COORDINATION OF AC PROTECTION SETTINGS DURING ENERGISATION OF AC GRID FROM A VSC HVDC INTERCONNECTOR

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Abstract

The Relatively low short circuit current limit of VSC converters in comparison to conventional synchronous generation can affect grid short circuit and dynamic characteristics during a black start. This can impair protection performance at both transmission and distribution levels. This paper investigates the protection issues related to black start and system restoration using VSC HVDC as the black start resource. A case study on the Scottish transmission system is used to examine the implications for protection devices operating in the unique scenario where the network is restored from HVDC. Given the greater flexibility in its black start operation, both traditional step by step energisation and soft energisation from the VSC HVDC are examined finding that soft energisation can mitigate the potential for large transformer inrush currents exciting resonances on the network.

1. Introduction

Decarbonisation of energy networks has meant conventional fossil fuel generation plants are being replaced with clean renewable generation. Traditionally, these fossil fuel plants would have been key components of a utilities black start and restoration plan. For example, "top down" black start plans involve the self-starting of the black start unit and energising a path to a nearby load to construct a power island, which is grown out towards other large fossil fuel plant which are used as additional energy and voltage control sources for the supporting of continued restoration. Removal of the fossil fuel generation sources means that the industry is looking to non-conventional sources for black start and restoration planning. Energy resources like wind power and solar power have a role to play in future restoration plans and is an area of continued research [1-3].

Interconnectors tend to represent high capacity connections to a system, at or up to the scale of the maximum loss level supported by that systems frequency containment policy and its availability and flexibility for cross-border trade is core to its market activity. An interconnector utilising Voltage source converter-based high voltage direct current (VSC HVDC) therefore has the capacity and the availability to become a valuable black start resource. The inherent controllability of a VSC means that the HVDC control can be operated in island mode on the and provide a stiff voltage and frequency on the ac side requiring black start, assuming the sending end of the HVDC is an active grid. Early in restoration when much active power flow may not be required, the VSC has the capability to act as a STATCOM providing reactive support to the restoring grid supporting circuit re-energisation and subsequent voltage containment. Later in restoration, the HVDC interconnector has a large active power resource to support load pickup and synchronisation to other islands whilst continuing to regulate the voltage and frequency of the power island which is in the process of being enlarged. There have been a few practical experiences using HVDC as a black start resource. After the US North Eastern blackout of 2003, the Cross Sound Cable, a VSC HVDC interconnector between New England and Long Island was used to energise portions of the Long Island grid [4]. There have been a number of black start tests using HVDC as the primary source, particularly using interconnectors between asynchronous areas, where the likelihood of both sides of the HVDC being blacked out is reduced. Black start tests on EWIC and Skaggerak 4 have been well documented [5,6]. These tests have determined several unique issues with both protection and operation of HVDC while restoring the ac grid. The major conclusion in both series of tests is the importance of studying the problem in detailed electromagnetic transient studies to understand and quantify the potential issues [7]. Furthermore, there is no substitution for field tests to determine the suitability of a black start plan.

A consequence of retirements of synchronous plants is reduced inertia and fault levels. For a black start condition using existing VSC-HVDC systems, there is no inertia present in the early stages with limited inertia present across restoration. Frequency management via rapid ramping controls maintain the power island however given the lack of inertia voltage angles within the power island may move dynamically as this is occurring. During a black start the ac system is also reliant on the black start resources to provide enough fault current to maintain a stable restored grid. The short circuit current of a VSC is limited by the overload limits of the power electronic switches, this limit may affect grid short circuit and dynamic characteristics during the energization of an ac grid from a

VSC HVDC system; thus, impairing protection performance at both transmission and distribution levels.

2. Protection considerations when black-starting from VSC HVDC

Restoration of an ac grid from a voltage source converter presents several challenges with regard to grid operation and protection. Line differential protection, impedance protection, busbar protection, breaker failure protection, overcurrent protection and transformer differential protection schemes are potentially affected. In addition, there is potential maloperation of other protection functions such as directional polarisation, frequency measurement algorithms, memory voltage, power swing detection, or phasor frequency tracking and compensation. In such cases, the sensitivity and reliability of the protection schemes will be degraded, which may pose dangers to public safety and grid assets as well as prevent or delay system restoration.

