short term overcurrent capability together with the reactive current prioritization. These requirements are case dependent and should be determined considering the weakest possible network conditions and the worst-case loading conditions. Such an example is discussed in Section 4. Designing converters to handle the same transient currents as synchronous machines is a very expensive approach. The proposed method shows that a seemingly feasible level of transient current capability for future MMC technologies along with proper controls can enable weak systems to successfully recover from a fault.

2.2. Energy Storage Mechanism

A key contribution to voltage and frequency support of a synchronous machine is the release of stored energy at the instant of fault recovery. Although the MMC does not have a rotating mass that stores energy, the voltage and frequency support can be achieved by:

1. **Quick power transfer from the rectifier system**: As soon as the fault is cleared, a large amount of power is absorbed from the rectifier system. The rate of change of power is limited by the DC system and converter...
impedance. Furthermore, most of the inverter-based generation (wind, solar, etc.) or the weak AC systems at the rectifier are not capable of providing a power boost.

2. **Changing the DC voltage:** During the fault, the DC voltage of the system is increased to store the energy in the DC transmission system and in the submodules. The entire system needs to be rated to a higher voltage rating. If required the DC voltage can be reduced temporarily to provide the energy support; however, this capability is limited by the AC/DC modulation index.

3. **Storing energy in the inverter submodules:** During the fault, the inverter submodule voltage is increased to store the energy. In this method the DC link voltage is kept constant however the submodule capacitor ratings should be increased depending on the number of submodules in the MMC and the amount of energy to be stored.

The authors have proposed to store the excess energy during the fault in the converter submodules, and then quickly release the energy at the recovery [13] as described in method 3 above. In order to achieve this the submodules should be able to handle short term overvoltages. Figure 1 shows the concept of energy storage in the inverter during a fault.

Under normal operation of MMC VSC converters, a fixed number of submodules are switched on per phase (i.e. total of upper and lower arm submodules switched on). The total of the voltages across these submodules is equal to the DC voltage. If the DC side voltage is regulated by the rectifier and the number of submodules switched on per phase is reduced at the inverter, these submodules will be charged to a higher voltage during the fault. Using the capacitor voltage balancing logic, all the submodules can be charged to a higher voltage. This mechanism was used to store the energy in the submodule capacitors. If a 500 MW, ±200 kV VSC bipole is supplying 450 MW, a total of 45 MJ is available for storage during a 100 ms solid 3 phase fault at the terminal. For an MMC with 110 sub modules per arm and a sub module capacitance of 10 mF, using (1) and (2) it can be shown that 45.0 MJ of energy can be stored in the converter if the submodule voltage can increase to 3.17kV (submodule voltage is 1.8kV under nominal conditions). It is expected that the manufacturers would be able to design their submodules to have these capabilities. The additional cost and the transient overvoltages would be some of the concerns for the design. It should be noted however that alternative solutions proposed in the literature require much higher ratings [3,4].

Energy stored in a submodule,

\[ E_{SM} = \frac{1}{2} CV^2 \]  

Total energy accumulated,

\[ \Delta E_{Tot} = (#\text{poles})(#SM)(#\text{arms})\Delta E_{SM} \]  

A controller as shown in Figure 2 was added to the low-level controls of the VSC. The controller is activated if the AC side voltage drops below a threshold value (i.e. a fault condition). Under normal operating conditions the controller is tracking the DC current and if the controller is activated, the current is held at the pre-fault current and the PI controller starts regulating the DC current to the pre-fault value by adjusting the number of submodules switched on per phase. When the fault is cleared, the fast controlling actions help to release the stored energy into the system quickly. The performance of the controller is discussed in Sections 4 and 5. Note that reducing the number of SM will not have an effect on the decoupled controls except the increase in transient currents which is accounted for with the increase in the current limit.

![Figure 1 - Energy Storage in Inverter Submodules During Fault](image)

![Figure 2 - Test System](image)
2.3. Controller Design Requirements

Most of the VSM control techniques discussed in literature incorporate the synchronous machine swing equations into the VSC controllers. These controllers depend on the frequency measurements and therefore transient performance cannot be guaranteed since the transient frequency measurements are not accurate (especially at the fault recovery). Our investigations have shown that acceptable performance can be achieved in future VSC MMC technologies (rating requirements specified in Section 4) by having typical VSC decoupled controllers along with the following novel control actions:

- **Voltage support**: A higher transient current rating expected of future MMC technologies along with reactive current prioritization with a carefully chosen limit can be essential to supplement a fast voltage controller with reactive power droop.

- **Energy Storage**: The proposed energy storage mechanism utilizing the submodule capacitors as described in Section II.B can significantly help the transient frequency recovery at the clearance of the fault.

In addition to the proposed control modifications it is recommended to incorporate a power oscillation damping (POD) controller. This addresses the issues of low damped electromechanical oscillations due to small low-inertia generators in weak systems. Additionally, a frequency droop control is an essential part of regulating the frequency in a weak grid. A tight dead-band is added to avoid unnecessary changes of the VSC power output for slight frequency fluctuations. Note that this controller is effective for frequency control after the initial transient period.

The overall control structure used at the inverter is shown in Figure 3 with the controls unique to the proposed technique highlighted in orange. Note that typical DQ controllers define the current limit around 1.1pu but the proposed technique shows the significance of high transient current limit with consideration of active and reactive current contribution. A typical PLL is used to measure the bus voltage angle. Note that the PLL design and tuning may have an impact on the performance of the VSC connected to a weak grid; however, the intention of this research was not to evaluate the PLL performance. The performance of the controllers depends on the system strength and other characteristics such as the loads of the AC system. Therefore, the performance of the proposed controllers was evaluated using a very weak test system described in the following section.

3. Test System

The test system represents a small remote network with a VSC, a small source of local generation as well as some loads connected to the strong AC network through a very weak connection as shown in Figure 4.

To represent the strong AC network a 10 GVA high inertia (H= 5 sec) synchronous generator and a load of about 6 GW was used. The short circuit level at the connection of the strong AC network to the transmission line is 40 GVA. A series R-L branch was used to represent the long transmission line (weak connection) between the strong AC network and the remote system. The R and L values were chosen to get a short circuit level of about 180 MVA at the connection point to the remote system.

The remote system consists of about 600 MW of load; a VSC supplying 450MW and about 100MW of local generation. The loads consist of 200MW of low inertia.
(H=1s) induction motor loads and 400MW of constant P-loads. Most of the reactive power required of the induction machine is supplied by shunt capacitor banks connected at the terminal.

The model assumed a VSC with ±200 kV, 500 MW half-bridge MMC HVDC bipole system with a metallic return. The DC link was assumed to be 50 km long. The rectifier system was connected to a Thevenin equivalent with a SCR of 4. The basic design parameters of the VSC are listed in Table I. The rectifier was assumed to be in DC voltage control and the inverter was in power control. The controllers for the inverter terminal are as shown in Figure 2 and Figure 3. The controller parameters are provided in Appendix A.

The local generation was represented using a 100 MVA synchronous generator with low inertia (H = 2 sec). The purpose of this was to introduce low damped electromechanical oscillations to the system (an additional challenge for the VSC recovery).

With the weak AC connection and the contribution of the local generation, the total short circuit level at the VSC terminal is about 500 MVA (i.e. SCR is about 1.0). The initial powerflow of the system is shown in Figure 4.

The proposed procedure is as follows:
1. Begin with a typical VSC current limit of about 1.1pu. Then, test a range of maximum reactive current contribution levels to determine if any of these conditions result in a successful recovery after a severe fault condition. The reactive current contribution in this test was adjusted from 0.6 to 1.1pu. Consider a 3ph-g fault at the inverter terminal to generate a worst-case fault condition. Ensure that the system recovery satisfies the grid code requirements for the normal operation range as specified in [1], that is between 49Hz and 51Hz.
2. If the grid code requirements are not met for any of the tests in step1 above, increase the transient overcurrent limit and repeat step 1.
3. Continue step 1 and step 2 until grid code requirements are met.

The test procedure was applied to the test system described in Section 3. Figure 5 shows that regardless of the contribution of reactive current, having a total current rating of 1.1pu does not return the voltage to its pre-fault steady-state value.

Next, the same tests were repeated at a total current rating of 1.3pu. The results, Figure 6, showed that if the maximum reactive current limit is between 0.9 and 1.1pu the voltage can return to its pre-fault value; however, it takes about 500 ms from the fault clearance to recover the voltage above 0.7 pu. This may not be acceptable based on the grid code requirements.

### Table I - MMC-VSC Parameters under nominal operation

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of submodules</td>
<td>110</td>
</tr>
<tr>
<td>Submodule voltage</td>
<td>1.8kV</td>
</tr>
<tr>
<td>Submodule capacitance</td>
<td>10,000 µF</td>
</tr>
<tr>
<td>Phase reactor size</td>
<td>50 mH</td>
</tr>
<tr>
<td>Converter Transformer</td>
<td>230/100kV, 300MVA, X=0.2 pu</td>
</tr>
<tr>
<td>DC side Voltage</td>
<td>200 kV</td>
</tr>
</tbody>
</table>

### 4. Test Scenarios for VSC with Proposed control in a Weak Grid

#### 4.1. High Transient Current Requirements

This section proposes and demonstrates using the test system a procedure to determine the requirement of transient current for a specific system. This method investigates successful recovery using practical transient current ratings and reactive current limits.
Then, the system was tested at a current rating of 1.5 pu. It can be seen in Figure 7 that as long as the maximum reactive current limit is 1.0 pu or above, the voltage recovery is acceptable. Note that this indicates that a certain amount of active current is necessary to support the recovery as well. The reactive and active current contributions during and after the fault are shown in Figure 8. The reactive current at the recovery is kept at the maximum by the reactive current prioritization logic and the remainder is used for the active current. If the converter total current rating is 1.5 pu and the maximum reactive current limit is 1.0 pu, there is enough margin for active current to support the recovery.
This analysis concludes that the converter current rating and the maximum reactive current limit determine the system recovery from the faults and these values need to be determined considering the worst-case system conditions. For the test system used, a current rating of 1.5 pu and a maximum reactive current limit of 1.0 pu is suitable and all the tests presented hereafter were carried out using these values.

4.2. Impact of Energy Storage Capabilities

Figure 9 and 10 show the VSC Inverter AC side and DC side response to a 3ph-g fault at the VSC inverter terminal with and without the energy storage mechanism. As seen in Figure 9, the converter stored about 40 MJ during the fault and the energy was released within 300ms from fault clearance. This helped to increase the frequency nadir (initial drop at the fault clearance) from 48.1 Hz to 49.4 Hz. This initial support also helped subsequent frequency recovery. Usually, in weak systems, load shedding schemes are activated if the frequency drops below 0.98 pu (49 Hz). It can be seen that the energy storage will avoid the load shedding in this system. It is also observed that the energy storage mechanism provides support for voltage recovery as well.

Figure 10 shows the effectiveness of the proposed controller mechanism used for energy storage. When the controller is activated, the DC current and DC powerflow almost remains at nominal values during the fault. Because of this, the impact on the rectifier side would also be minimal. The average submodule voltage increases from about 1.8 kV to about 3.1 kV during the fault and is reduced upon fault clearance.

In the above scenario, the energy storage mechanism was limited to 500 ms and if this duration is not sufficient to meet grid code requirements for voltage and frequency under the tested worst-case conditions, then the energy storage can be extended to cover the power oscillations as well. This will help to reduce the impact on the rectifier. Figure 11 shows the system performance with extended energy storage. The rectifier side is almost at the nominal power during and after the fault. This would be very helpful if the rectifier is fed by a weak system or renewable generators. These results also provide an indication of the converter requirements for high transient current and energy storage. Usually, these requirements would also be minimal.
depend on the IGBT capabilities. The maximum IGBT current increased from 1.33 kA to 2.34 kA during the fault and the current stayed at about 2 kA for about 400 ms. As described above, the submodule voltages were increased from a peak value of about 1.91 kV to about 3.18 kV at the maximum energy (~167% increase). If these temporary overvoltages and overcurrents can be handled by the IGBTs the energy storage mechanism described in this paper would be a feasible solution.

in Figure 12. It can be seen that the initial frequency swing is not significantly affected but the subsequent oscillations are damped within a few seconds. For this test all other controllers were kept enabled.

4.4. Frequency Control

The power mismatches in the remote system may lead to large frequency deviations. If the power mismatch is large, the weak AC connection to the strong grid may not be able to handle the excess power transfer. Therefore, a frequency controller needs to be attached to the VSC as shown in Figure 3. A slow PI controller with a “smart dead-band”, as defined below, is used.

If the frequency is deviated more than 0.1 Hz, the frequency controller is activated and when the frequency is reached back within the dead-band, the controller is kept activated for another 100 seconds.

Figure 13 shows the VSC power output and the frequency response for a trip of a 100 MW load in the remote system. If the droop is zero, most of the power mismatch is supplied by the VSC. By having a droop, the power mismatch can be shared between the VSC and the strong grid. If required, a special protection scheme (SPS) can be used to automatically adjust the VSC power reference if a large load or generator is tripped. As an example, the performance of the system with an SPS to adjust the power order by 100 MW when the load is tripped is shown in the Figure 13. The frequency response is improved.

4.3. Power Oscillation Damping

The power oscillation damping (POD) controller attached to the VSC controls was tuned to damp out the electromechanical oscillations produced by the local generator.

The frequency of the AC bus of the inverter was used as an input and a washout block with a time constant of 2s was used to capture the dynamic changes in the frequency. The lead-lag compensation and the gain were determined using small signal stability assessment techniques [14,15]. Note that since the frequency is the input to this controller the response will not be as fast as the energy storage mechanism which releases the energy immediately upon fault clearance. The frequency responses for a 3ph-g fault at the VSC inverter terminal with and without the damping controller is shown in Figure 12. It can be seen that the initial frequency swing is not significantly affected but the subsequent oscillations are damped within a few seconds. For this test all other controllers were kept enabled.

Figure 12 - Impact of Power Oscillation Damping Control at the Recovery of a 3ph-g fault
6. Conclusion

This paper has shown that a properly designed MMC can be used in a very weak system to regulate the voltage and frequency. The most important contributing factor for fault recovery was shown to be the transient current capabilities of the MMC. Both dynamic reactive current prioritization and enough active current margin is necessary. The required current limits and durations are case dependent and they should be determined considering the most critical grid conditions as illustrated in this paper. The recovery can be supplemented by having an energy storage mechanism to store and release energy in the event of faults. This helps the transient frequency drop as well as the subsequent frequency recovery which in turn avoids load shedding. An MMC system as described in this paper showed to recover within acceptable limits defined for unlimited operation duration in the European grid code [1] when recovering from fault conditions. This novel control approach can be extended to other multilevel converters as well.
7. Appendix A

Table II - MMC Controller Parameters

<table>
<thead>
<tr>
<th>PI controller</th>
<th>Kp</th>
<th>Ti</th>
</tr>
</thead>
<tbody>
<tr>
<td>DC voltage (Rectifier)</td>
<td>5.0</td>
<td>0.01</td>
</tr>
<tr>
<td>Power (Inverter)</td>
<td>1.0</td>
<td>0.08</td>
</tr>
<tr>
<td>AC Voltage*</td>
<td>1.0</td>
<td>0.02</td>
</tr>
<tr>
<td>Positive sequence D-axis current control</td>
<td>1.0</td>
<td>0.03</td>
</tr>
<tr>
<td>Positive sequence Q-axis current control</td>
<td>1.0</td>
<td>0.03</td>
</tr>
<tr>
<td>PLL</td>
<td>100.0</td>
<td>20.0</td>
</tr>
<tr>
<td>Frequency Control</td>
<td>4.0</td>
<td>0.05</td>
</tr>
<tr>
<td>POD Control</td>
<td>KPOD = 10.0</td>
<td></td>
</tr>
</tbody>
</table>

**Lead-Lag:**
- T1 = 0.3741
- T2 = 0.0578

**Washout:**
- Tw = 2.0

8. References


9. Biographies

**Malsha S. Annakkage** received a B.Sc. (Eng.) degree from the University of Manitoba, Canada, in 2013 and an M.Eng degree from the University of Toronto, Canada in 2015. She focused her bachelor's and master’s degrees in the energy systems area. Malsha worked at Manitoba Hydro International (MHI) from 2015 – 2017 as a power system specialist. She joined TransGrid Solutions (TGS) in 2017 as a power system specialist.

**Dr. Chandana Karawita** is a professional engineer with both industrial and academic experience in power systems. Dr. Karawita joined TGS in 2007 while doing his doctoral research at the University of Manitoba. He is well experienced in system planning studies related to HVAC, HVDC and FACTS devices. He is also involved
in state-of-the-art custom model development for HVDC and FACTS in both transient stability (PSSE, PSLF) and electromagnetic transient simulation (PSCAD) platforms. Dr. Karawita was instrumental in developing the dynamic phasor based small signal stability analysis package (TGSSR) for analyzing sub-synchronous frequency oscillations in power systems and many other in-house software tools. He actively contributes to various CIGRE working groups related to HVDC and FACTS, and is involved in academic research activities as an adjunct professor at the University of Manitoba.

**Udaya Annakkage** received the B.Sc. (Eng.) degree from University of Moratuwa, Sri Lanka, in 1982 and the M.Sc. and Ph.D. degrees from the University of Manchester Institute of Science and Technology (UMIST), Manchester, U.K., in 1984 and 1987, respectively. He has more than 30 years of experience in research and teaching. He is presently a Professor at the University of Manitoba, Canada. His research expertise is in the area of Power System Dynamics and Control.

**Dr. Hiranya Suriyaarachchi** received the B.Sc. Engineering degree from University of Moratuwa, Sri Lanka in 2003 and M.Sc. and Ph.D. degrees from University of Manitoba, Canada in 2008 and 2014, respectively. Since 2010, he is with TransGrid Solutions where he was involved with a number of HVDC projects in North America, Europe and in Asia. Dr. Suriyaarachchi is actively participating in some CIGRE and IEEE working groups on VSC HVDC technology.
1. Introduction

The traditional AC power system has been dominated by synchronous generation. Two specific properties of this form of generation that have been exploited by power engineers designing AC power systems are:

• the potential energy stored in the inertia of the rotor which can be used to stabilise the AC system frequency and
• the dynamic over-current inherently supplied by a generator when the AC side terminal voltage suddenly drops and/or changes angle.

Today the power system is changing, moving away from the traditional fossil fuel-based thermal generation and moving towards an AC system with a large amount of renewable generation along with an increasing number of DC transmission connections. Renewable energy is commonly connected to the grid via a Power Electronic (PE) interface which does not naturally exhibit the same properties as synchronous generation. Eventually, as the trend to decommission older fossil fuel-based generation in favour of renewable sources continues, there will be less synchronous generation and hence less inertia and less dynamic over-current, unless these can be realized by alternative means.

The increase in PE’s connecting generation to the grid raises the question of whether these PE interfaces can be made to emulate the same behaviour as synchronous machines and thereby, from the AC power systems designer’s perspective, reducing or even eliminating the impact of having less synchronous generation. Some power system utilities have already tried to address this by proposing new grid codes, requiring PE converters.
connecting generation (or energy storage) to the grid to behave as if they were synchronous generators. However, vendors of PE equipment have raised concerns, highlighting the cost impact on the PE equipment of these possible requirements.

Cigre Study Committee B4 (DC and Power Electronics) set up a Task Force, TF-77, with the aim of summarising both the requirements from the AC power system planners/operators and reviewing PE equipment control strategies, to see what could be achieved and the cost impact.

2. Generation or Transmission

Generation, with respect to power systems, refers to the conversion of some form of energy (fossil, wind, solar), into electrical energy. DC transmission is a means of ‘transporting’ electrical real power, that has been generated at one location to a load at another location, in an efficient and controllable manner. The controllability of DC transmission is important as the DC transmission line can act as a barrier, often referred to as a ‘firewall’ between two independent AC systems allowing power flow exchanges to take place so long as they do not impose undue stress on one of the interconnected power systems. If they do, then the DC link can take automatic action to change the power flow. This is advantageous when compared to an AC interconnection of synchronous generation where the dynamic power flow is uncontrolled, potentially leading to a cascading loss of the AC grid from one, initial disturbance.

Since Voltage Sourced Converter (VSC) technology has been introduced to High Voltage Direct Current (HVDC) there has been a tendency to think of an inverter (the receiving terminal) as a source of generation within the AC power system to which it is connected (this is illustrated by the change in sign of power from IEC 60033, where a LCC rectifier puts positive current into the DC system, to IEC62747 where a VSC takes positive current from the DC system). This is leading to proposals that future VSC converters should respond to AC system events in a way that emulates a synchronous machine providing inertia and fault current in the event of an AC system disturbance.

