Assessment Guide: GMD Harmonic Impacts and Asset Withstand Capabilities

2016 TECHNICAL UPDATE

Assessment Guide: GMD Harmonic Impacts and Asset Withstand Capabilities

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3002006444
Final Report, August 2016

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THE FOLLOWING ORGANIZATION, UNDER CONTRACT TO EPRI, PREPARED THIS REPORT:

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NOTE

Acknowledgments

The following organization, under contract to the Electric Power Research Institute (EPRI), prepared this report:

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This report describes research sponsored by EPRI.

This publication is a corporate document that should be cited in the literature in the following manner:

Assessment Guide: GMD Harmonic Impacts and Asset Withstand Capabilities. EPRI, Palo Alto, CA: 2016. 3002006444.

Abstract

Solar disturbances can induce quasi-dc geomagnetically-induced currents (GIC) through transformers in a transmission system, potentially resulting in asymmetric, or part-cycle, saturation. This saturation injects large and distorted transformer exciting currents into the system, which includes harmonic components. The flow of the harmonics in the transmission system, and the voltage distortion that results, can adversely impact bulk power system equipment and systems, including protection systems.

NERC TPL-007-1 requires Planners, Transmission Owners, and Generation Owners to perform a GMD Vulnerability Assessment. The Assessment states that the reactive power compensation devices and other transmission facilities that are tripped as the result of protection system operation or misoperation due to harmonics shall be removed from the system models used for steady-state performance. To comply with this requirement, an understanding of the impact of severe harmonic distortion on power system components, protection systems, and control systems is required. The purpose of this guide is to provide a convenient reference resource on the impacts of severe GIC-produced harmonics on equipment and systems.

This guide discusses the harmonic withstand and performance issues of major power system components, including transformers, shunt capacitor banks, generators, cables, overhead lines, high voltage direct current (HVDC) systems, flexible ac transmission system (FACTS) devices, surge arresters, distribution systems, consumer loads, relays, and protection systems.

Keywords

Geomagnetic disturbance
GMD
Geomagnetic induced current
GIC
Harmonics

Executive Summary

Solar disturbances can induce quasi-dc geomagnetically-induced currents (GIC) through transformers in a transmission system, potentially resulting in asymmetric, or part-cycle, saturation. This saturation injects large and distorted transformer exciting currents into the system, consisting of both fundamental-frequency and harmonic components. The fundamental exciting current is reactive, which can potentially lead to voltage depression and potentially system voltage collapse. In addition to the fundamental component, the exciting current of GIC-saturated transformers can have large harmonic components. The flow of these harmonics in the transmission system, and the voltage distortion that results, can also impact bulk power system equipment and systems, including protection systems. The consequences of the harmonic distortion during a severe GMD can extend beyond the routine considerations of power quality; the harmonic issues during GMD can potentially impact system security.

Harmonics during GMD can potentially cause critical components to be tripped during a time of system stress, and can cause permanent damage of major equipment that is not adequately protected from this stress. In particular, tripping of equipment providing reactive resources and system strength can aggravate the fundamental reactive current impacts described above, potentially resulting in voltage instability at a lesser degree of GMD severity than caused by the reactive current alone. Thus, studies of direct transformer saturation impacts and fundamental reactive impacts alone do not provide a complete assessment of bulk power system GMD vulnerability. Harmonic impacts also need to be considered as well.

NERC TPL-007-1 requires Planners, Transmission Owners, and Generation Owners to perform a GMD Vulnerability Assessment, and to develop a Corrective Action Plan if the assessment determines that system performance fails to meet defined criteria. The specification for the GMD Vulnerability Assessment states that the reactive power compensation devices and other transmission facilities that are tripped as the result of protection system operation or misoperation due to harmonics shall be removed from the system models used for steady-state performance. To comply with this requirement, an understanding of the impact of severe harmonic distortion on power system components, protection systems, and control systems is required. The purpose of this guide is to provide a convenient reference resource on the impacts of severe GIC-produced harmonics on equipment and systems.

This guide first discusses the harmonic withstand and performance issues of major power system components, including transformers, shunt capacitor banks, generators, cables, overhead lines, high voltage direct current (HVDC) systems, flexible ac transmission system (FACTS) devices, surge arresters, distribution systems, and consumer loads. Then, with an understanding of the system component harmonic withstand characteristics, relay and protection systems are covered.

Detailed evaluation of the harmonic impact on various types of equipment requires equipment data that are often not easily obtained, and can require specialized calculations that commonly-available harmonic analysis software typically does not support. Therefore, for each type of equipment and where feasible, this guide suggests simplified screening criteria. These criteria are intentionally conservative. Harmonic values exceeding these criteria do not imply that the component will endure excessive duty or trip, but rather indicate that more detailed evaluation of that component is prudent. The screening thresholds suggested in this guide incorporate ample safety factors depending on the uncertainty of the device parameters.

A summary of significant potential impacts of GMD harmonics, and the suggested preliminary screening criteria, are shown in Table ES-1.

Table ES-1
Potential impacts of GMD harmonics and suggested preliminary screening criteria

Potential Impact	**Discussion**	**Screening Threshold[1]**
TRANSFORMERS		
Winding heating due to harmonic current flow through the transformer.	Currents can be caused by saturation of other transformers. Impacts are significantly decreased by the transformer thermal time constant. Very large harmonic currents are required to create damage.	I_{rms} > 1.12 p.u. of transformer rated current (fundamental and harmonics) Root mean square current (I_{rms})

Harmonic blocking or harmonic restraint functions in differential relay schemes inhibit detection of internal faults during a GMD.	Other protection schemes will eventually detect an internal fault, but detection may be delayed and damage increased by blocking or insensitivity of the differential protection if an internal fault occurs during a GMD.	Differential second harmonic current greater than 0.1 p.u.
SHUNT CAPACITORS		
Thermal failure, fuse melting, or overload protection trip due to overcurrent.	Capacitors are likely to have high currents where they form resonances with the transmission system at integer harmonic frequencies.	I_{rms} > 1.35 p.u. (fundamental and harmonics)[2]
Dielectric failure due to excessive voltage.	Capacitor voltages may have highly amplified harmonic components due to resonances. Peak voltage is dependent on the phase relationship between harmonic and fundamental voltage components.	THD_V > 10%, and ΣV_n > 20%.[2,3] Total harmonic distortion (THD)
Capacitor bank protection false trips due to harmonic currents.	Certain protection schemes, such as zero-sequence overvoltage and ground overcurrent (with or without compensation), are vulnerable when applied using static or electromechanical relays. Digital relays are generally immune.	Evaluate in detail any capacitor banks using zero sequence overvoltage or ground overcurrent schemes with static or electromechanical relays.

Capacitor banks implemented as type-C filters overloads due to excess voltage distortion.	These filters provide damping and a low shunt impedance at low-order harmonic frequencies. Their tuning sections are particularly vulnerable to the high levels of distortion during a GMD.	Evaluate in detail any type-C filters tuned to the low-order harmonic range when GMD distortion exceeds the filter's design assumptions.
GENERATORS		
Harmonic current into the stator can cause excessive rotor heating.	The thermal time constant of the generator rotor significantly reduces the potential impact. Generators are largely unprotected from this potential impact.	< 350 MVA, THD_i > 0.107 p.u. 350 – 1250 MVA, THD_i > 0.107 – 0.00447 × (MVA-350) > 1250 MVA; THD_i > 0.067 p.u.
Negative sequence protection incorrectly trips due to relay harmonic response.	Electromechanical and static negative sequence relays are vulnerable due to the passive phase shifting networks used.	Evaluate any major generation units using static or electromechanical negative sequence relays.
Harmonic currents into the stator can cause high-frequency torque that may stimulate mechanical resonances.	Turbo-generator designers typically avoid mechanical resonances stimulated by normally-encountered harmonics (odd order). Even order (stator-side) harmonic currents are not typically a design objective.	Current standards do s not specifically address this impact. Contact the turbo-generator manufacturer for guidance if the harmonic currents approach or exceed the generator thermal impact screening thresholds above.

SURGE ARRESTERS		
Harmonic voltages can cause high peak voltages, potentially causing metal oxide varistor (MOV) arrester thermal instability, placing bus faults on the transmission system.	The peak voltage depends on the phase relationships between the harmonic and fundamental voltage components. Because of the temporary nature of maximum GMD intensity, this is a temporary overvoltage rather than a continuous voltage consideration. Extremely high levels of voltage distortion are necessary for this to be an issue.	Voltage THD greater than 35%.
TRANSMISSION CABLES		
Harmonic currents cause elevated cable temperature.	Due to the very long thermal time constants of cables, the thermal impacts are not deemed to be significant.	No specific screening is recommended, except for cables with multi-grounded shields and pipe-type cables. These should be evaluated in detail if heavily loaded and have substantial harmonic current flow.
Harmonic voltages cause increased cable dielectric loss heating and cable shield capacitive current heating.	Due to the very long thermal time constants of cables, the thermal impacts are not deemed to be significant.	No specific screening is recommended.
Harmonic currents cause increased voltage duty on cable shield voltage limiters.	Cable shield limiter voltage ratings are defined by fault current duty, and cables tend to be applied in strong systems with high short-circuit current levels. Therefore, this issue is not deemed significant.	No specific screening is recommended.

Improper protective relay operation (false trips and failure to trip).	Negative sequence and phase comparison schemes using electromechanical or static relays are particularly vulnerable.	Evaluate in detail any negative sequence or phase comparison protection schemes using static or electromechanical relays.
OVERHEAD TRANSMISSION LINES		
Harmonic currents cause elevated conductor temperature.	Loadflow capacity of transmission lines is reduced by harmonic currents and the increased skin effect losses they produce.	I_{60} > 95% rating, or I_{60} > 90% rating and $\sqrt{\Sigma I_n^2}$ > 10%, or $\sqrt{\Sigma I_n^2}$ > 10% of line rating
Harmonic current flow in lines can make parallel telephone circuits inoperable via induction.	The parallel telephone lines do not have to be close, nor in parallel for a long distance for interference to be severe. However, the number of affected phone lines is limited, and the duration of severe interference is likely to be short.	This is not a power system security issue, and does not need to be part of a bulk system GMD harmonic vulnerability assessment. Therefore, no screening criterion is suggested.
Improper protective relay operation (false trips and failure to trip).	Negative sequence and phase comparison schemes using electromechanical or static relays are particularly vulnerable.	Evaluate in detail any negative sequence or phase comparison protection schemes using static or electromechanical relays.
HVDC TRANSMISSION SYSTEMS		
Filters may become overloaded and trip, increasing reactive demand on the power system.	Low-order harmonic filters (n < 11) are particularly vulnerable. Tripping of an excessive number of filter or capacitor banks may initiate HVDC system shutdown.	Any low-order harmonic filters should be evaluated in detail.

Harmonic distortion may cause inverter firing angle advance, increasing reactive demand.	Relatively large changes in reactive demand can be caused by harmonic distortion of the ac bus voltage. This can be critical to bulk system voltage stability analysis.	$V_{THD} > 5\%$
Harmonic distortion can interact with HVDC converters and controls.	A wide variety of interactions are possible, including saturation of the converter transformer even if GIC is blocked, as well as transfer of harmonics between systems.	The HVDC system vendor should be consulted for guidance if distortion is substantially greater than design assumptions.
STATIC VAR COMPENSATORS (SVCs)		
Filters may become overloaded and trip, and may trip SVCs.	Most SVCs have low-order harmonic filters ($n < 11$) that are particularly vulnerable.	Any low-order harmonic filters should be evaluated in detail if the SVC is critical to system security.
Even-order harmonics may interact with the thyristor controlled reactor (TCR) and saturate the SVC transformer.	Some SVCs have flux balancing controls that avoid or minimize saturation, but interaction with severe even-harmonic distortion can cause other consequences even where flux balancing controls are used.	Evaluate any SVC that is critical to system security if even-order harmonic distortion is greater than design basis. Consult SVC vendor for guidance.
VOLTAGE SOURCE CONVERTERS IN TRANSMISSION APPLICATIONS (VSC-HVDC, STATCOM, UPFC)		
Severe harmonic distortion may overload the dc-bus or module capacitors.	Tolerance of distortion depends on design.	Consult system vendor for guidance if voltage distortion substantially exceeds the design basis.
WIND AND SOLAR PHOTOVOLTAICS (PV) PLANTS		
Severe harmonic distortion may cause overload of the dc-bus or module capacitors.	Tolerance of distortion depends greatly on design.	Consult generating unit or inverter vendor for guidance if the plant is considered critical to system security.

Harmonic protection functions may trip the plant during a GMD.	Harmonic protection functions, applied to prevent plants from exceeding current distortion limits, are non-directional and may operate for grid-produced distortion during a GMD	Current distortion exceeding 50% of trip threshold if simplistic models of voltage source converter (VSC) inverters are used.
DISTRIBUTION SYSTEMS AND LOADS		
Distribution capacitor banks may fuse out, increasing reactive demand on the transmission system.	Impact is limited to capacitors resonating at integer harmonics. It is infeasible to perform analysis of distribution systems in a bulk system study.	No screening is recommended. Instead, load power factor should be decreased in voltage stability studies to incorporate this impact.
Motors may overheat due to harmonic voltage distortion.	The thermal time constant of motors will provide some mitigation.	No screening is recommended; this is not a bulk system security issue.
Harmonic currents flowing into the distribution system can cause telephone interference.	Telephone cables are usually in close proximity to distribution feeders. Distribution harmonic flow may be particularly large between the substation and any feeder capacitors.	This is not a power system security issue and does not need to be part of a bulk system GMD harmonic vulnerability assessment. Therefore, no screening criterion is suggested.

Table notes:

1. Screening thresholds do not necessarily mean that the withstand capabilities of the components are exceeded, but further analysis as discussed in this guide is prudent.
2. The threshold shown is based on continuous duty. GMD duty is highly variable and hence, provides an inherent safety factor. Also, the parameters and withstand capabilities of capacitors are well defined.
3. An additional safety factor is provided by the fact that the harmonic components would have to perfectly align with the peak fundamental voltage in order for the capacitor peak voltage to exceed the 1.2 p.u. limit specified in IEEE 18.

In the development of this guide, a number of key overall conclusions were reached:

- Many harmonic impacts are thermal in nature. The highly variable nature of the geo-electric field during a GMD means

- that GIC, and the harmonic currents injected by GIC-saturated transformers, are similarly variable. Many power system components have relatively long thermal time constants, relative to the GMD intensity variations. Therefore, these time constants provide a filtering effect that reduces many types of GMD harmonic impact substantially from the severity that would occur if the harmonic currents produced at the peak GMD intensity were continuously applied. The reduction in impact is substantial in the case of transformers and cables, which have long thermal time constants.
- Many protective relaying problems that have occurred in prior GMD events can be attributed to relays that are undesirably sensitive to harmonic currents and voltages, or which have inaccurate response to these harmonics. These undesired characteristics are almost exclusively related to electromechanical and static (solid-state) relays. Modern digital relays have largely replaced these older types of relays. Digital relays that use full-cycle discrete Fourier transform (DFT) algorithms are insensitive to harmonics, which is desirable in almost all cases.
- Some capacitor banks are susceptible to harmonics, as their impedance decreases with frequency and they can engage in resonances with the system that amplify harmonic currents and voltages. In some cases, harmonic overload protection is not applied to transmission shunt capacitor banks.
- Some generators may not be sufficiently protected from potentially damaging harmonic currents. Such currents could potentially cause excessive rotor heating and stimulate mechanical vibrations at frequencies that turbine-generator designers did not anticipate.

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Section 1: Introduction

1.1 Background

Solar disturbances, such as coronal mass ejections, can initiate terrestrial geomagnetic disturbances (GMDs) when charged particles emitted from the sun interact with the earth's magnetic field. GMDs can result in the flow of very low frequency geomagnetically-induced currents (GICs) in power systems. The physics of this phenomenon have been extensively documented in the literature [1]. Basically, transmission lines and the return path through the Earth, closed through grounded-wye transformers, form a loop enclosing the slowly-changing magnetic field produced by auroral electrojet currents flowing in the upper atmosphere. Because the spectral content of the GIC induced in this loop is composed of very low frequencies, it can be considered essentially dc (i.e., quasi-dc) for most practical purposes related to power system impacts.

The voltage induced in the transmission line-Earth loop integrates to impose a quasi-dc flux bias on the transformers closing the loop. This includes both grounded-wye transformers closing the connection between the transmission system and Earth, as well as the series windings of autotransformers providing a dc path between different transmission voltage levels. The flux bias results in asymmetric, or part-cycle, saturation of the transformers, producing unusually large and highly-distorted exciting currents.

Asymmetric saturation of a transformer can have a direct impact on the transformer itself. Additionally, simultaneous saturation of many transformers may also impact power system performance via the large exciting currents drawn from the transmission system, regardless of whether the saturation poses any risk to the transformers. The potential for direct impacts of GIC saturation on transformers is widely recognized and is presently the subject of some controversy. Some have speculated that a severe but credible GMD event could result in the wide-scale failure of numerous critical power transformers [2]. Others, including many transformer experts, view the risk as limited to particular and generally a limited number of transformer designs, and assert that widespread transformer damage is unlikely [3].

Separate from the issue regarding direct impacts of GIC-caused saturation of transformers is the potential for widespread system impacts from the exciting currents drawn by saturated transformers. These exciting currents contain both fundamental-frequency and harmonic components. The fundamental exciting current lags the applied voltage by nearly 90 degrees, and is thus primarily reactive. The large amounts of reactive current absorbed by GIC-saturated transformers can lead to widespread voltage depression and possible instability. The fundamental-frequency reactive current impacts of GIC are widely recognized.

In addition to the fundamental component, the exciting current of GIC-saturated transformers can have large harmonic components. The flow of these harmonics in the transmission system, and the voltage distortion that results, can also impact bulk power system equipment and systems, including protection systems. Guidelines such as IEEE 519 provide recommended limits to harmonic current and voltage distortion. However, these limits are intended for the maintenance of power quality under routine, steady-state circumstances. The consequences of the large amounts of harmonic distortion during a severe GMD extend beyond the routine considerations of power quality; the harmonic issues during GMD are pertinent to system security.

1.2 GMD Impact Studies

Harmonics during GMDs can potentially cause permanent damage to major equipment and cause critical components to be tripped during a time of severe system stress, impacting grid security. In particular, tripping of equipment providing reactive resources and system strength can aggravate the fundamental reactive current impacts described previously, potentially resulting in voltage instability at a lesser degree of GMD severity than caused by the reactive current alone. Thus, studies of direct transformer saturation impacts and fundamental reactive impacts alone do not provide a complete assessment of bulk power system GMD vulnerability. Harmonic impacts also need to be considered as well.

The Federal Energy Regulatory Commission (FERC) has directed the North American Electric Reliability Corporation (NERC) in Order 779 to develop mandatory standards for operational response to GMD events, and to perform assessments of system vulnerability to GMD. In response, NERC has developed standards EOP-010-1 and TPL-007-1, respectively. NERC TPL-007-1 requires Planners, Transmission Owners, and Generation Owners to perform a GMD Vulnerability Assessment, and to develop a Corrective Action Plan if the assessment determines that system performance fails to meet defined criteria. The specification for the GMD Vulnerability Assessment states that the reactive power compensation devices and other transmission facilities that are susceptible to trip as the result of protection system operation or misoperation due to harmonics shall be removed from the system models used for steady-state performance. “Operation” in this context can reasonably be construed to include necessary tripping to protect equipment, and “misoperation” can be construed to include both false tripping due to harmonic distortion interference with protection system functionality and failure of protection to adequately protect equipment from harmonic stress during GMDs that leads to equipment failure and consequential tripping.

The requirement of TPL-007-1 to remove components from study models that are susceptible to harmonics can be met by a detailed harmonic analysis. Alternatively, the application of engineering judgment may suffice if sufficiently conservative. In either case, a thorough understanding of the impact of severe harmonic distortion on power system components, protection systems, and control systems is required.

1.3 Scope and Organization of Guide

The information required to assess the susceptibility of power system equipment and protection systems to harmonics is dispersed throughout the technical literature and industry standards, or has not yet been publicly documented. The purpose of this guide is to provide a convenient reference resource regarding the impacts of severe GIC-produced harmonics on equipment and systems.

Much of the industry's attention to GMD harmonics issues has been directed toward protective relays, primarily in response to numerous tripping incidents during the major March 1989 GMD event. However, system protection issues during GMDs are not limited to relay insecurity (false tripping). There is also the possibility that critical system equipment may not be adequately protected from the stresses caused by severe harmonic distortion in existing relay schemes. Therefore, this guide first discusses the harmonic withstand and performance issues of major bulk system components, and then discusses relay and protection systems.

This guide is organized by type of power system component or system. Included are protection systems, transformers, shunt capacitor banks, generators, cables, overhead lines, HVDC systems, FACTS devices, surge arresters, distribution systems, and consumer loads. The discussion of overhead lines includes the impact on external communication systems due to electromagnetic coupling with transmission lines.

Detailed evaluation of the harmonic impact on various types of equipment requires equipment data that are often not easily obtained and can require specialized calculations that commonly available harmonic analysis software typically does not perform. Therefore, for each type of equipment and where feasible, this guide suggests simplified screening criteria. These criteria are intentionally conservative. Harmonic values exceeding these criteria do not imply that the component will endure excessive duty, but rather indicate that more detailed evaluation of that component is prudent. The screening thresholds suggested in this guide incorporate ample safety factors depending on the uncertainty of the device parameters.

Section 2: General Aspects of Harmonic Impacts during GIC

Conventionally, harmonics have been considered as a “power quality” issue, where exceedance of standards may sometimes cause nuisance impacts and occasionally system or device misoperation. Only in rare circumstances during normal system conditions do harmonics result in equipment damage, and this damage tends to be minor and isolated. The characteristics and magnitude of harmonic distortion during a severe GMD could possibly cause major equipment damage and compromise system reliability.

2.1 Levels of Distortion

Magnitudes of harmonic current and voltage distortion during a GMD are likely to exceed distortion levels encountered during normal geomagnetic conditions. IEEE 519 recommends limiting transmission ($V_{nominal}$ > 161 kV) voltage distortion to 1%, and limiting total harmonic distortion (THD, i.e., root-sum-square of all individual harmonic components) to 1.5%. While this standard is not rigorously followed, it serves as a benchmark for typical harmonic distortion levels.

The spectral components of typical transformer exciting current with 0.1 p.u. net GIC (per-unit base is the crest rated current of the winding with the GIC) are shown in Figure 2-1. The THD of this current is 125% of the fundamental. The driving point impedances of transmission buses generally tend to increase with frequency until at least the first resonant frequency of the grid is reached, which is generally in the fifth to tenth harmonic range. This means that if a GMD causes a certain amount of fundamental-frequency voltage deviation, the concurrent levels of harmonic distortion in that system are likely to be multiples of the fundamental-frequency voltage deviation. Therefore, harmonic voltage distortion levels are likely to be in the multiple tens of percent – at GIC levels that could possibly precipitate fundamental voltage collapse.

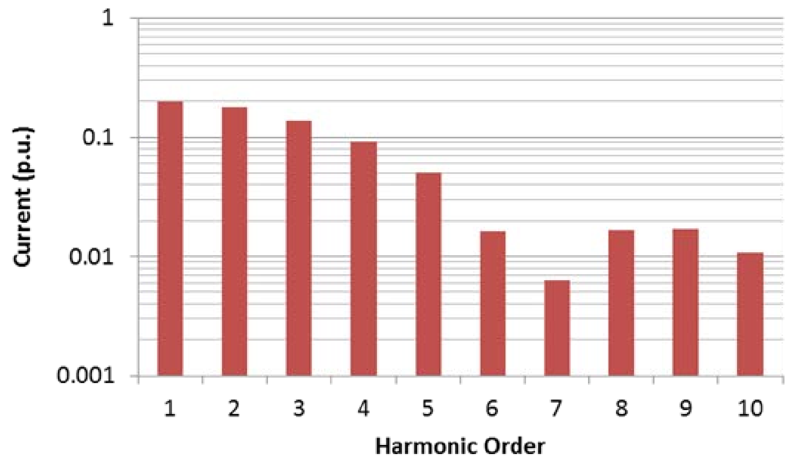

Figure 2-1
Exciting current harmonic components for 0.1 p.u. net GIC in a bank of single-phase transformers.

Figure 2-2 shows the variation of harmonic component magnitudes as a function of the net GIC magnitude. The oscillating magnitude of the higher harmonic orders is a function of the changes in duration (width) of the transformer exciting current pulses with increasing GIC. This pulse duration change is a function of the slope of the transformer's magnetization curve in the fully saturated region, which is often called the "air core inductance."