2.1. VSC HVDC current limits

Power electronics used for megawatt-class inverters tend to have very low, if any, overload capacity. They are typically designed to ensure that they can deliver full rated power over normal operating voltage range. This results in typical current limits of the order to 1.1-1.2pu [8]. The exact response of the VSC to short circuits depends on the real and reactive power control mode with dynamic reactive power response being common in Europe [9,10]. This contrasts with synchronous generators which can typically provide short circuit currents of the order of 5-7pu current [8].

Protection devices which operate using current measurements such as overcurrent, impedance, and unit protection relays typically include a minimum operating current setting. This is often configured based on factors such as minimum current transformer accuracy (e.g. 5-10% of CT continuous rated current), some percentage of the protected device's rated load (e.g. 120% of busbar rated current), or some percentage of minimum fault level (e.g. 80% of short circuit current under N-1 or G-1 contingency). The reduced short circuit current magnitudes during system restoration could compromise the ability of these protection devices to detect faults. This is particularly the case if the minimum operating current is configured based on device rated current or N-1 short circuit current magnitude.

2.2. VSC HVDC negative sequence current characteristics

Except for Germany [11], few if other grid entities have created requirements for VSC-interfaced energy sources to provide negative sequence current during unbalanced grid conditions such as single or two-phase faults. It has been common practice for VSC HVDC to incorporate negative sequence current control loops to damp out negative sequence components as these can give rise to even harmonic distortion and overvoltages on the dc side [12]. The VSC controller time-constants typically result in the negative sequence current being suppressed within 2-3 cycles. The impact of the absence or much-reduced presence of negative sequence current is different depending on the protection function, the relay manufacturer's algorithms, and the settings applied [8]. For this reason, it was considered important to use relay-specific models in simulations as well as performing lab-testing of the relay hardware. At a high level, the main impact is on directional polarisation functions, negative sequence overcurrent, and negative sequence unit protection [13].

2.3. Post-fault power recovery

A feature of the 2019 demand disconnection event in Great Britain was an unexpected post-fault power recovery behaviour from 800 MW Hornsea wind farm. This recovery resulted in a transient under-voltage which led to wind turbine overcurrent protection tripping. The reactive power swing was due to a change in collector network impedance associated with outages on the collector network at the time [14]. Similar issues could potentially exist with VSC HVDC during system restoration, but a thorough simulation and analysis at the design stage should avoid such behaviour.

2.4. Transformer inrush and line energisation

Transformer energisation usually results in severely distorted inrush current with high 2nd harmonic content due to the non-linear flux-current characteristics of the iron core. Under normal grid operating conditions with a strong source, the initial magnitude of the inrush current can be up to seven times the transformer rated current with an exponentially decaying characteristic [15]. The exact magnitude and shape of the inrush current depends on the core characteristics and remnant flux in the transformer core. This is a function of the point on-the voltage waveform at which each circuit breaker opened when the transformer was last switched out, and the point on the voltage waveform at which each of the three circuit breakers close to re-energise the transformer. The most severe inrush current typically decays within the first hundred milliseconds. This distorted inrush current still exists when transformers are energised from a VSC HVDC, although the VSC can only supply limited magnitude of current and remain stable for limited magnitude of harmonic distortion.

Unit protection uses current transformers on the windings with external connections to detect faults inside this protected zone. As current transformers are not normally installed on the internal delta-connected windings which are commonly used to provide a circulating path for the inrush current, the inrush current is seen as an internal transformer fault by the unit protection. To prevent unit protection from tripping during transformer energisation, inrush detection is commonly applied. A common approach to implementing this feature is to block differential function on one or more phases (cross-blocking) if 2nd harmonic current exceeds a set percentage of fundamental frequency current. Default settings vary between manufacturers, but 15% is a typical.

As inrush current can far exceed transformer rated current, overcurrent and impedance protection can be similarly exposed to incorrect tripping during transformer energisation. Again, inrush detection functions are employed to prevent incorrect protection operation. Inrush detection is not always applied to line protection relays, so there is a risk of tripping during system restoration. This is particularly the case when switch-on-to-fault (SOTF) protection is used where current is used to detect line energisation and not circuit breaker status or line voltage. Inrush detection functions often include a time-limit so that tripping is not compromised if a fault occurs during energisation. This time-limit – where applied to transformer unit protection - could also provide a means to automatically disconnect the transformer should the inrush current excite a harmonic resonance with the VSC HVDC. The magnitude of the current during such a resonance may not be high enough for the transformer impedance or overcurrent protection to operate, depending on the magnitude of the resonant current and the settings applied to the relays.