A DC transmission link has little inherent energy storage [1] and so, a response to a sudden demand in power flow at one end of a DC link will be rapidly transferred to the other terminal and on to the other AC system. If the other AC system is not able to accommodate the change in power demand, the DC link cannot respond. The amount of inherent storage in a DC transmission link (valves or transmission cable) is very small compared to both the requirements and capabilities of the connected AC grids. The main decision to be made is, therefore, the economically feasible level of over-capacity that can be justified in DC transmission links.

Typically, energy can be taken from interconnected networks in the same manner as AC interconnections. This approach has been well proven on a number of LCC HVDC interconnections using frequency or power angle feedback, for example Nelson River, New Zealand, Basslink and more recently INELFE. During network stress situations, usually only one of the connected networks is stressed and for the other, the disturbance appears as a typical load perturbation. Should future grid need demand that DC transmission links themselves be able to supply real power, beyond today’s capability, then this will necessitate a substantial change in converter design to include the additional energy storage elements such as batteries or super-capacitors which will lead to extra cost and, in some circumstances, to commercial conflicts between whether the DC link is a transmission asset or a generation asset. Provision of such additional ancillary services by DC links may some time even erode their commercial viability, if these are not properly accounted for and evaluated.

Today, it is possible to increase the energy rating of a VSC by increasing the number of sub-modules in series in each valve. This technique can be used to provide, for example, Power Oscillation Damping (POD) to the grid [1] but at the expense of additional sub-modules, resulting; increased capital cost, increased losses and increased footprint. Moreover, the energy density of VSC sub-modules is not adequate for applications that require multi-second supply of power such as frequency stability support.

3. Grid-Connected and Grid-Forming

Most PE converters today operate on the principle that there is already an existing AC system and the converter controller ‘locks’ to the phase of the AC voltage as its reference, referred to as ‘Grid-Following’. Real and
The following example can be used to illustrate the operating limit of a Grid-Following HVDC scheme. Below is a simulation of a 1 GW HVDC link connected to two equivalent networks (SCL1 = 1 GVA and SCL2 = 1.5 GVA). At t = 1 s, the breaker BRK1 opens which reduces the SCR from 2.5 (weak network) to 1.5 (very weak network).

The results illustrated in Figure 2 show the instability of the Grid-Connected control on the active and reactive power and also on the voltage at the connection point (Vpcc).

A second basic type of converter control is referred to as ‘Grid-Forming’. The basic idea of a Grid-Forming converter is that it can create an AC voltage with a controlled magnitude and frequency at its AC terminals in the absence of another source of AC voltage; hence, it can supply a passive load.

Consider offshore AC wind turbines connected to the onshore grid via VSC based HVDC transmission. Commonly, the HVDC offshore converter operates to create an AC voltage with a controlled frequency at its point of connection; this becomes the offshore AC bus reference. The PE converters associated with each wind turbine will lock on to the AC voltage created by the HVDC VSC. Hence, in this example, the offshore VSC converter reactive power flow is then a function of the magnitude and angle of the voltage produced by the converter with respect to the magnitude and angle of the voltage reference, from where the controller is taking its reference measurement. Often this type of controller is based on a Phase-Locked Loop (PLL) and uses a ‘vector-based control’ approach. Such an approach assumes that the grid reference voltage is insensitive to the current produced by the converter, and hence the real and reactive power can be simply and independently controlled by regulating real and reactive components of the converter current. However, the impedance of the equivalent AC network, as seen by the converter, increases (that is the Short Circuit Level, SCL, reduces), the interaction between the converter output current and the grid voltage at the point of connection increases, making stability of the controller harder to achieve. This means that this type of controller typically has a minimum Short Circuit Ratio (SCR) [2] at which the controller can stably operate. Inherently, therefore, this type of control requires an existing AC system, with a certain minimum SCL, for the controller to lock on to.

According to [2], the SCR is defined as:

$$SCR = \frac{SCL}{P_{HVDC}}$$

where the strength of the network is classified as follows:

- Strong network, if the SCR is greater than 3
- Weak network, if the SCR is between 3 and 2
- Very weak network, if the SCR is less than 2

The analytical analysis related to this instability between Grid-Connected control and a very weak network is presented in [3].

A second basic type of converter control is referred to as ‘Grid-Forming’. The basic idea of a Grid-Forming converter is that it can create an AC voltage with a controlled magnitude and frequency at its AC terminals in the absence of another source of AC voltage; hence, it can supply a passive load.

Consider offshore AC wind turbines connected to the onshore grid via VSC based HVDC transmission. Commonly, the HVDC offshore converter operates to create an AC voltage with a controlled frequency at its point of connection; this becomes the offshore AC bus reference. The PE converters associated with each wind turbine will lock on to the AC voltage created by the HVDC VSC. Hence, in this example, the offshore VSC converter

![Figure 1 - Illustration of a Grid-Following converter coupled to a weak network](image1)

![Figure 2 - Grid-Connected MMC - switching to a very weak network](image2)
is Grid-Forming whilst the converters associated with the offshore wind turbines are Grid-Following.

The terminologies for VSC operation modes are widely used but lack any strict definition. The Task Force adopted the following definitions:

- A **Grid-Following** (or Grid-Connected) converter is one that matches the AC grid voltage and frequency and can provide reactive current equal to the steady-state rated current during AC faults.

- A **Grid-Forming** converter is one that can regulate both instantaneous AC frequency and AC voltage. Such a converter is also able to provide reactive current equal to the steady-state rated current during AC faults.

- A **Synchronous Grid-Forming** converter is a Grid-Forming converter that is also able to operate in parallel with other AC frequency regulating equipment and converters.

- A **Virtual Synchronous Machine** (VSM) is a (Synchronous) Grid-Forming converter with energy storage capable of delivering additional energy for a short period of time, from the converter rather than the DC link and rated to provide a current greater than the steady-state rated current during a fault.

The Task Force identified that while Grid-Following and Grid-Forming VSC converter systems are widely available, the next step to Synchronous Grid-Forming converters is a challenging topic for future development.

### 4. Short Circuit Current

When an AC system fault occurs, a synchronous generator will inherently produce a large fault current, typically around 6 pu, which can be accommodated by the large thermal mass of the machine without incurring damage to the machine. Whilst this fault current can be problematic for the grid in terms of the maximum fault current to be interrupted by AC switchgear, the fault current can also provide some benefit to the AC system, namely:

- At locations some electrical distance from the fault, the fault current flowing through the impedance of the AC system will raise the AC voltage, improving the AC voltage profile of the AC grid during the fault, and

- Measurement of the high fault current can be used to detect the presence of the fault and initiate protective actions.

PE’s have negligible thermal mass and are, therefore, unable to carry large temporary currents. The short-term and steady-state current carrying capability of a PE converter is very nearly, the same value. Hence, a converter that has been designed and optimised for a particular voltage and current will not be able to respond to a disturbance by providing more than rated current. In some cases, dependent on the angle of the current, it may be necessary to reduce the current to less than the rated value in order to remain within the internal voltage rating of the converter. Hence, to mandate PE converters to supply fault current beyond their rated current capacity would require their effective rating to be increased. This would, therefore, require the installed converter to have a higher rating than its steady-state duty, that is, it would normally be operated with a curtailment, leading to increased capital cost, losses and footprint.

In a practical sense, it is not cost effective to overrate the capacity of all PE converters so that they can deliver high fault currents into an AC fault, equivalent to the behaviour of a synchronous machine. However, converter controllers could be configured to respond to drops in AC voltage by providing additional reactive current, up to their rated capacity. Assuming that not every PE converter is operating at its maximum capacity prior to the fault then the net additional current from the PE converters remote from the fault will help to improve the net voltage profile of the AC grid.

### 5. Fast Fault Current Response

If there is a sudden loss of generation within the AC grid the remaining generation must compensate by providing additional real power. In a synchronous generator dominated AC system the additional power, initially, is provided from the inertia of the synchronous generators and therefore responds ‘instantaneously’ to the AC disturbance. Taking energy from the inertia of the synchronous generators will result in these generators slowing down; that is, the AC frequency will start to fall. Within the AC system there will be load-shedding protection schemes co-ordinated with the maximum permissible Rate-of-Change-of-Frequency (RoCoF) aimed at tripping out load as the frequency falls to preserve the AC frequency.
therefore, has an inherent delay. In future, it may be possible to design PE controllers to apply current limits in such a way that the response time of the converter, within its current limit, is minimised.

6. Synchronicity

An intrinsic property of a synchronous machine is the coupling between the power system frequency and the imbalance between the electrical and mechanical torques applied to the rotor of the synchronous machine. The coupling of the rotating mass equation with the power flow on an inductive line creates a synchronising torque between interconnected synchronous machines, which results in the system typically being stable following a disturbance. Grid-following converters will act to maintain their output current and therefore not provide additional synchronising power. However, after fault clearing synchronous machines can cause undesired power oscillations. Grid-following converters normally do not participate in low frequency power swings, although they can provide additional damping to the system if requested. Hence, if PE converters were to completely mimic the behaviour of synchronous machines it is expected that this natural immunity to low frequency oscillations would be lost.

7. Benchmarking

To understand and quantify the issues associated with PE converters connected to the AC grid and to test future control strategies that could be used in PE converters, the TF proposed a test circuit, Figure 3.

From an AC system perspective, the ‘ideal’ response to an AC system fault would be to mimic the behaviour of a voltage source behind an impedance, Figure 3a. This will be an instantaneous response with the consequential current flow as a function of the voltage difference across the equivalent converter impedance and the impedance itself. However, unlike synchronous machines that have a large thermal mass and can, therefore, be subjected to short periods of large excess currents without incurring damage, PE’s have practically no thermal mass and are very sensitive to excess current. For this reason, most converter controllers operate on a principle of primarily controlling the current flowing through the PE’s, Figure 3b. In the event of a system disturbance, the first response of such a controller would be to hold the current to its present value and then, based on measurement of the change in AC voltage, change the current demand of the converter. This response, therefore, has an inherent delay. In future, it may be possible to design PE controllers to apply current limits in such a way that the response time of the converter, within its current limit, is minimised.

Figure 3 - Simplified model of a VSC converter
(a) Using voltage control (b) Using current control
9. Further Work
The TF recommends that further investigations are undertaken, specifically related to the implementation of converters associated with DC transmission. These further studies should consider:

- The development of a concise set of requirements appropriate to HVDC converters.
- The finalisation of a test bench simulation circuit to permit the comparison of synchronous generation dominated AC grids to PE dominated AC grids.
- Based on the test bench identify, through simulation, the inherent capability of HVDC converters considering different control modes.

8. Conclusion
The TF set out to provide an understanding of how the AC grid is changing through the transmission from mostly fossil fuel driven synchronous generation to renewable resources connected through PE. If also addressed the question of how converters associated with DC transmission can contribute to the stability of the AC grid.

As a result of the on-going changes in AC grids, some proposals have been made to impose new requirements on to future PE converters including those associated with DC transmission. In this paper the TF has attempted to identify how PE technology differs from synchronous generation and consequently, how trying to make PE converters replicate synchronous machine behaviour can have an impact on converter cost, losses and footprint. The impact of these changes should be fully analysed before imposing such requirements.

10. Reference
Abstract
This paper is focused on the study of the harmonics generated by a power flow controller (PFC) in a meshed multi-terminal direct current (MTDC) grid. The main goals are to identify their importance and relation to the switching frequency of the PFC and to study the harmonic propagation throughout the grid. Simulations of a model with realistic offshore grid parameters are performed in MATLAB/Simulink. Results show that the amplitude of the harmonics created by the PFC in the MTDC grid varies in size depending on the PFC switching frequency and on the type of resonance between harmonics and the impedance-frequency response of the grid. Furthermore, the amplitude of the harmonics decreases along the cable. In the case study considered, it is necessary to choose the PFC switching frequency well and to include filtering at the PFC outputs to avoid high-amplitude harmonics.

1. Introduction
The growth of electrical power demand has boosted the development and the implementation of DC high voltage transmission systems (HVDC) with the objective of interconnecting different grids or exploring further energy sources [1]–[3]. In any case, the integration of AC and DC systems is not trivial because of the intrinsic constraints of the already-installed AC transmission system. In this context, several works have been done using multi-terminal direct-current transmission systems (MTDC) as a solution, including meshed MTDC grids which increase the system’s robustness [3] [4].

The implementation of such systems creates critical challenges mainly in its operation and control. Some of the principal challenges are dealing with the dynamic behavior, its stability, its protection and the power flow control [5]. In the special case of meshed MTDC grids, parallel paths allow power to flow between two terminals (AC/DC converter). Depending on the cable resistances and on the operating point, some cables are subject to overloading while others are used far below their current capacity [6]. In this context, it is very important to be able to control the power flow and the currents in each path of the meshed grid. To meet this challenge, as the solutions available for AC grids (FACTS, phase shifting transformers…) cannot operate in DC grids, DC/DC power flow controllers (PFC) have been introduced [6]. The converter under consideration in this study was introduced in [7]. The voltage between its output and input, which is the origin of the harmonics, changes from 0 to a constant value following the fixed switching frequency. The harmonics can be transmitted to the grid and to the substations. If the harmonics amplitudes are high, the consequences are greater power losses due to frequency related effects, such as the skin effect, and equipment damage [8]. However, to our best knowledge, the evaluation of harmonics created by PFC in meshed HVDC grid has not been considered in the literature: in the papers dealing with PFC, cables are usually modeled as resistances or resistances in series with inductances and substations are often considered ideal voltage sources.

In this paper, simulation-based results will be explored to understand how PFC harmonics affect the behavior of the MTDC grid. The simulation is based on models of a MTDC grid, with cable models (models taking into account capacitive effects and propagation), conversion-station models as the equivalent DC-side impedance of MMC converter and ideal PFC models created in MATLAB/Simulink software. In section 2, the modelling of cables, AC/DC converters stations and PFC

KEYWORDS
Harmonics, High Voltage Direct Current, Modular Multi-Level Converter, Multi-terminal Direct Current, Power Flow Controller.
is presented, and the simulation parameters are defined in order to simulate a realistic offshore system. Then, time and frequency analyses of the considered MTDC grid currents and voltage are performed in section 3 and section 4. Finally, the harmonics propagation throughout the cables is analyzed in section 5.

2. Simulation methodology and parameters

The system to be studied and simulated is a multi-terminal direct current (MTDC) grid as presented in Fig. 1.

![Figure 1 – Considered MTDC grid topology](image)

This system is composed of three AC/DC converters, two DC/DC power flow controllers and six transmission cables. All the components in blue color represent the positive quantities and those in red color represent the negative quantities.

2.1. Cables

The first step to simulate a MTDC grid is to define a model of its respective cables. In the case of PFCs switching at frequencies up to 5 kHz, one needs to define a model valid up to several times this frequency to take harmonics into consideration. In this work, cascaded pi-sections were implemented. The maximum frequency at which this model can represent a real cable depends on the number of cascaded sections and on its length following (1) [9].

\[ f_{\text{max}} = \frac{N \cdot \nu}{8 \cdot l_{\text{tot}}} \]  

(1)

Where \( N \) is the number of sections in cascade, \( \nu \) is the propagation speed given by (2) in kilometers per second, and \( l_{\text{tot}} \) is the total length of the line in kilometers.

\[ \nu = \frac{1}{\sqrt{l \cdot c}} \]  

(2)

Where \( l \) is the distributed inductance parameter of the cable and \( c \) is the distributed capacitance parameter.

In this case study, the paths are modeled as DC cables with parameters presented in table I [10]. Furthermore, the number of cascaded pi-sections of each cable is given by (1). The \( f_{\text{max}} \) is set as five times the PFC switching frequency in order to obtain the correct impedance-frequency response up to the 5th harmonics. These parameters were chosen with the aim of performing a simulation of a realistic MTDC offshore system.

<table>
<thead>
<tr>
<th>Cable 1</th>
<th>Cable 2</th>
<th>Cable 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length (km)</td>
<td>0.095 Ohms/km</td>
<td>0.0135 ( 10^{-6} ) F/km</td>
</tr>
</tbody>
</table>

Table I – Distributed Cable Parameters

2.2. DC/DC Power Flow Controller.

The PFC used in this simulation is composed of a capacitance and four voltage-reversible switches, each one being realized with an IGBT and a diode connected in series [6]. The topology is presented in Fig. 2.

![Figure 2 – PFC Structure](image)

In this modeling, all components are considered to be ideal. The switching frequency of this PFC can reach 5 kHz. However, in the simulations performed, the PFC is operated with various switching frequencies between 840 Hz and 1500 Hz. The duty cycle used in all simulations is 0.7.
To obtain a given operation point of the grid, the power absorbed by conversion stations MMC2 and MMC3 is regulated by a feedback loop containing an integrator. In the same way, MMC1 is operated as a slack bus and its average voltage is maintained at a constant value. While MMC 1 is modelled as a DC voltage source at ±160 kV, constant power flows of 120 MW and 100 MW are set for MMC 2 and MMC 3 respectively.

### 3. Time response of MTDC grid with PFC

Operating a PFC in an MTDC grid changes the average value of its currents as showed in Fig. 4. In addition, harmonic currents are observed while PFC is on (Fig. 5).

**Figure 4** – Current flowing in the cable 1 with the PFC activated at t=3s with a duty cycle of 0.7 and a switching frequency of 1300 Hz

**Figure 5** – Current flowing in the cable 1 with PFC on

### 4. System Impedance-Frequency Response

To understand the behavior of harmonic currents in the MTDC grid, it is important to analyze the impedance of the MTDC system at the PFC outputs 1 and 5 according to Fig. 3 (Fig. 6 and Fig. 7).
The first resonance of the MTDC grid impedance at point 5 is around 845 Hz and, for point 1, it is around 1300 Hz. Furthermore, the grid impedance-response is minimal when frequency reaches 1250 Hz for point 5 and 1640 Hz for point 1. Operating the system at one of these frequencies can induce disturbances in current and voltage behavior. Figure 8 and Figure 9 show the FFT of the current that flows in cable 2 (Fig. 1) while DC/DC power flow controller operates at a switching frequency of 845 Hz and 1250 Hz respectively. Comparing these results, it is obvious that the fundamental is filtered due to the high impedance of the line at 845 Hz. Otherwise, while the PFC operates at 1250 Hz, harmonic currents have greater magnitude and they are mainly related to the fundamental, reaching a THD of 2.64%. This shows clearly the relation between the PFC switching frequency and the harmonic currents generated in the MTDC grid and the importance of the switching frequency of the PFC. Note that this choice also impacts the sizing of PFC elements (capacitor value in particular).

5. Harmonics Propagation

In order to understand the harmonic distribution throughout the cables, cable 1 is separated into three parts (Fig. 3). This way, the voltages can be measured at four different points (1, 2, 3 and 4) as presented in Fig. 10. It is obvious that the harmonics do not have a uniform distribution throughout the cable. The presence of harmonic attenuation is clear, and it depends on the distance considered. Anyway, the amplitude of harmonic voltages is still high, even 20 km from the PFC as presented in table II.
Table II - Voltage Harmonics Distribution at switching frequency of 1300Hz

<table>
<thead>
<tr>
<th>Distancea</th>
<th>0</th>
<th>6.67</th>
<th>13.34</th>
<th>20</th>
</tr>
</thead>
<tbody>
<tr>
<td>Harmonic order</td>
<td>Magnitude (V)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1st</td>
<td>3043.05</td>
<td>2818.91</td>
<td>2364.56</td>
<td>1714.61</td>
</tr>
<tr>
<td>2nd</td>
<td>1477.55</td>
<td>2078.83</td>
<td>1910.35</td>
<td>1029.14</td>
</tr>
<tr>
<td>3rd</td>
<td>103.39</td>
<td>84.87</td>
<td>26.15</td>
<td>48.32</td>
</tr>
<tr>
<td>4th</td>
<td>40.78</td>
<td>4.11</td>
<td>20.97</td>
<td>40.78</td>
</tr>
<tr>
<td>5th</td>
<td>75.64</td>
<td>24.58</td>
<td>10.74</td>
<td>16.53</td>
</tr>
</tbody>
</table>

a: km, from PFC to MMC 2 in Cable 1+

6. Conclusion

In this paper, the harmonics generated by a PFC operating in an MTDC grid are studied based on a MATLAB/Simulink model. The cables are modelled as cascaded pi-sections and the MMC converters are represented by their DC-side equivalent impedance while the PFC is modelled with ideal components. It shows that the operation of a PFC in an MTDC grid generates critical harmonics of decreasing amplitude along the cable. For large distances, the harmonics still have great magnitudes despite the attenuation. In this case, it is important to choose the PFC switching frequency well according to the grid impedance. Moreover, the implementation of filters at the PFC outputs is likely to avoid high-amplitude harmonics. Finally, in further studies, the modelling of skin effects in cables should be taken into consideration.