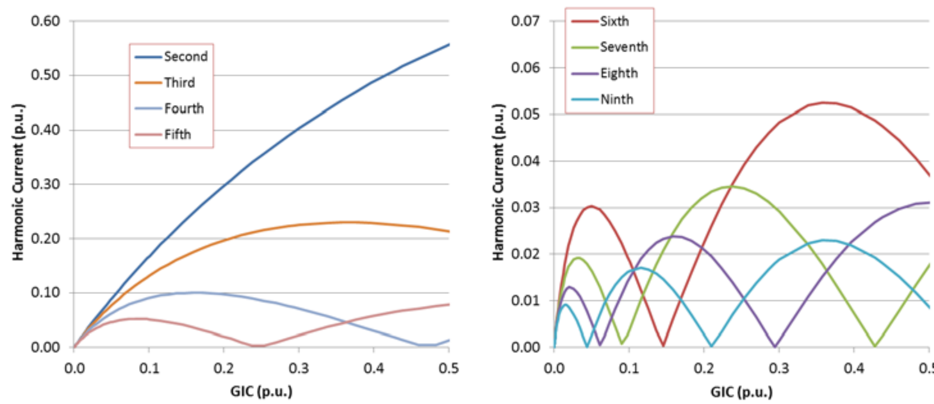

Figure 2-2
Exciting current harmonic components as a function of net GIC for a bank of single-phase transformers. (Saturated magnetizing slope is 30%.)

As the magnitude of net GIC through a transformer increases, the total harmonic component of exciting current increases, but at a non-linear rate (see Figure 2-3). As a result, the current THD, relative to the fundamental component of exciting current, tends to decrease with GIC level.

Voltage distortion is a function of both the harmonic currents injected by GIC-saturated transformers and the system impedances at the harmonic frequencies. System harmonic impedances, particularly at higher harmonic orders, are not well correlated to the fundamental-frequency short-circuit impedance. The harmonic impedances are substantially determined by the resonances of the system. At lower-order harmonics, fundamental and harmonic impedances are more closely correlated. In most transmission systems, the driving point impedance at any bus generally tends to increase more or less linearly with frequency until the first parallel resonance is approached. This first significant resonance is typically in the range of the fifth to tenth harmonics.

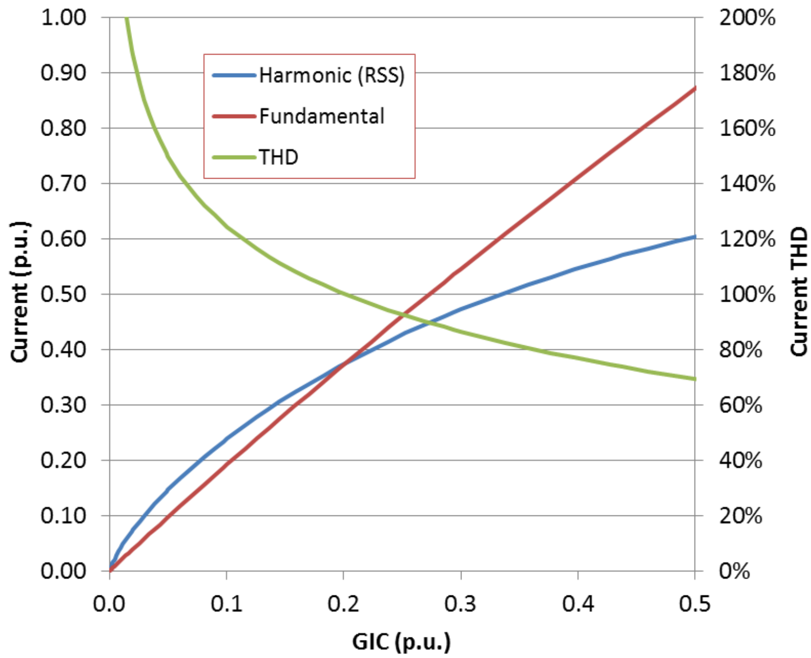

Figure 2-3
Exciting current fundamental and harmonic components, and current THD, as a function of net GIC for a bank of single-phase transformers. (Saturated magnetizing slope is 30%.)

In the idealized case of a single GIC-saturated transformer in a simple non-resonant inductive system, an approximate correlation between GIC and levels of voltage distortion can be made. Consider a transformer located at a bus that has an available short-circuit capacity that is twenty times the transformer's MVA rating (i.e., the fundamental impedance is 0.05 p.u. on the transformer's base). Assume further that the source impedance is inductive from the fundamental through the tenth harmonic, with the reactance increasing in proportion to the harmonic order. With these assumptions, the transformer exciting current spectral components shown previously in Figure 2-1 interact with this system impedance to create the voltage spectrum shown in Figure 2-4. The voltage THD in this example is 3.7%, and the fundamental voltage change is 1%, implying that voltage distortion is 3.7 times greater than the fundamental voltage drop caused by the GIC.

In reality, transformer saturation during a GMD may be widespread, with voltage distortion at any bus resulting from harmonic currents injected by many transformers throughout the system. Furthermore, the transfer impedances between remote current injections and local voltage have complex phase relationships. Thus, the voltage contributions from current injections at other locations may add in magnitude or may negate each other. Therefore, simplified correlations between GIC, fundamental voltage deviation, voltage distortion, and current harmonics through any system component are of limited value and should not be used for system vulnerability evaluations. The correlations shown here are for the purpose of illustrating that distortion of voltage and current is likely to be significant at any severity of GMD that may cause a significant fundamental voltage issue.

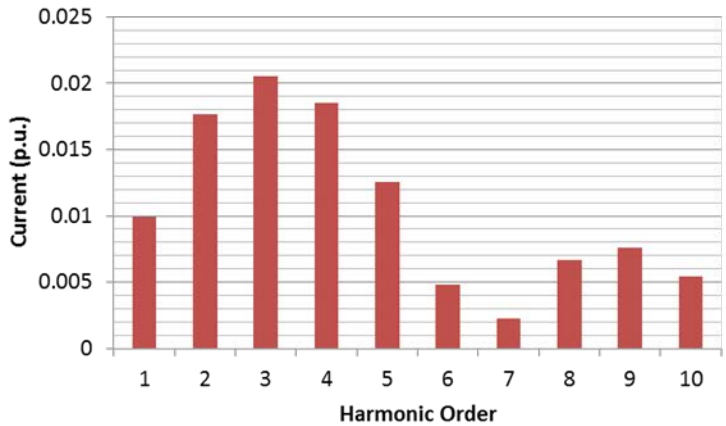

Figure 2-4
Harmonic voltage spectrum for current components shown in Figure 2-1 injected into an inductive system with short-circuit capacity twenty times the transformer rating.

2.2 Impact on Fundamental-Frequency Performance

Harmonic current and voltage distortion during GMDs could potentially result in equipment damage, protective tripping of equipment to prevent damage, false tripping by protection systems due to their erroneous response, or failure of protection systems to operate when required. Equipment that is more likely to be affected includes reactive power resources, such as capacitor banks, generators, and static VAR compensators (SVCs). Loss of this equipment during a GMD, when the voltage is already depressed by the excessive (fundamental-frequency) reactive power absorbed by GIC-saturated transformers, is likely to aggravate the voltage stability issue. In addition, direct or indirect GIC effects can result in tripping of system branches (e.g., lines, cables, transformers), which weakens the system and further increases reactive power demand. Therefore, an evaluation of bulk power system vulnerability to GMDs is incomplete without consideration of the harmonic impacts.

2.3 Distortion Quantification

Performing a GMD harmonic impact assessment requires either calculating or estimating the magnitudes of harmonic current and voltage for each affected system component. GMD-produced distortion tends to be most significant in the lower-order harmonic range. A general rule of thumb is that the geographic extent of the system model required to accurately calculate harmonic impedances is largest for the lowest-order harmonics because they tend to propagate more widely. The extent of the modeling needed for accuracy tends to decrease with increasing harmonic order. At any location, the current and voltage distortion severity is the result of the contributions of all GIC-saturated transformers in the system. These factors indicate that a large-scale system model is required to properly calculate GMD distortion.

To define the harmonic sources, a GIC flow analysis is necessary to determine the amount of net GIC in each transformer. Depending on the type and parameters of the transformer, the harmonic current injections can be determined based on the net GIC. However, before a harmonic analysis can be conducted, a fundamental-frequency loadflow must first be solved. The phase angle of the harmonic currents depends on the polarity of the GIC, and also is relative to the fundamental-frequency voltage of the bus where the transformer is located. For a large system study, there will be differences in fundamental voltage angles across the system that are related to the loadflow conditions. The amount of harmonic source phase shift, relative to an arbitrary universal reference, increases with harmonic order. This means that even small fundamental phase angle differences can have a large impact on the superposition of harmonic contributions from many transformers. For some types of transformers, the harmonic current injections are also dependent on the fundamental voltages of the buses to which the transformers are connected.

Detailed analysis of GMD-caused harmonic voltage and current distortion to determine the impacts on individual components and systems is a complex undertaking. The recommended practices to performing this type of analysis are beyond the scope of this guide, and could potentially be the subject of a future EPRI guide.

An alternative to detailed analysis is to make engineering estimates. However, simplifications such as disregarding distortion contributions from remote transformers can provide misleading information and overly optimistic conclusions. A simplified case study performed in a prior EPRI project showed that the majority of harmonic current contribution to a particular generator was due to a transformer located 200 miles away; the far away transformer had a greater impact than the unit's own step-up transformer [4]. Engineering approximations and rules-of-thumb require calibration and validation based on a body of experience built from detailed analysis. The industry, at this point, does not have this level of experience. Hence, simplified approaches to GMD harmonic distortion quantification as an alternative to detailed analysis cannot be recommended at this time.

Section 3: Transformer Harmonic Impacts

GIC flow in transformers can cause direct heating due to stray flux patterns resulting from part-cycle core saturation. These direct heating effects are outside of the scope of this guide and are not covered here. The harmonic currents flowing through transformer windings, caused by GIC saturation, are an additional source of heating. These indirect heating effects are not restricted to the exciting current of the affected transformer; harmonic currents caused by GIC saturation of other transformers may also be a substantial contributor. Even a transformer design that does not saturate from GIC (e.g., a three-leg core-form transformer in a non-magnetic tank) or a transformer in which GIC does not flow can be subjected to unusual heating as a result of harmonic currents injected by other transformers that flow through the windings. Voltage distortion caused by harmonic current flow in the transmission system could possibly cause additional transformer heating, but this is generally a relatively insignificant factor.

One example of a transformer that will not have direct GIC impacts, but which still could have thermal stress from harmonic current flow is a transformer to which GIC blocking devices are applied. Another example is a delta-wye transformer serving a distribution bus to which significant shunt capacitor compensation is applied. The delta winding on the transmission side does not allow flow of GIC, and the limited geographic extent of the distribution system means that any GIC on that side is trivial. Harmonic distortion on the transmission system, caused by saturation of other transformers, will cause harmonic current flow through the distribution substation transformer. If the distribution bus capacitor banks and the substation transformer inductance create a resonance at a harmonic frequency that is stimulated by the GMD (e.g., an even harmonic that is not normally encountered during normal conditions), then the harmonic current flow can be large.

3.1 Transformer Losses and Heating

Transformer heating is caused by electrical losses, and these losses are categorized as no-load (excitation) losses and load losses. Load losses, due to current flow through the transformer, are subdivided into I^2R loss and stray losses. Stray losses are due to stray electromagnetic flux in the windings, core, core clamps, magnetic shields, and tank walls. Stray losses can be further subdivided into winding eddy current losses and other stray losses that occur outside of the winding.

The critical temperature of a transformer is at the hottest spot of the winding, where elevated temperature leads to accelerated aging of the insulation. Degradation of the insulation results in the insulation material becoming more likely to fail when mechanical stress is placed on the winding by faults or energization inrush. In more extreme over-temperature situations, generation of gas bubbles in the oil can disrupt the electric field grading of insulation, potentially leading to immediate insulation failure (i.e., internal fault). Winding eddy current losses contribute directly to the rise of the winding hot-spot temperature above the oil temperature, as well as to the oil temperature rise above ambient. Other stray losses, however, contribute only to the oil temperature rise as they do not occur within the winding.

Both winding eddy current losses and other stray losses are in proportion to the square of the load current passing through the transformer. Winding eddy-current stray losses increase in proportion to the square of the current's frequency, and the other stray losses have been empirically found to increase in proportion to the frequency raised to the 0.8 power [5].

No-load losses are increased by GIC saturation, but this is a direct heating effect beyond the scope of this guide as it does not directly pertain to harmonics. Harmonic voltage distortion will also tend to increase no-load losses, but the impact is relatively minor unless the voltage distortion is very large. Excitation losses are subdivided into core eddy current and hysteresis losses. Eddy current core losses are in proportion to the rms magnitude of the applied voltage, and hysteresis losses are related to the peak flux [6]. In general, the rms voltage is reduced during a GMD due to the depression of the fundamental-frequency voltage due to reactive demand. Only if a particular harmonic voltage component is particularly large, such as could be caused by a severe resonance, would the rms combination of the depressed fundamental voltage and the harmonic voltage yield an elevated resultant. Flux is the time integral of voltage, so harmonic voltages have an impact on flux that decreases with harmonic order. The impact of the harmonic flux components on the peak flux is dependent on the phase relationships of the components. In general, with reduced fundamental flux the crest flux is unlikely to be elevated above nominal except in severely resonant conditions.

3.2 Transformer Thermal Behavior

During a GMD event, which might have a duration on the order of 30 hours, magnitudes of GIC are highly variable. Reference time-series values of geo-electric fields have been developed by the NERC GMD Task Force which are to be used in system GMD vulnerability studies [7]. These E-fields are plotted versus time in Figure 3-1 to Figure 3-3. It can be seen that the worst-case electric field intensities are short-duration spikes. Transformers, however, have thermal time constants that are long relative to these electric field variations. As a result, the impacts of the GIC on transformer temperatures are substantially reduced by the filtering effect of the thermal behavior.

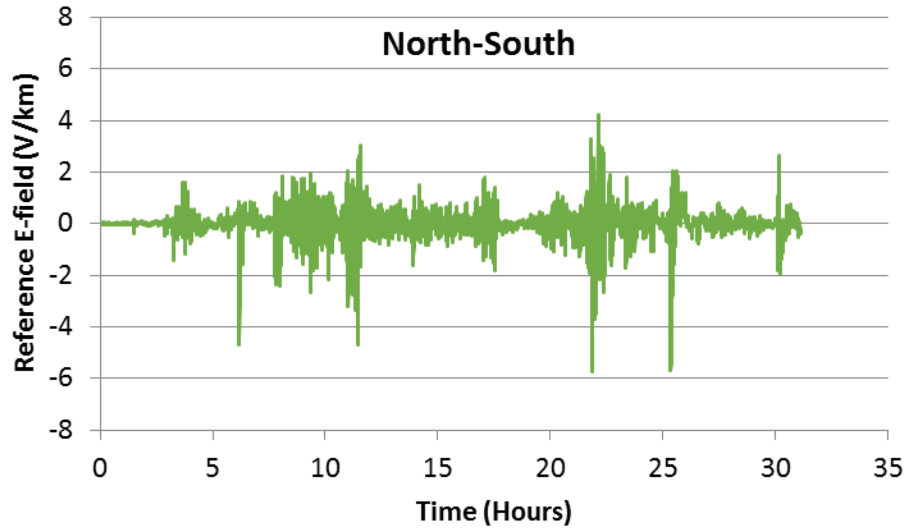

Figure 3-1
Reference North-South geo-electric field magnitude times series.

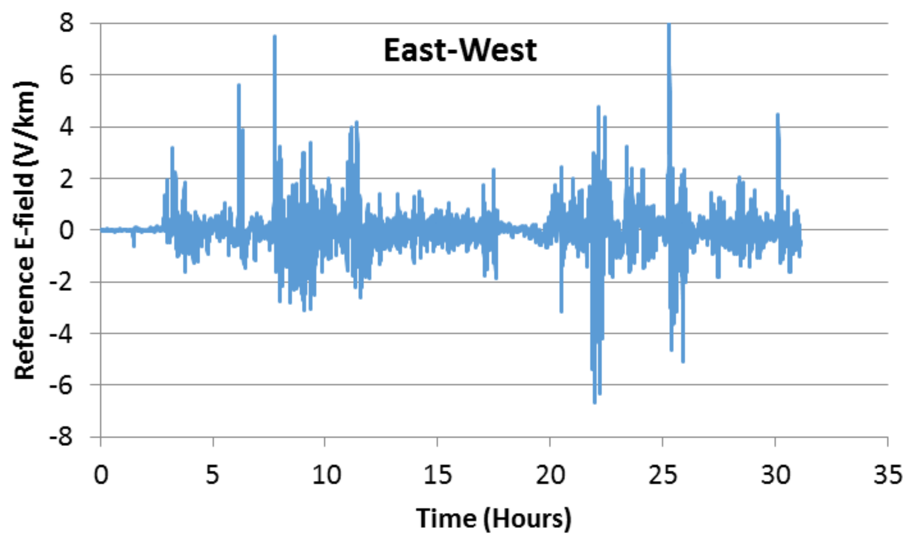

Figure 3-2
Reference East-West geo-electric field magnitude time series.

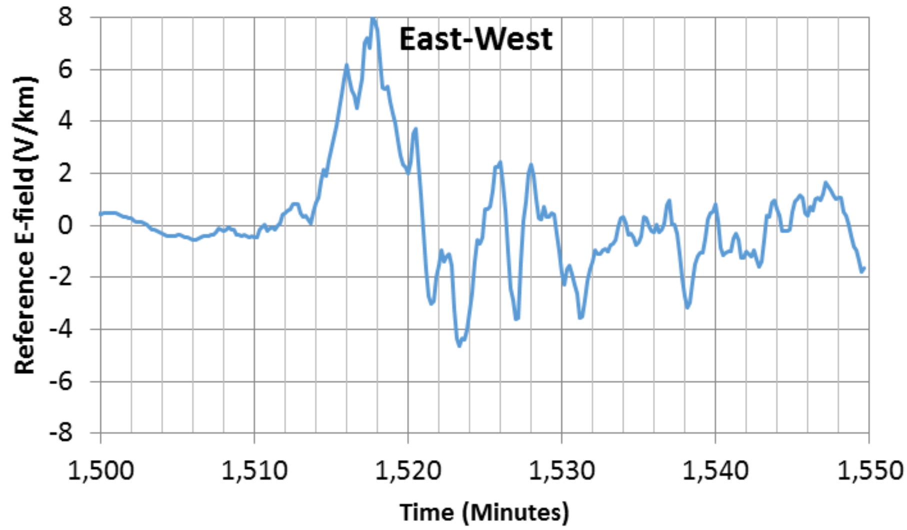

Figure 3-3
Reference East-West geo-electric field magnitude time series, expanded around time of peak.

Thermal Models

IEEE C57.91 provides extensive information regarding transformer thermal characteristics, thermal models, transformer insulation life, and critical transformer temperatures. This standard provides a thermal model for liquid-filled transformers that has two critical temperature rises and two time constants. The critical temperature rises are the temperature rise of the winding hot-spot over the top-oil temperature, and the temperature rise of the top oil above the ambient temperature. The time constant of the top-oil rise is quite long, on the order of 4 – 8 hours for typical power transformers. The time constant for the hot-spot rise is much shorter, on the order of five minutes for a typical transformer, but even this time constant has a substantial smoothing effect on GIC effects.

For electrical engineers, the thermal characteristics of transformers might best be understood by use of an electrical analog. Such an analog is shown in Figure 3-4. Current sources in this model represent heat injected into the transformer by electrical losses, capacitors represent the thermal capacitance (specific heat times mass), and resistors represent thermal resistance. Voltages in this electrical analog represent temperatures. Heat caused by conductor I^2R and winding eddy-current losses is injected at the hot-spot location. Thermal resistance R_{hs} is the thermal resistance between the hot-spot location and the transformer oil, and C_w represents the heat-storage capacity of the winding. R_{hs} and C_w together create the hot-spot temperature rise time constant. Thermal power caused by excitation losses and other stray losses are injected at the node to which the thermal capacitance Coil is connected. These losses, plus the flow of winding I^2R and eddy losses, sum to raise the temperature of the oil above the ambient temperature, which is represented in the analog as a voltage source. The thermal resistance between the oil and the ambient is represented by R_{oil}, and the combination of C_{oil} and R_{oil} define the top-oil temperature rise thermal time constant.

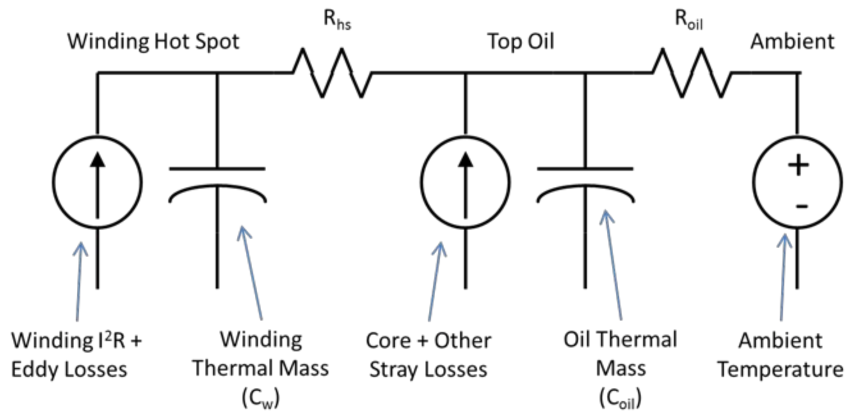

Figure 3-4
Illustrative electric circuit analog of simplified transformer thermal behavior.

Critical Temperatures and Accelerated Aging

The two critical temperatures defined by the thermal model are the top-oil temperature and the winding hot-spot temperature. The top oil temperature is the sum of the top-oil temperature rise and the ambient temperature; the latter is nominally assumed to be 30°C. IEEE C57.91 recommends that the oil temperature should not be allowed to exceed 110°C. The winding hot-spot temperature is the sum of the hot spot and top-oil temperature rises, and the ambient temperature. Nominal insulation life (180,000 hours or 20.55 years) is expected when the winding hot spot is continuously held at 110°C in a transformer designed with a 65°C average winding rise insulation system (the norm for modern power transformers). Elevation of the hot-spot temperature above 110°C results in accelerated aging at a highly nonlinear rate defined in Equation 3-1. The aging acceleration factor F_{AA} is the number of hours of insulation life lost for every hour of insulation exposure to the temperature Θ_{HS}. The aging acceleration factor is plotted as a function of temperature in Figure 3-5.

$$F_{AA} = \exp\left(\frac{15000}{383} - \frac{15000}{\Theta_{HS} + 273}\right) \qquad \text{Eq. 3-1}$$

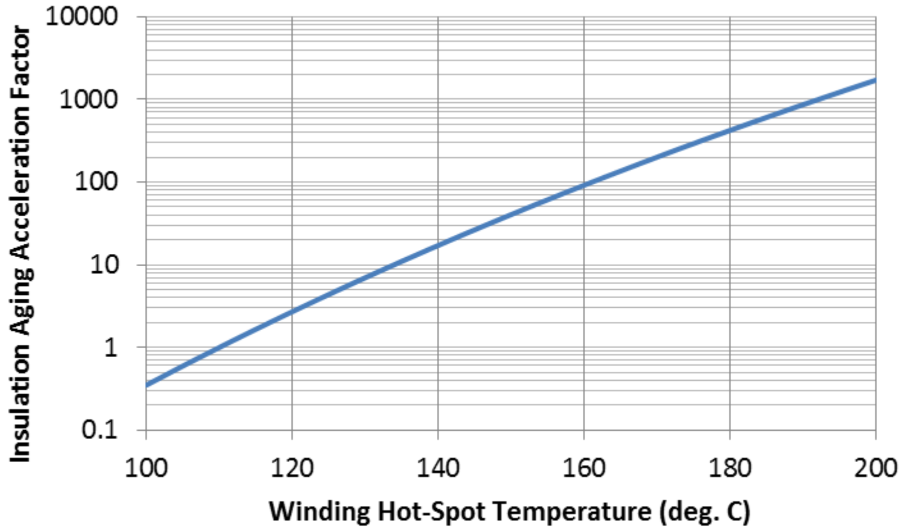

Figure 3-5
Transformer winding insulation aging acceleration factor (FAA) as a function of winding hot-spot temperature.

The effects of accelerated aging are cumulative; both temperature and duration of exposure are decisive factors. A transformer can be occasionally subjected to loading that elevates the hot-spot temperature above 110°C for limited periods if the resulted accelerated aging is compensated by other periods where the transformer is loaded to less than this temperature, and insulation aging is retarded. There is a limit to the maximum temperature, however, regardless of the duration of exposure. IEEE C57.91 recommends limitation of the maximum hot-spot temperature to 180°C in order to minimize the risk of gas bubble evolution. Gas bubbles can disrupt insulation voltage gradients, and result in immediate failure.