2.5. Application of soft energisation using VSC HVDC

Soft energisation can be used to energise transmission grid and one or more unloaded transformers. It has been used during system restoration tests in the past using synchronous generators and VSC HVDC [7]. With VSC HVDC this is achieved by slowly ramping the voltage from near zero volts up to rated voltage. The speed with which the voltage is ramped should be slow enough to mitigate the risk of transformer inrush current exciting a resonance, while being fast enough to ensure that faults can be detected and isolated quickly without causing damage or endangering safety. Some consideration should also be given to the impact on auxiliary power supplies and connected equipment.

Where under-voltage protection is deployed within the grid being energised – for example on the grid side of the HVDC converter transformer – the ramp must be fast enough to avoid this under-voltage protection from tripping. Alternatively, the under-voltage protection could be temporarily disabled during soft-energisation, although this may not be practical or preferable in some applications.

During soft-energisation the VSC follows a ramp in its voltage setpoint. The reactive power output responds to the setpoint and regulates the terminal voltage. If a fault is present, the reactive power (and hence fault current) will depend on the voltage setpoint and the impedance between the VSC and fault. At the start of the voltage ramp the fault current could thus be very low and likely to be below the grid protection minimum operating current. The fault clearance time will thus depend on the fault location and ramp rate. If the ramp takes place over tens of seconds or minutes, this could lead to long fault clearance times. Once the protection trips and isolates the fault, the voltage will immediately recover. If there are any transformers nearby, this jump in voltage will give rise to inrush current, which could excite the resonance which soft-energisation was intended to help avoid. This effect may limit the extent of network which can be soft-energised.

2.6. Re-connection of conventional power plants

Once the synchronous generators connect to the black start island the grid short circuit current level will increase; in general, this increase in fault level and inertia should reduce the risk of slow protection operation and maloperation. If the synchronous generator should trip, however, the HVDC can automatically regulate voltage and frequency by providing additional real and reactive power. As this response can be very fast it can result in large magnitude rate of change of frequency; this may be important to consider with respect to loss of mains protection on distribution-connected generation within the resupplied distribution grids.

2.7. Re-connection of Wind Power Plants, Solar PV, and Battery Energy Storage

To re-connect inverter-interfaced resources such as wind or solar power plants certain technical requirements must be met. Among these one of the most important is the short circuit ratio. Almost all commercial inverter-interfaced power plants operate in grid-following mode and thus need a relatively strong grid in order to ensure they provide stable response to grid disturbances [3]. The short circuit ratio is often in the range of 3 to 5. This may limit the number of inverter-interfaced power plants which can be re-connected during the early stages of system restoration, but, for those which are viable for reconnection the short circuit current ratio requirement should also ensure that the minimum operating current is exceeded for protection relays along the restoration path. These factors also mean that the net load being restored to a power island may be difficult to quantify and may fluctuate in scale across the period of its initial re-energisation, something that the VSC-HVDCs frequency and voltage control strategies would need to be robust to.

2.8. Synchronisation of black start islands and rebuilding grid to full integrity

Once two or more black start islands have been established and the path to their synchronising substation energised the islands are ready to be re-synchronised. Assuming the VSC HVDC is still in island control mode , it should remain in this mode until after the grids have been synchronised. When re-synchronising black start islands any frequency or phase angle difference may result in power swings between the two grids. It is possible in future restoration across two power islands that these two islands could be entirely or mainly supported by VSC-HVDC convertors in island control mode. Careful analysis of these power swings is important as they can cause impedance relay tripping unless power swing blocking is employed [16], further analysis of converter control strategies involved in such re-connections is also appropriate to avoid excessive interaction.

3. Case Study: Black Start of a portion of the Scottish grid from VSC-HVDC

In black start scenarios the aim is to expand power islands quickly and safely to pick up more generation and load. This study investigates restoration of a portion of the Scottish ac transmission network. The 400 kV ac network is energized from a generic model intended to represent a future 1,400 MW VSC HVDC interconnector with black start control. Figure 1 displays a representative diagram of the HVDC connected to the restoration path. The restoration plan is to pick up the ac network from the HVDC and expand the power island to synchronise with a synchronous generator. This case will examine transformer energisation, line energisation, soft start of the HVDC and short circuit faults. The modular multilevel HVDC model has been used with generic control parameters and is operated in island control mode during the restoration. Further details on island mode control can be found in [17]. The network is modelled in DIgSILENT PowerFactory with simulations carried out using the electromagnetic transients (EMT) mode.