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8. References


9. Biographies

Benhur Zolett was born in Erechim, Brazil. He is an energy engineering undergraduate student at the Federal University of Rio Grande do Sul (UFRGS), Brazil. In 2016, he was selected for the Eiffel Excellence Scholarship Program of the French Government. Benhur Zolett was an exchange student at École Centrale de Lyon from 2016 to 2018, when he completed the core courses of the École Centrale de Lyon engineering degree.

Yaocheng Li was born in China in 1996. He received B. Eng. degree in electrical engineering from the Southwest Jiaotong University (SWJTU), Chengdu, China, in 2018. From 2016 to 2018 spring, Yaocheng Li was an exchange student at École Centrale de Lyon. He is currently working towards the Ph. D. degree in Shanghai Jiaotong University. His research is on incipient fault in distribution system.
This paper presents a real-time co-simulation model suitable for analysing electromagnetic transients in a power system. The co-simulation model contains an Electromagnetic Transient (EMT) and a Transient Stability (TS) model. The interface between the two models is a portion of the network (“buffer zone”) modelled using Dynamic Phasors (DP). The need of Frequency Dependent Network Equivalent (FDNE) in EMT-TS co-simulation is avoided by using a dynamic phasor buffer zone. The challenges of interfacing EMT-DP and DP-TS are properly addressed in this paper. A data prediction method is used to overcome the time-step delay between EMT and DP models. The TS part of the simulation is carried out using a relatively larger time-step than DP and the problems caused by using two different time-steps are overcome by updating the DP-TS boundary voltages in the buffer zone at every DP time-step. The proposed method is numerically robust and efficient. IEEE 68 bus system with an LCC HVDC in-feed is simulated using the proposed co-simulation model and the results are validated using a complete EMT simulation, which is the best possible benchmark to compare results of the co-simulation model. The co-simulation model shows promising results under disturbances applied in the EMT model.

1. Introduction

Transient Stability (TS) studies and Electromagnetic Transient (EMT) studies are commonly used to analyse the dynamic behaviour of a power system. TS studies focus on slow electromechanical transients neglecting the fast electromagnetic transients in the system. The frequency bandwidth of a TS model falls into a narrow low-frequency range and therefore a relatively larger time-step (usually varies between 1ms to 10ms) is used in simulations. Due to the relatively large time step and the simplified models used, TS models can simulate large power systems containing thousands of buses [1]. The Electromagnetic Transient (EMT) models are the most accurate models available to study the transients in power systems. It can model the dynamics over a wide range of frequencies. It works with instantaneous voltages and currents. EMT models continuously follow the trajectories of the states of the system and therefore they need a very small time-step (e.g. 50μs) [2]. Thus, electromagnetic simulation programs can be computationally demanding to analyse large power systems [3].

Co-simulations (also known as hybrid simulations) are used to analyse electromagnetic transients in a large power system. Here, the power system is divided into two sub-systems. The study-zone that requires detailed studying is called the internal system and it is modelled using an EMT model. Rest of the system is called the external system and it is modelled using a TS model. Detailed modelling is used for transmission lines, machines and loads in the internal system and it may contain power electronic devices. EMT is a high-frequency model and TS is a low-frequency model. Frequency-Dependent Network Equivalent (FDNE) is one of the methods used to interface the low-frequency TS model to the EMT model. In this approach, FDNE represents the high-frequency behaviour of the external system and the TS model represents the low-frequency behaviour of the internal system.
frequency electromechanical behaviour. FDNE is a fitted admittance of the external system derived using the frequency response of the system using curve-fitting techniques [4]. Deriving an FDNE for the particular network being studied is an extra step that the user has to perform. The user must have a specialized knowledge to design the FDNE for a particular system. Automating the procedure to derive a system equivalent is also difficult [5]. Deriving the FDNE for a multiport connected system is a more challenging task. The accuracy of the simulation depends on how well the FDNE is tuned. The fitting methods that are used to generate the FDNE model tend to give non-passive models [6]. Passivity is a necessary requirement for the numerical stability of a simulation [7], [8]. Passivity enforcing methods require additional computations [9]. Considering the difficulties and complications of FDNE an alternative approach has been investigated in this paper.

The purpose of this work is to model a large power system using an EMT model (for the internal system) and a TS model (for the external system) without using an FDNE at the boundary buses. FDNE is avoided by using a Dynamic Phasor (DP) model of the interfacing “buffer zone” of the network, which can capture network dynamics. The accuracy and efficiency of the simulation can be significantly improved by using DP to model the buffer zone between EMT and TS. The concept of using a buffer zone is first reported in dynamic system equivalencing in EMT simulations [10], [11]. The same idea is extended in our work by using DP as the surface layer of the interface between the EMT-TS co-simulation. The high-frequency signals in the EMT system will travel only a short electrical distance due to high attenuation. Therefore, the interactions of the high-frequency signals with the external system can be accurately modelled by modelling the buffer zone using DP. At the low-frequencies, it is necessary to include both internal and external system dynamics. In [9], a transmission line connected between the EMT model and the TS model is modelled using DP. It has been shown that high accuracy can be gained by doing so. However, it is not always possible to find a single transmission line connecting two sub-systems. In order to find such a transmission line, the partitioning has to be done selectively. It will be convenient for the user if a multi-port buffer zone is allowed. A larger buffer zone will also improve the accuracy of an EMT-TS co-simulation.

In this paper, a multi-port buffer zone connecting EMT and TS simulations is modelled using DP. The buffer zone contains transmission lines and loads. The interfacing challenges in an EMT-DP-TS co-simulation are discussed in detail. Usually, the EMT solver runs separately from the DP model. Hence, if one needs to interface a DP model with the existing EMT solver the time-step delay due to the latency in exchanging data between the models has to be handled properly. In this paper, the numerical stability in EMT-DP and DP-TS is studied. The numerical instability caused by using a large time-step in TS is analysed and addressed properly.

The IEEE 68 bus system [12] with an HVDC in-feed is used as the test system. The proposed co-simulation model is validated using a real-time EMT simulation done on RTDS. This is the best possible benchmark to compare the results since the entire system can also be modelled using EMT. The rest of the paper continues as follows. The scope of the paper is summarized in Section 2. In Section 3, the interface challenges are analysed. The necessary building blocks of the proposed co-simulation model is presented in Section 4. The implementation of the proposed model is described in Section 5 and the results are presented in Section 6.

2. Scope of the Paper

The scope of the paper is summarized below:

a) The purpose of the proposed method is to study the dynamics in a portion of a large power system. The interested portion of the network is referred to as the internal system of the large power system. The internal system is simulated using EMT. Any low-frequency interactions between the internal and external systems are necessary for planning and design studies. Therefore, in this paper, the external system is modelled using a TS model that is capable of capturing those frequencies. The common industry practice of using a system equivalent can be replaced with the proposed method to produce reliable information on controller interactions and electromechanical oscillations.

b) The available co-simulation models use FDNEs at
their boundary between EMT and TS. As discussed in Section 1, FDNE has to be tuned in order to get accurate results. Tuning an FDNE for a multi-port boundary is a time-consuming task that the user has to perform. Therefore, this paper uses a DP modelled buffer zone to avoid the use of FDNEs. The goal is not to propose a method superior to FDNE, but a method that is convenient to the user. The proposed method is therefore validated against a complete EMT simulation.

c) We consider simulating a multi-port connected buffer-zone using DP and the size of the buffer zone and the number of interface nodes are not limited in this work.

d) In addition, the goal is to perform real-time simulations.

3. Interfacing Challenges of the Proposed Co-simulation Model

Interfacing different simulations can be challenging due to reasons such as (a) different frequency bandwidth, (b) time-step delay between the models and (c) two different time-steps of the models.

3.1. Achieving a Numerically Stable EMT-DP Interface

The cause of possible numerical instability of EMT and DP interface is the time-step delay in transferring data between the two models. Since EMT and DP run as separate solvers, the latency in exchanging data can make the simulation unstable. The instability issue in EMT-DP simulations is discussed in [13], [14] and [15]. Some solutions to overcome numerical instability due to time-step delay are given in [16]. Among these methods, the natural delay in a travelling wave in a transmission line has been used intensively in EMT simulations. It is also used in [14] to interface DP to an EMT simulation.

In [17], it was shown that using extrapolation of data the numerical instability due to time-step delay could be avoided in EMT simulations. In [15], linear extrapolation method is used to overcome the time-step delay in the EMT-DP interface. The same method is used in this work to interface EMT and DP. The same integration time step is used in both sides to have a robust interface. Longer time steps in DP side sometimes result in numerical instability. This is acceptable as the computational advantage is obtained by using a longer time step in the TS part of the network. The DP portion is a only a buffer and it is a relatively small part of the network.

3.2. Achieving a Numerically Stable DP-TS Interface

The challenge of interfacing TS and DP components is caused by their different time-steps. In [18], authors have shown that depending on the input impedance between TS and DP models the interface can only be stable either as a voltage source or as a current source. Since TS is a slowly varying model the time-step delay in communication with the DP model does not have an effect on numerical instability. However, higher time-step in the TS side results in instability problems [19]. Let us define the time-step of DP as $h_s$ and the time-step of TS as $h_t$. It should be noted that $h_t$ is much larger compared to $h_s$. The theory in [18] does not hold when one of the DP or TS component is modelled using a larger time step. The Section 3.2.1 below is added to clarify this further.

3.2.1. Analysis of Requirements for Numerical Stability with Interfacing Different Time-step Models

Let us consider a simple circuit with TS and DP sides with a voltage source and an RL branch. Figure 1 shows results with different time step ratios of DP-TS simulation. Figure 1-a shows the results for TS:DP ($h_t / h_s$) ratio of 1 and Figure 1-b shows the results for $h_t / h_s$ ratio of 20. As it can be seen from the figure, higher the time-step ratio more unstable the system will be. The ratio of the impedances between the TS and DP models decides whether the system is stable for a particular time-step. Figure 2 shows the results with different impedance ratios between DP and TS. Figure 2-a shows the results for TS:DP ($Z_{DP} / Z_{TS}$) ratio of 3 . Figure 2-b shows the results for $Z_{DP} / Z_{TS}$ ratio of 6 for the same unstable case with $h_t / h_s$ ratio of 20. The simulation become more stable with a higher resistance at the DP side. Therefore, most reliable solution would be to update boundary voltages every $h_t$ time-step for numerical stability since we cannot control the ratio of $Z_{DP} / Z_{TS}$. 


Let us partition the current vector as $\mathbf{I}$, and $\mathbf{I}_D$, where $\mathbf{I}$ is the vector containing current injections from the DP side and $\mathbf{I}_D$ is the vector containing the machine currents in the TS model. The vector $\mathbf{I}$ contains the current injections in the internal nodes at the TS side. The voltage vectors also follow same naming order and $\mathbf{V}$, $\mathbf{V}_D$, and $\mathbf{V}_R$. The voltages at the boundary bus at time $t$ can be written as:

$$\mathbf{V}_D(t) = \mathbf{Z}_{pp} \mathbf{I}_D(t) + \mathbf{Z}_{pq} \mathbf{I}_R(t) + \mathbf{Z}_{pr} \mathbf{I}_T(t)$$

(5)

During one TS time-step, The values of $\mathbf{I}_D(t)$ and $\mathbf{I}_R(t)$ do not change. The value of $\mathbf{I}_T$ changes in every DP time-step. Therefore, the voltage vector at $t = t + h_s$ can be written as:

$$\mathbf{V}_D(t + h_s) = \mathbf{Z}_{pp} \mathbf{I}_D(t) + \mathbf{Z}_{pq} \mathbf{I}_R(t) + \mathbf{Z}_{pr} \mathbf{I}_T(t)$$

(6)

By subtracting (6) from (5),

$$\Delta \mathbf{V}_D = \mathbf{V}_D(t + h_s) - \mathbf{V}_D(t) = \mathbf{Z}_{pp} (\mathbf{I}_D(t + h_s) - \mathbf{I}_D(t))$$

(7)

$$\Delta \mathbf{V}_D = \mathbf{Z}_{pp} \Delta \mathbf{I}_D$$

(8)

Equation (8) is solved in every DP time-step ($h_s$) and $t \neq jh_s$; where $j$ is a positive integer and $h_s$ is the time-step of the TS model. The number of calculations needed to solve (8) is independent on the number of nodes in TS but depends on the number of TS-DP boundary buses. In every DP time-step, the DP-TS boundary bus voltages are updated by adding the term $\Delta \mathbf{V}$ calculated in (8). For an example, if there are four boundary buses between TS and DP with shunt impedances and transfer impedances on the buses, there is only a 4x4 matrix to vector multiplication required for the calculation.
4. Proposed electromagnetic transient-transient stability co-simulation model using dynamic phasors

4.1. DP solver

DP is a phasor type simulation model. The dynamic phasor \( U(t) \) of a signal \( u(t) \) is expressed as the complex envelop \( (u(t)) \) of the signal shifted from the fundamental frequency \( (\omega_0) \).

\[
U(t) = u_+(t)e^{-j\omega_0 t}
\]

(9)

The derivative of the signal (9) is modelled in dynamic phasors as (10). Compared to a TS model there is an additional term \( \frac{d}{dt}U(t) \) modelling the dynamics.

\[
\frac{d}{dt}u(t) = \frac{d}{dt}U(t) + j\omega_0 U(t)
\]

(10)

Using this property, differential equations for a capacitor (capacitance = \( C \)) and an inductor (inductance = \( L \)) in a network can be represented using (11) and (12).

\[
I_c(t) = C \frac{d}{dt}V_c(t) + j\omega_c CV_c(t)
\]

(11)

\[
V_L(t) = L \frac{d}{dt}I_L(t) + j\omega_e UL(t)
\]

(12)

The signals \( I_c(t), I_L(t), V_c(t) \) and \( V_L(t) \) are phasors that change continuously according to (11) and (12). In this work, only positive sequence fundamental frequency dynamic phasors are used.

4.2. Interfacing EMT and DP Solutions

All simulations run in parallel and after each time-step, the solution of each simulation model is sent to the model connected to it. In EMT model, DP side is represented as a current source at each boundary bus. At every time-step, current source values are updated using the DP solution.

In the DP model, the EMT side is modelled as a voltage source. Voltages at the boundary buses are calculated at each time-step in EMT and sent to the DP model.

4.2.1. Phasor Extraction from EMT to DP Model

EMT simulation is carried out using instantaneous currents and voltages. On the other hand, DP simulation is a phasor model. At interface points, each solution must go through \( abc \) time-domain to \( RI \) phasor domain conversion or vice-versa. There have been many methods reported for converting time-domain quantities to phasor domain. These methods include Fast Fourier Transformation (FFT) [20], Phase Locked Loop (PLL) [13], consecutive curve fitting technique [21] or by balancing the energy in two sides [19]. The methods like PLL and FFT are necessary when you need synchronization for control components in the system. However, they introduce unwanted time delays. There is an initial point (time zero) in a simulation and therefore in this paper, an alpha-beta transformation is used for the conversion. This method is more efficient and numerically stable compared to other methods for a real-time simulation since it does not add time delays to the simulation.

The alpha beta components \( (v_\alpha, v_\beta) \) of a three phase signal is calculated using the transformation in (13) and (14).

\[
T_{\alpha\beta} = \begin{bmatrix} 1 & -1/2 & -1/2 \\ 0 & \frac{\sqrt{3}}{2} & \frac{\sqrt{3}}{2} \end{bmatrix}
\]

(13)

\[
v_{\alpha\beta} = T_{\alpha\beta}V_{abc}
\]

(14)

The phasors can then be calculated as in (15) and (16) using \( v_{\alpha\beta} \). The parameters \( V_m, \theta, \omega_0 \) and \( t \) are magnitude, phase angle, base frequency and time correspondingly.

\[
\theta = \tan^{-1}\left(\frac{v_\alpha}{v_\beta}\right) - \omega_0 t
\]

(15)

\[
V_m = \sqrt{v_\alpha^2 + v_\beta^2}
\]

(16)

4.2.2. Conversion of Phasors from DP to Instantaneous Values of EMT

The phasor solution of the DP model is converted back to three phase signal as \( V_\alpha = V_m\sin(\omega_0 t + \theta), \ V_\beta = V_m\sin(\omega_0 t + \theta - \frac{2\pi}{3}) \) and \( V_c = V_m\sin(\omega_0 t + \theta + \frac{2\pi}{3}) \).

4.3. Interfacing TS and DP Solutions

Interfacing a DP model to a TS model is straightforward since they both are phasor models. In the TS model, DP
are updated corresponding to the TS boundary calculation ($\Delta V_{BDR}$ and $\Delta I_{BDR}$).

• At the end of every $h_t$ time-step, the TS side will transfer the boundary voltages ($V_{BDR}$) calculated from the network solution to the DP side. Also, the DP side will transfer the calculated current injections ($I_{BDR}$) to the TS side.

• At the end of every integer multiples of $h_t$, “TS boundary voltage calculation” in the DP side is bypassed, as TS has new values of voltage injections ($V_{BDR}$).

• These steps are continued until the end of the simulation.

5.2. Simulation hardware

The EMT-DP-TS co-simulation is carried out in real-time using RTDS. The EMT part of the simulation is constructed by using existing RSCAD library components. DP and TS parts are user-written component models incorporated into RSCAD.

6. Simulation results

6.1. Test System

IEEE 68 bus system [12] is used as the test case for the proposed EMT-DP-TS co-simulation (Figure 4). It contains two subsystems. Subsystem 1 is the New England Test System (NETS) and subsystem 2 is the New York Power System (NYPS). Let us assume that there is a plan to replace the generation at bus 29 in NETS using an LCC HVDC in-feed. The objective of the study would be to analyze the performance of the HVDC system. Evaluation of the impact on the AC system and the testing HVDC control performance during Factory Accepting Tests (FAT) are some of the examples. Considering the fast dynamics and harmonics associated with the HVDC, it is more appropriate to model the system around the HVDC.
6.2. Case 1: Three Phase Fault at the Converter Bus

In this case, the performance of the co-simulation model is evaluated for a fault at the AC bus of the HVDC converter. The results are validated against a fully EMT simulated 68 bus system. A three-phase fault with a fault duration of 5 cycles is applied at bus 29 (HVDC converter bus) at $t = 10\, \text{s}$. Current through the DC line and converter AC side voltage (bus 29) are shown in Figure 5. Voltage at bus 54 and current in the branch connecting buses 54 and 53 are shown in Figure 6. Figure 7 shows the speed of generator 8, which is the closest generator to the faulted bus. The results match very well with the EMT simulation results.

in an EMT environment. The criterion for selecting the internal system is that the portion of the network where we are interested in high frequency phenomenas must be modelled using an EMT model. Therefore, the NETS is simulated using the EMT simulation. The HVDC in-feed (1000MW rating) is modelled using CIGRE HVDC benchmark system [22] and a small amount of filters are added at the terminal. Usually the Total Harmonic Distortion (THD) at the terminal is kept below 1.5% [23] and in this case, it is kept at around 3.4% purposely to have a significant amount of harmonics injected to the system.

Buses 61 and 53 are the interface buses between EMT and DP. The network containing the buses 61, 53, 47, 48, 40, 30, 36, 31 and 32 is simulated using DP (thick red colour lines). Rest of the NYPS is modelled using the TS model. Buses 36, 32, 31 and 40 are the interface buses between DP and TS. Generators 1-8 are modelled using a detailed machine model with stator winding dynamics [2]. Transmission lines in the EMT model are modelled using the Bergeron line model. Generators 10-16 are modelled using the simplified machine model given in [24]. The transmission lines in the DP and TS models are modelled using PI section models. In DP, the transmission lines are modelled incorporating dynamics whereas, in TS, constant admittances are used.

The objective of the study is to analyse the dynamics in NETS around the node where the LCC HVDC is connected to. Therefore, the faults are applied in NETS and the dynamics in NETS are analysed.

Figure 4 - IEEE 68 bus system

Figure 5 - Converter parameters for a three-phase fault at bus 29
6.3. Case 2: Three-Phase Fault at Buses Next to the EMT-DP Interface Buses

In EMT side, the buses connected to boundary buses (bus 53 and 61) are 60, 54 and 27. The faults are applied on bus 54 to check the accuracy of the proposed model. A three-phase fault with a fault duration of 5 cycles is applied at bus 54 at \( t = 10 \) s. Figure 8 shows voltage at bus 54 and current in line connecting buses 54 and 53. The current through the DC line and phase ‘A’ voltage at the converter (bus 29) are shown in Figure 9. Figure 10 shows the speed of the generator 1. The results of the co-simulation model match well with the EMT results except for some discrepancy in the current in Figure 8 during the fault.
6.4. Case 3: Three-Phase Fault at Buses Right at the EMT-DP Interface

In typical studies, faults are applied in the EMT side. In this study, faults are applied right at the interface buses to check the performance of the co-simulation model. We do not recommend applying faults at the interface bus. However, for the purpose of testing the numerical stability and robustness, a three-phase fault is applied at one of the interface buses, bus 53. Figure 11 shows voltages at buses 53 and 29 and current in the branch connecting 27 to 53 for the three-phase fault at bus 53. Figure 12 shows the generator 16 speed, which is inside the TS model.