3.3 Harmonic Load Currents

IEEE Standard C57.110 provides a method to calculate the capability of a transformer to carry distorted load currents. The C57.110 method is based on the calculation of harmonic loss factors which are proportionality factors representing the effective heating caused by the distorted load current compared to undistorted fundamental-frequency current. Because the winding eddy current losses and other stray losses have different degrees of frequency dependence, the harmonic loss factors for these two loss components are calculated separately. I2R losses are not frequency dependent; the heating caused by this component depends only on the rms magnitude of the load current in each winding and that winding's dc resistance. For the same value of fundamental load current, however, increased harmonic current distortion will result in an increase in the total rms current. The total rms current is calculated by Equation 3-2.

$$I_{RMS} = \sqrt{\sum_{n=1}^{n=n_{\max}} \left(I_n{}^2\right)} \qquad \textit{Eq. 3-2}$$

The harmonic loss adjustment factor for winding eddy current losses is calculated by Equation 3-3. In this equation I_n is the rms magnitude of current at harmonic order n, and P_{EC} and P_{EC_0} are eddy current losses for the distorted current and for undistorted fundamental current, respectively.

$$F_{HE} = \frac{P_{EC}}{P_{EC\_0}} = \frac{\sum_{n=1}^{n=n_{\max}} \left(I_n{}^2 \cdot n^2\right)}{\sum_{n=1}^{n=n_{\max}} \left(I_n{}^2\right)} \qquad \textit{Eq. 3-3}$$

The harmonic loss adjustment factor for other stray losses is calculated by Equation 3-4.

$$F_{HS} = \frac{P_{OSL}}{P_{OSL\_0}} = \frac{\sum_{n=1}^{n=n_{\max}} \left(I_n{}^2 \cdot n^{0.8}\right)}{\sum_{n=1}^{n=n_{\max}} \left(I_n{}^2\right)} \qquad \textit{Eq. 3-4}$$

The top-oil temperature rise, adjusted for the impact of harmonic current distortion on winding eddy current and other stray losses, can be calculated using Equation 3-5.1[1].

$$\Theta_{TO\_A} = \Theta_{TO\_A-rated} \cdot \left[\frac{I_{RMS-pu}{}^2 \cdot \left[1 - K_{ST} + K_{ST} \cdot \left[K_{EC} \cdot F_{HE} + \left(1 - K_{EC}\right) \cdot F_{HS}\right]\right] + 1/K_{LR}}{1 + 1/K_{LR}}\right]^{0.8}$$

Eq. 3-5

Where:

Θ_{TO_A} = Rise of top-oil temperature above ambient temperature for the given load current and harmonic distortion condition.

Θ_{TO_A}*-rated* = Rise of top-oil temperature above ambient temperature under rated conditions.

I_{RMS-pu} = Per-unit load current, including harmonic components.

K_{ST} = Ratio of stray losses (winding eddy current losses plus other stray losses) to total load loss.

K_{EC} = Ratio of winding eddy current losses to total stray losses.

K_{LR} = Loss ratio; ratio of load loss to no-load loss.

---

[1] This equation is based on the method of IEEE C57.110.

The adjusted winding hot-spot rise can be calculated by Equation 3-6.

$$\Theta_{HS\_TO} = \Theta_{HS\_TO-rated} \cdot \left[\frac{ I_{RMS-pu}{}^{2} \cdot \left[(1-K_{ST}) \cdot \dfrac{R_2}{R_1+R_2} + K_{ST} \cdot K_{EF} \cdot K_{ED} \cdot F_{EC} \right] }{ (1-K_{ST}) \cdot \dfrac{R_2}{R_1+R_2} + K_{ST} \cdot K_{EF} \cdot K_{ED} } \right]^{0.8}$$

Eq. 3-6

Where:

Θ_{HS_TO} = Rise of hot-spot temperature above top-oil temperature for the given load current and harmonic distortion condition.

$\Theta_{HS\_TO-rated}$ = Rise of hot-spot temperature above top-oil temperature under rated conditions.

R_1 = Per-unit resistance of the outer (typically higher-voltage) winding.

R_2 = Per-unit resistance of the inner (typically lower-voltage) winding.

K_{EF} = Ratio eddy-current losses in the inner winding to the total eddy-current losses.

K_{ED} = Ratio of winding eddy-current loss density in the area of the hot spot to the average eddy-current loss density of the inner winding

The hot-spot temperature Θ_{HS} is the sum of the ambient temperature Θ_A, top-oil rise, and hot-spot rise, as shown in Equation 3-7. It is Θ_{HS} that defines transformer insulation aging and the risk of gas bubbles.

$$\Theta_{HS} = \Theta_A + \Theta_{TO\_A} + \Theta_{HS\_TO}$$

Eq. 3-7

3.4 Evaluation of Harmonic Current Impacts

Thermal Time Constant Filtering of GMD Impacts

During a GMD, GIC flows are highly variable. Therefore, the levels of current and voltage harmonic distortion during a GMD will vary in a similar manner. Because transformers have long thermal constants, relative to the period of geo-electric field intensity variations, the actual temperature rises in transformers will be much less than the temperatures that would be reached if the peak electric field intensity were continuous.

GIC flows through transformers in a transmission system are linearly proportional to the geo-electric fields driving the GIC. The harmonic currents injected into the system, which cause additional losses and heating of transformers, are roughly proportional to the GIC magnitude. The load-loss thermal power injected into a transformer is proportional to the square of the transformer current. Therefore, incremental transformer heating due to a GMD event is approximately proportional to the square of the electric field intensity.

Figure 3-6 and Figure 3-7 plot the square of the NERC North-South and East-West reference E-fields (E^2), respectively. Also shown on these plots are the E^2 filtered with a five minute and four hour time constants. The shorter time constant is a conservative typical value for a power transformer's hot-spot rise time constant, and the longer four-hour time constant is a conservative typical value for the top-oil rise time constant.

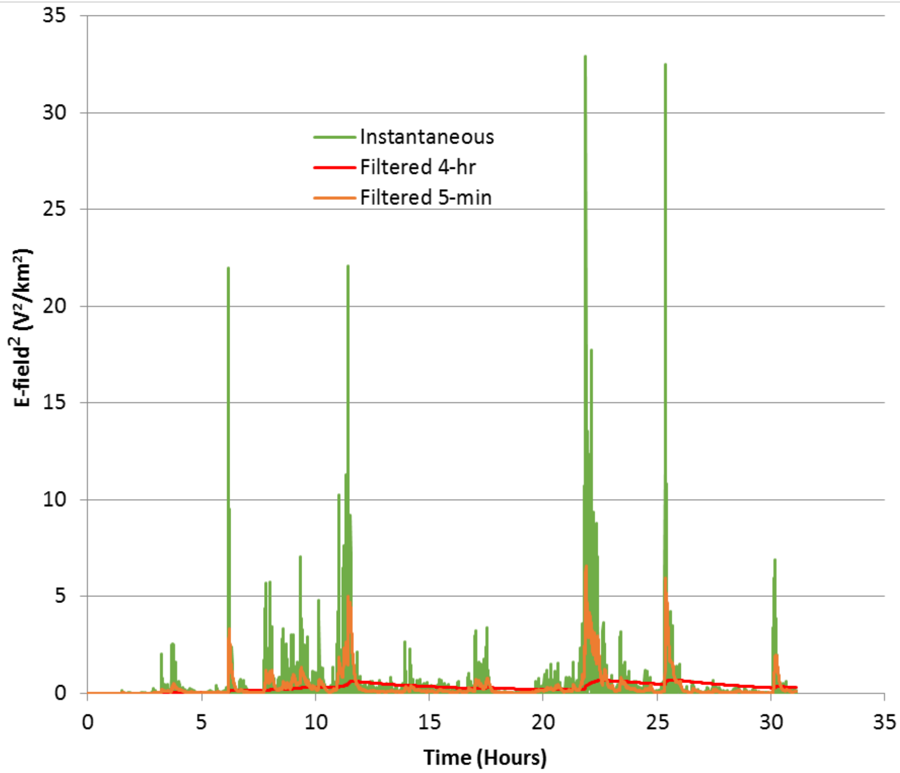

Figure 3-6
North-South reference geo-electric field intensity squared. Shown are the instantaneous values and the instantaneous values filtered through five minute and four hour thermal time constants.

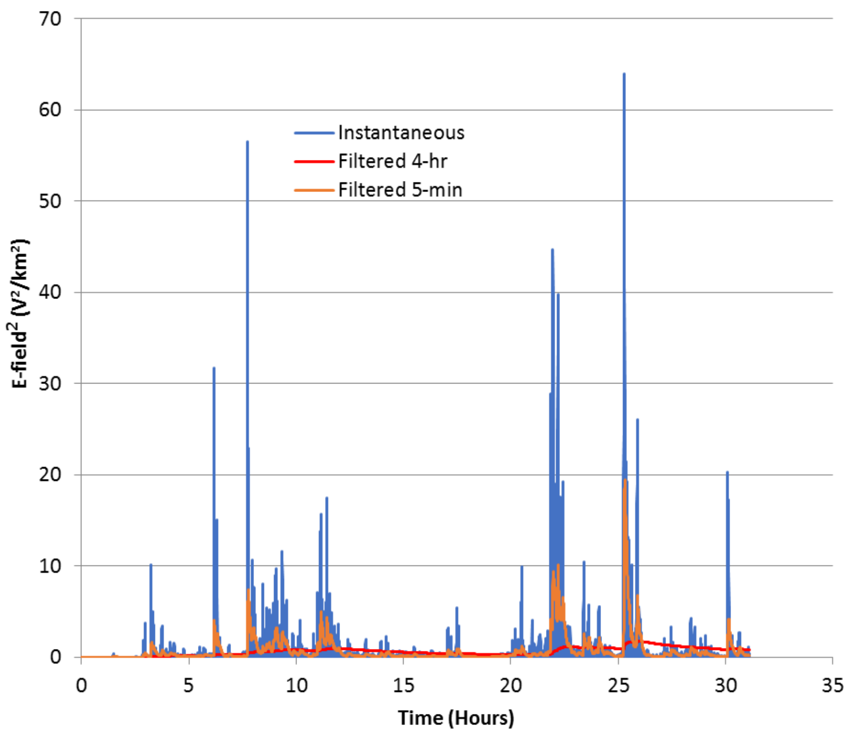

Figure 3-7
East-West reference geo-electric field intensity squared. Shown are the instantaneous values and the instantaneous values filtered through five minute and four hour thermal time constants.

The square root of the peak filtered E^2 values is a geo-electric field intensity, if present continuously, would create GIC and hence harmonic currents that would produce approximately the same peak temperature rises that would result from the variable E-field time series. The ratio of the peak filtered E^2 value divided by the peak unfiltered E^2 value is a factor that can be applied to the harmonic loading (I^2) used for the respective temperature rise calculation in order to define the peak temperature that would be reached without performing detailed thermal modeling. For the assumed thermal time constants, the filter factor K_{fhs} for the hot-spot rise is 0.3 based on the more severe East-West field orientation, and the factor K_{fto} for the top-oil rise is 0.027, respectively. These factors are dependent on the thermal time constants as shown in Figure 3-8 and Figure 3-9.

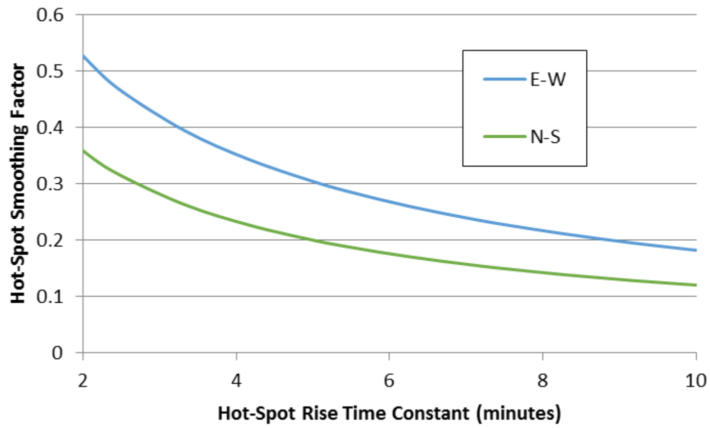

Figure 3-8
Hot-spot temperature rise smoothing factor versus hot-spot rise time constant, based on the NERC reference geo-electric field time series for East-West and North-South orientations.

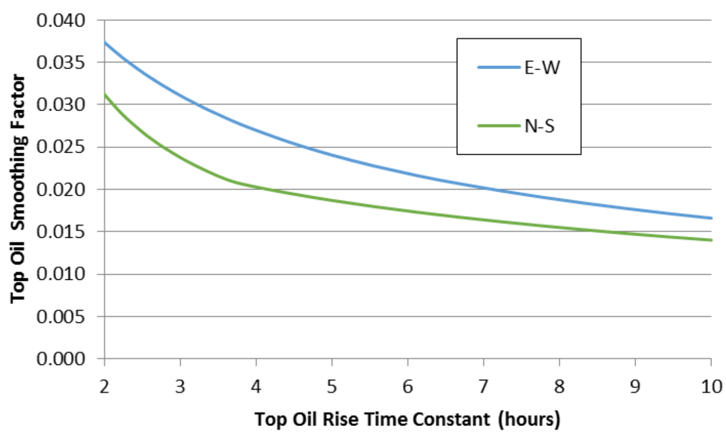

Figure 3-9
Top oil temperature rise smoothing factor versus top-oil rise time constant, based on the NERC reference geo-electric field time series for East-West and North-South orientations.

These factors can be applied directly to Equations 3-5 and 3-6, allowing prediction of the maximum temperature rise considering the filtering effect of transformer thermal time constants. The analysis is intended to be based on the harmonic currents at maximum GIC magnitude, without using detailed thermal modeling. Equation 3-8 uses K_{fto} to modify the magnitude of the maximum distorted load current to account for filtering effects on the top-oil rise, and Equation 3-9 uses K_{fhs} to modify the magnitude of the maximum distorted load current to account for filtering effects on the hot-spot rise.

$$\Theta_{TO\_A} = \Theta_{TO\_A-rated} \cdot \left[\frac{I_{RMS-pu}{}^{2} \cdot K_{fto} \cdot \left[1 - K_{ST} + K_{ST} \cdot \left[K_{EC} \cdot F_{HE} + (1 - K_{EC}) \cdot F_{HS}\right]\right] + 1/K_{LR}}{1 + 1/K_{LR}} \right]^{0.8}$$

Eq. 3-8

$$\Theta_{HS\_TO} = \Theta_{HS\_TO-rated} \cdot \left[\frac{I_{RMS-pu}{}^{2} \cdot K_{fhs} \cdot \left[(1 - K_{ST}) \cdot \frac{R_2}{R_1 + R_2} + K_{ST} \cdot K_{EF} \cdot K_{ED} \cdot F_{EC}\right]}{(1 - K_{ST}) \cdot \frac{R_2}{R_1 + R_2} + K_{ST} \cdot K_{EF} \cdot K_{ED}} \right]^{0.8}$$

Eq. 3-9

GIC Saturation

If a transformer is saturated by GIC, the flow of exciting current harmonic components through the windings depends on the harmonic impedances of the transmission system at the transformer's terminals, as well as the transformer's own impedances. Therefore, the harmonic loading will be different for each winding. The thermal equations above could be modified to take into account the individual winding heating effects. However, there are other thermal effects of saturation that play a larger role. During saturation, the flux patterns change and this will affect the distribution and amount of winding eddy current losses. In addition, saturation will increase stray flux heating that increases top-oil temperature rise. The direct thermal effects of GIC saturation on a transformer are outside of the scope of this guide. Therefore, the guidance provided here is with respect to transformer heating caused by harmonic currents flowing through a transformer, such as could be the case if a transformer and a nearby capacitor bank or harmonic filter form a resonant circuit causing abnormally large harmonic current loading through the transformer.

Calculation Example

Problem statement: Load flow analysis indicates that a transformer carries rated fundamental-frequency load current at the time of peak GMD activity. (This is a conservative assumption for the type of transformer application in this example, because transformers in such bulk supply applications are rarely loaded to capacity in order to provide reserve capacity in the event of a contingency.) GIC flow and harmonic analyses have determined that, due to a resonance with a nearby capacitor bank on the LV side, the transformer carries harmonic currents as shown in Table 3-1 at the time of maximum GMD impact on the system. The transformer windings are connected in delta/grounded-wye (delta on the HV side), so the transformer does not itself experience GIC flow. The transformer's physical parameters are as shown in Table 3-2. Calculate the maximum expected top-oil and winding hot-spot temperatures.

Table 3-1
Example transformer load current spectrum

Harmonic Order (n)	Transformer Current (p.u. on transformer base)
1	1.000
2	0.111
3	0.020
4	0.484
5	0.643
6	0.018
7	0.083
8	0.060
9	0.006
10	0.103

Table 3-2
Example transformer physical parameters

Transformer Parameter		Value
Rated top-oil rise	$\Theta_{TO\_A\text{-}rated}$	50°C
Top-oil rise time constant	τ_{TO}	4 hours
Rated hot-spot rise	$\Theta_{HS\_TO\text{-}rated}$	30°C
Hot-spot rise time constant	τ_{HS}	5 minutes
Loss ratio (load loss / core loss)	K_{LR}	4.5
Outer (HV) winding resistance	R_1	0.015 p.u.
Inner (LV) winding resistance	R_2	0.019 p.u.
Stray loss fraction	K_{ST}	0.12
Eddy loss fraction	K_{EC}	0.33
Winding eddy fraction	K_{EF}	0.6
Eddy distribution factor	K_{ED}	4.00

Applying Equations 3-2 through 3-4, $I_{RMS\text{-pu}}$ is determined to be 1.29 p.u., the harmonic adjustment factor for winding eddy current losses (F_{HE}) is 9.41, and the harmonic adjustment factor for other stray losses (F_{HS}) is 1.97. Using Figure 3-8 and Figure 3-9, the worst-case top-oil time constant filtering factor Kfto is 0.027 and the worst-case hot-spot time constant filtering factor K_{fhs} is 0.3. The top-oil temperature rise, calculated by Equation 3-8, is 50.83°C which is only less than one degree greater than that resulting from the undistorted fundamental-frequency load current alone. The hot-spot temperature rise is more significantly affected by the harmonic currents produced by the GMD. This temperature rise, calculated by Equation 3-9, is 40.95°C, compared to 30°C for undistorted load current alone. The hot spot temperature is 121.8°C which, according to IEEE C57.91, results in an insulation aging acceleration factor of 3.2. The hot spot, however, is at this maximum temperature for only a short period during the 31 hour duration of the NERC reference GMD event.

To examine the impact of GMD harmonics on transformer insulation loss of life, a thermal model as defined by IEEE C57.91 was applied to calculate the hot spot temperature and the aging acceleration factor in ten-second increments. Using the transformer data described above, rated fundamental-frequency load current was applied continuously along with harmonic loading that varied in proportion to the East-West reference geo-electric field defined by NERC. Figure 3-10 plots the resulting hot spot temperature and insulation aging acceleration factor as a function of time. The cumulative sum of the aging acceleration factors indicate that the example transformer would be subjected to 33.6 hours of aging over the 31 hour GMD duration. Thus, the incremental loss of life due to the time-varying harmonic loading is 2.6 hours, or 0.00144% of the transformer's 180,000 hour nominal life.

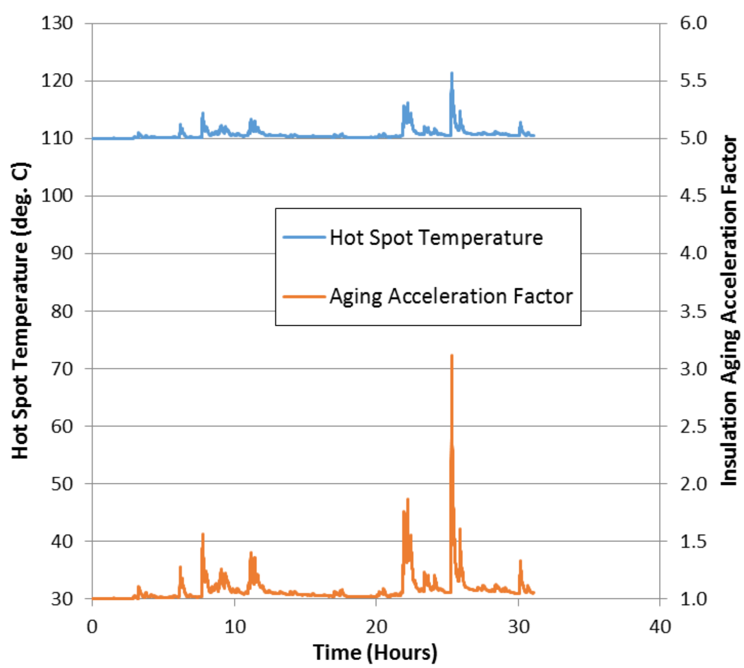

Figure 3-10
Hot spot temperature and insulation aging acceleration factor for the example transformer, based on thermal modeling in accordance with IEEE C57.91.

The maximum hot-spot temperature and insulation aging determined for this example is quite benign. Therefore, analysis was performed to determine how much harmonic current causes the example transformer to reach the critical 180°C maximum hot spot temperature, if it is assumed that the harmonic current magnitude follows a time series in proportion to the NERC East-West reference geo-electric field. This analysis was performed for time-varying single-harmonic current, superimposed on continuous one per unit load fundamental load current. Figure 3-11 displays the results which show that very high peak harmonic current magnitude is required, with this critical harmonic current level decreasing with harmonic order. A transformer thermal model was used to determine the cumulative transformer aging for the case with 1.49 p.u. fifth harmonic current, which is 70.3 hours. The incremental insulation aging is insignificant in comparison to the 180˚C maximum hot spot temperature, which could potentially result in immediate failure due to gas bubble evolution.

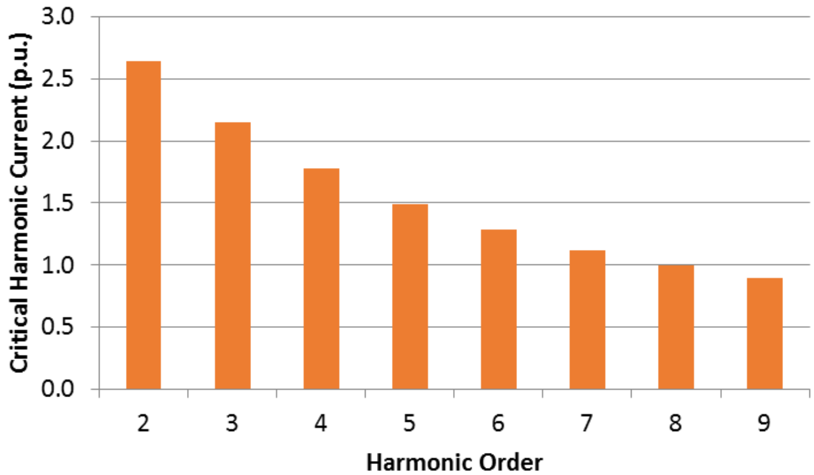

Figure 3-11
Critical magnitude of single-harmonic current, superimposed on rated fundamental load current, that results in transformer hot-spot temperature reaching the critical 180°C. Harmonic currents shown are the magnitude at the peak of a GMD following a time pattern as defined by the NERC reference geo-electric field time series.

3.5 Transformer Screening

The parameters of the example transformer are sufficiently typical to reach the generalized conclusion that maximum hot spot temperature is the critical factor for GMD harmonic thermal effects, and accelerated insulation aging need not be considered as a significant factor due to the short duration of the highest temperatures. It can also be concluded that harmonic currents at GMD peak would need to be very large in order to cause significant thermal damage, assuming that the harmonic current magnitudes follow a temporal pattern similar to the reference geo-electric fields defined by NERC.

It would be impractical to apply the detailed thermal analysis described in this section to every transformer in a transmission system GMD vulnerability evaluation. At fully fundamental frequency load current, the typical transformer analyzed in this section could withstand superimposed harmonic currents up to the rated current magnitude at peak GMD, for harmonic orders up to eight. Harmonics at orders greater than eight are not expected to be present with very high magnitude as the result of a GMD. Applying a 100% safety factor because of the uncertainty of transformer parameters, the harmonic current threshold at full fundamental-frequency current loading is 0.5 p.u. This equates to a total load current rms magnitude of 1.12 p.u. which is recommended as the conservative screening criterion. Harmonic current magnitudes can be quite large without exceeding this threshold. For example, if four different harmonics have 0.35, 0.25, 0.15, and 0.05 p.u. magnitudes, superimposed on rated fundamental current, this threshold is not exceeded.

Section 4: Capacitor Banks

The inherent electrical characteristics of capacitors results in increased capacitor currents and voltages due to harmonic distortion created by GIC-saturated transformers during a GMD. The impedance of capacitors is inversely proportional to harmonic order, and their negative reactance interacts with positive inductive reactance in the system to create resonances that amplify currents and voltages.