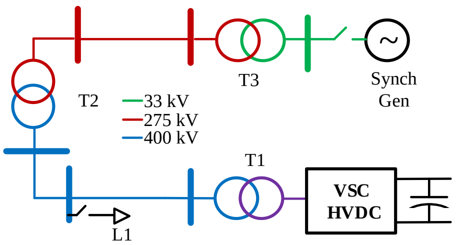

Figure 1: Representative diagram of the restoration path

3.1. Transformer and Line Energisation Tests

The first portion of the study investigates a traditional ac switching process, bringing the voltage at the ac terminals of the HVDC close to nominal voltage and switching in lines and transformers one by one. Figure 2 shows one example of energising the transformer T1, the inrush currents of the transformer are clearly visible. These inrush currents depend on the remnant flux and point on wave of switching but in most cases they are damped out after 2 seconds.

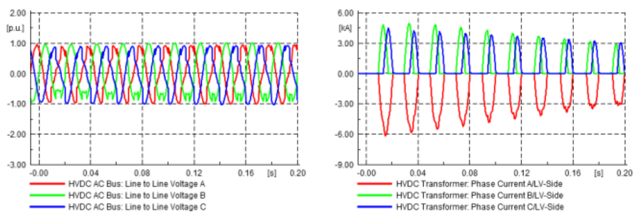

Figure 2: Transformer voltage and current clearly showing inrush during energisation of T1

Figure 3 shows the next switching step adding a long ac line after the 400 kV substation. Each switching action creates inrush currents and voltage fluctuations that the HVDC must control, damp, and ride-through. Switching long ac lines can excite resonances in the system and lead to an undamped resonance condition. In this case the transient harmonic frequency is around 300 Hz and is not damped leading to overvoltage protection on the HVDC tripping at t=0.9s.

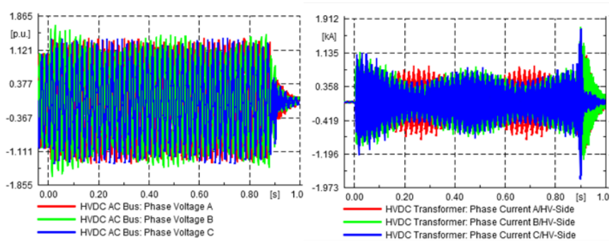

Figure 3: Energisation of long 400 kV AC line without load damping in the system, overvoltage protection trip at t=0.9s

Specific damping controls developed on the HVDC controller can be added to minimise the influence of resonance. These controls need to be designed, tuned and tested for the specific ac network. Another option for the operator is to connect load to provide damping, if it is available. Early in restoration there is no load on the network to provide damping. In this study, a 40 MW industrial load (L1) is present at a 33 kV bus connected via intermediate 132 kV bus (not shown on diagram) to the 400 kV network.

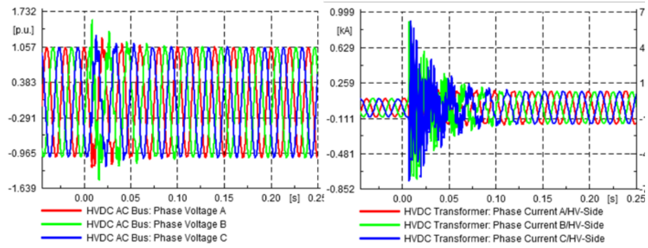

Figure 4: Energising a long 400 kV ac line with load providing damping.

Figure 4 shows the energisation of the same long ac line as Figure 3. Energising the load provides sufficient damping to continue energising ac lines and transformers along the restoration path. It is worth noting that operator may not have available load to switch in and provide damping. In these scenarios the operator may rely on specific controls developed on the HVDC to damp resonances.

Figure 5 shows the energisation of a 400/275 kV 1000 MVA transformer. The switching action causes inrush currents which excite a resonant condition in the network causing a temporary overvoltage; the HVDC over-voltage protection operates to de-energise the grid. In a system restoration situation this would necessitate the restoration path being energised once again. The connection of load into the network provided sufficient damping to prevent these overvoltages.