7. Discussion

The proposed DP buffer-zone for EMT-TS co-simulation is a convenient alternative compared to the other methods proposed in the literature. Faults were applied at different locations to test the robustness of the proposed approach and compared against an EMT simulation. Without any exceptions, all simulations produced results similar to that is presented above. The HVDC link is also simulated in different locations in the internal system and the same level of accuracy in the results was observed.

7.1. Limitations of the Proposed Method

1. One limitation of the proposed interface is performance under an unbalanced fault. In the approach presented in this paper, both DP and TS parts are modelled using positive sequence voltages and currents. In order to handle unbalances, the negative and zero sequence components should be considered in DP and TS side. A phase ‘A’ to ground fault is applied at bus 60 and the phase ‘A’ and ‘B’ voltages of bus 60 and current in the branch connecting buses 61 to 60 are shown in Figure 13. For this particular case, the difference in the results are negligible however, the error would be case dependant. The work done in this paper can be extended to study the sequence components.
2. It was shown using simulations, that applying faults in the boundary buses tend to give some errors to the simulation. Therefore, we do not recommend applying faults on the boundary buses.

3. The proposed co-simulation can perform well at sufficiently high frequencies applicable to typical planning studies. It was shown using simulations (Section 6) that even with a THD of 3.4 the simulation results show a good agreement. To test this further, a source with 1kHz and a magnitude equal to 20% of the bus voltage is added to bus 22 (the bus circled in green). The voltage at bus 22 and current from bus 27 to 53 are shown in Figure 14. It can be seen that the 1kHz component is well captured in the co-simulation model. As stated in Section 2 (scope of the paper), the goal is to use the co-simulation model to capture electromechanical oscillations and controller interactions with the external system. For this purpose, 1kHz is more than sufficient.

8. Conclusions
An EMT-TS co-simulation model suitable for analysing a large power system has been presented in this paper. The interface between EMT and TS models has been achieved by using DP to model a multi-port buffer zone between the two models. This would be a simple alternative to the existing FDNE models proposed in the literature. The methods of achieving numerical stability and accuracy of EMT-DP and DP-TS interfaces have been discussed. The accuracy and the stability of the proposed co-simulation model have been validated against a complete EMT simulation model using IEEE 68 bus system. The co-simulation model shows promising results under disturbances applied in the internal system.

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10. References
11. Biographies

Harshani Konara received the B.Sc. (Eng.) degree from the University of Peradeniya, Peradeniya, Sri Lanka, in 2012 and M.Sc. degree from the University of Manitoba, Winnipeg, MB, Canada, in 2016. She is currently working toward the Ph.D. degree at the University of Manitoba, Winnipeg, MB, Canada.

Udaya D. Annakkage received the B.Sc. (Eng.) degree from the University of Moratuwa, Moratuwa, Sri Lanka, in 1982 and the M.Sc. and Ph.D. degrees from the University of Manchester Institute of Science and Technology (UMIST), Manchester, U.K., in 1984 and 1987, respectively. He is presently a Professor at the University of Manitoba, Winnipeg, Manitoba, Canada.

Chandana Karawita received the B.Sc. (Eng.) degree from the University of Moratuwa, Moratuwa, Sri Lanka, in 2002 and the M.Sc. and Ph.D. degrees from the University of Manitoba, Winnipeg, MB, Canada, in 2006 and 2009, respectively. He joined TransGrid Solutions, Canada, in 2007 and is now serving as a Vice President, System Studies.
Mechanical explosion characteristics of wind turbine blades under integrated thermal, electromagnetic and airflow impact of lightning induced arcs

W. YUa, J. YANb, Q. LIa, *, Z. GUOa, M. ZHANGa, H. LA, W-H. SIEWc

a State Key Lab of Alternate Electrical Power System with Renewable Energy Sources, North China Electric Power University, Beijing 102206, China
b Department of Mechanical and Energy Engineering, Southern University of Science and Technology (SUSTech), Shenzhen 518055, China
c Department of Electronic & Electrical Engineering, the University of Strathclyde, Glasgow G1 1XQ, UK

Abstract

To improve the lightning protection capability of the wind turbine blades, it is necessary to study the mechanical explosion characteristics of the blades suffering from lightning strikes. Impulse current experiments on the real blades have been done and it’s found that the main damage type might be either cracking at the trailing edge or the web breaking. Generally, the blades started to crack at the trailing edge near the breakdown point where the impulse current is injected, and thereafter the cracking extended gradually toward both the tip and root directions of the blades. To account for the above findings, a modified magnetohydrodynamics (MHD) model for the lightning induced arcs along the blades was established, and the airflow and the gas pressure distribution was calculated accordingly. The simulation results show that, the resultant huge pressure at the trailing edge of the blades is supposed to be the principal culprit for trailing edge cracking. Therefore, a fillet transformation design at the bonding of the trailing edge is presented in this paper to reduce the transient pressure. The proposed research of this paper provides a theoretical basis as to improve structural design of the blades from the viewpoint of lightning protection.

1. Introduction

With the increasing demands of the renewable generation, wind power generation is developing towards much higher capacity per unit and more intelligent [1]-[3]. However, the problem of lightning strikes on wind turbines has become increasingly prominent. More than 3/5 of natural accidents on wind turbines are caused by lightning strikes, which seriously threaten the normal operation of wind farms. According to lightning event statistics of 508 wind turbines in US wind farms, 304 blades have been struck by lightning in 5 years. Therefore, on average, each wind turbine experienced blade damage due to lightning every 8.4 yr [4].

In order to improve the lightning protection capability of wind turbine blade, discrete receptors and down conductors are recommended to be installed on the blade as lightning protection system [5]. However, the lightning protection system may fail to intercept the lightning downward leader. When the interception failure occurs, the lightning downward leader can easily penetrate the blade surface, which will lead to the lightning arc getting inside the blade. Besides, upward-initiated lightning prevails at wind turbines, which causes even severer damages on wind turbines [6]. The coupling effect of thermal, magnetic and airflow, induced by the lightning arc, will tear or crack the blade and even burn it out, as shown in Fig. 1.

On the one hand, many researches have contributed to improving the lightning protection system of wind turbine blade [7]-[10]. On the other hand, the damage of blade due to the lightning strikes can be reduced by a strong

* lqmeee@ncepu.edu.cn (Q. Li)

KEYWORDS

Air pressure distribution, lightning induced arc, mechanical explosion characteristics, wind turbine blade.
design of mechanical structure, which requires the study of the mechanical explosion characteristics of the blade under the lightning induced arcs. Both simulation and experimental work have been done to study the damage characteristics of blade materials under the impulse current and the tolerance capability of different blade materials [11]-[14]. However, the structural damage characteristics of the blade material are still in the preliminary exploration stage. The pressure distribution in the closed cavity under the impulse current was tested, and the effect of different water vapor content inside the blade on the damage was studied [15]-[16]. However, the physical characteristics of mechanical damage of wind turbine blades under the lightning induced arc have not been deeply explored. The intrinsic characteristics of mechanical explosion still need to be further revealed.

In addition, the environment inside blade chamber is multiphysics coupled under the stress of lightning induced arc. To study the damage characteristics of the blade, the distributions of the temperature, airflow and electromagnetic inside the blade need to be clarified. Extensive modeling and calculation of the multiphysics coupling and the motion characteristics of arc plasma have been carried out in various research fields [17]-[20], such as vacuum arc and power system switching equipment. The MHD model of arc is commonly adopted, that is, according to the three dynamic equations of mass conservation, momentum conservation and energy conservation of arc fluid, the MHD model of arc is obtained by combining the arc electromagnetic characteristics described by Maxwell’s equation. The internal temperature, magnetic field, flow rate and pressure distribution in the model can thus be calculated.

However, the methods mentioned above are not directly applicable to the modeling of lightning induced arc inside blade, because the blade model in this paper is irregular while the geometric models involved in these studies are mostly symmetrical models. The boundary conditions of the model in this paper become more complex and the mathematical model to express the particular arc path should additionally be considered. Besides, the transient characteristic of the lightning induced arc increases the difficulty of calculation, so it is necessary to further optimize the mathematical model of the arc.

In this paper, the typical characteristics and dynamic process of structural damage of the blade were obtained based on the mechanical explosion experiment of the blade under impulse current. Considering the typical path of lightning induced arc, a MHD model of the arc inside the blade was established. The distributions of temperature, airflow and pressure in the blade chamber were calculated. Furthermore, the typical mechanical weaknesses inside the blade were obtained based on the model. The results can provide theoretical guidance for blade design from the perspective of lightning protection.

2. Experimental study of the mechanical explosion characteristics of the blade under impulse current

5-meter long blades were adopted as experimental specimens in this paper, as shown in Fig. 2, considering that the lightning strikes hit mainly within 5 meters far from the blade tip [4].
A typical blade comprises two blade sides, that is, pressure side (PS) which withstands the wind and suction side (SS) opposite to the PS. Generally, two blade webs are installed inside the blade as supports between PS and SS. However, such supports are not adopted at the area near the blade tip because of the narrow space. The down conductor is usually placed along the inner surface or the web of the blade.

Typical down conductor setups adopted in this paper are shown in Fig. 3(a) and 3(b), in accordance with the current-leading wires shown in Fig. 3(c) and 3(d), respectively. The current-leading wire is set as shown in Fig. 4 corresponding to the case without blade webs.

As the blade is sealed while the current-leading wire needs to be placed inside the blade artificially, the experimental specimens should be cut to make operation windows. After placing the nickel-chromium made wires inside the blades, the windows are sealed again, ready for experiment. Taking the specimen of down conductor setup 1 as an example, one operation window was cut out of the SS of the specimen while a small hole was drilled on the PS so that the nickel-chromium wire with a diameter of 0.1mm can pass through. After connecting the nickel-chromium lead with the down conductor, the operation window was sealed again.
According to the IEC standard 61400-24 and considering the safety of explosion experiment, an impulse current with an amplitude of 150 kA, a time duration of 25 μs/250 μs and a specific energy of 4 MJ/Ω were chosen, while the nominal amplitude and specific energy of the impulse current generator were 200 kA and 10 MJ/Ω. In order to observe the dynamic process of blade damage in detail, a high-speed camera with a frame rate of 1000 was used adopted. The shooting time of the camera was set to 0.84s before the generation of impulse current and 1s after that. The experiment platform was set as shown in Fig. 5.

With the impulse current setting represented above, several blade explosion experiments were conducted to observe the damage process of the specimens. In most cases, the blades were seriously damaged. The common damage among the experiments is the cracking of the trailing edge shown in Fig. 6(a). It’s noted that the web near the trailing edge will be blown into pieces after the explosion experiment, as shown in Fig. 6(b), when the down-conductor is fixed between the two webs.

Fig. 7 depicts the typical dynamic explosion process of the blade with down conductor setup 1, arc ignited 3 m far away from the blade tip, captured by high speed camera. To make the blade specimen much more prominent, red dotted lines are used in the figures. The arc generated by the impulse current firstly broke through the position where the arc was ignited (32ms), followed by the blade material combustion caused by the high arc temperature, with the frame rushing out from the crack (135ms). Then the cracking spread to the tip and the blade body, and by 156ms the arc reached the maximum size of the crack. Finally, until 276ms, the flare disappeared and the mechanical damage process of the blade ended.
In order to compare the different damages of the blades with different arc ignited positions, blades with the down-conductor setup 2 shown in Fig. 3(b) were adopted, on which the impulse arc was ignited 1m, 2m and 3m far away from the blade tip, respectively. It should be noted that the blade web disappears at the position 1m far away from the blade tip, where the current-leading wire is set along the inner surface of blade, as shown in Fig. 4. The dynamic explosion process with arc ignited at 3m position of the blade was similar to that in Fig. 7. The other two processes of blade explosion with arc ignited at 1m and 2m far away from the tip are shown in Fig. 8, where the blade frame is highlighted by red dotted lines.

The two specimens began to burst close to the blade tip, not right at the point where the arc was ignited, which are different compared with the process with arc ignited at 3 m far away from the blade tip. The closer to the tip of the blade, the smaller the width of the adhesive during blade manufacture, so the damage toward the tip direction was significantly more severe than that towards the blade root. It’s also observed from the data captured by high speed camera that the mechanical damage towards the tip was not caused only by the one-time airflow impact, but by the repeated airflow impacts, which was more serious on the specimen with arc ignited at 1m position.

From 94ms of Fig. 8(a), the flare near the blade tip flew back and forth between the arc ignited position and the blade tip for about 115ms, while the flare in the other direction only moved slowly towards blade root. The main cause is predicted that there is enough space in...
the chamber near the blade root, making airflow move smoothly, while it is narrow near the blade tip, making airflow be blocked to form backflows.

According to the experiment conducted in this paper, the main damages are the carbonization and cracking of the blade at the trailing edge. The damage boundary and length of the blade with arc ignited at different positions are depicted in Fig. 9. It is noted that the carbonization zone of the blade is also part of cracking zone. Therefore, the length of the carbonization damage caused by high arc temperature is much smaller than the crack length due to the airflow impact. For 3m arc ignited case, the crack lengths from the arc ignited position to both the blade tip and the blade root were similar. However, the crack length near the blade tip was much larger than that toward the blade root. One cause is predicted to be the backflow caused by the airflow moving in the narrow the chamber near the blade tip.

It should be pointed out that the damage of the blade with the arc ignited where was 1m far away from the blade tip was the most serious. Because of the absence of the blade webs, the high temperature of the arc caused the material carbonization in the whole blade chamber. Furthermore, the crack extended to even the leading edge of the blade without the blocking effect of the webs.

It's known from the experiment results that when fixing the down-conductor between the both blade webs, the crack of the trailing edge of blade will reduce compared with fixing the down-conductor between the blade web and the trailing edge. However, the latter setup will increase the probability of the blade web damage. The damages are different when igniting the arc at different positions of the blade. The damage is the most serious when the arc is ignited at the position where the blade web disappears near the blade tip. Thus, the specific protection for the web-losing position of the blade should be taken into consideration.

3. Damage mechanism of the blade under multiphysics coupling effect
3.1. Modeling of the coupling of thermal, electromagnetic and airflow fields

The damage experiments of the blades were introduced in Section 2. However, it is difficult to present the most details of the explosion process by experimental method considering that the blade explosion is a dynamic and multiphysics coupling process. Thus simulation method is suggested based on the explosion experiment in this paper.

The MHD model was adopted to depict the electromagnetic, thermal and airflow characteristic of the lightning induced arc. There are some application cases of MHD on electric arc field for reference. Considering the three-dimensional asymmetric structure of the blade, some simplifications were applied to ease the calculation of the model.

Table 1 illustrates the geometry model of the blade adopted in this paper. The blade section where the arc is ignited is chosen as the geometry model. Model 1 and model 2 represent the sections which are 2 m far away from the blade tip, while model 3 represents the blade section which is 1 m from the tip. The red lines in the models represent the current-leading wires and it is assumed that the plasma generated by the impulse current distributes along the current-leading wire and the area vertically versus the wire, shown as the red-slash areas. Considering that the blade webs have blocking effect on the multiphysics’ distribution generated by the impulse current, the blue areas shown in the blade calculation models are selected to be the calculation domains. Because of the absence of blade webs in model 3, the whole blade chamber is chosen to be the calculation domain.

The lightning induced arc develops randomly inside the blade and increases the complexity while calculating the distribution of multiphysics in the blade chamber. Taking the typical development of lightning induced arc into consideration, the following assumptions to calculate the model are proposed.

a) It is assumed the current density to be the maximum at the current-leading wire, set as $J_{\text{max}}$ and that $J$ decreases linearly downward, set as 0 at the SS of the blade.

b) The direction of the current density $J$ of the arc active region is considered to be parallel to the current-leading wire.

c) The arc development path laid along the inner surface of the blade is considered to be line segment $l_{\text{arc}}$. Particularly, the arc path is considered as a broken line in model 1. Each segment is solved separately and the results are added together while calculating this case.
After the current density is obtained, the distribution of magnetic induction $B$ can be obtained according to Biot-Savart’s law shown as (4), and the electric field strength $E$ is obtained according to Ohm’s law as (5).

$$B = \frac{\mu_0 I(t)}{4\pi} \frac{A \times e_{r_2}}{r_2^2} + \int_{l_{arc}} \frac{\mu_0 I(t)}{4\pi} \frac{dl \times e_{r_2}}{cr_2}$$

$$J = \sigma E$$

where, $\mu_0$ is the magnetic permeability, $dl$ is the line integral element, $e_{r_2}$ is the unit direction vector between the current element and the point to be calculated, $r_2$ is the distance between the point to be determined and the direction vector, $\sigma$ is the conductivity, $I'(t)$ is derivative of the current value versus time, $c$ is the speed of light.

Equations (6) to (8) are fluid dynamic equations composed of continuity equations, momentum conservation, and energy conservation equations. The current density $J$, the magnetic induction $B$ and the electric field strength $E$ obtained above will be brought into (6) to (8), from which the internal temperature, airflow and pressure distribution of the blade under the lightning arc can be calculated.

$$\frac{\partial \rho}{\partial t} + \nabla \cdot (\rho \mathbf{u}) = 0$$

$$\frac{\partial \rho \mathbf{u}}{\partial t} + \mathbf{u} \cdot \nabla \rho + \nabla \cdot (\rho \mathbf{u} \mathbf{u}) = -\nabla p + \nabla \cdot (\mathbf{r} (\nabla \cdot \mathbf{u}) + \rho \mathbf{u})$$

$$\frac{\partial (\rho C_p T)}{\partial t} + \nabla \cdot (\rho C_p T \mathbf{u}) = \nabla \cdot (k \nabla T) + \sigma E^2 + q_{rad} + q_{\eta}$$

where $\rho$ is the fluid density, $p$ is the pressure, $T$ is the temperature, $u$ is the fluid velocity, $R$ is the gas constant, $\mu$ is the dynamic viscosity, $g$ is the gravity acceleration, $C_p$ is the fluid constant pressure heat capacity, $k$ is the...
thermal conductivity, $q_{\text{rad}}$ is radiant heat, being 0 in this paper, $q_n = 0$ refers to viscous heat.

The MHD model was calculated by finite element method in Comsol Multiphysics. And the calculation domain was divided into meshes, which are 0.65mm in length as the minimum and 14.4mm as the maximum. Besides, time step of the transient calculation was set as 10μs. To verify the validation of the proposed model, the following calculations were compared:

The minimum peak current value of the lightning which causes the blade damage is 30 kA from the observation data of a blade company in China. Because the time parameter is not clear, the authors chose four typical time durations of lightning first stroke, that is, 1.2/50μs, 10/100μs, 18/200μs and 25/250μs. The pressure range at the trailing edge of the blade was obtained by applying lightning parameter mentioned above, shown in Table 2.

Table 2 - Maximum value of pressure at the trailing edge under the current with peak value of 30kA

<table>
<thead>
<tr>
<th>Blade type</th>
<th>Model 1</th>
<th>Model 2</th>
<th>Model 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Air pressure at the trailing edge (×10⁴Pa)</td>
<td>15~55</td>
<td>2.5~10</td>
<td>7~30</td>
</tr>
</tbody>
</table>

It’s pointed out that the epoxy resin is treated as adhesive to stick the upper and the nether skins at the trailing edge of blade. Therefore, the mechanical strength of the trailing edge is determined by the ability of the adhesive, known also as peel strength. The typical peel strength of epoxy resin ranges from 79 to 315 N/25mm, representing that the maximum pressure can be suffered by the epoxy resin is 15 to 63 kilopascal after conversion, similar to the data shown in Table 2. Therefore the validation of the proposed calculation model is verified.