Although capacitors are reasonably robust to harmonics, the tendency for capacitors to amplify harmonic currents and voltages, combined with relatively short thermal time constants, make capacitors arguably the most vulnerable to GMD of the major power system components. Aggravating the impact of this sensitivity is the fact that failure or protective tripping of capacitor banks at the height of a GMD abruptly deprives the system of their reactive power contribution at a time when voltages are likely to be depressed by fundamental reactive current absorbed by transformer saturation. Widespread trip-off of capacitor banks could potentially be the trigger that sends a system into voltage collapse during a GMD.

The harmonic withstand of capacitors is specified in IEEE Standard 18-2012. The critical factors are the total rms current, total reactive power, and peak voltage. The current standard does not provide guidance regarding withstand of capacitors to short-duration stresses, except to indicate that capacitors are capable of withstanding infrequent switching transient voltages to twice the rated crest voltage. Switching transients are typically of sub-cycle duration, and thus are not indicative of the ability of capacitors to withstand highly variable GMD activity where the durations of peak harmonic voltages are on the order of minutes. Prior versions of IEEE-18 indicated that capacitors should withstand 1.3 p.u. overvoltage for one minute duration. However, it is also stated in IEEE Standard 18-1992 that these overvoltages are "without superimposed transients or harmonic content…". Considering the criticality of capacitor banks to voltage support during GMD, it is prudent to base evaluations of capacitor duty during GMD events on the duty at the GMD activity peak compared to the steady-state withstand capabilities of the capacitors.

The brevity of this report section is not indicative of low degree of risk of capacitors to GMD-generated harmonics. The brevity stems from the fact that capacitor steady-state harmonic withstand capability is well defined and easily calculable. Capacitors are potentially the most vulnerable to GMD harmonics of any major power system component.

4.1 Current Rating

IEEE Standard 18-2012 specifies that capacitors shall be capable of withstanding continuous (steady state) total rms current equal to 135% of nominal based on rated kvar and rated voltage. The total rms current includes both fundamental and harmonic components as indicated in Equation 4-1.

$$I_{rms} = \sqrt{\sum_{n=1,2\ldots n}\left(I_n^{\;2}\right)} \leq 135\% \qquad \textit{Eq. 4-1}$$

The total rms current causes heating of conductors within the capacitor units (e.g., metal foil) as well as either internal or external fuse links. Exceeding the current withstand capability can result in failure of capacitor units or operation of fuses. Overcurrent protection is often applied on capacitor banks as a means of fault detection and to avoid bank current overload. Depending on the overcurrent relay design, the overcurrent protection may or may not respond to the harmonic currents that cause increased rms current during GMD. If overcurrent protection is not provided, or is not responsive to harmonic components, individual capacitor units may fail. Failure of multiple capacitor units will generally result in pickup of the bank internal imbalance protection and cause the bank to be tripped.

4.2. Dielectric Heating

Heating of the capacitor unit's dielectric is proportional to the frequency and the square of the applied voltage. The volt-amperes produced by a capacitor is equal to the square of the voltage times the capacitive susceptance, and the susceptance is proportional to frequency ($B_{cap} = 2\pi f C$). Therefore, the volt-amperes produced by the capacitor, including harmonic volt-amperes, is indicative of the dielectric heating. IEEE Standard 18-2012 specifies that capacitors shall withstand 135% rated volt amperes. Exceeding this limit can cause capacitor element failure, placing increased stress on the remaining elements within a capacitor unit, and potentially lead to cascading failures of the elements within a unit. Multiple unit failures will cause pickup of the capacitor bank imbalance protection and cause bank tripping. The calculation of volt-amperes is shown in Equation 4-2.

$$Q_{total} = \sum_{n=1,2\ldots n}\left(I_n \cdot V_n\right) \leq 135\% \qquad \textit{Eq. 4-2}$$

4.3 Voltage Withstand

IEEE Standard 18-2012 places two limits on voltage across capacitors: 110% of rated rms voltage and 120% of rated peak voltage. Excessive voltage across a capacitor's dielectric can cause breakdown and shorting of capacitor elements. This results in increased voltage stressed on other capacitor elements at a time when the overall bank is heavily stressed, and cascading failure of other elements can occur. Excessive capacitor unit failure will cause pickup of the capacitor bank imbalance protection and the bank will be tripped. The total rms voltage, including harmonic components, is calculated by Equation 4-3.

$$V_{rms} = \sqrt{\sum_{n=1,2\ldots n} \left(V_n^{\ 2}\right)} \leq 110\% \qquad \textit{Eq. 4-3}$$

The peak voltage is based on the instantaneous waveform, and the phase relationships of the various harmonic components are of critical importance. When frequency-domain (i.e., phasor) harmonic analysis is performed to determine capacitor peak voltages, the harmonic and fundamental voltage phasors must be converted to the time domain and summed as indicated in Equation 4-4. Proper analysis requires careful attention to the phase relationships of each harmonic injection with the injections at other harmonics at the same location, and to harmonics injected simultaneously at other locations. In addition, the phase relationships between the harmonics and the fundamental must also be correctly maintained.

$$V_{peak} = Max\left[\sum_{n=1,2\ldots n} V_n(t)\right] \leq 120\% \qquad \textit{Eq. 4-4}$$

4.4 Type-C Filters

Capacitor banks can interact with system inductances to form resonances that can substantially amplify harmonic distortion. A solution sometimes used is to implement the shunt capacitive compensation in the form of a “type-C” filter, which provides a damped filtering effect over a range of frequencies [8]. A single-line diagram of a type-C filter is shown in Figure 4-1. The main capacitor section is the same as would normally be applied as an ordinary capacitor bank for the desired degree of compensation. The tuning section is designed to be series-resonant at the fundamental frequency, thus minimizing the fundamental voltage across the damping resistor. This ideally eliminates fundamental-frequency losses and damping resistor duty. At frequencies above fundamental, the tuning section provides a damped inductive impedance that partially cancels the capacitive reactance of the main capacitor section, reducing the net harmonic impedance of the filter and providing considerable damping. This filter thus provides a means to supply capacitive compensation while mitigating harmonic distortion, particularly in the low-order harmonic range.

The ratings of type-C filter components, particularly the damping resistor, are driven by background distortion sources and filter tuning drift. Design typically considers ordinary levels of background distortion, with conservative margin. Levels of voltage distortion during a severe GMD event, however, can be far greater than the assumptions typically used for design and component rating specification. The ability of the filter components to withstand GMD activity depend on the details of the design, harmonic distortion magnitude and duration, and the thermal time constants and temporary overload characteristics of the filter components. As a general recommendation, all type-C filters should be analyzed in detail for any GMD event resulting in distortion significantly greater than the design assumptions.

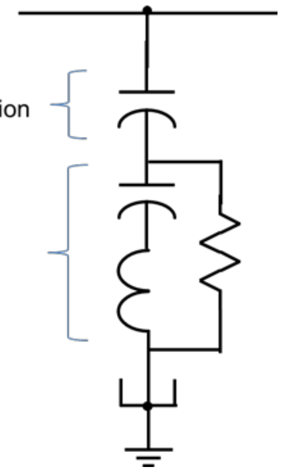

Figure 4-1
Type-C filter single line diagram.

4.5 Capacitor Screening

The current, volt-ampere, and voltage withstand capabilities specified in IEEE 18, and discussed in this section, are based on continuous duty. A prior version of the standard, IEEE 18-1992, specified considerable temporary overcurrent and overvoltage capability for capacitors. Although this temporary overload specification is not in the current standard, it is reasonable to assume that capacitors should be able to endure greater duty than these thresholds for the relatively short duration (on the order of 30 seconds) of peak GMD activity. This margin between temporary and continuous withstand capability can be considered as a safety factor. Also, the parameters and capabilities of capacitors with respect to steady-state harmonics are well defined. Therefore, screening thresholds based on the IEEE 18 specified continuous withstand capabilities can be considered to have sufficient inherent safety margin.

Typical harmonic analysis software provides total rms current, including harmonic components, for branches including capacitor banks. Therefore, the recommended overcurrent screening threshold is 135% of rated capacitor current.

IEEE-18 specifies overvoltage limits in terms of both the rms voltage and the peak voltage. Rms voltage should be directly available from the harmonic analysis results. Frequency-domain harmonic programs, however, do not typically provide peak time-domain voltages. Harmonic and fundamental voltage phasors would need to be transformed to the time domain to determine peak values. For simplicity in screening using frequency-domain harmonic analysis programs, the recommended screening threshold for peak voltage is the sum of the harmonic voltage component should not exceed 0.2 p.u. This assumes that the harmonic component phase angles are adversely aligned with the fundamental voltage such that the voltage peak is maximized. This is an unlikely circumstance, so this screening has additional inherent safety margin.

Because of the significant vulnerability to GMD of type-C filters, tuned in the low-order harmonic range, detailed evaluation of the filter's withstand capabilities should be performed for any level of harmonic voltage distortion at the filter location exceeding the filter's design assumptions.

Section 5: Generators

5.1 Rotor Heating from Negative Sequence Fundamental Current

Fundamental-frequency currents flowing in the stator of a synchronous generator create flux waves that have apparent rotation relative to the rotor with rotational direction depending on whether the current is positive or negative sequence. Positive sequence waves rotate forward in the same direction as the generator rotor, and negative-sequence waves rotate in the reverse direction. Generators are always coupled to the grid using grounded wye (HV side) delta (generator side) step-up transformers, therefore zero sequence currents do not flow into a generator and are not a consideration.

In the rotor's reference frame, rotating forward at synchronous speed, the flux wave caused by positive-sequence fundamental-frequency currents appears fixed. With pure positive sequence current, there is no alternating flux component seen by the rotor, and thus the fixed flux does not induce current in the rotor. Negative-sequence fundamental currents, however, create a flux wave that rotates at synchronous speed with respect to the stator in the reverse direction. From the rotor reference frame, the apparent rotation of this flux wave is at twice synchronous speed. The magnitude of the flux seen by the rotor oscillates at twice the fundamental frequency, inducing parasitic currents in the rotor surface, rotor bar slot wedges, and to a lesser extent, the field winding.

The parasitic ac currents in the rotor resulting from negative-sequence fundamental-frequency stator currents cause heating of the rotor. At low levels, this heating over an extended period of time will accelerate degradation of field winding insulation. High levels of negative-sequence heating, however, can potentially result in immediate machine failure. One failure mode of concern is yielding of the aluminum rotor slot wedges that retain the field windings in the slots. High temperatures cause aluminum to substantially lose mechanical strength, and these slots are exposed by high centrifugal loadings. If the rotor wedges fail to retain the field winding bars, catastrophic destruction of the generator can result. Other failure modes include arcing across the field winding insulation and failure of the rotor retaining rings.

IEEE Standards C50.13 and C50.12 specify negative sequence current withstand capabilities for cylindrical-rotor and salient-pole synchronous generators, respectively. Cylindrical-rotor generators are used for all thermal generation applications, including fossil-fueled and nuclear steam turbo-generators as well as gas turbines, and comprise the vast majority of generators in the bulk power grid.

The continuous negative sequence current capability for these machines is specified by these standards as a function of machine type, rating, and cooling design. The capability for machines with indirectly cooled cylindrical rotors is 10%. For directly cooled cylindrical rotors, the capabilities are 8% for machines up to 350 MVA, 5% for machines larger than 1250 MVA, for ratings between these values as shown in Equation 5-1.

$$\%I_2 = 8 - \frac{MVA - 350}{300} \qquad \text{Eq. 5-1}$$

The negative sequence current limit for salient pole generators with connected amortisseur windings is 10%, and 5% for salient pole generators with unconnected amortisseurs.

The short-duration negative-sequence current withstand capability is specified as a maximum I_2^2t. For a generator with an indirectly cooled cylindrical rotor, the limit is 30%. For directly cooled rotors up to 800 MVA rating, the limit is 10%, and decreases for larger generators according to the formula shown in Equation 5-2.

$$\%I_2 \cdot t = 10 - 0.00625 \cdot (MVA - 800) \qquad \text{Eq. 5-2}$$

5.2 Rotor Heating from Harmonics

Harmonic components flowing into a generator also cause rotor heating. While similar to the heating caused by negative-sequence fundamental current, the degree of heating created by harmonic currents depends on the harmonic order and whether the currents are positive or negative sequence. A common misconception is that only negative sequence harmonics cause generator rotor heating; this is absolutely not true. <u>Both positive and negative sequence harmonics cause rotor eddy currents and result in potentially damaging rotor heating</u>, but the frequency of the rotor eddy currents and thus the heating impact differ for positive and negative sequence stator harmonic currents. Zero sequence harmonic currents, including those injected by saturation of the generator step-up transformer, do not flow into the generator.

Harmonic currents flowing in the stator of a synchronous generator create flux waves that have apparent rotation at a speed that is dependent on the harmonic order, and direction of rotation depending on whether the harmonic current is positive or negative sequence. The apparent rotational speed of the flux wave in the stator (stationary) reference frame is the harmonic order times the synchronous speed. Positive sequence waves rotate forward in the same direction as the generator rotor, and negative-sequence waves rotate in the reverse direction. The relative speed of rotation in the rotor reference frame is the harmonic order minus one for positive sequence harmonics, and the harmonic order plus one for negative sequence harmonics. Therefore, the induced rotor eddy currents have a frequency that is plus or minus one order from the harmonic order of the current into the generator, depending on whether the stator harmonics are negative or positive sequence.

Table 5-1 provides the relationships between stator positive and negative sequence currents with the harmonic order seen by the rotor. Stator entries in bold type indicate the "classic" or normally assumed relationship between harmonic order and sequence characteristic. This classic relationship only occurs when a balanced nonlinearity is excited by a balanced fundamental voltage, and the transmission system is perfectly balanced. The magnetic structures of three-phase transformer cores are inherently unbalanced, so GIC saturation of these transformers produce harmonic currents that do not follow the classic relationship. Transmission system impedances, while reasonably balanced at the fundamental frequency, tend to be more substantially unbalanced near resonant frequencies and thus cause harmonics injected in one sequence to be transformed to the other sequences (i.e., fifth harmonic injected in the negative sequence can be partially transformed into positive and zero sequence components).

Table 5-1
Relationships between stator and rotor harmonic orders

Stator Positive Sequence Harmonic Order	Stator Negative Sequence Harmonic Order	Rotor Order
1 (Fundamental)		0 (dc)
2		1 (Fundamental)
3	1 (Fundamental)	2
4	**2**	3
5	3	4
6	4	5
7	5	6
8	6	7
9	7	8
10	**8**	9

5.3 Equivalent Negative Sequence Duty

Because generator rotors are magnetic material, skin effect is very pronounced and results in a substantial reduction of the depth of eddy current penetration into the rotor with increasing frequency. Because the skin depth is proportional to the square root of the reciprocal of frequency, the resistance of the eddy current path increases with the square root of frequency, as do the power losses. The ability of a generator to endure rotor heating is defined by the standards in terms of the negative sequence fundamental current. It is therefore possible to relate the heating caused by harmonic currents to an equivalent amount of fundamental negative sequence current. The eddy power loss weighting factor is the square root of the rotor harmonic order divided by two. The factor of two is because the second harmonic rotor eddy currents caused by negative-sequence fundamental currents is the reference value.

For example, the amount of heating given by a certain magnitude of fourth harmonic positive sequence current is approximately equal to 1.22 times the heating caused by the same amount of negative sequence fundamental current.

In a GMD event, generators may be subjected to harmonic currents of multiple orders and sequences at the same time. The total heating effect of currents at different harmonics is calculated by the square root of the sum of the frequency-weighted squares of the individual harmonics. IEEE C50.12 and C50.13 use Equation 5-3 to define the equivalent negative sequence current (I_{2eq}) for generator stator currents with harmonic distortion.

$$I_{2eq} = \sqrt{I_2{}^2 + \sum_n \left(\sqrt{\frac{n+i}{2}} \cdot I_n{}^2 \right)} \qquad \textit{Eq. 5-3}$$

Where:

i = +1 when n = 5, 11, 17, etc.

i= -1 when n = 7, 13, 19, etc.

I_n = current magnitude at harmonic n in the stator reference frame

I_2 = negative sequence fundamental, as defined.

These standards define the index i for only odd harmonics, and implicitly assume that the harmonics always fall into the classic order (i.e., fifth as negative sequence, seventh as positive sequence, etc.). During a GMD, there will be large amounts of both even and odd harmonics. Also, unless the transmission system only has no three-phase transformers (i.e., all transformers are banks of single-phase units), then it is not a valid assumption that harmonics fall into the classic sequence pattern. It is far better to define i according to the sequence component, and not to specific harmonics. Using this definition of i, the formula can be generalized to include both even and odd harmonics. However, the formula as shown in these standards becomes confusing in its use of I_2 to indicate negative sequence fundamental current (which is a common industry usage) when I_2 could also mean second harmonic stator currents (I_n for n = 2) if the formula is generalized. To avoid confusion, a rewritten version of Equation 5-3 is recommended, as shown in Equation 5-4.

$$I_{2eq} = \sqrt{\sum_{n=1,2,3\cdots} \left(\sqrt{\frac{n+i}{2}} \cdot I_n{}^2 \right)} \qquad \textit{Eq. 5-4}$$

Where:

i = +1 for negative sequence harmonic components.

i= -1 for positive sequence harmonic components.

I_n = current magnitude at harmonic n in the stator reference frame.

n = all harmonic orders having significant current, including fundamental (n=1)

It should be noted that in Equation 5-4, ordinary fundamental-frequency positive-sequence load current has a weighting factor of zero, and fundamental negative sequence has a weighting factor of one.

Both Equations 5-3 and 5-4 make a simplification that may not always be conservative. A negative sequence harmonic at order n-1 and a positive sequence harmonic at order n+1 both cause rotor eddy currents at order n. These equations calculate the equivalent current by the root-sum-square combination of these components, as if they were at different frequencies on the rotor reference frame. In actuality, the nth harmonic rotor current components they create are phasors that may add or cancel depending on their phase relationships. Calculations of these phase relationships are subject to considerable uncertainty. As an alternative, a conservative assumption can be made that the components are in phase and thus their magnitudes sum algebraically.

On the average, the I_{2eq} calculated by Equations 5-3 or 5-4 provide reasonable evaluation of the rotor heating impact of harmonic currents in a synchronous generator. Under the worst case condition of rotor current component in-phase superposition, however, these formulas may underestimate the heating impact. The formula in Equation 5-5 provides an alternative highly conservative estimate.

$$I_{2eq} = \sqrt{\sum_{n=1,2,3\cdots}\left(\sqrt{\frac{n}{2}}\cdot\left(I^{+}{}_{n+1} + I^{-}{}_{n-1}\right)^{2}\right)} \qquad \textit{Eq. 5-5}$$

Where:

$I+_{n+1}$ = Positive-sequence current magnitude at order n+1

$I-_{n+1}$ = Negative-sequence current magnitude at order n-1

Note that $I-_0$ when n = 1 is dc in the stator, which is zero.

In Equation 5-5, it should be noted that for n = 1, the equation calls for the “zero” order (i.e., dc) component of current. GIC does not propagate into the generator, and there is no other cause for direct current.

5.4 Thermal Time Constant Filtering

Like a transformer, a generator rotor has a large thermal mass, leading to a relatively long thermal time constant. This thermal time constant can be approximated by the ratio of the generator’s I_2^2t limit divided by the square of the steady-state I^2 limit. Figure 5-1 shows the approximate rotor thermal time constant for directly-cooled round-rotor synchronous generators, based on the transient and steady-state negative sequence current limits provided by IEEE C50.13. The thermal time constant of an indirectly cooled round rotor is 0.83

hours. Thus across the range of round-rotor generator ratings and cooling designs, the thermal time constant is within the range of 0.4 and 0.83 hours.

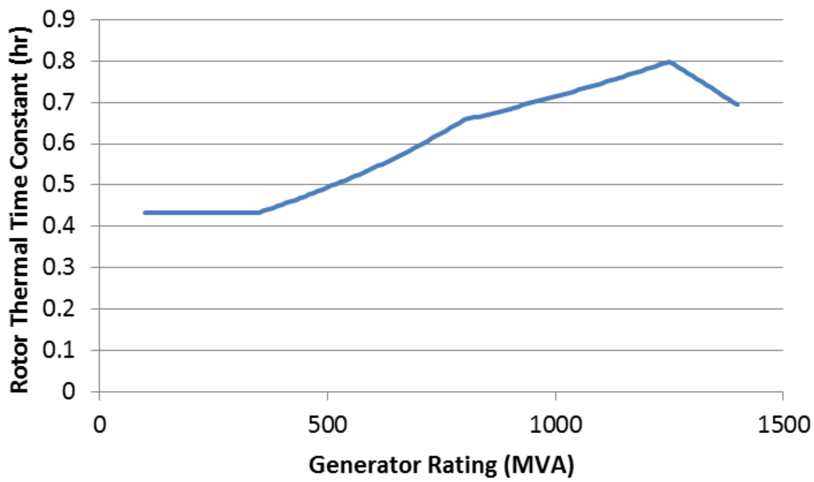

Figure 5-1
Approximate thermal time constant of directly-cooled round-rotor synchronous generator rotors.

As discussed previous in subsection 3.2, geo-electric field intensity is highly variable during GMD. Transformer GIC levels are proportional to the geo-electric field intensity, and the harmonic currents produced by saturation of transformers carrying GIC are roughly proportional to GIC. Therefore, the harmonics that create generator rotor heating during a GMD are in rough proportion to the variable geo-electric field.

Thermal smoothing factors, similar to those developed in subsection 3.4 for transformers, can be defined as a function of thermal time constant, based on the NERC reference geo-electric field time series. The I_{2eq} at the peak geo-electric field intensity can be multiplied by this smoothing factor to determine the equivalent negative sequence current from a rotor heating standpoint, considering the filtering effect of the rotor's thermal time constant on the highly variable electric field pattern. Figure 5-2 shows the thermal smoothing factor as a function of rotor thermal time constant, based on the NERC East-West geo-electric field pattern. As defined here, the rotor heating smoothing factor is defined as the square root of the thermally filtered I_{2eq}^2 heating – assumed to be in proportion to the square of the geo-electric field intensity, in contrast to the smoothing factor definition used for transformers in subsection 3.4 which is the thermally-filtered geo-electric field magnitude squared – without the square root. The difference is with regard to how these smoothing factors are applied. The generator smoothing factor is intended to be applied to the maximum I_{2eq} magnitude, whereas the transformer thermal smoothing factors are applied to the square of transformer current.

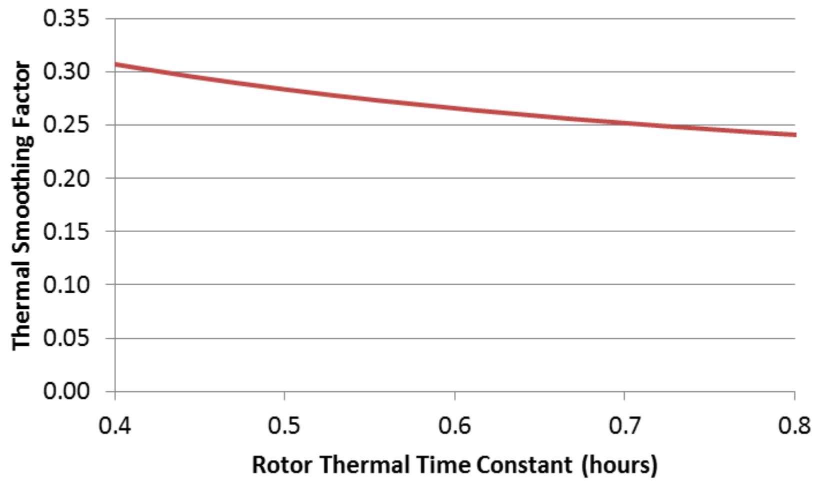

Figure 5-2
Thermal smoothing factor as a function of rotor time constant, based on NERC East-West reference geo-electric field intensity time series.

The results shown in Figure 5-1 and Figure 5-2 can be combined to show the thermal smoothing factor for generator rotor heating as a function of generator MVA rating. It can be observed that the smoothing factor remains in a rather tight range between 0.24 and 0.30 across the range of generator ratings. As a simplified rule, this smoothing factor can be conservatively assumed to be 0.3 for all generators. This means that the generator rotor temperature reached during a GMD, with a pattern of variation similar to the NERC East-West reference geo-electric field time series, will be the same temperature as if I_{2eq} of 30% of the peak I_{2eq} magnitude is applied on a continuous basis.