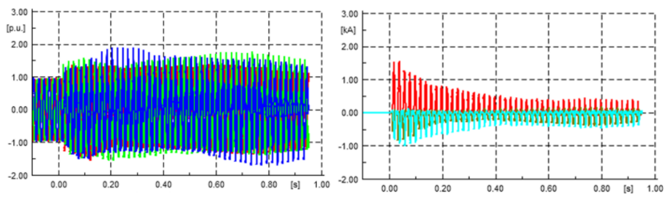

Figure 5: 400/275 kV transformer 3 phase voltage and current showing inrush exciting a resonant condition

With the load added to the grid statistical switching simulations of subsequent transformer energisation were performed with a time-variation in A-phase circuit breaker close time of +/- 10ms and B-phase and C-phase variation of +/-0.05 ms around the A-phase circuit breaker close instant. Figure 6 shows the impedance zones and trajectory seen by the impedance protection relay on the 400 kV line supplying to the transformer as an example of one of these simulations. Despite the magnitude of the inrush current the impedance does not enter any of the tripping zones.

Using VSC HVDC to energise a network component-by-component in the traditional manner is practical for this case study, but care is needed in ensuring sufficient load is connected or that sufficient HVDC damping controls are available and tested to mitigate resonances that can be excited by transformer inrush or line energisation.

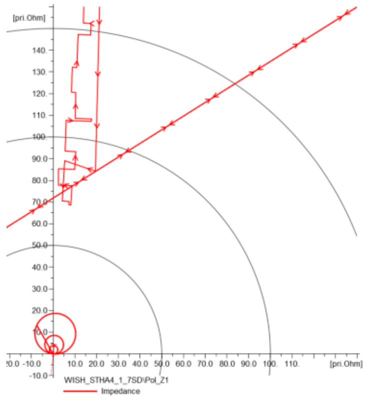

Figure 6: impedance zones and trajectory seen by the impedance protection relay on the 400 kV line

3.2. Soft Energisation

An advantage of using HVDC for black start is a granular control of voltage across a wide range of timeframes and magnitude and therefore the ability to soft start the network via a defined strategy of voltage ramping by the VSC-HVDC. With this approach multiple lines and transformers are energised in a single pass with the HVDC terminal voltage ramped from zero to rated voltage over a period of seconds to minutes. This can much more rapidly re-energise the network area that the HVDC is capable for supporting load for, ahead of re-energising that load. The ac breakers on the entire restoration path are closed (the load is disconnected) and the voltage is ramped up slowly.

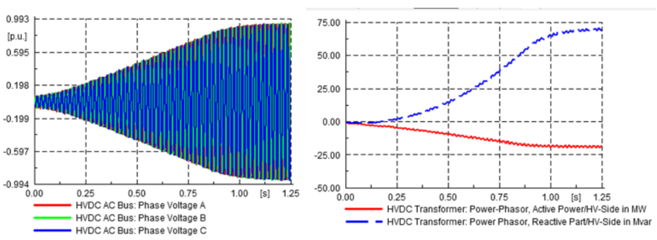

Figure 7: HVDC Voltage, active and reactive power during soft start of restoration path

Figure 7 shows the voltage, current, active and reactive powers at the HVDC terminals following the soft start ramp over a period of 2 seconds. Transients and transformer inrush currents are reduced, and no unstable resonance is observed. This soft energisation can only be used once in the black start strategy to build up the initial network, subsequent stages must then follow a traditional path as previously outlined. In any soft start energisation there is a risk across the extent of network being re-energised there is a latent fault existing which may have resulted from the conditions leading up to the black start or actions in response to it. As such it is important that this strategy is also tested for robustness to energisation onto a latent network fault.

The soft energisation sequence was repeated in Figure 8, but with single and three-phase faults at different locations in the grid. It was observed that it took approximately 0.2 s in the worst case for current to reach the unit protection minimum operating current and the relays to trip; however, after the circuit breakers tripped and isolated the faulted line, the voltage on the healthy part of the grid recovered rapidly. This step-change in voltage had a similar effect on nearby transformers as a regular energisation and so significant inrush current flowed and again excited a harmonic resonance. This experience would suggest that soft-energisation should be used with caution where the risk of faults on the grid is abnormally high.