3.2. Distribution of multiphysics inside the blade

Current and magnetic induction distribution can further cause heat transfer, airflow, and even the blade to withstand impact pressure. While the blade webs exist, the distribution of the temperature, airflow and pressure inside the blade are different according to different down-conductor setups. The comparisons of temperature, airflow and pressure distributions between model 1 and model 2 are shown from Fig. 10 to Fig. 15(when the peak value of impulse current is 90kA). The impulse current first generates high temperature near the current-leading wire (shown in Fig. 10, Fig. 13), then the high temperature area gradually diffuses into the whole blade chamber, which causes the air flowing rapidly in the chamber (the speed distributions of airflow are shown in Fig. 11, Fig. 14). Fast flowing air in the blade chamber impinges on the blade inner surface (pressure distributions in the blade are shown in Fig. 12, Fig. 15), eventually causing structural damage to the blade. It’s noted that relative value of pressure was adopted, and the reference pressure level was set as one standard atmospheric. From the pressure distribution inside the two models, it can be found that the boundary between the upper inner surface of the blade and the blade web near the trailing edge will be subjected to a large pressure, and then the high-pressure area will spread further. The narrow areas inside the blade chamber such as nether inner surface of the blade and the bonding point of trailing edge are subject to high pressure threats.
diffuse faster in this area than those in model 2. The bonding places inside the blade are usually considered as the mechanical weaknesses of the blade, such as the bonding between the trailing web and the upper inner surface (marked as bonding 1 in this paper), the bonding between the trailing edge and the nether inner surface (bonding 2) and the bonding at the trailing edge (bonding 3). Fig. 16 depicts the pressure changes of the three weak positions, showing that the peak pressures at the weaknesses in model 1 are 2.3 times, 2.7 times and 5.5 times those in model 2, respectively, which are in accordance with the impulse current experiment that the trailing edge is much easier to crack in model 1 than that in model 2.

It’s worth noting that at the position near the blade tip, when blade webs disappear, the heat and airflow generated by the impulse current will diffuse in the whole blade chamber. Fig. 17 describes the pressure of leading edge and trailing edge of the blade in model 3. It can be found that the peak pressure of leading edge is equivalent to that of trailing edge, which means that the leading edge is also a severe area of cracking at this case.
4. Improvement design of blade structure based on multiphysics calculation of lightning induced arc

The bonding places inside the blade are easily subjected to great impact pressure, thus they are usually considered as the mechanical weaknesses of the blade. To reduce the cracking probability of blade, the key solution is to reduce the peak pressure suffered by the mechanical weaknesses.

Considering that the bonding places inside the blade are mostly sharp or slender, this paper considers changing these areas to fillets to reduce the peak pressure. While manufacturing a blade, it can be cast into a specific fillet with epoxy resin at the bonding places. Table 3 describes the schematic diagrams of fillet transformation at bonding places inside the blade.

Table 3 - Schematic diagram of fillet transformation in the blade

<table>
<thead>
<tr>
<th>Fillet position</th>
<th>Fillet transformation diagram</th>
<th>Fillet radius (mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bonding 1</td>
<td><img src="image" alt="Fillet transformation diagram for Bonding 1" /></td>
<td>10, 20, 30</td>
</tr>
<tr>
<td>Bonding 2</td>
<td><img src="image" alt="Fillet transformation diagram for Bonding 2" /></td>
<td>10, 20, 30</td>
</tr>
<tr>
<td>Bonding 3</td>
<td><img src="image" alt="Fillet transformation diagram for Bonding 3" /></td>
<td>5, 10, 15</td>
</tr>
</tbody>
</table>

According to IEEE STD 1243 [21], the cumulative probability of the lightning first stroke current from 10kA to 50kA is around 70%. Besides, Orville et al. observed the lightning phenomenon in the United States from 1989 to 1999 and found that the median of the first stroke of lightning was around 30 kA [22]. To make the comparison of different fillet transformations convincing, peak current with 30kA is adopted. Based on the calculation method proposed in Section 3.1, the pressure distribution in the blade is calculated, and the peak pressure values before and after the fillet transformation are recorded in Table 4. Pressure reduction rate is proposed to quantify the effect of fillet transformation. It’s defined as the difference between the pressures before and after fillet transformation divided by the radius of the fillet. The pressure reduction rates at transformation places were calculated, shown in Table 4.

<table>
<thead>
<tr>
<th>Fillet position</th>
<th>Fillet radius (mm)</th>
<th>Peak pressure ($\times 10^4$Pa)</th>
<th>Pressure reduction rate ($\times 10^4$Pa/mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bonding 1</td>
<td>0</td>
<td>6</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>10</td>
<td>5.9</td>
<td>0.01</td>
</tr>
<tr>
<td></td>
<td>20</td>
<td>5.5</td>
<td>0.025</td>
</tr>
<tr>
<td></td>
<td>30</td>
<td>5.1</td>
<td>0.03</td>
</tr>
<tr>
<td>Bonding 2</td>
<td>0</td>
<td>5.2</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>10</td>
<td>5.1</td>
<td>0.01</td>
</tr>
<tr>
<td></td>
<td>20</td>
<td>5.1</td>
<td>0.005</td>
</tr>
<tr>
<td></td>
<td>30</td>
<td>5.0</td>
<td>0.007</td>
</tr>
<tr>
<td>Bonding 3</td>
<td>0</td>
<td>70</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>26.4</td>
<td>8.72</td>
</tr>
<tr>
<td></td>
<td>10</td>
<td>20</td>
<td>5.2</td>
</tr>
<tr>
<td></td>
<td>15</td>
<td>16</td>
<td>3.6</td>
</tr>
</tbody>
</table>

It can be seen that after the fillet transformation, the peak pressure values at the three bonding places are reduced to some extent, among which the peak pressure at bonding 3 reduces the most. When bonding 3 transforms to a fillet with radius of 5mm, the suffered peak pressure here is significantly reduced. However, when continuing to increase the fillet radius, the pressure reduction rate will decrease. It’s pointed out that the fillet transformations at bonding 1 and bonding 2 receive less effect.

5. Conclusion

This paper conducted the impulse current experiment on real-scale blade specimens to explore the mechanical explosion characteristic of wind turbine blade. Combining with finite element calculation of multiphysics inside
the blade under the effect of lightning induced arc, improvement suggestions of structure design in the blade are proposed. The main conclusions are summarized as follows:

(1) The damage process and its dynamic characteristics of wind turbine blade were simulated based on impulse current experimental platform in this paper. The blade cracks at the trailing edge close to the position where the arc is ignited, and then cracks toward both sides. When fixing the down-conductor between the both blade webs, the crack length of the trailing edge of blade will reduce, meanwhile the damage of blade webs and the area between them will increase. However, while fixing the down-conductor between the trailing web and the trailing edge, the damage mainly occurs outside the trailing web, but the crack of trailing edge will be much severer. Igniting the impulse arc far away from the blade tip, the damage area of blade will expand equally to both sides. When the arc is ignited near the tip of the blade, the damage in the direction of the blade tip will be more serious than the direction of the blade root, and even the tip of the blade will be compromised.

(2) In order to calculate the multiphysics distributions in the blade chamber, the MHD model of impulse arc in the blade considering the arc paths was established in this paper. It’s found that the narrow spaces referring to the bonding places are subjected to higher pressure, such as the boning of webs and inner surface of the blade, and the boning at the trailing edge. When the down conductor is set between the trailing web and the trailing edge, the pressure suffered by the trailing edge is much higher compared with that when fixing the down-conductor between the two blade webs. It’s worth noting that the leading edge has cracking risk where the impulse arc hits near the blade tip without webs inside.

(3) Based on the explosion experiment and the MHD simulation of the blade specimens, improvement of the structure design in the blade is proposed. By transferring the sharp bonding places inside the blade to fillet, the peak pressure value at these places will decrease. It’s pointed out that the fillet transformation at the trailing edge gains great effect. The peak pressure here will decrease rapidly when increasing the radius of the fillet. However, the effect of fillet transformation at the bonding of webs and inner surface is not obvious.

6. Acknowledgement
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7. References
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Adaptive tolerance band for shunt automatics to avoid reactor hunting during power system restoration

M. REZA SAFARI TIRTASHI*, O. SAMUELSSON®, J. SVENSSON®, R. ERIKSSON®

*Power Systems Engineer, Solvina AB, Gothenburg, Sweden
®Professor of Electric Power Systems, IEA, Lund University, Lund, Sweden
®Associate Professor of Electric Power Systems, IEA, Lund University, Lund, Sweden
®Senior Power System Analyst, Swedish National Grid, Stockholm, Sweden

Abstract
This paper concerns the reactor hunting phenomenon during power system restoration. The adaptive tolerance band concept is proposed as a new control scheme for shunt automatics to eliminate reactor hunting. To apply the concept, two control schemes are proposed. In the first scheme called the prediction method, the short circuit power of each bus in the system is calculated from the bus impedance matrix and then is used to predict the voltage change after shunt reactor connection. Next the shunt reactor tolerance band is adjusted based on the predicted voltage change. In the second scheme called the observation method, first the shunt reactor is connected then the voltage change is determined and the shunt reactor tolerance band is adjusted based on the observed voltage change. The performance of the proposed control schemes is evaluated on the NORDIC32 test system. The proposed schemes lead to a faster power system restoration.

1. Introduction
Modern society depends on secure and reliable electricity supply. In fact, power networks are the backbones of modern industrial societies. The threat to the availability of power is the large-scale blackouts. These have significant impact on society and entire economy [1]-[4] and rapid power system restoration is an important issue for operators [5]. The main goal for Transmission System Operators (TSOs) is to restore the power system as fast and securely as possible to reduce social and economic consequences for the population. The build-up and build-down are two strategies for restoring a power system following a blackout. The decision to determine which strategy can be applied depends on the network topology. For the build-up strategy, the whole system is divided into sub-systems and after making electrically isolated islands, they are synchronized and interconnected to restore the whole power system. The build-down strategy is usually used for partial blackouts: first the status of the circuit breakers and also power plants are checked. Then from the running parts of the system, the transmission lines are connected to other stations in order to supply them with emergency power. After energizing the high voltage transmission lines, then the generators are synchronized to the system. The power system loads are connected after the main part of the bulk-power system is restored [6]-[10]. In this strategy, if the long transmission line is energized before reconnecting the loads and also re-synchronizing the generators, then that might result in excess of reactive power and a voltage increase along the line that can reach damaging levels. This phenomenon is called Ferranti effect [11] and could happen for countries like Sweden which have long transmission lines.

In order to manage the high voltages caused by the Ferranti effect, shunt reactors are installed in the system to lower the voltage. These reactors have an Extreme Voltage Automatics (EVAs) [12] to switch them on/off. The EVAs work based on a local scheme with a tolerance band. It means they switch the reactors once the local bus voltage is out of a tolerance band. During the restoration process, since the power system is weak, connecting a shunt reactor might immediately lead to too low voltage. If the voltage gets below the lower limit, then the automatics will disconnect the reactor again. This repetitive connection and disconnection of the shunt reactors is called reactor hunting [8] and causes voltage fluctuations in the system as it happened in the 2003 Swedish/Danish blackout [12].

*reza.safari@solvina.com
mechanism. The adaptive tolerance band is introduced and explained in Section 3. Section 4 describes the test system. In section 5, the simulation results for applying the prediction method is provided. Section 6 concerns the simulation results for observation method application. In section 7, the comparison between prediction and observation methods is done and finally section 8 concludes the paper.

2. Problem Demonstration

The reactor hunting phenomenon can be demonstrated using a simple model circuit as shown in Fig. 2a.

During the restoration for that blackout, reactor hunting occurred in two 400 kV substations which are pointed out by the black arrows in Fig. 1. The operating voltage level used by the Swedish TSO is 415 kV [12]. The voltage rose to 476.5 kV in one of these substations which corresponds to 115 % of the operating voltage [12]. In the other substation, a communication failure prevented quick termination of the reactor hunting.

Very few publications concern reactor hunting which delay power system restoration. The common practice for TSOs to avoid reactor hunting is turning off the shunt automatics during the restoration period. That leaves the shunts in manual operation which leads to longer restoration process [8], [13], [14], [15].

To remove the reactor hunting issue and to keep the automatic operation of the shunts during the restoration period, the adaptive tolerance band strategy is proposed in this paper. Adaptive tolerance band with/or automatic adjustment of the voltage regulator gain is already applied to avoid SVC output hunting [16], [17].

In this paper which concerns the reactive shunts, the main idea is instead of having fixed tolerance band for the shunt automatics, it can change and be adaptive. Two methods are proposed for setting the adaptive tolerance band; prediction and observation methods. The performance of both the prediction and observation methods is evaluated on the NORDIC32 test system [18]. The PowerFactory [19] is used to conduct the simulations. The adaptive tolerance band strategy is thus demonstrated using two proposed methods. The methods keep the automatic operation of the shunts during the restoration. With this, the operators save time by not having to manually turn off the automatics and also if the shunts were never in manual control, there is no need to remember activating the automatics.

The remainder of the paper is organized as follows: Section 2 describes the reactor hunting phenomenon and its mechanism. The adaptive tolerance band is introduced and explained in Section 3. Section 4 describes the test system. In section 5, the simulation results for applying the prediction method is provided. Section 6 concerns the simulation results for observation method application. In section 7, the comparison between prediction and observation methods is done and finally section 8 concludes the paper.

2. Problem Demonstration

The reactor hunting phenomenon can be demonstrated using a simple model circuit as shown in Fig. 2a.

The energized portion of the system is modeled by the Thévenin equivalent circuit. Then a lossless transmission line is energized from the intact point of the functioning network. A shunt reactor can be connected to the remote end of the line to lower the voltage. To show the reactor hunting phenomenon, three cases are considered:

- Case 1: one transmission line is energized from a weak network
- Case 2: one transmission line is energized from a strong network
- Case 3: two parallel transmission lines are energized from a strong network

The parameters of the network, transmission line and the shunt reactor are provided in Table 1 which are relevant for the situation at the 2003 Swedish/Danish blackout.

<table>
<thead>
<tr>
<th>Network</th>
<th>Transmission Line</th>
<th>Shunt Reactor</th>
</tr>
</thead>
<tbody>
<tr>
<td>$V_{th}=400$ kV</td>
<td>$X=120$ $\Omega$</td>
<td>$Q=200$ Mvar</td>
</tr>
<tr>
<td>$X_{th}=8$ $\Omega$ Strong</td>
<td>$Y=0.000819$ S</td>
<td></td>
</tr>
<tr>
<td>$X_{th}=80$ $\Omega$ Weak</td>
<td>Length=400 km</td>
<td>$X_{sh}=800$ $\Omega$</td>
</tr>
</tbody>
</table>

For each case, the voltage at the end of the transmission line $V$ is calculated [11] before and after the reactor connection as shown in Fig. 2b.
During normal operation, the tolerance band for shunt automatics is usually set to [380-420] kV for the 400-kV transmission system [20]. During the restoration time, the upper limit of the tolerance band is usually increased to create a safer margin for avoiding reactor hunting [12]. The new upper limit is set to 440 kV [12]. The horizontal black dashed lines in Fig. 2b show the tolerance band for the shunt automatics, [380-440] kV during the restoration time.

The short circuit power of the shunt reactor bus for three cases of Fig. 2b is calculated [11] and provided in Table 2.

Table 2: Short circuit power of the shunt reactor bus

<table>
<thead>
<tr>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>( S_{sc}=920 ) MVA</td>
<td>( S_{sc}=1327 ) MVA</td>
<td>( S_{sc}=2522 ) MVA</td>
</tr>
</tbody>
</table>

Based on the Fig. 2b and Table 2, the lower short circuit power is corresponding to the weaker network also higher voltage change. If we consider [380-440] kV as acceptable tolerance band for shunt automatics actions during the restoration time, then a reactor is connected when the voltage exceeds 440 kV and is disconnected as voltage goes below 380 kV. From Fig. 2b, in case 1 reactor connection causes the voltage to go below the lower limit, and while reactor disconnection leads to a voltage level above the higher limit. With these EVA settings, neither position is acceptable and the reactor will repeatedly be connected and disconnected. This repetitive process of connection and disconnection of the shunt reactors is called reactor hunting and naturally causes large voltage fluctuations with a time cycle governed by the delay times of the reactor relay in combination with the response time of the circuit breaker [8]. In this paper, the reactor hunting time cycle is 2 s [21].

3. Adaptive Tolerance Band to Avoid Reactor Hunting

To avoid reactor hunting, the control scheme proposed in the paper is instead of having fixed tolerance bands for the shunt automatics, they should be adaptive based on the network strength. In fact, the EVA settings will change based on the operating condition and automatic operation of the shunts can continue during the restoration time. This speeds up the restoration process.

As demonstrated in section 2, one indicator for the network strength is the short circuit capacity. To derive the approximate formula to relate the short circuit capacity to the voltage and reactive power changes, Fig. 2a is considered while the shunt reactor is not connected at the remote end of the transmission line. Moreover, Thévenin reactance is disregarded since it is assumed that the voltage at the sending point of the transmission line (E<0) is fixed corresponding to a strong network that holds the sending point voltage constant. Also, transmission line admittances are disregarded since they do not affect too much the short circuit power at the remote end of the line.

By applying all above assumptions, the reactive power received at the remote end of the transmission line can be written as (1). Then the approximate amount of the shunt compensation needed to adjust the voltage at the remote end of the line can be derived from (2).

\[
Q = \left( \frac{EV}{X} \cos \delta - \frac{V^2}{X} \right) \tag{1}
\]

\[
\frac{\partial V}{\partial Q} = \left( \frac{\partial Q}{\partial V} \right)^{-1} = \left( \frac{E}{X} \cos \delta - \frac{2V}{X} \right)^{-1} \tag{2}
\]

As mentioned, the sending point voltage is fixed, also if the transmission line is unloaded, then \( \delta=0 \). Because of the Ferranti effect, the voltage at the receiving end of
the line is higher than the sending point voltage, then the following equation is proposed:

\[ V = \alpha E \]  

(3)

Where \( \alpha \) is a constant value greater than 1. This value can be approximately presented as a function of transmission line length [8]. It is corresponds to \( \alpha = 1.15 \) for the last line of first restoration path sequence which is energized later in section 5 for prediction method application. This value is used in this paper in all cases.

The short circuit power at the end point of the line is calculated as follows:

\[ S_{sc} = \frac{V^2}{X} = \frac{\alpha^2 E^2}{X} \]  

(4)

By applying the above assumptions, then:

\[ \frac{\partial V}{\partial Q} = \left( \frac{\partial Q}{\partial V} \right)^{-1} = \left( \frac{E}{X} \frac{2V}{X} \right)^{-1} = \frac{X}{E(1-2\alpha)} \]  

(5)

Then if we consider (4), the following equation can be derived:

\[ \frac{\partial V}{\partial Q} = \left( \frac{E\alpha^2}{1-2\alpha} \right) \frac{1}{S_{sc}} \]  

(6)

Then the voltage variation can be derived as follows:

\[ \frac{\partial V}{\partial Q} = \left( \frac{E\alpha^2}{1-2\alpha} \right) \frac{\partial Q}{S_{sc}} \]  

(7)

(7) shows that the voltage change at the specified node can be predicted if the sending point voltage, the short circuit power of the node also the amount of reactive power change is known. This equation includes the \( \alpha \) term also. Traditionally this term is not included in the equation and it is proposed here to have a safe margin for the lower tolerance band adjustment in order to avoid the reactor hunting.

During the restoration process, when a specified transmission line is energized (7) can be employed to predict the bus voltage after shunt reactor connection. Then before the reactor connection, the EVA setting of the shunt reactors can change accordingly to avoid reactor hunting.

To show how (7) could be used to avoid reactor hunting, this equation is applied for case 1 of Fig. 2b. The value for \( \alpha = 1.15 \) and the sending point voltage is 400 kV (1 pu). If the nominal value of the shunt reactor which is 200 Mvar considers, then the voltage change for case 1 is around 22%. So, the predicted voltage is around 351 kV after the shunt reactor connection based on the (7). Therefore, if the EV A lower limit is set to 351 kV for case 1, then the reactor hunting would be removed completely. Fig. 3a illustrates how the lower threshold should be adjusted to avoid reactor hunting. The reason for modifying only the lower limit is that the voltage will rise due to the Ferranti effect when a new transmission bus is energized. So, if the upper limit is selected to be adjusted, then energizing the new transmission bus makes the situation worse and leads to even higher voltage.

Obviously short circuit power can be utilized as a parameter to describe how strong a specified bus in the system is, and then shunt reactor tolerance bands can be adjusted based on that to avoid reactor hunting.

One method to calculate the short circuit power for each bus in the system is from bus impedance matrix, Zbus [22]. The diagonal elements of Zbus are equal to Thévenin impedance of corresponding buses which is inversely equal to the corresponding bus short circuit power [23]. So, to access the short circuit power of each bus during power system restoration, obtaining the accurate bus impedance matrix continually is of interest.