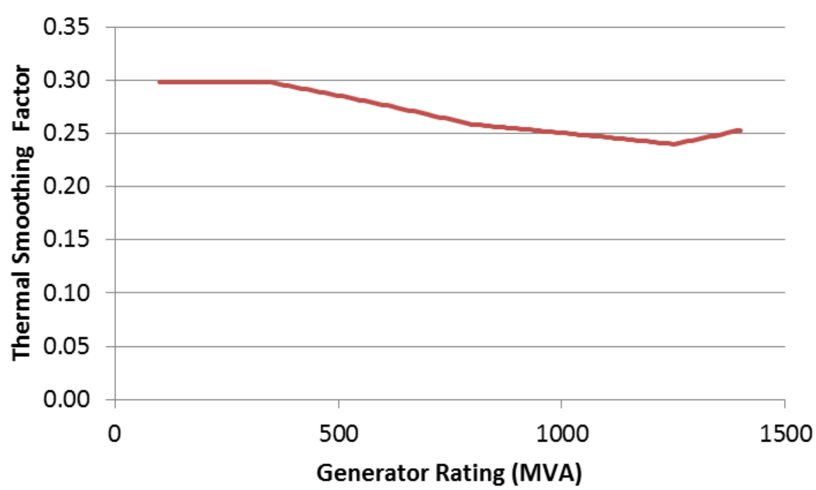

Figure 5-3
Thermal smoothing factor as a function of generator MVA rating, based on NERC East-West reference geo-electric field intensity time series.

5.5 Generator Harmonic Impact Example

Problem Statement: System harmonic analysis predicts the harmonic current components shown in Table 5-2 will flow into the stator of a 600 MVA, 25 kV round-rotor synchronous generator with a directly-cooled rotor. The negative sequence fundamental current is 208 A. The fifth harmonic in this example is amplified by a resonance near that frequency. Calculate the magnitude of fundamental-frequency negative sequence current, if applied continuously, that would result in the same maximum rotor temperature.

Table 5-2
Example generator harmonic current components

Harmonic Order	Positive Sequence Current (A)	Negative Sequence Current (A)
2	614	2,012
3	491	386
4	187	89
5	857	2,245
6	25	47
7	32	8
8	28	62
9	4	11

For this example calculation, the more conservative Equation 5-5 is used. The steps of the calculation, starting with conversion of the currents to per-unit on the generator's rating, are shown in Table 5-3. In this severe case, the equivalent continuous fundamental-frequency negative sequence current is more than 9%, and exceeds the generator's withstand capability. If the less conservative Equation 5-4 is used, the I_{2eq} is 0.2847 before application of the thermal time constant smoothing factor, and 0.0854 after.

Table 5-3
Calculation of equivalent steady-state fundamental negative sequence current

Harmonic Order on Rotor Reference Frame (n)	I^{+}_{n+1} (p.u.)	I^{-}_{n-1} (p.u.)	$\sqrt{\frac{n}{2}} \cdot \left(I^{+}_{n+1} + I^{-}_{n-1}\right)^2$
1	0.0443	0.0000	0.0014
2	0.0354	0.0150	0.0025
3	0.0135	0.1452	0.0308
4	0.0618	0.0279	0.0114
5	0.0018	0.0064	0.0001
6	0.0023	0.1620	0.0468
7	0.0020	0.0034	0.0001
8	0.0003	0.0006	0.0000

9	0.0000	0.0045	0.0000
10	0.0000	0.0008	0.0000
	$\sum \sqrt{\frac{n}{2}} \cdot \left(I^{+}_{n+1} + I^{-}_{n-1}\right)^2$		0.0931
	$I_{2eq} = \sqrt{\sum \sqrt{\frac{n}{2}} \cdot \left(I^{+}_{n+1} + I^{-}_{n-1}\right)^2}$		0.3052
I_{2eq} adjusted for thermal time constant smoothing ($0.3 \times I_{2eq}$)			0.0916

5.6 Mechanical Resonance Excitation

The rotating magnetic fields caused by synchronous generator stator harmonic currents interact with the dc magnetic field produced by the rotor to cause mechanical torque pulsations. The frequency of this mechanical stimulus is the same as the frequency of the harmonic as seen in the rotor reference frame; stator harmonic order plus one for negative-sequence harmonics and stator harmonic order minus one for positive-sequence harmonics.

A turbine-generator shaft is a complex mechanical system with many modes of natural-frequency torsional vibration. Stimulation of a mode can result in substantial amplification of the response, which is mechanical deflection of certain parts of the machine. When sufficiently amplified by mechanical resonance, the deflections can cause material fatigue and possible failure.

Some modes of torsional oscillation or vibration have natural frequencies below the fundamental. These subsynchronous modes can be stimulated by interaction with low-frequency grid resonances resulting from series capacitor application, resulting in the phenomenon known as subsynchronous resonance (SSR). SSR has resulted in catastrophic failure of steam turbo-generators on multiple occasions [9]. Harmonic currents do not cause stimulus of subsynchronous modes, but turbine generators have many mechanical modes above synchronous frequency as well.

Negative sequence fundamental current results in torsional stimulus at twice the fundamental frequency (i.e., 120 Hz in 60 Hz machines). Generators are routinely exposed to negative sequence fundamental, both on a continuous basis due to transmission line impedance imbalance and load imbalance, and more severely for shorter durations due to unbalanced grid faults. Considerable attention during turbo-generator design is focused on ensuring that torsional resonances are sufficiently separated in frequency from 120 Hz. Providing frequency separation of higher-frequency torsional oscillation modes from integer multiples of fundamental, however, is more difficult. Torsional resonant frequencies change to some degree with operating conditions [10], and these changes become more pronounced for higher-frequency modes. There is also substantial uncertainty in the calculation of higher-frequency turbo-generator torsional modal frequencies.

Bulk transmission systems, under normal circumstances, have limited amounts of ambient harmonic distortion. The most significant background distortion under normal conditions in most transmission systems tends to be at the fifth and seventh harmonics. Some attention during turbo-generator design is given to avoiding torsional resonance near the sixth harmonic (in the rotor reference frame), as this is stimulated by fifth harmonic negative sequence currents and seventh harmonic positive sequence currents. Harmonic distortion during a GMD, however, will tend to involve harmonic orders that are not typically experienced at significant magnitude during normal conditions, such as even-order harmonics. Levels of distortion are likely to be far more severe during a GMD than the normal levels of distortion for which the industry has experienced. It is quite possible that a torsional frequency stimulated by harmonics during a GMD may coincide with the resonant frequencies of one or more torsional modes.

Higher frequency torsional mode shapes tend to involve participation by the turbine blades [11]. If a blade vibration mode coincides with a stimulated frequency the possibility of loss of blades from fatigue due to torsional vibration may be high. Fatigue of turbine blades due to torsional vibration has resulted in loss of turbine blades, significant unbalance conditions on the turbine generator, and catastrophic failures due to the resulting high lateral vibration [10]. Thus it appears that there is a plausible risk to turbo-generators from severe harmonic distortion during a GMD. There have been no documented cases, however, of such failures as the result of GMD.

Material fatigue is a function of the number of cycles to which a part is exposed times a highly nonlinear function of the maximum mechanical deflection. Thus, there is a cumulative effect of extended exposure, and a generator can be exposed to more severe harmonic currents for a short period of time than they can withstand on a continuous basis. The material fatigue process is different than thermal heating, and a simple time constant cannot be defined. Therefore, evaluation of the irregular pattern of duty caused by a GMD requires detailed generator information that is not readily available.

It is not feasible to give generalized guidelines for the evaluation of turbo-generator torsional vibration risk from GMD. Generators operate routinely with continuous harmonic distortion exposure up to and beyond the guidelines of IEEE 519. The levels of distortion during GMD could be far greater than the IEEE 519 guidelines, however, and this is uncharted territory. Turbo-generator manufacturers should be contacted to obtain their recommendations regarding the ability of specific machines to withstand abnormal harmonic distortion. Vibration test analysis of machines can also be used to indicate the correlation of torsional resonance modes with harmonic frequencies.

5.7 Generator Screening

For a generator rated 1250 MVA, the I_{2equiv} limit is 0.05 per unit, based on continuous duty. The thermal time constant filtering factor, as discussed in this section is 0.3 or less for a typical generator. Therefore, the I_{2equiv} limit based on the peak GMD intensity is 0.05/0.3 or 0.167. Available harmonic analysis programs do not facilitate convenient evaluation of I_{2equiv}. Therefore, an approximate correlation between total harmonic current distortion (THDI) was determined. For harmonic components in the low-order range that might flow into a generator during a GMD, a current THD of less than 0.1 per unit should not cause I_{2equiv} exceeding 0.167. Because the generator thermal withstand capability is well defined, a 50% safety factor is recommended. This yields a screening limit for generators 1250 MVA and larger of 0.067 p.u. The generator I2 limit as specified in C50.13 is a function of the transformer MVA. Applying the ratio of 0.067/0.05 to the I_2 limits of the standard, the following THDI screening thresholds are recommended:

- For generators rated up to 350 MVA: THDI > 0.107 p.u.
- For generators rated 1250 MVA and larger: THDI > 0.067 p.u.
- For generators rated 350 MVA to 1250 MVA: THDi > 0.107 – 0.00447 x (MVA – 350)

Section 6: Surge Arresters

Surge arresters are universally applied at transformer terminals and other locations within HV and EHV substations in order to protect equipment from impulse (lightning) and switching overvoltages. Prior to the introduction of gapless metal-oxide surge arresters (MOSA) in the 1970s, the silicon-carbide arresters used at that time had series gaps. Unless the applied voltage exceeds the gap sparkover voltage, silicon-carbide arresters are not sensitive to the applied voltage. The transition to gapless MOSA provided superior protective characteristics, but these arresters are also vulnerable to thermal instability and failure if exposed to excessive continuous and temporary voltages beyond their maximum continuous operating voltage (MCOV). At this time, the vast majority of substation surge arresters are MOSA, having replaced the older gapped silicon-carbide arrester technology.

While a GMD will generally cause reduction in system fundamental voltage, due to the reactive demand of GIC-saturated transformers, the injected harmonic currents can result in harmonic voltage components superimposed on the fundamental. If a harmonic resonance condition that results in an amplified harmonic voltage component is combined with a situation where the phase relationship between the fundamental and harmonic voltage is such that the peaks of the components align, it is possible for voltage peaks during a GMD to exceed the crest value of the MCOV. (MCOV is specified as an rms voltage, the crest voltage at MCOV is $\sqrt{2}$-MCOV.)

6.1 Thermal Stability of MOSA

A key characteristic of a MOSA is that the nonlinear resistive element is in the circuit at all times, due to the absence of a series gap, and is always at some level of current conduction. Figure 6-1 shows the voltage-current characteristic of a typical MOSA at a normal operating temperature. The leakage current while energized at voltage less than MCOV causes power dissipation that elevates the temperature of the metal-oxide varistor (MOV). Elevation of temperature increases leakage current and power dissipation. When the arrester is exposed to voltage at or below MCOV, the increase of heat transfer to the ambient with elevated temperature is greater than the increase in power dissipation, and the MOSA remains thermally stable.

Voltage greater than the MCOV, for an indefinite period of time, can cause the temperature of the MOV to exceed the thermal stability point. The thermal stability temperature is where incremental temperature rise causes power dissipation to increase faster than heat transfer out of the arrester to the ambient. If the arrester reaches this temperature, and the overvoltage remains, the arrester will go into thermal runaway, and fail. Reaching the critical temperature takes a period of time that depends on the severity of the overvoltage. Except for special applications and designs (e.g., series capacitor protection), MOSA are not intended to be applied for the purpose of limiting such temporary overvoltages (TOV). Instead, arrester application is constrained such that the selected arrester will survive the worst-expected TOV. For this reason, arrester manufacturers publish TOV versus exposure time curves or data for their products, such as the typical curve shown in Figure 6-2

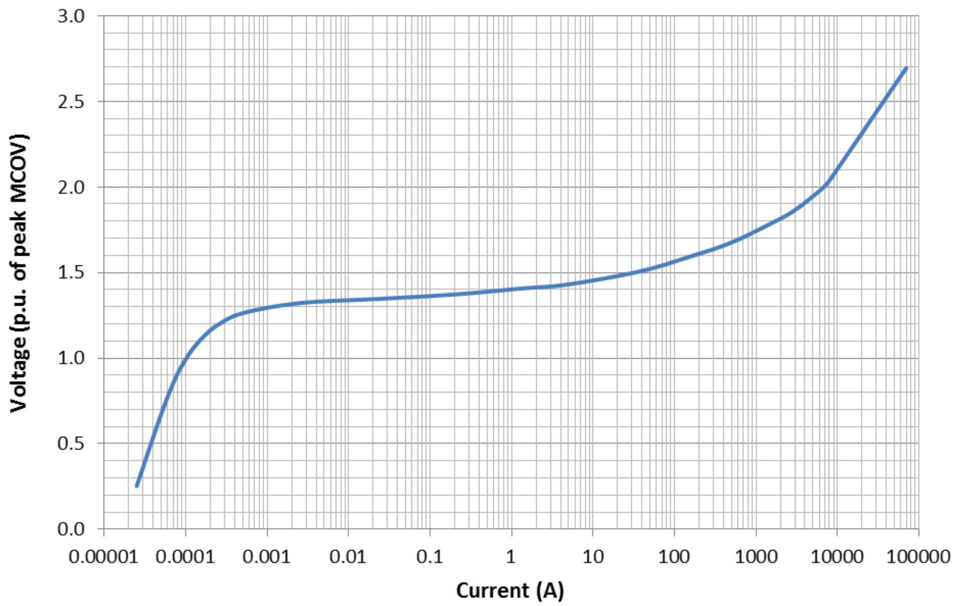

Figure 6-1
Voltage-current curve for a typical metal-oxide surge arrester.

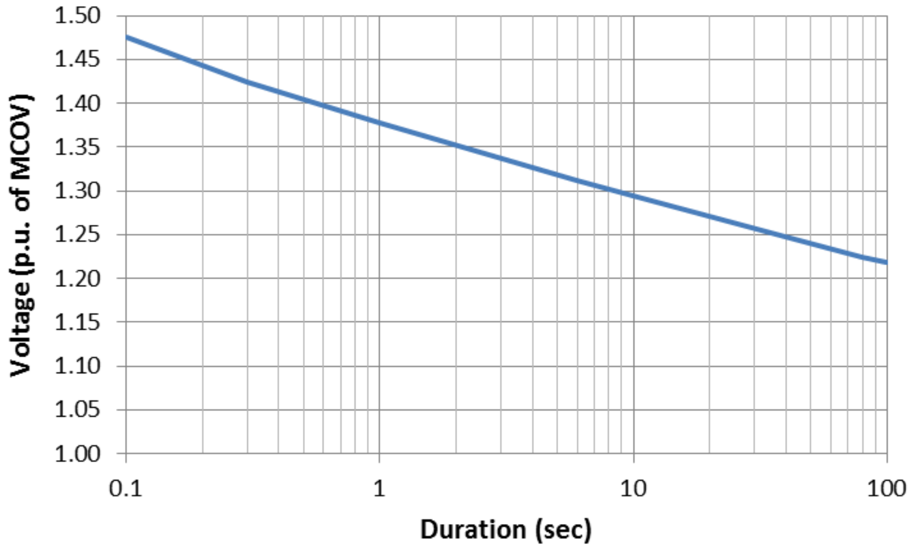

Figure 6-2
Temporary overvoltage (TOV) withstand capability of a typical metal-oxide surge arrester.

6.2 Peak Voltage Sensitivity

The TOV tests specified by IEEE C62.11 are performed using fundamental frequency voltage. As a matter of industry practice and test lab convenience, TOV capabilities of MOSA are specified in terms of rms voltage magnitude. This has led to a misunderstanding that when a complex waveform composed of fundamental and harmonic components is applied to a MOSA, it is the rms magnitude of this waveform that is relevant. This is definitely not the case. Due to the extreme nonlinearity of MOSA, the TOV duty is best defined by the peak voltage and not the rms magnitude.

This is illustrated by calculations of power dissipation using the V-I curve shown in Figure 6-1 with waveforms composed of pure fundamental voltage, and fundamental with superimposed harmonic components. The results of these calculations are shown in Table 6-1. In each case, the magnitude of the harmonic component is adjusted such that the power dissipation is the same as the dissipation with a 1.35 p.u. fundamental-frequency voltage applied. Examination of these data clearly indicates that the peak voltage is very nearly the same for all of these cases, but the rms voltage is not a valid indicator of the TOV duty.

Table 6-1
Combinations of fundamental and harmonic voltage causing MOSA power loss equivalent to 1.35 p.u. undistorted fundamental voltage

Harmonic Order	Fundamental Magnitude (p.u. of MCOV)	Harmonic Magnitude (p.u. of MCOV)	Peak Voltage (p.u. of MCOV)	RMS Voltage (p.u. of MCOV)
	1.35	0	1.35	1.35
2	1.0	0.362	1.362	1.064
3	1.0	0.357	1.357	1.062
4	1.0	0.368	1.368	1.066
5	1.0	0.362	1.362	1.064
6	1.0	0.374	1.374	1.068
7	1.0	0.366	1.366	1.065
8	1.0	0.376	1.376	1.068
9	1.0	0.369	1.369	1.066
10	1.0	0.379	1.379	1.069
2	0.9	0.463	1.363	1.012
3	0.9	0.458	1.358	1.010
4	0.9	0.469	1.369	1.015
5	0.9	0.463	1.363	1.012
6	0.9	0.474	1.374	1.017
7	0.9	0.467	1.367	1.014
8	0.9	0.478	1.378	1.019
9	0.9	0.470	1.370	1.015
10	0.9	0.481	1.381	1.020

Because of the extreme nonlinearity of MOSA, the impact on arresters is defined almost completely by the duration and magnitude of the worst-case period of temporary overvoltage magnitude. Within the voltage range of relevance to TOV withstand, a 5% change in peak voltage will result in more than an order of magnitude change in arrester power dissipation. Harmonic voltages that may drive high TOV peaks during a GMD are highly variable over time. The severity of the harmonic voltages will be approximately related to the amount of GIC in the system transformers that inject the harmonics, and is thus related to the geo-electric field intensity driving the GIC. Figure 6-3 plots the East-West geo-electric field intensity of the NERC reference GMD time series for the period around the peak magnitude. The field intensity is above 90% of the peak for less than 30 seconds. Therefore, it is recommended that the 30-second TOV withstand capability of an arrester be used to evaluate the predicted peak harmonic voltages that might occur during a GMD. For a typical station-class MOSA, this is approximately 1.35 times the MCOV.

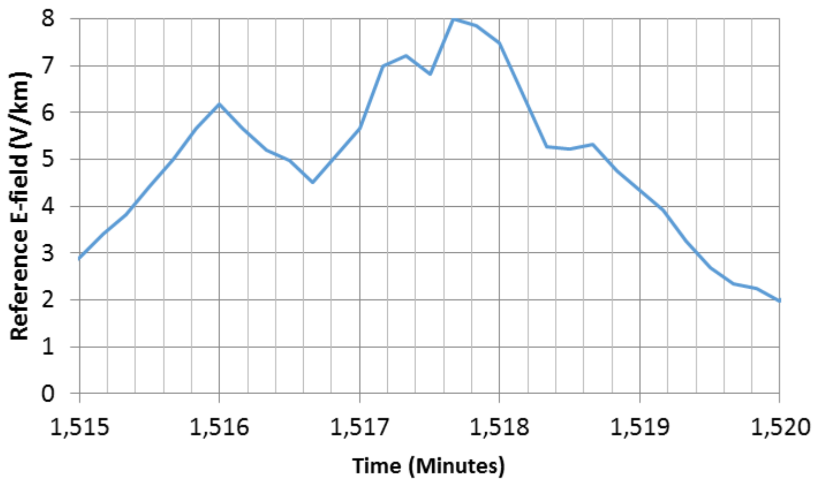

Figure 6-3
Peak of the East-West geo-electric field of the NERC GMD standard drafting team reference time series.

6.3 System Security Implications

For a station class arrester, as used in substations, arrester failure will result in a permanent short-circuit fault that requires the transformer or substation bus section to which the arrester is applied to be tripped out of service. During a GMD, when a system is stressed by extraordinary reactive power demand, the occurrence of a bolted substation fault and potential loss of a major component may be of particular significance to system security. For example, if the system's voltage stability is marginal, the fault may be the trigger that could drive the system into collapse.

The magnitude of harmonic voltage required to damage a typical MOSA, however, is quite large. With even the most adverse phase relationship between harmonic and fundamental voltage components, the distortion would need to exceed 35%. Reaching this magnitude of harmonic voltage distortion would generally require the existence of a lightly-damped system resonance at a harmonic frequency excited by the harmonic current injection by GIC-saturated transformers. However, because currents at all of the low-order frequency harmonics are injected by each saturated transformer, and a typical transmission system will have a number of resonant frequencies, stimulation of a resonance is a very distinct possibility.

6.4 Arrester (Bus Voltage) Screening

Because surge arresters are applied to virtually every transmission bus, harmonic analysis results should be identified where the total harmonic voltage distortion exceeds 35%. This is conservative because this assumes that harmonic voltage components are aligned to create a 1.35 p.u. peak voltage, which is the typical arrester TOV withstand for the presumed duration of maximum GMD intensity.

Also, the voltages applied to surge arresters inside of harmonic filters should also be similarly screened.

Section 7: Transmission Cables

Transmission cables have quite large distributed shunt capacitances. As a result they, like shunt capacitor banks, provide an attractive low-impedance shunt path for harmonic currents and can interact with grid inductances to create resonances that can greatly amplify harmonic currents and voltages. The cables themselves are potentially sensitive to thermal and cable sheath voltage impacts of extraordinary harmonic currents during GMD.

Underground transmission cables often have shunt reactor compensation. While this can be effective in cancelling much or all of the fundamental-frequency charging current of the cable, it must be emphasized that the shunt reactor compensation provides little impact on harmonic performance. This is because that while the cable shunt capacitive susceptance increases with frequency, the susceptance (inverse of reactance) of the shunt reactors decrease with the reciprocal of frequency.

7.1 Main Conductor Heating

Skin and Proximity Effects

The ac resistances of cable main conductors, or cores, are greater than their dc resistances due to skin and proximity effects. These effects are frequency dependent, creating greater effective resistance with increased frequency. Cables conducting a certain magnitude of rms current that includes harmonic distortion will have greater losses than the same cable would sustain with an equal amount of fundamental frequency current. Increased losses means more heat deposited into the cable core and thus increased temperature.

Skin effect is caused by the electromagnetic fields, produced as a result of current flow on a given cable core, interacting with the current flow such that the core's current density is concentrated around the perimeter of the conductor. Proximity effect is caused by interaction between the current flows on adjacent conductors, producing asymmetric current density. In general, skin effect is roughly an order of magnitude more significant than proximity effect for large transmission cables.

Detailed calculation of skin and proximity effects requires complicated analysis, using equations including Bessel functions [12] or by the use of finite element numerical methods. A lookup table approach to calculation of skin effect is provided in various cable handbooks, such as [13]. Using this approach, the ratio of ac resistance to dc resistance for a 1000 mm^2 (1973 kcmil) copper cable core is plotted as a function of harmonic order in Figure 7-1. IEC 60287-1-1 provides approximate formulas for the skin and proximity effects. These formulas have a range of accuracy, however, that does not extend to large transmission-class cables at harmonic frequencies and are not of use for evaluating GMD impacts on cables.

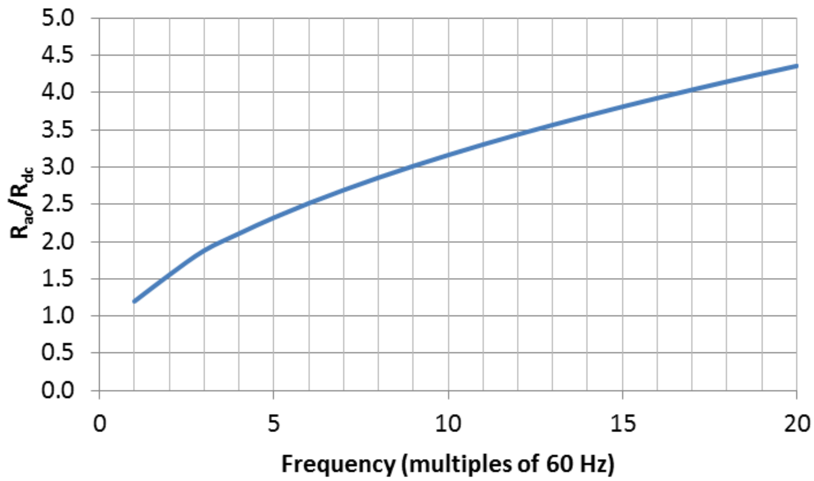

Figure 7-1
Ratio of ac to dc resistance for a 1000 mm² copper cable core as a function of harmonic order.