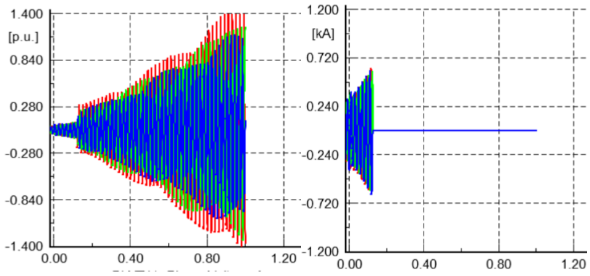

Figure 8: Voltage and current during soft-start of restoration path with permanent 3-phase fault

3.3. Grid Faults and Loss of Generation

Protection systems along the restoration path were modelled with manufacturer-specific models and parameterised using site-specific data. The relays included electromechanical, static, and numerical devices. After performing a coordination study of impedance protection relays EMT simulations were performed to examine the response of the relays considering the HVDC controller characteristics and dynamic behaviour. Due to the power rating of the HVDC and tap-position of the grid-transformer there was a maximum of 2.3 kA available for close-in faults on the 400 kV grid.

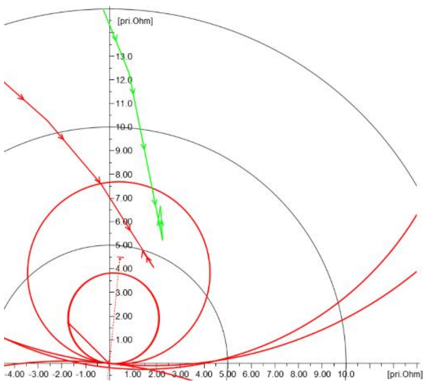

Figure 9: Relay characteristic and impedance on 400 kV line

With current transformer ratios of 2000/1A and minimum operating currents in the range of 0.1-0.2pu the HVDC was found to be capable of supplying sufficient short circuit current for protection to quickly isolate low-impedance faults all the way to the synchronous generator. The use of auto-transformers with grounded neutral connections also ensured sufficient zero sequence current for ground fault elements to operate. No protection relays on the path used negative sequence overcurrent, negative sequence unit protection, or negative sequence directional polarisation and so the absence of negative sequence current from the VSC had limited impact compared to the other issues discussed. Figure 9 shows the impedance relay characteristics and the relay calculated impedance for a three-phase fault at 95% along a 400 kV line. The relay can be seen to correctly detect the fault in Zone 2.

The VSC will regulate frequency up to its available real power limit. Simulations were performed to study the response of the system to the tripping of synchronous generators in the black start island. Figure 10 shows the frequency response and rate of change of frequency following the tripping of 220 MW of hydropower generation when approximately 300 MW of load has been picked up. The response of the VSC HVDC occurs within cycles of the tripping, but this also results in a correspondingly high ROCOF which could lead to disconnection of distribution-connected generation by loss-of-mains protection.

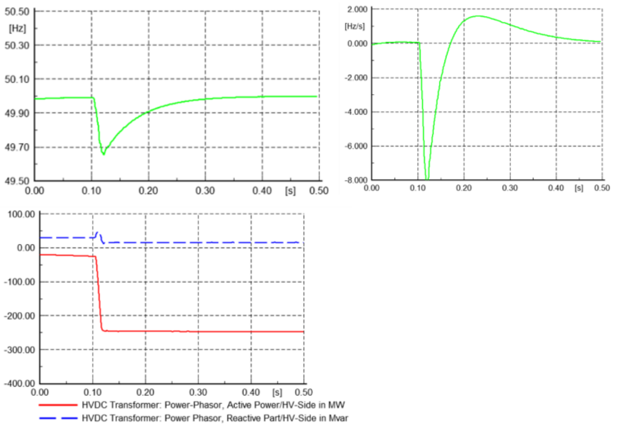

Figure 10: Frequency, Rate of change of frequency and Active & Reactive power response of HVDC during loss of synchronous generation

4. Conclusions

This paper has evaluated the protection implications of black starting and restoring an ac network from VSC HVDC interconnector. Reduced short circuit current magnitude and reduced negative sequence current magnitude from inverter interfaces can affect the ability of protection devices to detect faults and correctly determine fault direction during the early stages of system restoration. Potential mal-operation of protection during low inertia black start and restoration scenarios are discussed. Soft-energisation from VSC HVDC is assessed to mitigate the risk of transformer inrush current exciting harmonic resonance. In a soft start scenario, the presence of faults and fast voltage recovery after fault clearance could cause transformer inrush.

5. Acknowledgments

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