The bus impedance matrix is mainly derived from the bus admittance matrix, \( Y_{bus} \), since it is easily constructed branch by branch from primitive admittances [11]. So, if the \( Y_{bus} \) is known, then \( Z_{bus} \) can be calculated based on the following:

\[ Z_{bus} = Y_{bus}^{-1} \]  

(8)

The bus impedance matrix should be updated in each step of the restoration process to have updated short circuit power. The main action during restoration process which is related to the reactor hunting phenomenon is when the new bus is energized from the existing bus through a transmission line. So, updating the \( Z_{bus} \) when the new bus is connected to the network.
reactor hunting, the tolerance band lower limit for the shunt automatics will change based on the measured deltaV. The adjusted lower limit is set to be below the low measured voltage to have a safe margin for avoiding the reactor hunting. The simplified description of the observation method is illustrated in Fig. 3b.

In this method, an extreme low voltage is considered as a limit which should not be violated when adjusting the tolerance band lower limit. This is because we want to be sure that the observation method will not cause further issues in the grid during the restoration. If the extreme low voltage limit is hit, then the observation method will not proceed further and be stopped and it is because of too big shunt reactor rating.

4. Test System

To evaluate the performance of the prediction and observation methods, the NORDIC32 test system [18] is used to conduct dynamic simulations. This test system is shown in Fig. 4.

In large scale power systems, inverting Ybus to reach Zbus is not the best option since Ybus for large systems include many zero elements which make it sparse. Instead, the Zbus for large scale power systems is directly constructed element by element using different algorithms [23]. The elements here mean transmission lines, generators and buses.

In this paper which concerns NORDIC32 test system, to calculate the Z_bus, first it is assumed that the blackout happened for some parts of the system. Then for the energized network, the bus admittance matrix is first constructed, since it is not too large-scale system. Then the bus impedance matrix is calculated by (8). After that, during the restoration process, once a new bus is energized or a transmission line is connected between two existing buses, then the bus impedance matrix is updated based on the above explanations. From the updated bus impedance matrix, the short circuit power corresponding to each bus is derived and then based on (7) the voltage change is predicted. Next, the lower limit of the tolerance band for the shunt automatics is adjusted accordingly.

The second control scheme presented in the paper to apply the adaptive tolerance band strategy is called observation method as stated earlier. This method is based on the voltage change measurement at buses in the system. First the shunt reactor at the target bus is connected, then the voltage change measurement (deltaV) is noted and the shunt automatic threshold band is adjusted based on this. As mentioned earlier, to avoid
It is assumed that the bus impedance matrix $Z_{bus}$ can be constructed from the functioning network admittance matrix. Also, the $Z_{bus}$ can be updated during system restoration. Then the short circuit power is derived from the bus impedance matrix in each stage of the restoration process and finally the voltage change after shunt reactor connection is predicted based on (7). So, the EV A setting of the shunt reactors can change accordingly to avoid reactor hunting.

The starting point for the simulations is a blackout of the southern and central areas in the NORDIC32 test system. As mentioned, during normal operation, the default tolerance band for shunt automatics is [380-420] kV. The new upper limit during the restoration is set to 440 kV [12] to avoid the unnecessary need for reactor connection and consequently avoiding the possible threat of reactor hunting. The lower limit is adjusted based on the voltage change prediction.

The first considered restoration path is as following and pointed out by the red track in Fig. 4.

BE then ED then DF then FH.

To explain the above energizing sequence; note that for example BE means the bus E (4041) is energized from bus B (4031) in Fig. 4, then ED means bus D (4044) is energized from bus E (4041) and so on. In case of existing two parallel transmission lines between two buses, only one of them will be energized.

After following the first path at the end the transmission line between buses 4045 and 4062 in Fig. 4 is energized. Fig. 5a shows the reactor hunting at bus 4062 (H) when the line 4045-4062 is connected at $t=10$ s.

To avoid reactor hunting at bus 4062, the corresponding short circuit power from the updated bus impedance matrix is utilized in (7) while the nominal value of the shunt reactor is considered for the reactive power change. The updated bus impedance matrix at this stage represents the whole north and external areas of NORDIC32 with inclusion of the red path ending at bus...
4062 in Fig. 4. To calculate the voltage change, \( \alpha = 1.15 \) is used. After that the tolerance band lower limit is adjusted and set to 364 kV based on (7). A simulation using the adjusted tolerance band is shown in Fig. 5b. As it can be seen in this figure, the reactor hunting is eliminated using the proposed prediction method. It is also clear that there is a safety margin for the tolerance band lower limit adjustment and this is because of including the \( \alpha \) term in (7).

One interesting feature of the prediction method application is that once the power system is getting stronger, then the shunt automatic tolerance bands are automatically reset in order to control the voltage of the power system for normal operation. It actually means the voltage stays closer to the nominal value which corresponds to better voltage quality. To show this feature, after following the first restoration path, red track in Fig. 4 and energizing the bus 4062 and removing the reactor hunting there, the line 4032-4044 is energized. Fig 6a shows the voltage at bus 4062. As it can be seen, after energizing the line 4032-4044 at 10 s, the voltage goes up and the tolerance band lower limit is also adjusted. Then the line 4032-4042 is energized at 20 s and finally the line 4042-4044 is energized at 30 s. These line connections make the power system stronger which corresponds to higher short circuit power. So, based on the prediction method explanation and with respect to bus impedance matrix update description provided in the section 3, the new lower limits are set and shown in Fig. 6a by the black dashed line.

Fig. 6b shows the evolution of the voltage profile along the energized buses as the restoration continues. Three stages are shown corresponding to finalizing the three tracks:
- Red track: lines BE then ED then DF then FH.
- Green track: bus 4044 is connected to bus 4032 also through the green path.
- Blue track: bus 4044 is connected to bus 4032 also through the blue path.

In Fig. 6b, the corresponding voltage profile for these three tracks has the same color as it is in Fig. 4. For bus 4062 (H), there are two values for each track, one without shunt reactor connection and another one with shunt reactor connection. The default tolerance band, [380-440] kV, is also depicted in Fig. 6b by the horizontal black dashed lines. Moreover, to explain how voltage profile of the buses is affected by the network strength, the corresponding short circuit powers for three tracks of Fig. 4 are depicted in Fig. 6c. For the red track which is corresponding to the lowest short circuit powers, once the shunt reactor is connected at bus 4062, the lowest voltage reaches 373 kV while for stronger cases it is 378 kV and 386 kV, see Fig. 6b. This means if the shunt automatic tolerance band is fixed to [380-440] kV, then reactor hunting will occur at bus 4062 for the red and green scenarios. So, if we aim to avoid reactor hunting, then the tolerance bands for the shunt automatics cannot be fixed and they must be adaptive based on the network strength. It is also noticeable that in the blue track, strongest case, there is no hunting since the lowest voltage after shunt reactor connection (386 kV) is within the default tolerance band.

6. Observation Method Application to Avoid Reactor Hunting

Figures To evaluate the performance of the observation method, one random restoration strategy is considered in PowerFactory for the NORDIC32 test system. Like the prediction method application, the simulation results are obtained once the blackout happened in the southern and central areas.

The sequence of energizing the transmission buses for the second restoration path is as following:

BE then ED then DF then FG.

Fig. 7a shows the reactor hunting at bus 4051 (G) while the default tolerance band for the restoration [380-440] kV is used. In this figure, the transmission line between buses 4045-4044 is energized at 10 s.

By applying the proposed observation method which is explained in section 3, the reactor hunting is removed at bus 4051 as it is shown in Fig. 7b. The new lower limit
fails, as it failed during 2003 Swedish/Danish blackout, then it might be problematic. But for the observation method, the whole process can be done locally. One solution could be to combine the methods and let the observation method serve as a backup to the prediction method operating with an additional delay should the prediction method not respond.

Finally like any prediction and forecasts, the prediction method application might have some prediction errors. This would not be a problem for the observation method application.

8. Conclusion

When In this paper, a new control strategy called adaptive tolerance band is proposed to eliminate the reactor hunting phenomenon during power system restoration. First the reactor hunting is addressed and its mechanism is explained based on a simple circuit model. Then the adaptive tolerance band strategy is explained thoroughly. To apply the adaptive tolerance band, two control schemes are proposed in the paper; prediction and observation methods. In the prediction method, based on the updated bus impedance matrix, the short circuit power associated to each bus has been calculated during system restoration. Then the voltage change is predicted ahead of the shunt reactor connection. Next, the lower limit of the shunt reactor tolerance band is adjusted which leads to reactor hunting avoidance. In the observation method, first the shunt reactor is connected to the system and the voltage change is measured which takes some time and then the tolerance band is adjusted. Using the prediction method, it is possible to detect when extreme low voltage will be encountered. Then it can be decided to carry on with the restoration, to take another path for the restoration or take additional measures to control the voltage. In the observation method, this possibility is not available. In the prediction method, once the network is getting stronger, the tolerance bands are reset based on the network strength but in the observation method case, resetting the bands must be done manually, typically once restoration is finalized. To implement the prediction method, there is a need to have access to short circuit power of each bus in the system continually during each step of restoration. So, a centralized control is needed for prediction method to be implemented. This centralized work needs communication and if that communication fails, as it failed during 2003 Swedish/Danish blackout, then it might be problematic. But for the observation method, the whole process can be done locally. One solution could be to combine the methods and let the observation method serve as a backup to the prediction method operating with an additional delay should the prediction method not respond.

Finally like any prediction and forecasts, the prediction method application might have some prediction errors. This would not be a problem for the observation method application.

9. Appendix

Let us assume that an n-bus power system has the following voltage-current relations [23]:

$$\text{Figure 7 - Reactor hunting at bus 4051 for the second restoration path while the default tolerance band is used (a), No reactor hunting at bus 4051 for the second restoration path after applying observation control scheme (b)}$$

based on the observation method is set to 356 kV and is shown in this figure.

Both the prediction and observation methods have also been implemented in the NORDIC32 test system in the Advanced Real-time Interactive Simulator for Training and Operation (ARISTO) [24] which is a real-time simulator developed by the Swedish TSO. Application of prediction and observation methods avoids reactor hunting for different restoration paths in ARISTO software just like in PowerFactory.

It is important to note that despite using the Swedish test system as the case study and referring to Sweden at some points in the paper, but the reactor hunting might happen in any systems with long transmission lines which implement the build-down strategy for the restoration.

7. Prediction and Observation Methods Comparison

The prediction method application leads to the tolerance bands adjustment ahead of the shunt reactor connection. For the observation method, the shunt reactor should first be connected and the voltage change should be measured which takes some time and then the tolerance band is adjusted. Using the prediction method, it is possible to detect when extreme low voltage will be encountered. Then it can be decided to carry on with the restoration, to take another path for the restoration or take additional measures to control the voltage. In the observation method, this possibility is not available. In the prediction method, once the network is getting stronger, the tolerance bands are reset based on the network strength but in the observation method case, resetting the bands must be done manually, typically once restoration is finalized. To implement the prediction method, there is a need to have access to short circuit power of each bus in the system continually during each step of restoration. So, a centralized control is needed for prediction method to be implemented. This centralized work needs communication and if that communication
If the new bus (p) is added to the existing bus (k) through a transmission line with impedance (Zl), then the schematic diagram of the circuit is as shown in Fig. 8 [23].

\[
\begin{align*}
V_k &= Z_{kk}I_k + Z_{ke}I_e + \ldots + Z_{kp}I_p + \ldots + Z_{kI}I_I + Z_{kl}I_l \\
V_p &= Z_{pl}I_p
\end{align*}
\]

The current \(I_p\) will affect the voltage at bus k as follows:

\[
V_k = Z_{kk}I_k + Z_{ke}I_e + \ldots + Z_{kp}I_p + \ldots + Z_{kI}I_I + Z_{kl}I_l
\]

\[ (10) \]

\(I_p\) will affect the voltages of all other buses as:

\[
V_i = Z_{ik}I_k + Z_{ik}I_k + \ldots + Z_{ik}I_k + Z_{ik}I_k + \ldots + Z_{ik}I_k + I_p + \ldots + Z_{ik}I_k + Z_{ik}I_k
\]

\[ (11) \]

The voltage at bus p is given by:

\[
V_p = V_k + Z_{pi}I_p = Z_{pi}I_p + Z_{pi}I_p + \ldots + Z_{pi}I_p + \ldots + Z_{pi}I_p + (Z_{pi} + Z_k)I_k
\]

\[ (12) \]

Then the new voltage current relations would be as follows [23]:

\[
\begin{bmatrix} V_k \\ V_p \\ V_n \end{bmatrix} = \begin{bmatrix} Z_{original} & Z_{kl} & \cdots & Z_{kp} \\ Z_{kl} & Z_{kk} & \cdots & Z_{kn} \\ \vdots & \vdots & \ddots & \vdots \\ Z_{kp} & Z_{kn} & \cdots & Z_{nn} \end{bmatrix} \begin{bmatrix} I_k \\ I_p \\ I_I \\ I_n \end{bmatrix}
\]

\[ (13) \]

where \(Z_{original}\) is provided in (9).

10. Acknowledgement:

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11. References

Improved local control of reactive shunts to enhance post-disturbance voltage control

M. REZA SAFARI TIRTASHI\textsuperscript{a}, O. SAMUELSSON\textsuperscript{b}, J. SVENSSON\textsuperscript{c}

\textsuperscript{a}Power Systems Engineer, Solvina AB, Gothenburg, Sweden  
\textsuperscript{b}Professor of Electric Power Systems, IEA, Lund University, Lund, Sweden  
\textsuperscript{c}Associate Professor of Electric Power Systems, IEA, Lund University, Lund, Sweden

Abstract

Shunt reactors and capacitors are important reactive resources to regulate the reactive power balance and improve the voltage control in power systems. Reactive shunts are commonly controlled using a local scheme, which switches the shunt when the local bus voltage is outside a tolerance band. An alternative control strategy proposed in this paper is called the neighboring scheme. In this strategy both the local and neighboring bus voltages are considered. The neighboring bus voltages are estimated based on the measurements at the local buses. So, the voltage control can still be implemented completely locally. To investigate the performance of the local and neighboring schemes, dynamic simulation of disturbances in NORDIC32 test system is conducted and the results demonstrate better performance for the neighboring scheme. Finally, static analysis using the PV curves concept and modal analysis is conducted to verify why the neighboring scheme performance is better than the local scheme.

1. Introduction

The shunt reactors and capacitors are one of the traditional reactive power resources which are used in power systems to regulate the voltage. Consequently, they have large impact on voltage control in the system [1]-[2] and may also improve voltage stability. Switching of them to control the voltage usually occurs quite frequently in power systems, often on a daily basis [3].

Shunt reactors are applied to compensate for the effect of line capacitance and to limit voltage rise in power systems. They are usually used for long Extra High Voltage (EHV) overhead lines and can be connected to the transmission systems either directly or to the tertiary winding of a primary substation transformer [4]-[5].

Similarly, shunt capacitors are used to supply reactive power and boost the voltage in power systems when they are loaded [4]. From voltage stability perspective, shunt capacitors are useful to allow the nearby generators to be a fast-acting reactive power reserve by letting them operate near unity power factor [6]. They are usually distributed throughout the transmission systems to improve the overall voltage profile of the grid. They also significantly contribute to increase the maximum transfer of the transmission lines in a way that is economical, easy and quick to install [7].

Although reactive shunt control is important for balancing the reactive power in power systems, few publications question their control scheme [2], [5], [8]. Traditionally shunt reactors and capacitors are manually or automatically switched on/off [5]. In the manual case, based on the system situation, system control room staff takes a decision [9]. In the automatic case, shunt elements could be either mechanically switched or thyristor controlled. Both cases normally use a well-established local scheme which switches the shunts when the local bus voltage is outside the nominal range typically between 0.95 to 1.05 p.u. [10]. The concept of neighboring compensation is applied in [11] for voltage improvement in transmission systems. The whole paper is about static analysis and the dynamic simulation is not provided. Also, the suggested coordination scheme needs communication and it cannot be implemented locally.

As an alternative to the local scheme this paper proposes the neighboring scheme for controlling shunt reactors and capacitors to improve voltage control and possibly also voltage stability in power systems. The main focus is to improve voltage control when the power system is subjected to large disturbances which may lead to long-term instabilities. To evaluate the scheme, NORDIC32 test system [12] is utilized. The Advanced Real-time Interactive Simulator for Training and Operation (ARISTO) [13] is used to conduct the dynamic simulations to evaluate the local and neighboring schemes. ARISTO is a real-time simulator developed by the Swedish TSO

\* reza.safari@solvina.com
mainly for operator training. Dynamic simulation results for NORDIC32 test system in ARISTO are presented and thoroughly discussed. Moreover, to explain why neighboring scheme performance is better than the local scheme in the dynamic simulation, a static analysis is conducted using PV curves and modal analysis [4], [10].

The main contribution of the paper is the neighboring scheme as an improvement of the local scheme for shunt reactors and capacitors control to improve voltage control in power systems. This new control algorithm is communication free and still lets the voltage control be done locally.

The remainder of the paper is organized as follows: Section 2 describes the proposed control algorithm. The test system used in the paper is explained thoroughly in section 3. ARISTO simulation results are presented and completely discussed in section 4. Section 5 concerns the static analysis. The conclusion is provided in section 6.

2. Control Algorithm

As mentioned, shunt reactors and capacitors are traditionally used to control the voltage in power systems. They are manually or automatically switched on/off [5] based on the local bus voltage. We propose a new algorithm to control shunt reactors and capacitors, which improves voltage control in the system. Based on the proposed algorithm, the reactive shunt control considers also the voltage at the neighboring buses and its switching decision is made based on the voltages at both the local and the neighboring buses. The neighbor bus means the bus(es) at the remote end of any line(s) connected to the local bus, see Fig. 1.

![Figure 1](image1.png)

Figure 1 - For a local bus i with three neighbors j, j+1 and j+2, the local scheme uses only voltage at bus i (a). The neighboring scheme uses also voltage at neighbor buses j, j+1 and j+2 (b)

The main concept of the proposed algorithm is illustrated and compared with the local scheme in Fig. 2 for the case of low voltage. With the local scheme, the local reactive shunt is just sensitive to the local bus voltage (Vi). But in the neighboring scheme, once either the local or a neighbor bus voltage is below the lower limit, then reactive power injection will increase at the local bus. Increasing reactive power injection corresponds to first reactor disconnection and then capacitor connection.

![Figure 2](image2.png)

Figure 2 - Basic flow chart of the local(a), and neighboring(b) methods for control of reactive shunts for the case of low voltage. For the neighboring scheme, shunts at bus i (local bus) are controlled using voltages at bus i and the neighboring buses j, j+1 and j+2. Increase Q_injection corresponds to first reactor disconnection and then capacitor connection.
The detailed implementation of the proposed algorithm in ARISTO for NORDIC32 test system is shown in Fig. 3.

This control algorithm should be applied at each transmission level bus in the system with controllable reactive shunts. As shown in Fig. 3, first the voltage at the specified bus is measured. If the power system is subjected to a disturbance, then the voltage at some buses may be out of the tolerance band, typically the critical ones are those below the lower voltage level. The scheme for managing high voltages is analogous, but is omitted here for clarity.

To tackle the lower voltage, first the algorithm tries to disconnect the available shunt reactors then connect the available capacitors at the local bus. In each step of disconnecting the shunt reactors or connecting the shunt capacitors, the algorithm waits for a specified time delay then the voltage level is measured and checked. The reason for waiting time is that the voltage should stabilize before a new switching is considered. The waiting time is set to 2 seconds [14]. Once the voltage level is within the tolerance band for the local bus, the algorithm tries to satisfy the neighbor bus voltages. These are estimated based on the descriptions provided in the Appendix. The estimation part is pointed out by the red cursor in Fig. 3. The neighboring bus voltages can also be communicated from the neighboring buses to the local bus but this requires a supervisory system and communication.

If the voltage level is below the lower limit at the neighboring bus, then the same procedure is applied as for increasing the local bus voltage. So, all the buses with controllable shunt reactors and capacitors are switched if either the local or neighbor bus voltage is below the lower limit. Since the neighboring bus voltages are estimated at the local buses, so the proposed algorithm is communication free which is a big advantage from implementation point of view. It means the voltage control can still be accomplished completely locally.

The voltage control at the local bus is prioritized over the neighbor bus voltage control. It means once the voltage is low at the neighbor buses and when the local shunt capacitors turn on to support the neighbor bus voltage, the voltage at the local bus might reach the value above the upper limit. In such a case, the local capacitor will remain turned off to keep the local bus voltage within the acceptable range. In this case, the neighboring scheme reverts to the local scheme.

3. NORDIC32 Test System

To apply the proposed control algorithm, the NORDIC32 test system as shown in Fig. 4 is used.

The test system has long transmission lines from the northern hydro power dominated part towards the central load area with a large amount of thermal power. The model includes three voltage levels; 400, 220 and 130 kV and is divided into four main areas:
- North: mostly hydro generation and some load
- Central: much load and large thermal power plants
- Southwest: few thermal units and some load
- External: mixture of generation and load [12].