Effective Current

Typically, a transmission cable will be loaded by a combination of fundamental and several significant harmonic current components during a GMD. For any spectrum of current components, an effective rms current can be calculated that, when used with the fundamental-frequency resistance, will provide the same amount of heating as the distorted current. The effective current can be compared against a cable's fundamental-frequency current rating to determine the thermal impact of GIC-generated harmonic currents. The calculation of the effective current is shown in Equation 7-1, where I_n is the current at harmonic order n, I_{rms} is the total rms current including the harmonic components, and $K_s(n)$ is the skin effect coefficient R_{ac}/R_{dc} at the harmonic order n.

$$I_{eff} = I_{rms} \cdot \sqrt{\frac{\left(1 - \sum_{n=2,3\ldots} \frac{I_n^{\,2}}{I_{rms}^{\,2}}\right) \cdot K_s(1) + \sum_{n=2,3\ldots} \left(\frac{I_n^{\,2}}{I_{rms}^{\,2}} \cdot K_s(n)\right)}{K_s(1)}}$$

Eq. 7-1

For fundamental current plus various amounts of a single-harmonic distortion, relative to the total rms current, the ratio of effective current to the total rms current is shown in Figure 7-2 for the 1000 mm² cable as a function of the harmonic order. It can be seen that, unless the amount of current distortion is quite high, the heating produced is not a great amount more than indicated by the rms current magnitude.

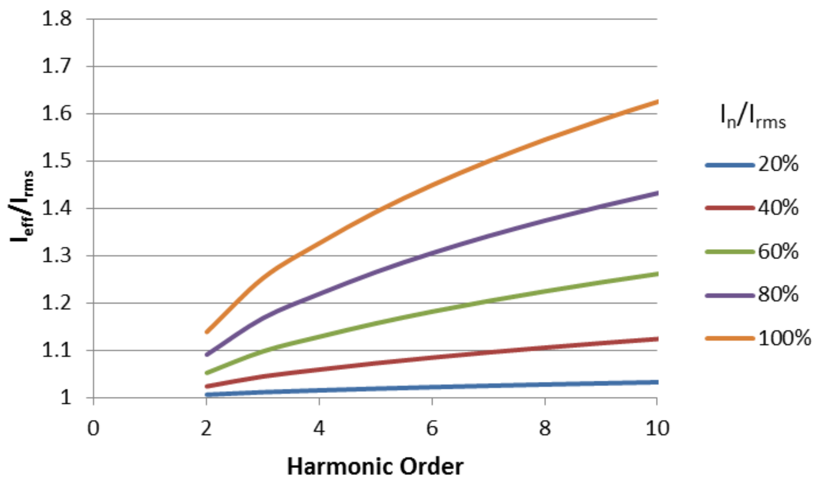

Figure 7-2
Ratio of effective cable core current to the actual rms current for fundamental current plus various levels of single-frequency harmonic distortion, as a function of the harmonic order of the distortion, for a 1000 mm^2 copper cable core.

Thermal Time Constant Filtering

The thermal time constants of underground cables are very long, on the order of 30 – 100 hours [14]. As a result, the thermal impacts of harmonic currents on underground transmission cable core heating is greatly mitigated. Using the NERC East-West reference geo-electric field time series, the incremental temperature rise caused by harmonics in a cable with a 30 hour time constant is the same as if 8.9% of the peak harmonic current is applied continuously. I.e., the thermal time constant filtering factor for the GIC-generated harmonics is 0.089.

It can thus be concluded that, unless harmonic current in a transmission cable during a GMD is extreme, core heating should not be an issue of major concern with regard to GMD impact.

7.2 Cable Shields

To avoid excessive voltages that are dangerous and would lead to cable jacket breakdown, cable shields and sheaths must be grounded. There are three different types of grounding used for transmission cables, and the type of grounding used greatly affects the susceptibility of the cable to harmonic currents. The shield grounding types are:

1. Multi-point grounding, where the shields for all three phases are connected to ground at multiple points along the cable run. Although the normal cable

neutral grounding practice for distribution, this type of grounding is uncommon for transmission cables with the exception of submarine cables.

2. Single-point grounding, where the shield sections are grounded at only one location. The length of a single section must be limited in order that the voltages induced on the shield by the cable core current are not excessive. A cable shield may need to be broken into a number of separate sections to meet this objective. Single point grounding is generally used only on relatively short transmission cables.
3. Cross-bonding, where the cable shields or cores are transposed at 1/3-length intervals. This is the most common grounding type for moderate- and long-length cables.

Shield Currents with Multi-Point Grounding

Current flow in the cable cores induces longitudinal voltages on the cable shields, due to the mutual inductance. Multi-point grounding completes a path via ground for parasitic currents to flow in the shields, causing additional losses and heat. The heating from shield losses can decrease the fundamental-frequency ampacity of the cable by 30%. It is for this reason, and the value of the energy losses, that this grounding method is uncommon for transmission applications. However, because the other two grounding methods are impractical for submarine cables, multi-point grounding is used for this type of transmission application.

The voltage induced on the cable shields is directly proportional to both the magnitude and the frequency of the core current. Cable shields have a relatively small conductor cross-sectional area, but a large radius, thus their self-impedance is very resistive. As a result, the shield self-impedance does not increase with frequency as fast as the induced voltage increases. The parasitic shield current, as a proportion of the cable core current magnitude, increases with frequency. Therefore, the cable shield losses become more significant at harmonic frequencies.

Due to the lesser thermal mass of the cable shield compared to the cable core, and the smaller thermal resistance from the shield to the ambient, the thermal time constant of the shield can be expected to be somewhat less than the core. Therefore, the shield will have a larger thermal time constant filtering factor and may be slightly more susceptible to the peaks of GMD activity.

Where submarine cables, or any other transmission cables using multi-point bonding, are expected to experience substantial harmonic current flow during GMD, detailed analysis of shield heating and thermal performance of the particular cable is warranted.

Cable Sheath Voltage Limiters

For cables with single-point shield bonding, cable sheath voltage limiters are used at the ungrounded ends of the cable shield sections. These limiters are essentially distribution-class metal-oxide surge arresters, and their purpose is to limit transient voltages between the shield and ground resulting from cable switching and lightning strikes. These limiters are not designed to limit temporary overvoltages on the shield during faults. Likewise, cable limiters are used at the transposition points (bonding boxes) of cross-bonded cables for the same purpose.

The induced voltage appearing across a cable sheath voltage limiter is linearly proportional to both the magnitude and frequency of the cable core current. Because voltage limiters are highly nonlinear devices, they are sensitive to the peak, or crest, value of the voltage waveform. The phase relationships between the fundamental and harmonic components are needed to precisely determine the peak voltage to which the limiter is exposed. However, a worst-case analysis can be performed by assuming that all components align such that the composite voltage waveform peak is equal to the sum of the individual components.

The allowable limiter voltage during a GMD can be determined in relationship to the voltage present during a transmission system fault. Limiters are selected such that the imposed voltage during a transmission fault is less than the temporary overvoltage (TOV) limit of the device for the expected worst-case fault duration. The allowable voltage during a GMD, which can have extended duration, should be limited to the maximum continuous operating voltage (MCOV) of the device. The TOV capability of a distribution-class surge arrester for a 15 cycle duration (backup fault clearing assumed) is approximately 1.5 times the MCOV rating. It can therefore be assumed that the MCOV rating of the sheath limiter is approximately 1/1.5 times the voltage present during a fault. From this, the relationship between cable current (fundamental and harmonic components) and design fault current levels shown in Equation 7-2 can be used to screen for potential cable sheath limiter issues during GMD.

$$1.5 \cdot \sum_{n=1,2\ldots} \left(I_n \cdot n \right) \leq I_{fault} \qquad \textit{Eq. 7-2}$$

Transmission cables are typically used primarily in urban areas where fault current levels are commonly an order of magnitude or more greater than load currents. Therefore, unless harmonic currents are exceptionally large and at the upper range of harmonic orders (frequencies) generated during a GMD, cable limiter voltages are unlikely to be a critical issue.

7.3 Pipe Heating

Certain cable types, such as high-pressure fluid-filled (HPFF) and high-pressure gas-filled cables are installed within steel pipes having typically ¼ in. wall thickness. The magnetic fields produced by cable core current induce eddy current losses within the pipe. Because the steel pipe is a ferromagnetic material, the resulting losses are nonlinear and require very complex calculations. Harmonic distortion of the cable current will increase these losses. Where pipe-type cables are exposed to extreme levels of harmonic current during GMD, evaluation of the pipe losses may be necessary to quantify the cable thermal performance.

7.4 Dielectric Heating

Dielectric losses can be an important component of the total losses, and heat input, in certain types of transmission cable. These losses can be very substantial in paper insulated cables, such as high-pressure fluid-filled pipe-type (HPFF) and self-contained fluid-filled (SCFF) cables. For solid-dielectric cross-linked polyethylene (XLPE) cables, dielectric losses are more than an order of magnitude less than a similar HPFF cable and are not generally of great significance to the cable thermal performance [15].

Dielectric losses are in proportion to the frequency and the square of the magnitude of voltage, as indicated in Equation 7-3. Tan(δ) is the cable insulation dissipation factor, and is a constant. Where a cable is subjected to a distorted voltage, the dielectric losses (P_{dist}) relative to the dielectric losses during nominal fundamental-frequency voltage (P_{nom}) is provided by Equation 7-4.

$$P_{dielectric} = 2\pi \cdot f \cdot C \cdot V^2 \cdot \tan(\delta) \qquad \textit{Eq. 7-3}$$

$$P_{dist} = P_{nom} \cdot \left(1 + \sum_{n=2,3\ldots} \left(n \cdot V_n{}^2\right)\right) \qquad \textit{Eq. 7-4}$$

The dielectric losses due to fundamental voltage are nearly constant through time, but the incremental dielectric losses due to harmonics will vary in approximate proportion to the GMD intensity. Therefore, the incremental dielectric heating effect due to a GMD is moderated by the smoothing effect of the cable's thermal time constant.

The significance of the increased dielectric losses on cable temperature depends on the other losses components. If the total losses under distorted conditions, including core conductor losses, shield losses, pipe losses, and dielectric losses, are equal or less than the total loss under rated undistorted conditions, it can then be concluded that cable will not be overheated. However, the dielectric heating is subject to essentially the same long thermal time constant as the cable core heating. Therefore, considering the highly variable nature of GMD intensity, the impact of incremental dielectric heating caused by GMD harmonics is deemed to be minimal.

7.5 Capacitive Currents in Cable Shields

Most transmission cable, except for short sections and undersea cables, have shields that are either divided into short single-point grounded sections, or the shields are cross-bonded. In either case, the shield will not carry current due to induction from harmonic currents passing through the cable. The shields (or sheaths) will carry capacitive currents due to the voltage applied to the cable. Because the cable's insulation capacitive susceptance is proportional to frequency, harmonic voltage distortion has a disproportionate impact on the capacitive currents that flow in the shield. The resistances of the shields are relatively constant over the frequency range of GMD-produced harmonic distortion because cable shields are thin and skin effect is not significant. Therefore, the power loss (and heat input) to the shield, relative to the power loss caused by rated fundamental voltage, is given by Equation 7-5.

$$P_{shleld} = P_{nom} \cdot \left(1 + \sum_{n=2,3...} (n \cdot V_n)^2\right) \qquad \text{Eq. 7-5}$$

The shield losses due to fundamental-frequency capacitive currents are nearly constant through time, but the incremental losses due to harmonics will vary in approximate proportion to the GMD intensity. As in the case of dielectric heating, the incremental shield current heating effect due to a GMD is moderated by the smoothing effect of the cable's thermal time constant. Also as in the case of dielectric losses, the significance of the increased capacitive shield current losses on cable temperature depends on the other losses components. Considering the highly variable nature of GMD intensity, the long thermal time constant of the cable, and the fact that there are other more constraining limitations to the voltage distortion that the transmission system can tolerate, the impact of incremental cable shield heating caused by GMD harmonic voltage distortion is expected to not be of substantial significance.

7.6 Transmission Cable Screening

Because of the very long thermal time constants of cables, thermal impacts of GMD harmonics are not expected to be significant with possible exceptions of cables with multi-grounded shields and pipe-type cables. Cable shield voltage limiter duty is also not expected to be significant in realistic scenarios. Therefore, no specific screening is recommended for transmission cables in general, with the further recommendation that transmission cables with multi-grounded shields and pipe-type cables should be specifically evaluated if they are heavily loaded and have significant harmonic current flow during GMD.

Section 8: Overhead Lines

Overhead transmission lines have a degree of thermal sensitivity to harmonic currents. In addition, harmonic current flowing in overhead lines has the potential to cause disruptive interference with telephone circuits that are in parallel with the transmission line.

8.1 Conductor Ampacity

Skin Effect

Skin effect increases the effective ac resistance of overhead line conductors, similar to the skin effect impact has on underground cable ac resistance. A key difference is that most overhead conductors have cores to provide mechanical tensile strength. These cores are non-conductive (aluminum conductor composite reinforced - ACCR), less conductive (aluminum conductor allow reinforced), or composed of ferro-magnetic material for which the self-inductance virtually blocks current flow in the core (aluminum conductor, steel-reinforced - ACSR). In comparison, most underground cables are solid with uniform conductor material. Detailed calculations of skin effect for overhead conductors require complicated analysis, using equations including Bessel functions [12] or by the use of finite element numerical methods. Graphical presentations of the skin effect factor for tubular conductors are provided in [16]. Using this approach, the ratio of ac resistance to dc resistance for a 2167 kcmil ACSR (Kiwi) conductor is plotted as a function of harmonic order in Figure 8-1.

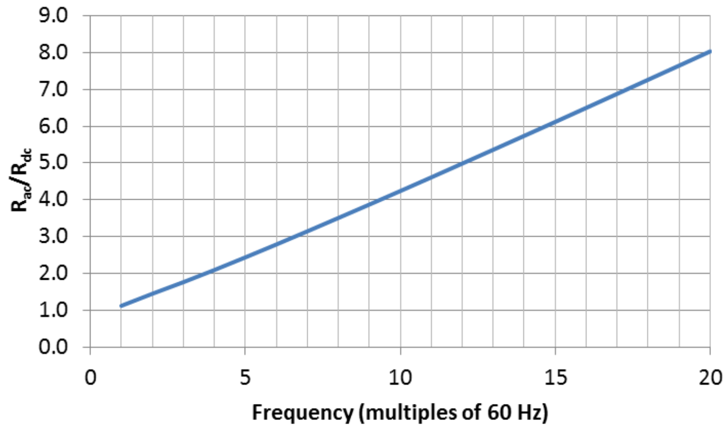

Figure 8-1
Ratio of ac to dc resistance for a 1000 mm² copper cable core as a function of harmonic order.

Effective Current

Typically, an overhead transmission line will be loaded by a combination of fundamental and several significant harmonic current components during a GMD. For any spectrum of current components, an effective rms current can be calculated that, when used with the fundamental-frequency resistance, will provide the same amount of heating as the distorted current. The effective current can be compared against a conductor's fundamental-frequency current rating to determine the thermal impact of GIC-generated harmonic currents. The calculation of the effective current uses the same Equation 7-1 as used for underground cables.

For fundamental current plus various amounts of a single-harmonic distortion, relative to the total rms current, the ratio of effective current to the total rms current is shown in Figure 8-2 for a 2167 kcmil (Kiwi) ACSR conductor as a function of the harmonic order.

Figure 8-2
Ratio of effective conductor current to the actual rms current for fundamental current plus various levels of single-frequency harmonic distortion, as a function of the harmonic order of the distortion, for a 2167 kcmil ACSR (Kiwi) conductor.

The thermal impact of harmonics can also be viewed in terms of the available fundamental-frequency ampacity, for a given magnitude of single-frequency harmonic current. This is shown in Figure 8-3 for the example conductor.

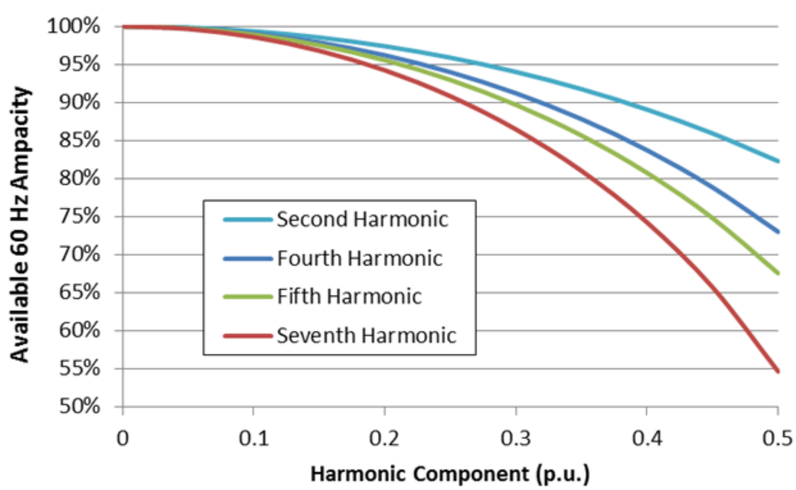

Figure 8-3
Available fundamental-frequency conductor ampacity versus harmonic current magnitude for single-frequency harmonic distortion, based on a 2167 kcmil ACSR (Kiwi) conductor.

Thermal Time Constant Filtering

The thermal time constants of overhead transmission line conductors are much shorter than those of underground cables, on the order of 10 to 30 minutes. As a result, overhead lines are much more vulnerable to peaks of GMD activity than underground cables. Using the NERC East-West reference geo-electric field time series, the incremental temperature rise caused by harmonics in a conductor having a ten minute thermal time constant is the same as if 42.7% of the harmonic current at GMD peak is applied continuously. I.e., the thermal time constant filtering factor for the GIC-generated harmonics is 0.427.

8.2 Telecommunication Interference

Harmonic currents flowing in overhead transmission lines create magnetic fields that can couple with telephone circuits that are in parallel with the transmission line. Based on experience with HVDC projects, it is known that the induced harmonic voltage can disrupt ordinary copper telephone circuits. The parallel telephone need not be immediately adjacent to the transmission right-of-way in order for transmission line harmonic currents to disrupt communications. The interfered telephone line could be separated by hundreds or even thousands of feet from the transmission line and still be disrupted, and the parallel longitudinal exposure length can be as short as a fraction of a mile for closer separations. While this is not strictly a power system problem, disruption of telephone service by power line harmonics can be an added factor in the potential societal disruption of a severe GMD. Because of the variable nature of the GMD severity, the duration of worst-case telecommunication disruption should be short and only a subset of telephone circuits would be affected.

Modern telephone lines are shielded and circuit pairs are twisted. Telephone cable shielding is capable of reducing the induced voltage by a factor ranging from 6dB to 10 dB (2 to 3.2) [17] [18]. Telephone sets are connected across the pairs, and are not directly exposed to the longitudinal voltage produced by induction. Imbalances in the telephone circuit, however, convert some of the longitudinal voltage into a transverse voltage across the pair. The target minimum balance factor is 60 dB, which means that the transverse voltage is 0.1% of the induced longitudinal voltage. The acceptable transverse voltage at 1 kHz, however, is only 0.245 mV. Considering shielding and telephone circuit balance, the critical longitudinal induced voltage is 490 mV to 775 mV at 1 kHz.

The acceptable transverse voltage is frequency dependent, based on the characteristics of both the telephone equipment and the sensitivity of human hearing. A weighting factor called the “C-message weighting factor” is used to relate noise voltages at any frequency to the equivalent 1 kHz value. This weighting factor is plotted as a function of frequency in Figure 8-4.

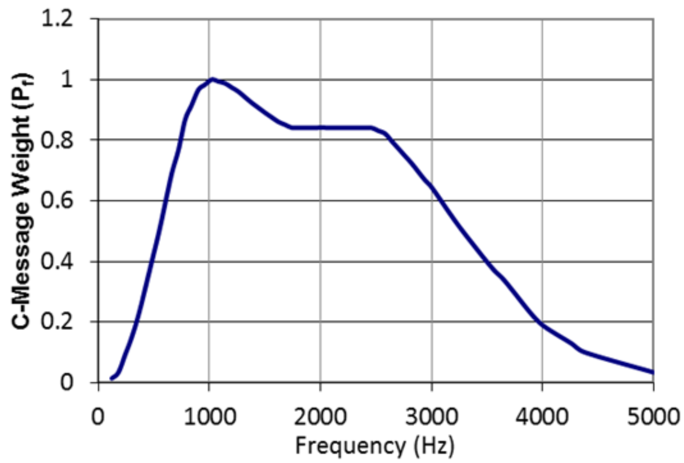

Figure 8-4
C-message weighting factor as a function of frequency.

For a given magnitude of harmonic current in the transmission line, the induced voltage in the phone line is proportional to frequency. In order to weight different frequencies of power line harmonic currents for their telephone interference potential, a different weighting factor called the "TIF weighting factor" is used. Equation 8-1 relates the TIF factor (T_f) to the C-message factor (P_f) and the frequency f in Hz.

$$T_f = 5 \cdot f \cdot P_f \qquad \text{Eq. 8-1}$$

A figure of merit called the "IT product" is used to evaluate the telephone interference potential created by transmission line currents having multiple harmonic components. The IT product is calculated by Equation 8-2.

$$IT = \sqrt{\sum_{n=2,3,\ldots} \left(T_n \cdot I_n\right)^2} \qquad \text{Eq. 8-2}$$

The voltage induced by power line currents depend greatly on whether the currents are in a balanced mode (positive or negative sequence) or in the residual mode (zero sequence). The magnetic fields caused by the individual phases carrying pure balanced mode currents substantially cancel except when very close to the line. The magnetic fields caused by residual mode currents, however, drop off much more slowly, approximately at a rate proportional to the reciprocal of the separation distance. In practice, pure balanced mode currents are not a significant contributor to telephone interference. However, harmonic currents that are injected in the balanced mode by their sources often are partially converted to the residual mode by system imbalances. These imbalances become progressively more significant with increased frequency. The end result is that harmonic currents injected in a balanced mode, with consideration of typical system imbalances, have a telephone interference potential about one order of magnitude less than currents injected directly in the residual mode.

The actual longitudinal voltage induced on a telephone cable is affected by many parameters, including:

- Phase spacing and configuration of the power transmission line.
- Separation between the telephone and power transmission lines.
- Earth resistivity.
- Longitudinal length of exposure.
- Angle between the lines, if not parallel.
- Ground wires and counterpoises on the transmission lines.

Thus it is difficult to make a rigid determination of the IT level where telephone communications are disrupted. IEEE-519 indicates an IT product of 25,000 or greater is likely to cause telephone interference in distribution applications. IT product limits between 10,000 and 50,000 have been successfully used as specification criteria for the harmonic performance of HVDC and SVC projects. These specifications are based on balanced mode injection, so a comparable IT product threshold for residual mode injection is 1,000 to 5,000.

Data for a typical 230 kV horizontal-construction transmission line at various earth resistivities and separation distances were presented in Cigre Technical Brochure 553. These results are the basis of the plots in Figure 8-5 and Figure 8-6 which show the balanced and residual IT levels required to achieve 775 mV/km of longitudinal voltage at 1 kHz as a function of separation and resistivity. From these results and the general experience of the industry with HVDC and SVC specifications, it can be assumed that telephone interference problems may begin to appear for IT = 10,000 (balanced) and are very likely to completely disrupt at least some telephone circuits for IT = 100,000.

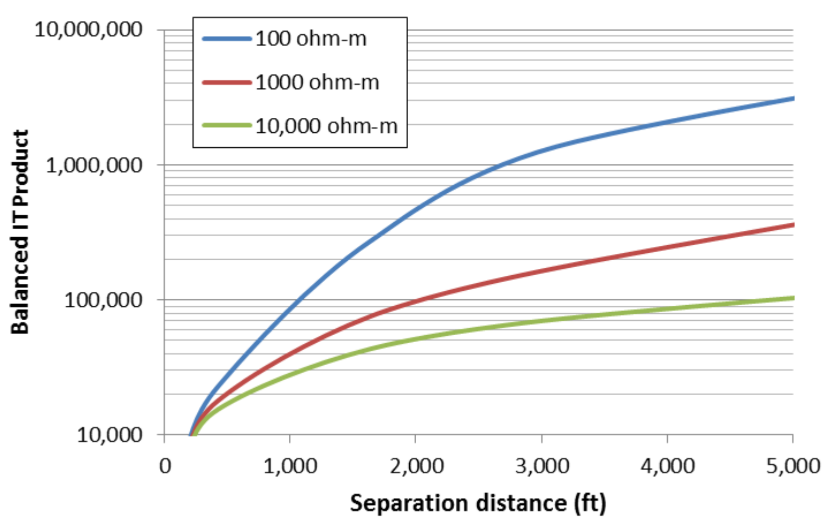

Figure 8-5
Transmission line balanced-mode IT product required to cause excessive induced voltage in a one-mile parallel telephone cable as a function of separation

distance for various levels of earth resistivity. Based on a typical 230 kV horizontal-configuration line.

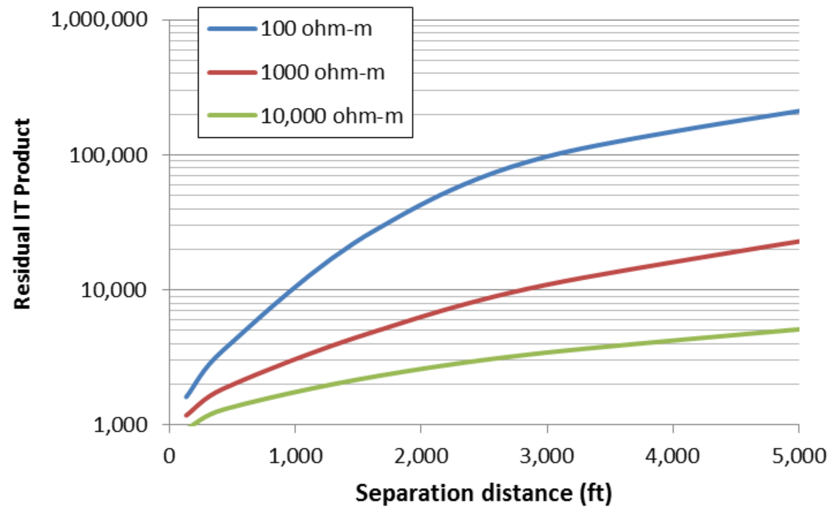

Figure 8-6
Transmission line residual-mode IT product required to cause excessive induced voltage in a one-mile parallel telephone cable as a function of separation distance for various levels of earth resistivity. Based on a typical 230 kV horizontal-configuration line.

Harmonic currents in a particular transmission line during a GMD are the result of the superimposed injections by many saturated transformers, and affected by complex system resonances. However, in order to illustrate the telephone interference potential during GMD, a simplified example is used. In this example, it is assumed that a bank of three 150 MVA 230Y/132 kV transformers is at the end of a radial transmission line. Assuming no resonant amplification of the harmonics, the equivalent balanced IT product is plotted as a function of GIC in Figure 8-7 and in Figure 8-8 at two different GIC ranges. In this calculation, contribution of zero sequence harmonics (harmonic orders that are multiples of three because single-phase transformers are assumed) are scaled up by a factor of ten in order to account for their increased telephone interference potential. These figures also shows the IT product with the zero sequence harmonics removed, as if a delta transformer winding with sufficiently low impedance diverts all zero-sequence exciting currents from entering the transmission system. Delta windings are present in most transformers, and where not present, typically the transformer is constructed on a three-leg three-phase core that provides the equivalent of a delta winding. The delta windings, however, have inductance and they will not divert all of the zero-sequence harmonic currents caused by GIC saturation. Therefore, the IT product with a realistic delta winding will lie between the lines of these graphs. This example illustrates that a GMD may cause disrupted telephone communications on circuits to transmission lines at even a considerable distance.

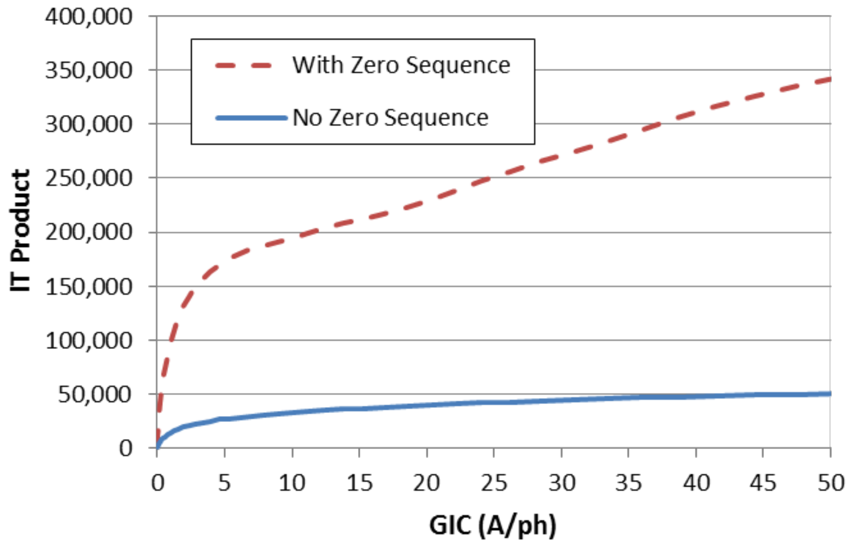

Figure 8-7
Telephone interference IT product as a function of GIC flowing through a bank of 150 MVA, 230Y/132 kV transformers. (GIC range 0 to 50 Amperes per phase.)

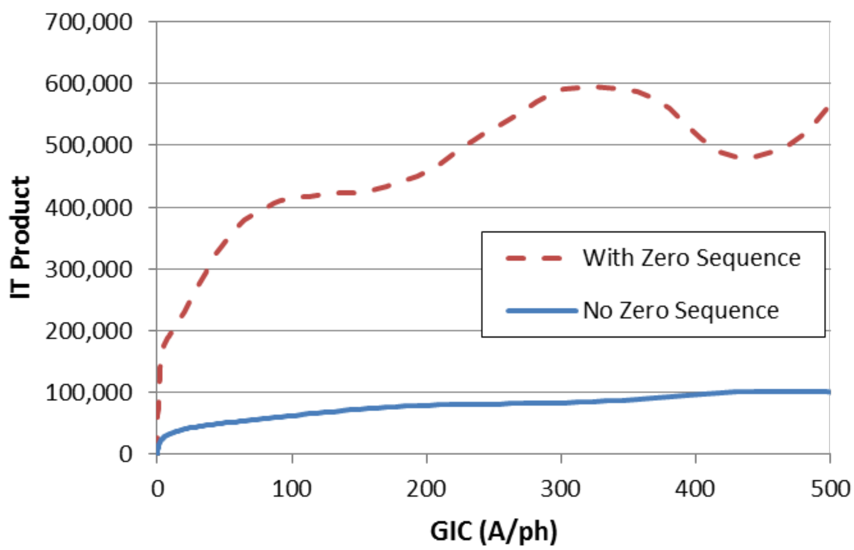

Figure 8-8
Telephone interference IT product as a function of GIC flowing through a bank of 150 MVA, 230Y/132 kV transformers. (GIC range 0 to 500 Amperes per phase.)

8.3 Transmission Line Screening

For overhead line ampacity screening, the results shown in Figure 8-3 can be used as guidance. The thermal time constant filtering effect can be ignored as the safety margin, yielding the following criteria indicating that more detailed analysis should be performed for any line where:

- The fundamental current loading is greater than 95% of rating, or
- The fundamental current loading is greater than 90% of rating, and the total rms magnitude of harmonic current exceeds 10% of rating, or
- The total rms of harmonic current exceeds 20% of rating.

Telephone interference is not a bulk power system security issue, the number of phone circuits coupled to transmission lines is limited, and the duration of peak GMD activity is brief. Therefore, there is no recommendation for telephone interference screening as part of a GMD harmonic impact assessment.

Section 9: HVDC Systems

HVDC transmission systems are complex with many components and subsystems, including controls that are potentially affected by harmonic voltage distortion. The response of the HVDC controls to distortion, while necessary for proper HVDC operation, can substantially increase the fundamental-frequency reactive power demand of the HVDC converters during GMD at a time when reactive power margins are diminished by GIC saturation of many transformers throughout the system.

Large amounts of capacitive compensation are used at conventional HVDC systems to compensate the large reactive power demand of the converters and to reduce harmonic distortion during normal operation. The capacitor banks and harmonic filters, which also provide capacitive compensation, can interact with the system impedance to create impedance resonances at frequencies in the low-order harmonic range that may be stimulated by GIC-saturated transformers. As a result, the harmonic voltages may be significantly amplified at HVDC converter stations. Harmonic filters, particularly those tuned to harmonic orders below the eleventh, are particularly susceptible to overload from GMD-produced harmonics and may trip, increasing the net reactive demand placed on the ac system by the HVDC system.

This section addresses the GMD vulnerability of conventional ("classic") line-commutated HVDC systems. In the past two decades, another form of HVDC transmission based on voltage-source converters has emerged. This technology differs substantially with regard to its characteristics and vulnerabilities with respect to GMD. Because VSC technology is used for several other transmission-connected applications, it is covered separately in Section 11.

HVDC systems include a number of components, such as transformers and capacitors, which are covered elsewhere in this guide. Coverage in this section is limited to components and controls unique to HVDC systems. This section is not intended to be a primer for basic HVDC technology. The user of this section is assumed to be familiar with HVDC system concepts and performance.

9.1 System and Control Complexity

HVDC system controls are highly complex and are specific to the particular HVDC system vendor. The details of the controls, particularly those that operate on a cycle-by-cycle basis and may be most responsive to voltage distortion, are proprietary and are generally not available. Therefore, only limited generalizations can be made regarding the response of the system controls to GMD-produced voltage distortion. Where an unusually large amount of ac distortion is predicted to be present at an HVDC converter station's ac bus during severe GMD, or the HVDC system is of particularly large importance to the overall transmission system security, specific time-domain simulation studies may be justified in order to evaluate performance.

One general conclusion that can be reached, however, is that the basic power conversion functionality of the system should be quite tolerant of distortion. HVDC systems are designed to operate during severe voltage distortion that can occur after ac fault clearing, where transformer inrush may stimulate harmonic resonances. GIC saturation is very similar to inrush, with the difference that GIC saturation can persist for a much longer duration. While the controls should maintain converter functionality, there can be secondary impacts of the control response to the distortion that may affect the overall system performance.

9.2 Filter Bank Tripping

Conventional (LCC) HVDC converter inject a relatively large amount of harmonic current into the ac bus at the "characteristic" harmonic orders $12k\pm1$ where k is a positive integer (i.e., 11^{th}, 13^{th}, 23^{rd}, 25^{th}, etc.). The converter also injects non-characteristic harmonics at other orders due to interaction with ac system voltage imbalance, converter transformer impedance imbalances, and certain complex interactions. The most significant of the non-characteristic harmonics is the third order (which is a positive-sequence harmonic in this case).

In order to meet harmonic performance specifications, shunt filters are applied. These filters are basically shunt capacitors with tuning reactors, and sometimes resistors. They provide a low-impedance path in order to bypass the harmonics from flowing into the ac system. At fundamental frequency, the filters exhibit a capacitive reactance and thus provide reactive power to help compensate for the large reactive power demand (low power factor) of the converter. The reactive power demand of an LCC HVDC converter is typically on the order of 40% to 50% of the real power (MW) rating.

Because the harmonic filters are a low impedance path at their tuned frequencies, they will provide a low-impedance path for harmonics at the filters' tuned frequencies that are injected by GIC-saturated transformers. Filters may overload, and this may result in tripping or filter component damage. It is typical to provide filter overload protection, so tripping without damage is the more likely outcome. While equipment may be protected from damage by tripping, this also results in a substantial decrease in the converter terminal's reactive compensation.

Interactions between harmonics produced by GMD and HVDC terminal harmonic filters are not limited to the harmonic orders to which the filters are tuned. At harmonic orders near the tuned frequencies, the filters may exhibit sufficiently low capacitive or inductive reactances such as to resonate with grid inductive or capacitive reactances, respectively, such as to cause parallel (impedance) resonances. Such resonances can greatly amplify harmonic currents within the filters. HVDC filter designers attempt to avoid resonances at harmonic orders that are normally excited by the HVDC harmonic current injection and background grid harmonic distortion. Under normal conditions, both sources are primarily odd-order harmonics. Thus, less emphasis is given to avoiding resonances at even-order harmonics, which are injected by GIC saturated transformers.

The magnitudes of harmonics injected by GIC-saturated transformers have a generally decreasing trend with increasing harmonic order. At the lowest characteristic harmonic frequency, the eleventh harmonic, the saturated transformer current injection is relatively low. In comparison, the converter injection at the characteristic harmonics is large. Therefore, GMD-caused overload of HVDC terminal filters at the eleventh and higher orders is less likely. The most vulnerable filters are those tuned to the low-order non-characteristic harmonics. A common practice, however, is to provide filtration of these relatively low-level low-order harmonics using double-tuned or triple-tuned harmonic filters that also provide filtration at higher order characteristic harmonics. Protective filter tripping takes the entire bank out, and not just a portion of the bank associated with the low-order tuning (double-tuned and triple tuned filters do not have specific components assigned to the different tuned frequencies, anyhow). Therefore, if several filter banks have low-order tuning, GMD harmonics can result in a large reduction in reactive compensation.

9.3 Inverter Commutation Margin

Harmonic distortion of the ac bus voltage at inverter terminals of HVDC systems may decrease the commutation margin, or the apparent commutation margin as measured by the control system. Insufficient commutation margin can result in commutation failure, which momentarily interrupts power transmission and may apply a large transient reactive demand on the ac system during the post-failure recovery process.

All HVDC inverters have a minimum commutation margin regulator (e.g., constant extinction angle control), which advances the valve firing to maintain sufficient commutation margin in order to minimize risk of commutation failures. Generally, the speed of the commutation margin regulator response is faster than the rate of harmonic voltage distortion increase due to a GMD. Thus, commutation failure should not occur as a direct result of GMD-produced harmonic distortion. An exception can be a situation where the harmonic current injection by GIC-saturated transformers is already established, and a switching event takes place in the system (e.g., capacitor bank insertion or tripping) such that the tuning of a resonance shifts to a harmonic frequency. This can cause an abrupt increase in harmonic voltage distortion that is too rapid for the controls to follow, and could result in a commutation failure. Commutation failures do not cause any direct damage, but the system disturbance it creates could trigger other events in a system that is severely stressed by a GMD.

Even when harmonic distortion does not cause commutation failure, the response of the extinction angle control can cause a large increase in the reactive power demand of the inverter. The reactive demand of the inverter is determined by the advance angle (β) measured relative to the fundamental voltage, as well as the direct current magnitude and the converter transformer impedance. Harmonic distortion can decrease the actual commutation margin for a particular valve in two ways by:

1. Decreasing the instantaneous commutating voltage, and
2. Causing a commutating voltage zero crossing in advance of the fundamental voltage's zero crossing.

Both of these effects are illustrated by comparing Figure 9-1 and Figure 9-2. Figure 9-1 shows an undistorted commutating voltage, with the commutation period indicated. The firing of the next valve at $\alpha = 180° - \beta$ (145° in this example) begins the commutation process. When the volt-seconds shown by the shaded area drive the current to zero, forcing the current to commutate completely to the incoming valve, the commutation period ends at $\alpha = 180° - \gamma$. The extinction angle γ in this example is 17° ($\alpha = 163°$). Figure 9-2 shows the same fundamental commutating voltage, but with a large harmonic distortion added. (This example shows an eleventh harmonic distortion, which is a higher order than is likely to be problematic in a GMD event, but the higher harmonic is used to facilitate the illustration.) The harmonic distortion causes the commutating voltage to reach its negative-going zero crossing 8° in advance of the fundamental zero crossing. In order to maintain the minimum extinction angle (assumed to be 17° in this example), the valve firing is advanced. As seen in this figure, the distortion decreases the voltage magnitude during the commutating period. This would tend to extend the period of commutation, or overlap angle μ, except that the advance of the firing also places the commutation period at a higher magnitude part of the fundamental voltage waveform. The "bite" taken out of the composite waveform by the distortion is offset by the higher fundamental magnitude in this example, such that the overlap angles μ are approximately equal in the distorted and undistorted cases. As a result primary reason that the firing advance angle β in the distorted cases is larger than that in the undistorted case (44° instead of 35°) is the shift in the voltage zero crossing.

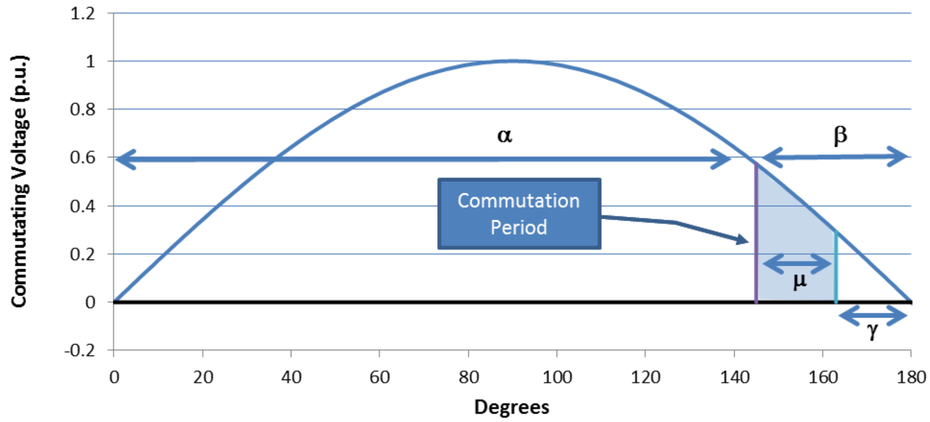

Figure 9-1
Illustration of undistorted commutating voltage and the key control angles.

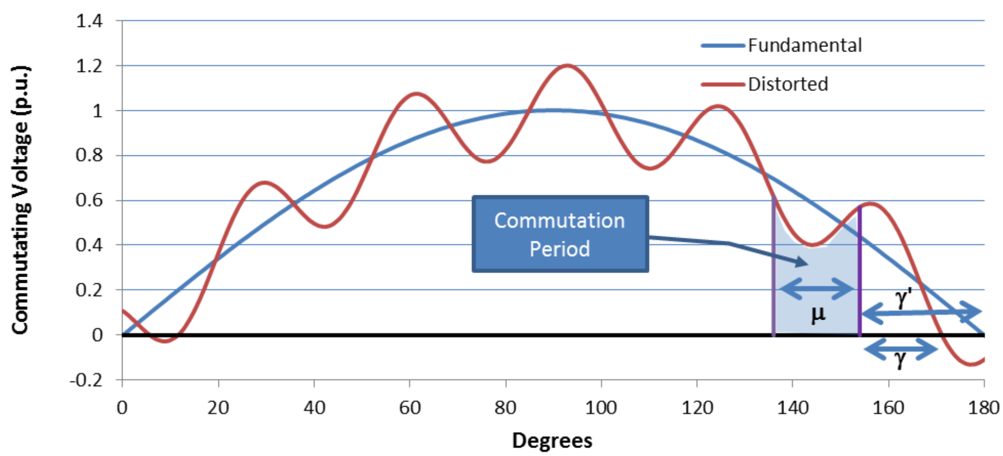

Figure 9-2
Distorted (red) and undistorted commutating voltages.

Modern HVDC controls use "equidistant firing" where valve gating in the 12-pulse is performed at 30° intervals. Voltage distortion and voltage phase imbalance will cause different extinction angles for each of the valves. In order to preserve commutation margin in the most critical valve, the minimum commutation margin control advances the valve firing of all valves back based on the minimum commutation margin (either extinction angle or area under the commutating voltage curve after the end of commutation) of any valve. The fundamental-frequency reactive power demand of the converter depends on the advance angle β relative to the fundamental voltage, with increased advance angle resulting in increased reactive demand. Thus, in order to preserve commutation margin, the reactive power demand is increased.

The term "commutation margin control" is used generically here because this control function can take two forms. The most common implementation is a constant extinction angle control where the time, in electrical degrees, is measured from the end of commutation until the negative zero crossing of the commutating voltage. The alternative method is based on measurement of the actual commutation margin, as defined by the volt-seconds left over after the end of commutation. This is the area under the commutating voltage waveform from the end of commutation until zero crossing. The impact of various amounts and orders of harmonic distortion on HVDC converter reactive demand is shown in Figure 9-3 and Figure 9-4. The phase relationship of the distortion to the fundamental was iteratively adjusted to maximize the reactive power demand. With valve firing at 30° intervals, it is not unreasonable to assume that the distortion may easily reach these maximized levels. Figure 9-3 is based on a constant extinction angle control, and Figure 9-4 is based on a commutation margin volt-seconds measurement. While there are differences in the response to particular harmonic orders, the overall conclusion is that both types of controls are similarly sensitive.

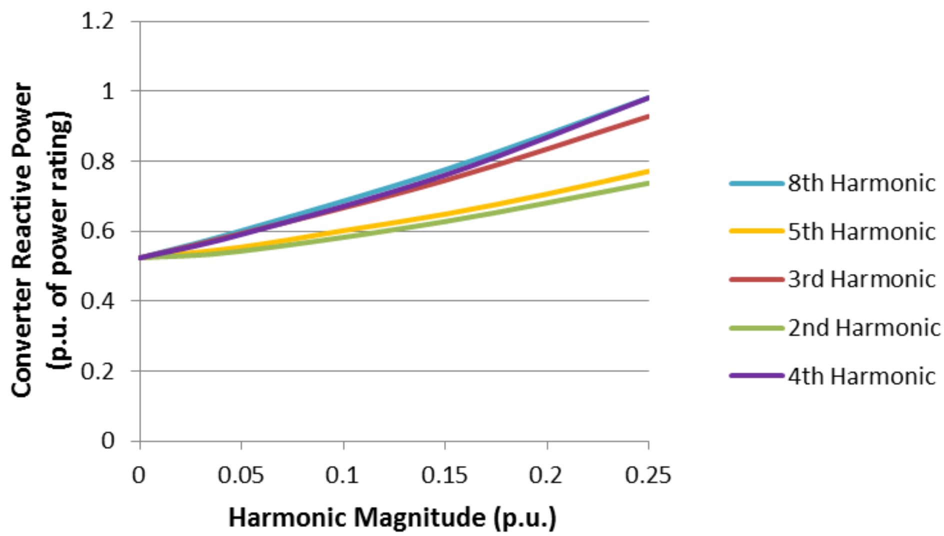

Figure 9-3
HVDC inverter reactive power demand with harmonic distortion superimposed on the fundamental voltage. Commutation margin regulation based on constant extinction angle, measured from the end of commutation until the negative zero crossing of commutating voltage.

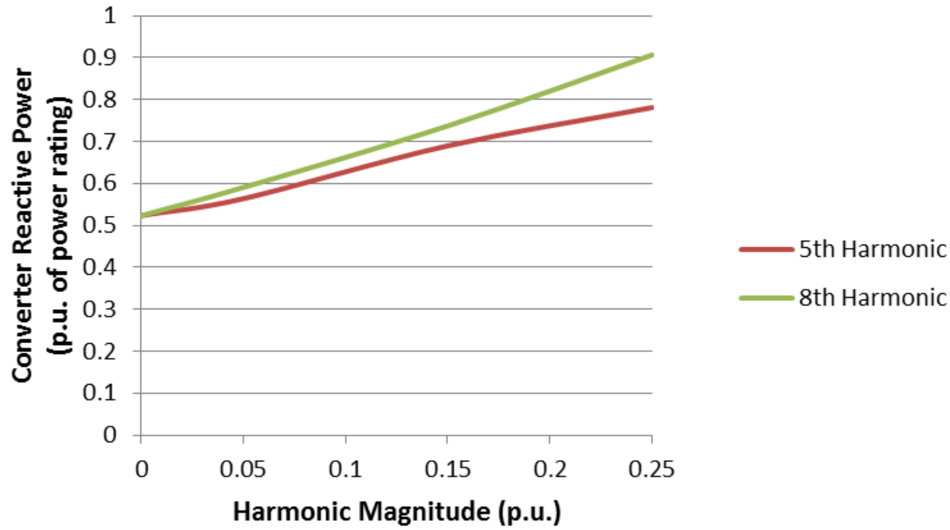

Figure 9-4
HVDC inverter reactive power demand with harmonic distortion superimposed on the fundamental voltage. Commutation margin regulation based on constant commutation volt-seconds following the end of commutation until the negative zero crossing of commutating voltage.

High levels of harmonic distortion can cause the very large reactive power demand of an HVDC converter (typically on the order of 40% to 50% of power rating) to nearly double. This increase of reactive power demand due to voltage distortion during a GMD, combined with the substantial probability of some of the HVDC terminal's reactive compensation (ac harmonic filters and capacitor banks) tripping, can have potentially serious transmission system consequences.

9.4 Harmonic Transfer between AC and DC Systems

Harmonic distortions on the ac system couple through an HVDC converter to the dc side. Likewise, dc-side harmonic ripple couples to the ac side. The interactions are complex, as the conversion process translates the frequencies of the ac and dc sides [19]. A positive-sequence ac-side harmonic voltage or current at harmonic order $k - 1$ translates to dc-side oscillations at harmonic order k, and also oscillations at $12m \pm k$, where $m = 0, 1, 2\ldots$ A negative-sequence ac-side harmonic voltage or current at harmonic order $k + 1$ results in oscillations on the dc side at $12m \pm k$. Oscillations of the direct current at harmonic k result in ac-side currents at both sidebands of the dc modulation frequency; positive sequence current at harmonic order $k - 1$, and negative sequence current at harmonic order $k + 1$.

This harmonic transfer behavior has a number of implications to the HVDC system response to GMD-produced harmonic distortion, and to modeling performed to assess system harmonic performance during GMD. One implication is that dc-side equipment is vulnerable to GMD distortion via transfer from the ac side. One vulnerable component category is dc-side harmonic filters. A geomagnetic disturbance affecting the Radisson terminal of the Hydro-Quebec-New England HVDC system in 1991 resulted in a failure in a dc-side double-tuned sixth/twelveth harmonic filter [20]. The GMD resulted in high magnitude fifth and seventh harmonic distortion on the ac bus voltage. This resulted in excessive sixth harmonic duty imposed on the dc-side filter, and a component failure resulted. This failure did not result in tripping of the dc filter, but did result in substantial detuning. It was observed that this detuning of the dc filter resulted in an immediate decrease of the ac-side fifth and seventh harmonic distortion.