To investigate the dynamic phenomena related to voltage control, the influential dynamics must be considered in NORDIC32 test system. The main focus of this paper...
4.1 Line Tripping

The first disturbance applied on the NORDIC32 test system is tripping of the two transmission lines between buses 4044 and 4045 at 60 s. This disturbance leads to low voltages below the reactive shunts tolerance band lower limit in the system as can be seen in Fig. 5. The minimum voltage level for shunt actions is set to 395 kV, which is 5% below the operating voltage level of 415 kV used by the Swedish TSO [14]. Fig. 5 shows the voltage curve for local and neighboring schemes in bus 4044 which is located in the central area. As it can be seen in Fig. 4, there is no shunt capacitor at this bus to be switched on. The voltage variations are caused by the stochastic load variations that are modeled in ARISTO. The minimum voltage level of the reactive shunts tolerance band, 395 kV, is shown in Fig. 5 by the black dashed line.

As it can be seen, at the early stage following the disturbance, there are some transients coming from short-term dynamics in the system. These transient oscillations are damped out after a few seconds and the short-term equilibrium is established. Then the power system is driven by the long-term dynamics which are tap changer and OXL actions. Tap changer actions lead to load recovery on the distribution side of the transformers and it causes further sag in the transmission side voltages. Also, some of the generators in the central

4. Dynamic Simulation Results

In this part, to evaluate the capability of the local and neighboring schemes for voltage improvement in large scale power system, NORDIC32 is used and two different large disturbances are considered. The applied disturbances lead to low voltages and action of protective relays also loss of synchronism for one disturbance in the system.
Fig. 7 shows the voltage curves for neighboring and local schemes at bus 4044 in NORDIC32 which is located in the Central area.

Like at the previous disturbance, first there is an initial transient period which is excited by the short-term dynamics, then the long-term dynamics take over the system behavior which here leads to long-term voltage instability in the system. Meanwhile, to counteract the disturbance effect and compensate the lack of the reactive power, there are two capacitor connections. The time of the connections of the first and second capacitors for the local and neighboring schemes are given in Table 1.

Table 1 - Reaction time for capacitors connection for generator outage scenario

<table>
<thead>
<tr>
<th>Conditions</th>
<th>Bus</th>
<th>Time (Sec)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Neighboring</td>
</tr>
<tr>
<td>First capacitor</td>
<td>4041</td>
<td>64 s</td>
</tr>
<tr>
<td>Second capacitor</td>
<td>4051</td>
<td>321 s</td>
</tr>
</tbody>
</table>

In this scenario, the neighboring scheme application apparently gives sooner action of the shunts and leads to avoiding voltage collapse in some parts of the system. In the local scheme case, because of the tap changer action and thermostatic load behavior, the voltage gradually continues to decline further and further at transmission level, ultimately leading to action of distance protection and cascading line tripping. Finally, the under-voltage protection for the generators acts, leading to collapse in some parts of the central area in the system. For some generators, the out of step relay is also activated.

For this disturbance, the number of capacitors connected to the system is the same for the local and the neighboring schemes but they are connected at different time instants. It means the effectiveness of the control strategies for the reactive shunts critically depend on time which is in line with literature [16]-[17]. The injected reactive power by the shunt capacitors corresponds to the square of the voltage level. The sooner action of the shunts...
with the neighboring scheme thus translates to capacitor connection at a higher voltage level, and still with the same number of capacitors connected, the amount of reactive power injection is thus larger for the neighboring scheme than the local one. This greater reactive power injection led to better voltage control for the neighboring scheme.

The steady-state voltages for buses 4011 (North), 4071 (External) and 4063 (South) are shown in Fig. 8. As it can be seen, the voltage is higher in the north and south parts with the local scheme. As mentioned above, by applying the neighboring scheme, the power system blackout could be avoided in the applied disturbance scenario as shown in Fig. 7. In the local scheme case, a blackout ultimately happened for some parts of the system. In fact, by applying the local scheme, the five interconnecting transmission lines between northern and central parts in NORDIC32 got heavily overloaded and could carry less power than when applying the neighboring scheme. So, if the transfer in those five lines decreases, then the system could survive by applying the local scheme as well. By changing the transfer, it can be found that the transfer limit with respect to voltage collapse is 3036 MW for the local scheme and 3291 MW for the neighboring scheme. The neighboring scheme thus raises the transferred power by 255 MW.

Many other disturbances on the NORDIC32 test system have been simulated. In all cases, controlling the reactive shunts with the neighboring scheme leads to better or the same performance compared to the local scheme. So, the neighboring scheme can improve the post-disturbance voltage control compared to the local scheme.

5. Static Analysis

To complement the dynamic simulations, the local and neighboring schemes are here analyzed using static analysis in terms of PV curves and modal analysis.

5.1 PV Curve Analysis for the Local and Neighboring Schemes

As mentioned above, in both of the considered disturbances, the neighboring scheme led to sooner action of the shunts which corresponds to higher voltage and larger reactive power injection to the system. This part aims to explain, using the PV curves, why the neighboring scheme led to sooner action of the shunts in the dynamic simulation. To do so, the capacitor connection at bus 4041 which happened during the dynamic simulations is considered here. For another capacitor connection which happened at bus 4051, the analysis is analogous.

The starting point is the situation after the outage of the generator at bus 4047. To generate the PV curves, the loads in the central and south areas are increased. The generators at buses 4041 and 4061 hit their OXL limits after the outage of the generator at bus 4047. It means their terminal buses will turn from PV to PQ buses. Bus 4031 is excluded from the PV curve analysis since the OXL is not activated there and this bus is PV bus during the whole dynamic simulation and its voltage is constant all the time. The PV curves for the three buses 4041, 4044, 4061 are plotted in Fig. 9. The load recovery translates to moving right along the PV curves.

The lower acceptable voltage level is 395 kV. So, the capacitors will connect to the system if the voltage is below that level. Based on Fig. 9, bus 4044 is the first bus which violates the nominal voltage range. Next the bus 4041 is violating the limit at higher active power thus corresponding to later time.

When the local scheme is utilized, the capacitor at bus 4041 connects to the system once the voltage is below the lower limit at just its own bus. For the neighboring scheme, the capacitor at bus 4041 will be switched on once the voltage either at its own bus or at the neighboring buses violates the lower limit. So once either of the lines
in Fig. 9 goes below 395 kV, the capacitor at bus 4041 connects to the system. Based on Fig. 9, the red line (corresponding to bus 4044) is going below 395 kV at much lower active power value which corresponds to earlier time compared to other buses. This agrees well with the dynamic simulations. So, the neighboring scheme application leads to sooner action of the shunt capacitors which corresponds to higher voltage level and larger reactive power injection to the system. This led to post-disturbance voltage control improvement and better performance in the dynamic simulations.

5.2 Modal Analysis for the Local and Neighboring Schemes

In section 5.1, PV curves are utilized to explain why neighboring scheme led to sooner action of the shunt capacitors and also more reactive power injection to the system compared to the local scheme in the dynamic simulation. This part aims to demonstrate based on the modal analysis of the first disturbance scenario, line tripping, that if the neighboring scheme is applied then the most critical bus voltages in the system would possibly be used for switching the shunt capacitors. For the second disturbance scenario, generator outage, the analysis is analogous.

The linearized steady state system power voltage equations are as follows:

\[
\begin{bmatrix}
\Delta P \\
\Delta Q
\end{bmatrix} = \begin{bmatrix}
J_{P\theta} & J_{PV} \\
J_{Q\theta} & J_{QV}
\end{bmatrix} \begin{bmatrix}
\Delta \theta \\
\Delta V
\end{bmatrix}
\]  

(1)

where,
\[J_{P\theta} = \frac{\partial P}{\partial \theta}, \quad J_{PV} = \frac{\partial P}{\partial V}, \quad J_{Q\theta} = \frac{\partial Q}{\partial \theta}, \quad J_{QV} = \frac{\partial Q}{\partial V}\]

and
\[
\Delta P = \text{incremental change in bus active power} \\
\Delta Q = \text{incremental change in bus reactive power} \\
\Delta \theta = \text{incremental change in bus voltage angle} \\
\Delta V = \text{incremental change in bus voltage magnitude}
\]

\[
\begin{bmatrix}
J_{P\theta} & J_{PV} \\
J_{Q\theta} & J_{QV}
\end{bmatrix}
\]
is the Jacobian matrix of the partial derivatives.

If the active power flow is assumed constant then:

\[
\begin{bmatrix}
0 \\
\Delta Q
\end{bmatrix} = \begin{bmatrix}
J_{P\theta} & J_{PV} \\
J_{Q\theta} & J_{QV}
\end{bmatrix} \begin{bmatrix}
\Delta \theta \\
\Delta V
\end{bmatrix} 
\]

(2)

\[
\Delta Q = J_R \Delta V
\]

(3)

Where \(J_R\) is the reduced Jacobian matrix as follows:

\[
J_R = J_QV - J_{Q\theta}J^{-1}_{\theta\theta} J_{\theta\theta}\]

(4)

The reduced Jacobian matrix eigenvalues and eigenvectors show the voltage stability characteristics of the power system [4].

\(J_R\) can be diagonalized as following equation:

\[
\eta J_R \varepsilon = \Lambda
\]

(5)

where:
\(\eta = \text{left eigenvector matrix of } J_R\)
\(\varepsilon = \text{right eigenvector matrix of } J_R\)
\(\Lambda = \text{diagonal eigenvalue matrix of } J_R\)

Based on this [4], the corresponding \(i^{th}\) modal voltage variation can be determined as following equation:

\[
v_i = \frac{1}{\lambda_i} q_i
\]

(6)

where \(\lambda\) is the eigenvalue of \(J_R\) and \(q\) is the vector of modal reactive power variations represented by:

\[
q = \eta \Delta Q
\]

(7)

If \(\lambda_i > 0\) for all \(i\), then the system is voltage stable. Otherwise it is unstable from voltage stability perspective. On the other hand, the magnitude of \(\lambda_i\) determines the degree of stability of \(i^{th}\) modal voltage. It means the smaller values for \(\lambda_i\) indicates the closer the \(i^{th}\) modal voltage is to being unstable. So, the smallest eigenvalues of \(J_R\) are of interest to study the voltage stability in the system.

The relative participation of bus \(k\) in mode \(i\) is as follows:

\[
P_{ki} = \varepsilon_{ki} \eta_{ik}
\]

(8)

The specified bus participation in a given mode indicates the effectiveness of remedial actions applied at that bus to stabilize that mode [4]. In fact, once the smallest eigenvalues of \(J_R\) which is corresponding to the specified modes in the system is known then it can be determined which bus has largest participation factor for that modes. Then the weak buses in the system from voltage stability perspective could be determined.
If we take the capacitor connection at bus 4041 which happened during the dynamic simulation for both disturbance scenarios, then for this connection bus 4044 and 4061 are considered as neighbor buses. Bus 4031 is not included in the analysis since as mentioned it is a PV bus during the whole dynamic simulation and its voltage is constant. For the capacitor connection at bus 4051, the analysis is the same.

Table 2 shows the participations of buses 4041, 4044 and 4061 in the two most unstable modes in the system. Clearly, the bus 4044 has the highest participation. So, among these three buses, bus 4044 is the most critical bus from voltage stability perspective. If the capacitor connection at bus 4041 is made based on the local scheme, then the bus 4044 which is the most critical bus among these three buses is not involved in making the switching decision. With the neighboring scheme application instead, the bus 4044 is also involved in making the switching decision at bus 4041. So, the possibility of involving the weak buses from voltage stability perspective in the capacitor’s connection decisions are higher in the neighboring scheme compared to the local one.

Table 2 - Bus participation for the first disturbance scenario

<table>
<thead>
<tr>
<th>Bus Numbers</th>
<th>First mode</th>
<th>Second mode</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bus 4041</td>
<td>0.0012</td>
<td>0.0031</td>
</tr>
<tr>
<td>Bus 4044</td>
<td>0.0584</td>
<td>0.0955</td>
</tr>
<tr>
<td>Bus 4061</td>
<td>0.0008</td>
<td>0.0144</td>
</tr>
</tbody>
</table>

6. Conclusion

In this paper, the local and neighboring schemes are applied to control the reactive shunts and voltage improvement when the power system is subjected to a large disturbance. The local scheme has been used by TSOs around the world as a traditional way to control the shunt reactors and capacitors. This scheme switches the shunts when the local bus voltage is outside a tolerance band. For the neighboring scheme, both the local voltage and neighboring bus voltages are used in a simple fashion. The NORDIC32 test system is utilized to investigate the performance of the considered control algorithms. Dynamic simulation results of the NORDIC32 test system prove better performance for the neighboring scheme compared to the local one in the sense of suppressing the disturbance effects and improving the post-disturbance voltage control. Even though the neighboring scheme has a simple control concept and its difference from the local scheme is small, still it could provide better performances compared to the established local one. Moreover, the neighboring scheme led to sooner action of the shunts which for the declining voltage corresponds to higher level and more reactive power injection. Finally, the static analysis using PV curves and modal analysis is conducted and verify why neighboring scheme performance is better than the local scheme in the applied disturbance scenarios.

7. Appendix

Since it is not efficient to transfer the reactive power over long distances, then the long transmission line model is not needed to take into account for neighboring voltage estimations. The $\pi$ circuit model [18] is instead considered to estimate the neighboring bus voltages, see Fig. 10.

The following relationship holds among apparent, active and reactive powers at the sending point of the line.

$$S = P + jQ = VI^*$$

where $S$, $P$, and $Q$ are the apparent, active and reactive powers, $V$ and $I$ are the voltage and current at the sending end of the line.

If the voltage at the sending point is considered as reference which means it has zero phase angle, then the current is:

$$I = \frac{P - jQ}{V^*}$$

The current passing the first shunt branch is:

$$I_1 = j \frac{B}{2} V$$

where $B$ is the susceptance of the transmission line.

Then $I_2$ is:

$$I_2 = I - I_1$$
Then the neighboring bus voltage is:

$$V_n = V - (R + jX)I_2$$  \[13\]

where $R$ and $X$ are the resistance and reactance of the transmission line.

Based on the (13), the neighboring bus voltages are estimated at the local bus.

8. Acknowledgement:
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9. References
Parameterization of aggregated Distributed Energy Resources (DER_A) model for transmission planning studies

I. ALVAREZ-FERNANDEZ*, D. RAMASUBRAMANIAN*, A. GAIKWAD*, J. C. BOEMER*
*University of Central Florida (UCF), Electric Power Research Institute (EPRI) United States of America

Abstract
With an increased number of distributed energy resources (DERs) connected to the distribution system, visibility of the response of the aggregated DER to a transmission system event can be critical to bulk power system stability. This study focuses on parameterizing an aggregated model of DERs that includes advanced functions such as voltage ride through and dynamic voltage support that has been previously developed. In order to provide model parameters appropriate for an actual distribution system, dynamic simulations based on a detailed feeder model were executed to evaluate its dynamic voltage response with non-smart legacy DERs. Parameters obtained from detailed simulations were played-in a positive sequence simulation software to observe the response of the DER_A model. DER_A model’s behaviour correlates with results from detailed simulation for the induced voltage events. Further studies ought to be performed to capture DER response in a wide arrangement of distributions systems to develop generic parameters.

1. Introduction
With the increased proliferation of distribution connected behind the meter inverter based resources, transmission planning and analysis have to be expanded to consider the effects of these resources. However, until recently, no effective simulation model existed in order to suitably represent the aggregated performance characteristic of hundreds of distributed connected resources (DERs), especially the tripping of a varying number of these resources for an event on the transmission system. Due to being spread out along a feeder, a single transmission system event can result in either only few DERs tripping, or all DERs tripping. The level of the voltage sag/swell on the substation bus, the duration of the event, the type of DER and its location on the feeder with respect to the substation all play a role in determining the number of DERs that trip. In March 2018, under the aegis of the Western Electricity Coordinating Council (WECC) Model Validation Working Group (MVWG), a positive sequence model that would represent this aggregated performance of DERs was approved for use in bulk power system planning studies. This model has been named as DER_A [1] and is now available in the latest versions of four major positive sequence time domain simulation software (GE – PSLF™, Siemens PTI PSS®E, PowerWorld Simulator, Powertech Labs DSA Tools).

As with any aggregated model, parameterization of the variables is an important step. Preliminary work on parameterizing this model was carried out in [2]. However, due to the heavy computation burden of the method, large sets of simulations could not be run to obtain a complete picture of the parameters. There has been recent research work which looks at the dynamic equivalent modelling and parameterization of active distribution networks [3]-[7]. The dynamic equivalent model has been constructed considering the uncertainty in parameter values, variation in depth and magnitude of the transmission voltage events, and behavior of induction motor loads. Modelling the partial voltage tripping characteristic of distribution connected inverters has also been discussed. However, in these works, derivation of the parameters of the aggregated model has been carried out assuming perfect knowledge of the distribution circuit, and the locations of the inverters on the circuit. The impact of change in location of the inverters has not been addressed. This is because it has been assumed that the distribution system

* dramasubramanian@epri.com

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operator would be the entity responsible for creating and parameterizing the dynamic equivalent model before handing it off to the transmission system operator [5]. While this approach may be suitable in a vertically integrated utility, it involves a tremendous amount of data transfer and protocols in order to be achieved at an interconnection level, or even at an independent system operator (ISO) level.

Due to the aforementioned reasons of lack of observability, transmission system planning at an ISO level is essentially blind to the locations and types of distributed connected inverters. Further, industry wide, there is an immediate need to be able to parameterize the aggregated model to allow the transmission system planning department to have some visibility of the expected performance from DERs. Thus, this paper aims to provide an insight into derivation of a set of generic parameters for aggregated distributed energy resources. Additionally, in this paper, a new process is detailed which significantly improves the computation burden while maintaining the accuracy of the results.

2. Methodology
The parameterization of the variables of the DER_A model was carried out using the IEEE 8500 Node Test Feeder [8] simulated in the OpenDSS software [9]. This test feeder allowed to adequately simulate abnormal voltage conditions to observe the aggregated response of individual legacy DERs allocated at various distances from the substation. The DERs were exposed to voltage sags and swells below/above their under-voltage/over-voltage trip thresholds. It was found that trip of the DERs occurs in a narrow voltage range of a small percentage of the nominal substation voltage and is dependent of the location of the DERs. The ratio of the total DER injected power remaining (DERs that were able to ride through) after each voltage abnormality and the total power before the disturbance are extracted to observe the tripping characteristics of the aggregated DERs with respect to voltage sag/swell and distance from the substation. These simulations results provide the voltage break points for low/high voltage cut-out of inverters (vl0, vl1, vh0, vh1), parameters needed to allow emulation of partial tripping for the DER_A model.

The IEEE 8500 Node Test Feeder has around 11.0 MW of load with a substation voltage of 1.05pu. The one-line diagram as well as the voltage profile with balanced loads and without any additional inverter are shown in Figure 1 and Figure 2 respectively. In Figure 2, phases A, B, and C are denoted in black, red, and blue respectively while the red dots denote the voltage magnitude on the secondary side of each individual pole mounted load step down transformer whose primary side is on the 12.47 kV main trunk line.

The feeder was scanned to extract buses with a line to line voltage rating of 12.47 kV and three phase connection capability. A total of 642 buses possessed these characteristics. This allowed to sort and separate the buses based on their distance with respect to the substation. Four distance ranges were allotted: 0-5km, 5-10km, 10-15km, and 0-15km (covering the entire feeder length). The number of available nodes per distance range is tabulated in Table 1. A total of 100 individual random locations were chosen from each distance range to install DERs with various combinations of both Type A and B inverters. In this work, total MW of the DER on the feeder was varied but the number of inverters were kept constant, along with different types of inverters. It is expected that since all inverters have to be certified against a specific grid code (such as IEEE 1547), the fault ride through behaviour of these inverters would also be consistent. Thus, the aim for generalization is to base it upon the per unitized results.

![Figure 1 - 8500 Node Model One-Line Diagram](image-url)
based upon ratio of load to inverter. With this, the exact number of inverter does not matter.

<table>
<thead>
<tr>
<th>Location Range</th>
<th>Number of Possible 3-Phase Connection</th>
</tr>
</thead>
<tbody>
<tr>
<td>0-5km</td>
<td>150</td>
</tr>
<tr>
<td>5-10km</td>
<td>243</td>
</tr>
<tr>
<td>10-15km</td>
<td>249</td>
</tr>
</tbody>
</table>

The inverters are designed using OpenDSS generator model=7 which is current limited with a constant active and reactive power. This model approximately represents the dynamic behaviour of a legacy inverter. Generator model 7 is a type of generator model in OpenDSS that can be used to restrict the magnitude of the fault current of the generator. It has no explicit relation to IEEE Std 1547-2003. Traditionally, distribution system simulations are mainly steady state or quasi static simulation wherein multiple power flow solutions are evaluated. The need for a dynamic simulation (wherein differential equations are integrated with small time steps) has traditionally not been required. However, with increased inverter presence in the distribution system, the can be a need for dynamic simulations. Creation and development of these dynamic models in standardized industry wide simulation software is a sequential process. Thus, while a detailed inverter controls dynamic model is being created presently, as an interim solution, the dynamics of the generator model was used to mimic an inverter. Thus, in order to restrict the fault current to a certain value, model 7 from the OpenDSS library was used. Its behaviour was verified by placing a generator at an arbitrary three phase bus in the feeder; a voltage sag was induced to observe the voltage, current, active and reactive power as shown in Figure 3. V1, V2 and V3 correspond to the voltages at each phase of the generator, similarly I1, I2, and I3 represent the current at each phase of the generator. P/Q 0, 1, 2 correspond to zero sequence, positive sequence and negative sequence active and reactive power output of the generator. The maximum reactive Q injection has a value of 6.0e-05. This plot thus serves as a sanity check to ensure that the generator model is operating in unity power factor mode even during the time domain dynamic simulation.

Figure 2 - 8500 Node Model LN Voltage Profile with balanced load and without DER

Figure 3 - a) Voltage/Time b) Current/Time c) Active Power/Time d) Reactive Power/Time
The generator model is \( \Delta \) connected at each of the randomly selected 100 individual locations through a three phase \( \Delta \)-Y 12.47/0.36kV transformer. For the DER, the terminals of DER were at a voltage level of 0.36kV. However, the main trunk line of the feeder has a voltage level of 12.47 kV, which is assumed to be a standard North American distribution voltage level and is characteristic of the IEEE 8500 Node benchmark feeder. Thus, the primary of the DER transformer has a voltage rating of 12.47 kV. The per unit transient reactance (Xdp) and sub-transient reactance (Xdpp) were set as 5.27pu and 5.0pu respectively. The inertia constant of the machine (H) was set to 100.0s and the damping constant (D) to 0.2. A voltage relay and a monitor were connected on the secondary side of each transformer. The monitor allows the power to be extracted for each voltage sag/swell simulation to be able to identify the ratio of DER active power after each voltage event.

A hosting capacity study was performed using EPRI-DRIVE tool [10] to acquire a sense of the total amount of MWs of DER the feeder could accommodate. This analysis was performed with PV as the DER type with a full uniform distribution along the feeder at peak load level (11MW). The limits used in the calculation of hosting capacity are shown in the Table 2.

Additionally, it was assumed that the DERs would be operating at unity power factor as they are assumed to legacy inverters whose operational performance is according to IEEE Std 1547-2003. Three values were extracted based on the PV concentration in the feeder:

- For the full feeder: 3.3 MW
- For the front of the feeder: 3.4 MW
- For the end of the feeder: 1.7 MW

Based on these results, the maximum amount of power injection was chosen to be 3.5MW due to inability to obtain hosting capacity for specific location ranges within the feeder. Therefore, the power of the legacy inverters was chosen to be either 15kW or 35kW; for all combinations of Type A or B inverters the power will range between 1.5-3.5MW. The rated power along with trip characteristics for both inverter types are tabulated in Table 3.

### Table 3 - Legacy Inverters based on IEEE1547-2003 [11]

<table>
<thead>
<tr>
<th>Inverter Type</th>
<th>P (kW)</th>
<th>S (kVA)</th>
<th>Under-voltage Trip</th>
<th>Over-voltage Trip</th>
</tr>
</thead>
<tbody>
<tr>
<td>Group A (residential)</td>
<td>15</td>
<td>15</td>
<td>0.88pu for 0.1s</td>
<td>1.2pu for 0.1s</td>
</tr>
<tr>
<td>Group B (commercial)</td>
<td>35</td>
<td>35</td>
<td>0.5pu for 0.1s</td>
<td></td>
</tr>
</tbody>
</table>

In IEEE Std 1547-2003, the voltage trip threshold values can be different based upon whether the DER is less than 30kW or greater than 30kW. Thus, with regard to thus, in this paper, Type A inverters designate the inverters with a rating less than 30kW and Type B has a rating greater than 30kW. Dynamic simulations were performed to derive the relationship between the voltage sags/swells and the ratio of DERs that recovered after each

![Figure 4 - Played in voltage sags/swells for Group A](image-url)
Table 2 - Criteria used for evaluation of hosting capacity

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Value</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primary Over-Voltage</td>
<td>1.075</td>
<td>the allowable overvoltage threshold (Vpu)</td>
</tr>
<tr>
<td>Primary Voltage Deviation</td>
<td>3</td>
<td>the allowable voltage change threshold (%V)</td>
</tr>
<tr>
<td>Primary Under-Voltage</td>
<td>0.95</td>
<td>the allowable undervoltage threshold (Vpu)</td>
</tr>
<tr>
<td>Secondary Over-Voltage</td>
<td>1.05</td>
<td>the allowable overvoltage threshold (Vpu)</td>
</tr>
<tr>
<td>Secondary Voltage Deviation</td>
<td>5</td>
<td>the allowable percent voltage deviation</td>
</tr>
<tr>
<td>Regulator Voltage Deviation</td>
<td>50</td>
<td>the allowable regulator voltage change threshold (%V)</td>
</tr>
<tr>
<td>Thermal for Load</td>
<td>100</td>
<td>the allowable thermal threshold for forward power flow (% of normal rating)</td>
</tr>
<tr>
<td>Thermal for Gen</td>
<td>100</td>
<td>the allowable thermal threshold for reverse power flow (% of normal rating)</td>
</tr>
<tr>
<td>Additional Element Fault Current</td>
<td>10</td>
<td>the allowable additional fault current threshold (%)</td>
</tr>
<tr>
<td>Breaker Relay Reduction of Reach</td>
<td>10</td>
<td>the allowable reduction in fault current threshold (%)</td>
</tr>
<tr>
<td>Sympathetic Breaker Relay Tripping</td>
<td>150</td>
<td>the allowable zero sequence current threshold (A)</td>
</tr>
<tr>
<td>Unintentional Islanding</td>
<td>100</td>
<td>the allowable DER generation beyond switchable elements threshold (% of minimum load at the switchable element)</td>
</tr>
<tr>
<td>Fault Current Contribution</td>
<td>1.2</td>
<td>the fault current contribution of the DER considered in the analysis (pu of full output current)</td>
</tr>
<tr>
<td>Penetration Interval</td>
<td>0.1</td>
<td>minimum penetration increment for analysis (MW)</td>
</tr>
<tr>
<td>Maximum Penetration Low kV</td>
<td>10</td>
<td>how high to analyze for low kV class feeders (MW)</td>
</tr>
<tr>
<td>Maximum Penetration High kV</td>
<td>20</td>
<td>how high to analyze for high kV class feeders (MW)</td>
</tr>
<tr>
<td>Maximum Penetration Multiplier for Small Distributed DER</td>
<td>1</td>
<td>how high to analyze for distributed DER analysis (pu of peak load)</td>
</tr>
<tr>
<td>Maximum DER Output Change for OV/UV</td>
<td>100</td>
<td>the power output change of the DER considered in the analysis, used for overvoltage and undervoltage metrics (% of nameplate)</td>
</tr>
<tr>
<td>DER Power Factor</td>
<td>1</td>
<td>power factor of the DER considered in the analysis, positive is inductive</td>
</tr>
<tr>
<td>Include Existing DER</td>
<td>0</td>
<td>1: include DER from the model in the DRIVE HC analysis, 0: do not include</td>
</tr>
<tr>
<td>Include Losses</td>
<td>0</td>
<td>1: Yes, 0: No</td>
</tr>
<tr>
<td>Minimum limit for Ratings</td>
<td>1</td>
<td>Ignore element thermal ratings in the thermal HC analysis if below this value (A)</td>
</tr>
<tr>
<td>Maximum limit for Ratings</td>
<td>1000</td>
<td>Ignore element thermal ratings in the thermal HC analysis if above this value (A)</td>
</tr>
<tr>
<td>opflex_threshold</td>
<td>100</td>
<td>the allowable DER generation beyond switchable elements threshold (% of minimum load at the switchable element)</td>
</tr>
<tr>
<td>3V0_threshold</td>
<td>100</td>
<td>the allowable DER generation on the substation threshold (% of minimum load on the substation transformer)</td>
</tr>
<tr>
<td>ExcludeExistingOVviolations</td>
<td>1</td>
<td>1: adjust thermal and voltage violations to just within threshold, 0: do not adjust</td>
</tr>
<tr>
<td>PeakLoad</td>
<td>1</td>
<td>1: use offpeak load conditions in HC analysis, 0: do not use</td>
</tr>
<tr>
<td>OffPeakLoad</td>
<td>0</td>
<td>1: use offpeak load conditions in HC analysis, 0: do not use. If neither peak or offpeak are selected, opppeak will be analyzed</td>
</tr>
<tr>
<td>MiddayPeakLoad</td>
<td>0</td>
<td>Not Applicable</td>
</tr>
<tr>
<td>MiddayOffPeakLoad</td>
<td>0</td>
<td>Not Applicable</td>
</tr>
<tr>
<td>maxstep</td>
<td>20</td>
<td>maximum penetration increment to take in the HC analysis (MW)</td>
</tr>
<tr>
<td>stepreduction</td>
<td>0.5</td>
<td>This is the reduction in penetration increment to take from the approximated HC value (%)</td>
</tr>
<tr>
<td>IncludeOV</td>
<td>1</td>
<td>Option to bypass analysis 1: include overvoltage analysis, 2: do not include. Will be discontinued in next verion.</td>
</tr>
<tr>
<td>IncludeUV</td>
<td>1</td>
<td>Option to bypass analysis 1: include undervoltage analysis, 2: do not include. Will be discontinued in next verion.</td>
</tr>
<tr>
<td>IncludeVdev</td>
<td>1</td>
<td>Option to bypass analysis 1: include voltage deviation analysis, 2: do not include. Will be discontinued in next verion.</td>
</tr>
<tr>
<td>IncludeRVdev</td>
<td>1</td>
<td>Option to bypass analysis 1: include regulator voltage deviation analysis, 2: do not include. Will be discontinued in next verion.</td>
</tr>
<tr>
<td>MinZstep</td>
<td>0.01</td>
<td>The change in impedance must be greater than this value to conduct between two buses to conduct a voltage-based hosting capacity analysis.</td>
</tr>
<tr>
<td>MaxTapRegs</td>
<td>0</td>
<td>Push voltage profiles based on the bandwidth of the regulators. i.e., voltages pushed up for overvoltage HC analysis</td>
</tr>
<tr>
<td>LSdeploy</td>
<td>0</td>
<td>consider DER distributed across 1: all 3ph feeder nodes, 2: front half (based on resistance from feederhead) of feeder 3ph nodes, 2: back half (based on resistance from feederhead) of feeder 3ph nodes, 4: Use a user defined file (may not apply)</td>
</tr>
<tr>
<td>deploydist</td>
<td>1</td>
<td>consider DER distributed 0: non-uniform, 1: uniform. Uniform is DERof equal size across all locations in LSdeploy, non-uniform weights larger DER to locations further from feeder head.</td>
</tr>
</tbody>
</table>
event. This is done by setting OpenDSS in dynamics mode and at every time step, the voltage sags/swells are induced at the substation via an external voltage source. The simulation runs from 0-5s with a step size of 4ms. The played in voltage sags/swells parameter values at the substation are user selected and set as tabulated in Table 4 and plotted in Figure 4 for Group A.

<table>
<thead>
<tr>
<th>Voltage Event</th>
<th>Group A</th>
<th>Group B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sag</td>
<td>0.94, 0.93, 0.92, 0.91, 0.9, 0.89</td>
<td>0.5, 0.49, 0.48, 0.47, 0.46, 0.45</td>
</tr>
<tr>
<td>Swell</td>
<td>1.11, 1.12, 1.13, 1.14, 1.15, 1.16</td>
<td></td>
</tr>
</tbody>
</table>
3. Simulation results

Simulations were executed for all combinations of Group A and Group B inverters from 0-100 in increments of 10 (i.e. A=100 and B=0, A=90 and B=10, …, A=0 and B=100) for all four location ranges. Although the total amount of simulations was extensive and time intensive, computation time was significantly reduced by using Python parallel processing. This allowed for all four location ranges to run all voltage sags/swells and combinations simultaneously. Figures 8 and 9 display the voltage profile when 100 Type A and Type B DERs respectively are placed throughout the feeder. The rise in voltage profile due to the presence of DERs is observable from these figures. This rise in voltage profile can impact the tripping profile of DERs to voltage events on the transmission system.

At the end of the event, i.e. at 5s, the aggregate power from the remaining DERs that were able to ride through the event was stored and the ratio of this remaining DER’s active power is calculated by dividing the total remaining power by the total initial power. For a single simulation of 100 Group A inverters the total active power before any voltage sag/swell is induced is 1.5MW. The total output of the DERs before and after the voltage events are shown in Figure 5, Figure 6 and Figure 7.

Time-Current Characteristic Curve (TCC_Curve) is used to define the voltage relays that monitor each DER. These relays require time curves and they vary with accordance to over-voltage/under-voltage of Group A and B inverters following Table 3 under-voltage/over-voltage trip characteristics.

Figure 8 - 8500 Node Model LN Voltage Profile with balanced load and with 100 Type A DERs

Figure 9 - 8500 Node Model LN Voltage Profile with balanced load and with 100 Type B DERs
Additionally, for each combination, 20 simulations were carried out. Here, one simulation is defined as the process of random selection of 100 locations for the DERs followed by applications of all voltage sags/swells. However, since the 100 locations were selected randomly from a larger subset of suitable locations, 20 simulations Monte Carlo simulations were carried out to account for the uncertainty in actual location of an individual DER. The results of the ratio of DER active power with respect to sag level at the substation are shown in Figures 10 and 1. Based on these results, one can conclude that the location of high concentration of DERs plays a role with how many trip with each voltage event. This is predominately due to the nature of the feeder. The majority of available three phase buses are located between the range 5-10km, lining up closely with the results obtained from the full range simulation (0-15km). Availability of three phase buses in the 0-5km range is smaller than the others by a factor of 3. Furthermore, hosting capacity at the end of the feeder is 1.7MW which is half of the total maximum power injection possibly causing instability during the 0-5km range simulation. The red line in the plot depicts a possible characteristic for the DER_A model’s voltage trip settings.

Figure 11 displays the results for 100 DERs, 50 Group A and 50 Group B inverters. The lower band of each plot provides the ratio of active power after each sag for Group B inverters with under-voltage trip of 0.5pu (blue). The same applies for Group A inverters, but with a higher under-voltage trip value of 0.88pu (blue). Since the over-voltage trip characteristics are the same for both inverter types, the ratio of active power after the voltage sags has a linear trend (green). These results provided the necessary preliminary trip characteristics to parameterize the DER_A model. Most of the DER_A parameters are determined based upon the grid code assumed for the individual inverters on the feeder. As the basis of this study is to use the IEEE Std 1547-2003 as the grid code for the inverters, the parameter values follow from this standard. This standard does not mandate voltage control from distribution
connected inverters and also requires unity power factor operation. Thus, the gain $K_{qv} = 0$ and the flag $PfFlag = 1$. Due to these settings, the values of the voltage control loop deadband ($dbd1$, $dbd2$) do not matter. Additionally, since the intended operation is unity power factor, the value of the time constant $T_p$ also does not matter.

Further, since there is no voltage control and a unity power factor operation is set, the current priority on the inverters must be active current priority. This results in the $PqFlag=1$. Along with this current priority, the maximum value of current that can be injected is assumed to be 1.2pu. Although no standard specifies maximum value of current, this value is obtained based upon a general rule of thumb obtained from inverter manufacturers.

The IEEE Std 1547-2003 also does not mandate any form of frequency control. Thus, the $FreqFlag = 0$ and as a result, the value of other variables in the frequency control loop do not matter. This leaves only the voltage trip logic and few time constants to be parameterized. The time constants $T_{iqg}$, $T_g$, and $T_v$ are given values of 0.02s. This amounts to little more than one cycle of a 60 Hz sine wave. The exception is the time constant $T_{rv}$ which is given a value of 0.005s. The reason for this is that in the OpenDSS simulation, the relay models do not have a setting to represent measurement delay, thus, in order for the voltage trip logic of the DER_A model to provide similar results as obtained from the detailed distribution simulation, the this voltage measurement transducer time constant is set to as low a value as possible while still maintaining numerical stability of the simulation. Since the positive sequence simulation is carried out at a time step of 4.1ms (quarter cycle on a 60 Hz basis), the time constant was given a value of 5ms. Of course it could have been possible to completely bypass this voltage measurement transducer block by providing a time constant value that is lower than the time step of integration, but it was felt that this block should remain in the control loop as in reality, there would always be some time constant, however small, in measurement of voltage.

Finally, the parameters of the trip characteristics can be obtained from observing the value of the cut-out points of the red curve in Figure 14. The values in the figure are however values of voltage at the substation as in the detailed OpenDSS simulation, the substation voltage was the one which was varied. The DER_A model’s trip characteristic however requires thresholds that would correspond to the model’s terminal voltage which is different from the substation bus as can be seen from Figure 12. Thus, in order to parameterize the voltage thresholds in the DER_A model, the threshold values obtained from the detailed OpenDSS simulation are reduced by the voltage drop across the feeder. These values were then implemented and compared to the DER_A model performance. To do so, the benchmark test system shown in Figure 12 was used.

![Figure 12 - DER_A Benchmark Test System](image-url)
DER_A voltage break points for low/high voltage cut-out of inverters (vl0, vl1, vh0, vh1) correspond to the DER_A model’s terminal voltage, where the values provided by OpenDSS correspond to the substation voltage. The DER_A model block diagram is displayed in the Figure 13 containing the preliminary parameters such as voltage breakpoints and timers.

With these parameters, the same voltage sags/swells were played-in in a positive sequence simulation software (GE – PSLF™ [12]) to observe the response of the DER_A model. The results were plotted with respect to the results obtained from OpenDSS simulations. The DER_A model with the parameters displayed above was placed at both Bus Y and X of the benchmark test system. Figure 14 shows the comparison between the two. It can be seen that the results from the DER_A model largely align with the outputs from the OpenDSS simulation. The solid black horizontal lines in the figure are the ratio of post disturbance active power to pre-disturbance active power as measured from the DER_A model. The sag/swell level corresponding to each line are the x-axis values of the point on the black horizontal line that is closest to the red linear characteristic. The solid black horizontal lines correspond to the DER_A model while the blue and green dots correspond to the OpenDSS simulation. The red line is the characteristic drawn through the blue and green dots to obtain the voltage trip characteristic for the DER_A model.

4. Conclusion

In this paper, an improved parameterization process for the DER_A model has been discussed. The process makes use of the popular OpenDSS platform. Due to the increased computational efficiency, it is possible to
observe the impact of random placement of individual DERs along a feeder while also observing the impact of the distance of the individual DER with respect to the substation. Both these criteria play a crucial role in determining the number of DERs that remain connected to the system following a voltage event. Using the simulation results from OpenDSS, parameterization of the DER_A model was made possible and preliminary positive sequence simulation results align with the performance characteristics from the OpenDSS simulations.

While validation of the performance of the aggregated DER_A model is best conducted against observed measurements, unfortunately, to date and to the author’s knowledge, there have been no measurements recorded at the substation level that can point towards this type of DER tripping. EPRI is presently working with few utility members to evaluate the possibility of setting up data recorders in order to obtain such information for future behaviour. Therefore, in the interim, the capability obtained from an OpenDSS simulation (whose validity has been benchmarked for quite a few years now and use of OpenDSS is now considered to be an industry standard) is used as a proxy for measurement data in order to parameterize the DER_A model.

Some of the future work to be done is to evaluate different types of feeders such as rural, semi-urban, and so on to see whether the results would hold the same trend or not. Additionally, only 3-ph inverters and balanced voltage events were considered in this work. The impact of 1-ph inverters and unbalanced voltage events is to be evaluated in the future. For now, the DER considered has been a PV resource. However generally, if the DER is interfaced through an inverter (say a battery), then the same results should hold as the characteristics of the inverters used for PV would largely be the same as inverter used for PV. Consideration of this variation in inverter characteristics is also a topic of future research.

Accommodating higher shares of PV might violate the hosting capacity of the feeder. In this regard, if a higher share is to be accommodated, industry practice on ensuring adequate hosting capacity is first to be investigated. Subsequently, upon per unitization of the results based upon the MW of load, the parameters of the model can be derived. This derivation of the parameters based upon the per unit results is a topic that is presently being investigated at EPRI.

5. Bibliography