This 1991 incident clearly demonstrates that the impedance presented by a dc converter to the ac system is significantly affected by the frequency characteristics of the dc side, including resonant conditions. The ac-side impedance at harmonic order n in the positive sequence is also affected by the ac system impedance at harmonic order n-2. Likewise, the impedance of the converter seen in the negative sequence on the ac side at harmonic n is affected by the ac system impedance at harmonic order n+2. This complex interaction characteristic is also of significance to harmonic performance modeling of the ac system.

An HVDC system does not completely decouple the harmonic performance of the ac systems to which it connects. Transfer of harmonic distortion from an ac system to the dc system through the converter, and vice versa, means that harmonic transfer between ac system can also take place. For example, a positive-sequence voltage distortion at harmonic order k will result in direct current oscillations at harmonic order k-1. The direct current harmonic at terminal (Terminal 1) is likely to also be present at the other terminal (Terminal 2), at a greater or lesser magnitude depending on the resonance characteristics of the dc system. The dc oscillations at order k-1 will cause current components k (positive sequence) and k-2 (negative sequence) to be injected into the ac system at Terminal 2. In addition, negative sequence current at harmonic order k-2 will also be injected into the ac system at Terminal 1.

One of the most complex ac-dc interactions is core saturation instability. This phenomenon can begin with a positive-sequence second harmonic voltage distortion on the ac system. This translates to a fundamental-frequency dc-side current oscillation, particularly if a series resonance is present on the dc side near the fundamental frequency. The dc-side fundamental oscillations translate to positive-sequence second harmonic and negative-sequence 0 harmonic (i.e., dc) on the ac side. The dc component on the ac side will result in saturation of the converter transformer that is unequal in the phases. The saturation can reinforce the positive-sequence second harmonic voltage distortion, thus closing an interaction loop that can become unstable under certain conditions. Such core saturation instability has occurred several times in operating HVDC systems, each time unrelated to any GMD. (For example, the initiating event could be transformer energization that produces second harmonic distortion.) However, the presence of GMD distortion could be a potent driver of a core-saturation interaction of an HVDC system, even if conditions are not sufficient to result in a true closed-loop instability. For example, the interaction can cause severe saturation of the HVDC terminal's converter transformers, even if these transformers are blocked from direct GIC flow.

9.5 Discontinuous Currents

Ac-side harmonic distortion results in dc-side harmonic ripple that may exceed normal design parameters. As a result, current ripple magnitude can exceed the dc component if the HVDC system is operated at a low power level, and current may become discontinuous at frequencies that are not normally encountered. Discontinuous current provides complications to converter operation, including current chopping phenomena which can cause dangerous transient voltages [21].

9.6 HVDC System Screening

If the harmonic distortion present at the ac bus of an HVDC system substantially exceeds the background distortion level assumed in the HVDC system design, further investigation is warranted, particularly if the HVDC system is critical to system security. In particular, any harmonic filters having branches tuned below the eleventh harmonic should be carefully evaluated to determine if overload may occur. With regard to possible interactions between harmonics and the HVDC system control and operations, the HVDC system vendor should be consulted for guidance.

Voltage stability studies (fundamental-frequency) should take into account the likelihood of increased reactive power demand by HVDC inverters in response to harmonic distortion. This can be done by increasing the minimum extinction angle (gamma) setting accordingly. Approximately a 10% increase in reactive demand may occur with 5% voltage distortion, with this value suggested as a distortion threshold for further study and inclusion on fundamental-frequency voltage studies.

Section 10: Static Var Compensators (SVC)

Similar to HVDC systems, static var compensators are complex systems that include a number of components and subsystems that can be vulnerable to GMD-related harmonic distortion. Large amounts of capacitive compensation, in the form of harmonic filters, mechanically-switched capacitor banks, and thyristor-switched capacitor banks are installed at SVCs to provide reactive power to the system. The capacitor banks and harmonic filters can interact with the system impedance to create impedance resonances at frequencies in the low-order harmonic range that may be stimulated by GIC-saturated transformers. As a result, the harmonic voltages may be significantly amplified at SVC installations. Harmonic filters, particularly those tuned to harmonic orders below the eleventh, are particularly susceptible to overload from GMD-produced harmonics and may trip, decreasing the reactive power available to the system.

The proper performance of SVCs can be of critical importance to transmission system security, particularly during a GMD event when the system is stressed due to excess reactive power demand resulting from widespread transformer saturation. During a severe 1989 GMD that affected much of North America, a blackout of the Hydro Quebec system occurred that was attributed to the tripping of SVCs. Although this SVC failure was attributed to overly conservative protective functions, harmonics may also interact directly with the SVC operation to produce undesirable impacts.

This section covers conventional SVCs using thyristor controlled reactors (TCRs) and thyristor-switched capacitors (TSCs). Dynamic reactive compensation devices based on voltage-source converter technology, more correctly called STATCOMs (static synchronous compensators), are covered in a separate section on VSC technology. SVCs include a number of components, such as transformers and capacitors, which are covered elsewhere in this guide. Coverage in this section is limited to components and controls unique to SVCs. This section is not intended to be a primer for basic SVC technology. The user of this section is assumed to be familiar with SVC system design, performance, and operation

10.1 Harmonic Filters

Harmonic filters are installed at SVCs to divert the harmonic currents injected by the TCRs from flowing into the transmission system. As low impedance shunt paths for harmonics at their tuned frequencies, SVC filters will also absorb harmonic currents injected by GIC-saturated transformers, including transformers other than the SVC's own transformer. At fundamental frequency, the filters exhibit a capacitive reactance and thus provide reactive power that is used to provide a portion of the SVC's capacitive output range.

The potential for SVC filter overload during a GMD are essentially the same as discussed in subsection 10.1 for HVDC ac-side filters. One notable difference is that most SVCs are 6-pulse devices, so their characteristic harmonics include the fifth and seventh harmonics. Thus, SVCs will typically have filters tuned to these harmonics, which are harmonics that are injected with significant magnitude by GIC-saturated transformers. As a result, these filters may be particularly prone to overload during a GMD. Depending on the protection strategy for a particular SVC, tripping of its harmonic filters may result in tripping of the entire SVC system.

Interactions between harmonics produced by GMD and SVC harmonic filters are not limited to the harmonic orders to which the filters are tuned. At harmonic orders near the tuned frequencies, the filters may exhibit sufficiently low capacitive or inductive reactances such as to resonate with grid inductive or capacitive reactances, respectively, such as to cause parallel (impedance) resonances. Such resonances can greatly amplify harmonic currents within the filters. SVC filter designers attempt to avoid resonances at harmonic orders that are normally excited by the SVC harmonic current injection and background grid harmonic distortion. Under normal conditions, both sources inject primarily odd-order harmonics. Thus, less emphasis is given to avoiding resonances at even-order harmonics, which are injected by GIC saturated transformers.

10.2 Even-Order Interaction with TCR

Even-order harmonic voltages applied to a TCR having thyristor gating synchronized to the fundamental voltage will cause unequal current flow in each polarity. The resulting direct component of current will tend to saturate the SVC's transformer. Because of the magnitude and polarity of the dc produced in each phase, the dc does not necessarily have a common-mode (zero sequence) component (and any common mode dc produced would tend to circulate within the typical delta connection of most TCRs). Therefore, an SVC transformer that has a GIC blocking device in its neutral, or has only delta windings can still have part-cycle saturation as a result of this frequency translation phenomenon.

Figure 10-1 shows waveforms for a TCR subjected to a distorted voltage having a 0.2 p.u. second harmonic component. TCR firing delay angle (α) is 45° in this example, relative to the fundamental-frequency voltage waveform (shown in the figure for reference). The resulting TCR current is substantially asymmetric, having a dc component of 0.058 p.u. The magnitude and polarity of the dc component varies with the phase angle of the harmonic voltage relative to the fundamental voltage, the phase angle (212°) in this example maximizes the dc.

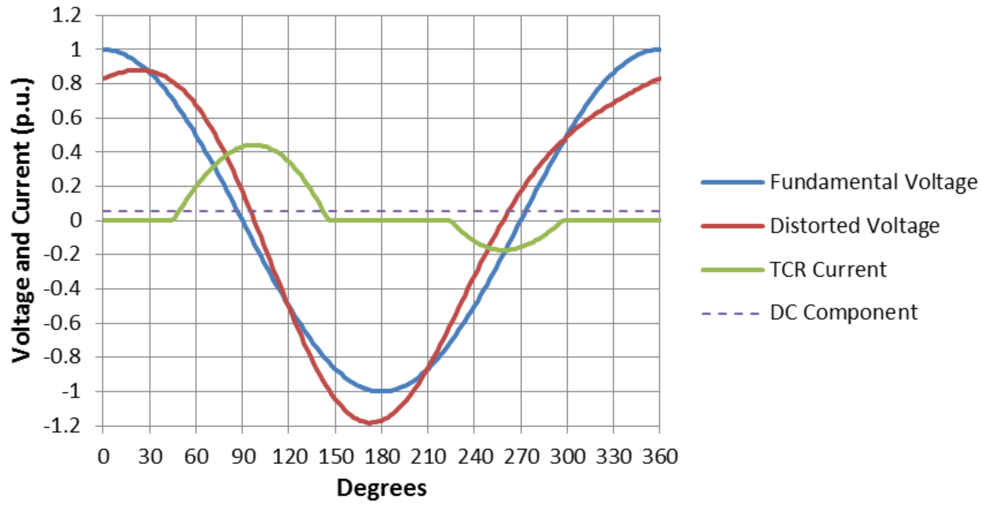

Figure 10-1
Illustration of a superimposed 0.2 p.u. second harmonic voltage on thyristor-controlled reactor current.

The cross-distortion admittance (I_{dc}/V_{harm}) is plotted as a function of the TCR firing delay angle in Figure 10-2. This cross-distortion admittance is plotted versus the fundamental admittance in Figure 10-3.

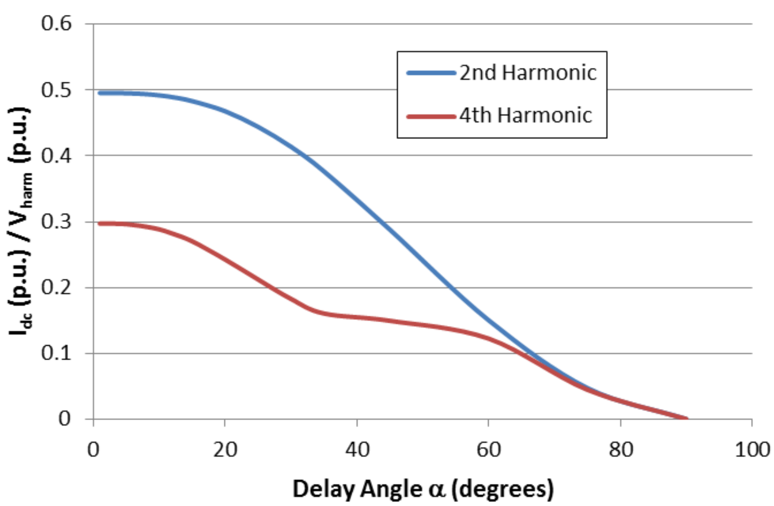

Figure 10-2
Ratio of direct current produced by TCR to the applied even-harmonic voltage (cross-distortion admittance), as a function of TCR firing delay angle α for superimposed second and fourth harmonic distortion.

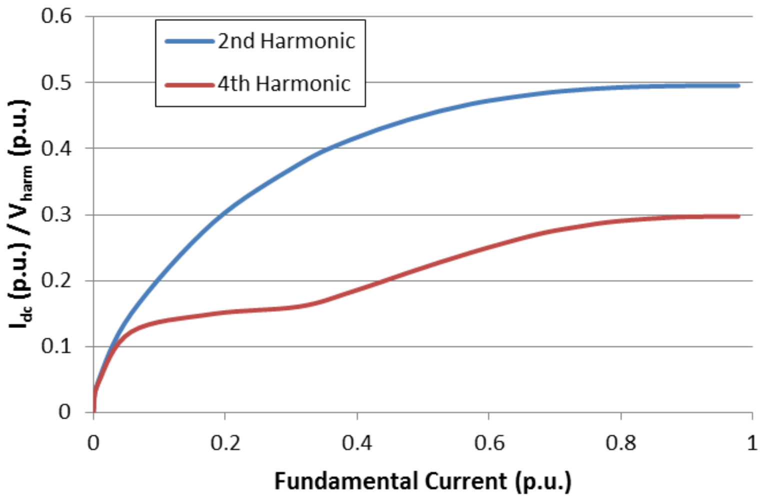

Figure 10-3
Ratio of direct current produced by TCR to the applied even-harmonic voltage (cross-distortion admittance), as a function of TCR fundamental current for superimposed second and fourth harmonic distortion.

Many SVC controls have flux balancing functions that asymmetrically adjust the thyristor valve firing times of the two conduction polarities in order to cancel the generation of direct current. The performance of such a control function during a GMD was evaluated in [22]. The conclusions reached were that, although the dc component can be reduced by such a control, the asymmetric valve gating aggravates second harmonic distortion such that the distortion is worse with the balancing control enabled than is produced by the transformer dc saturation without the control.

10.3 TSC Performance

The thyristor switch of a TSC does not provide phase control, as in a TCR, but can only provide binary on-off switching of the capacitor bank. When the TSC valve is ungated (turned off), the conduction ceases at a current zero. If the voltage is undistorted, the current zero occurs coincident with a voltage peak. The capacitor voltage is then trapped at that peak value, bleeding off very slowly thereafter. If the TSC is to be turned on again, before the capacitor voltage decays, the thyristor switch is gated when the grid-side voltage equals the capacitor voltage. If the magnitude of the grid voltage had decreased after the TSC is turned off, and thus the peak grid voltage may not reach to the trapped voltage level of the capacitor, the thyristor switch is gated when the voltage difference is at a minimum.

Harmonic voltage distortion may interfere with proper TSC reinsertion. When the grid-side voltage magnitude is less than the trapped capacitor voltage, harmonic distortion of the voltage may confound the control algorithms used to predict the minimum voltage difference timing. As a result, TSC reinsertion could occur with sub-optimal timing and create an excessive transient with potential consequences to the thyristor switch, the capacitor units, and any equipment affected by the voltage transient that can be produced.

10.4 Other SVC Control Interaction and Protection Issues

SVC controls are complex and are specific to the particular SVC vendor. The details of the controls, particularly those that operate on a cycle-by-cycle basis and that may be most responsive to voltage distortion, are proprietary and are generally not available. Therefore, only limited generalizations can be made regarding the response of the system controls to GMD-produced voltage distortion. Where an unusually large amount of distortion is predicted to be present at an SVC's bus during severe GMD, or the SVC is of particularly great importance to the overall transmission system security, specific time-domain simulation studies may be justified in order to evaluate performance.

Because TCR valve firings are discrete events, the interactions between harmonic voltage distortion and an SVC can be extremely complex. Very severe distortion can cause switching times to suddenly change or bifurcate, and control of the SVC becomes unstable [23].

Certain SVC control functions may need to be turned off during GMD events. In one SVC, power oscillation damping and negative sequence control functions are turned off during GMD events [24]. It is not documented whether this action is related to harmonic interactions with the control, or due to potential direct saturation of the SVC transformer by GIC.

The SVC trips triggering the 1989 Hydro-Quebec blackout during a severe GMD event were not caused by complex control interactions but rather by protective function settings established on the basis of normal system conditions without consideration of the unique operating environment during a GMD. Each of the SVC trips was related to protections sensitive to harmonic duty, including peak-value overvoltage protection, capacitor overload, and harmonic filter overloads. It was retrospectively determined that the protection settings had been set too conservatively, and did not allow more than a fraction of the inherent overload capability of the protected components to be used [25].

10.5 SVC Screening

Background harmonic distortion in any significant GMD event can be expected to create voltage distortion at low-order harmonic frequencies that exceeds typical SVC filter design assumptions. Therefore, any low-order filters should be evaluated in detail if the SVC is critical to system security.

Interaction between even order harmonic voltage distortion and TCRs are highly dependent on SVC control design. The SVC vendor should be consulted for guidance if the even-order harmonic distortion exceeds the SVC design basis, which is the likely case.

Section 11: Voltage-Source Converters

Voltage-source converter (VSC) technology is becoming increasingly used for applications connected to bulk transmission systems. These applications include:

- VSC-HVDC transmission. This is marketed under the tradenames HVDC-Light, HVDC-Plus, and Max-Sine, and is used for point-to-point power transmission or interconnection of adjacent asynchronous systems.
- FACTS (Flexible AC Transmission Systems) applications, a subset of which use VSC technology for dynamic reactive support (STATCOM) and power flow control (UPFC).
- Wind turbine generators. Including full-conversion (Type IV) wind turbines for which all of the output is coupled asynchronously to the grid through VSC, and double-fed (Type III) wind turbines using VSC to implement double-fed asynchronous generators.
- Solar PV plants; which produce dc power

The vulnerabilities of all of these VSC applications to GMD-produced harmonic distortion are similar, and are discussed in common in this section. The literature, however, provides little information on these vulnerabilities.

11.1 Lack of Capacitors and Filters

Compared to thyristor-based conversion technology (conventional or "classic" HVDC and SVCs), which typically have twelve switching events per fundamental cycle, a VSC typically has an effective switching rate in the kHz range. Some VSC technologies, such as modular multi-level converters (MMC) have such a high effective switching rate that harmonic filters are often not needed. Filters are typically used with pulse-width modulated (PWM) converters, but the characteristic frequencies are high and these filters are tuned well above the range of significant stimulus from GIC-saturated transformers. The filters used for PWM converter applications are typically much smaller than those used for conventional thyristor-based converters, and thus are much less likely to resonate with the grid at the low-order harmonics injected by transformers during a GMD.

A significant characteristic of VSCs are their ability to inject as well as absorb reactive power, without the use of shunt capacitors or shunt reactors. This fact, combined with the small filters or absence of harmonic filters, results in much less potential for creating low-order resonances that amplify harmonics injected during a GMD.

11.2 Frequency Translation

Similar to a conventional HVDC converter, VSC also have a frequency translation effect in interactions between the ac and dc sides [26]. Positive-sequence currents and voltages on the grid or ac side at harmonic order $k - 1$ translate to dc-side oscillations at harmonic order k. A negative-sequence ac-side harmonic voltage or current at harmonic order $k + 1$ results in oscillations on the dc side also at harmonic order k. Oscillations of the dc voltage at harmonic k result in ac-side voltage components at both sidebands of the dc modulation frequency; positive sequence current at harmonic order $k - 1$, and negative sequence current at harmonic order $k + 1$.

VSC have very large capacitances on their dc bus. Ac-side voltage distortion translates to dc-side harmonic current in the dc capacitors. This can overload these capacitors. The presence of the large capacitors, however, will tend to decouple harmonic interactions from one VSC-HVDC terminal to another.

11.3 Renewable Energy Plant Harmonic Protection Functions

Some utilities established a practice of installing harmonic current monitors at the point of interconnections between non-utility renewable energy generation plants that use VSC inverters (solar PV and Type III and Type IV wind turbines). In some cases, these monitors are applied with tripping functions to ensure that these generating facilities do not inject harmonic currents exceeding the interconnection agreement or grid code. Although these harmonic current monitors are non-directional and unable to discriminate between harmonic currents caused by sources in the transmission grid from sources within the generating plant, these harmonic protections are applied with the implicit assumption that the generating plant is the source of distortion.

Renewable generating plants typically have extensive MV cable collector systems with substantial charging capacitance, and may also have shunt capacitors or harmonic filters located on the MV bus. In addition, the VSC inverter units have an apparent impedance at low-order harmonic frequencies that is defined not only by the physical parameters of the converter (e.g., phase inductors), but also by the controls. Harmonic analysis tools that do not adequately model the inverter harmonic impedance characteristics may yield erroneous results.

The impedance of the plant at the point of interconnection is complex and may have series resonances at or near the low-order harmonic frequencies for which there may be substantial POI voltage components due to GIC saturation of transformers in the transmission grid. As a result, there can be substantial harmonic current flow across the POI during a GMD from the utility grid into the generation plant as the result of the saturated transformer sources in the transmission grid. Non-directional harmonic current protection functions may cause unnecessary tripping of these generating facilities during a GMD, causing potentially significant step decreases in power generation resources while the grid is potentially under severe stress.

11.4 VSC Screening

For VSC devices that are critical to the transmission system, such as VSC-HVDC, STATCOMs, and FACTS devices such as UPFCs, the system vendor should be consulted if voltage distortion values exceed the design basis for the systems.

Where renewable plants using VSC inverters have harmonic protection schemes, detailed evaluation should be performed if harmonic currents exceed 50% of the trip point, if the harmonic analysis does not fully consider the harmonic impedance characteristics of the inverters, including the influence of controls on the impedance. For any meaningful analysis of renewable plant harmonic current flow, the electrical details of the plant, including interconnection transformer, collector cable capacitance, and any capacitor or filter banks need to be modeled.

Section 12: Distribution Systems and Loads

Harmonic voltages, present at the transmission level and produced by GIC saturation of bulk transmission system transformers during a GMD, propagate down to distribution systems and to customer end-use loads. While these distribution system and end-use impacts are unlikely to have any significant impact on the bulk transmission system security, these impacts may increase societal impacts of a GMD event.

12.1 Distribution Capacitors

Shunt capacitors are routinely used at distribution substation buses, on primary distribution feeders, and at some customer loads. The amount of capacitance, relative to the short-circuit impedance of the system at the capacitor locations, frequently results in resonances in the low-order harmonic range that can be excited during a GMD. Where resonances occur, they may result in excessive capacitor unit duty, harmonic overvoltages, and increased load impact. Because distribution capacitors are located relatively close (electrically) to loads, however, the loads will provide significant damping to resonances in most cases. As a result, the distribution resonances are less likely to result in a large amplification factor.

Distribution feeder capacitors are usually protected only by fuses. A particularly severe resonance situation could result in operation of these fuses, removing the capacitors from service. This may reduce the power factor of the distribution circuits, placing greater reactive demand on the transmission system. However, resonances sufficiently severe to remove capacitors are likely to affect only a limited fraction of the distribution capacitors in service, and therefore the bulk system impact should also be limited.

12.2 Motor Loads

Induction motors at customer facilities will have increased rotor heating during a GMD due to harmonic voltage distortion. The significance of the incremental heating depends on the degree to which the motors are loaded; mechanical loading of end-user motors is often less than the motor's rating, providing margin for distortion-related heating in most cases. Another mitigating factor is that motors, like the large synchronous generators discussed in section 5, have a thermal time constant that will smooth some of the rapid variations in GMD impact and this decrease the peak temperature reached.

Distorted voltage applied to induction motors can also decrease the motor torque available at rated speed, and can cause parasitic torques at lower speeds that can potentially prevent a motor that has just been started from reaching its full speed [27].

12.3 Other Consumer Loads

The harmonic distortion withstand capability of end-user equipment, other than perhaps motors, is largely undocumented. There is a wide variety of equipment, and many different designs, so it is infeasible to make generalized conclusions. IEEE Standard 519 provides harmonic voltage distortion limits as a recommended practice. However, in practice these distortion guidelines are frequency exceeded by a large amount during normal system conditions, with few reports of adverse consequences.

Many small single-phase generator sets, commonly used by consumers as backup generators typically have very distorted voltage output waveshapes (>15%), yet these units are frequently used with a wide range of consumer equipment with success in most cases. There are anecdotal reports of modern home heating units with variable speed drives that are unable to cope with highly distorted voltage. Some of the higher-quality backup generators advertise a voltage THD less than 6%.

Some consumer and industrial control products use 60 Hz zero crossings as a time reference (e.g., some digital clocks that do not use an internal quartz crystal reference). Harmonic voltage distortion can cause multiple zero crossings which can result in erroneous operation. Most sensitive consumer equipment today (e.g., computers, home entertainment, etc.) are supplied via switched-mode power supplies which provide very good buffering of the electronics from power line distortion.

Due to the wide diversity of end-use equipment and the lack of documented harmonic distortion withstand capability of this equipment, it is not possible to provide a good guideline for the evaluation of GMD-caused distortion. It is quite clear that IEEE-519 is too conservative to be recommended as a realistic criterion.

12.4 Telecommunication Interference

Similar to the potential telephone interference caused by harmonic currents in HV transmission lines, harmonic currents in distribution systems during a GMD can also be disruptive to telephone function. The harmonic currents are generally smaller at the distribution level, but the distances between distribution feeders and telephone cables are very small. Harmonic currents can be particularly significant where feeder capacitors resonate at a harmonic excited by the GMD. Everyday distribution circuit harmonics pose a challenge to telephone utilities in maintaining an acceptable level of circuit noise. The much larger harmonic currents during GMD may cause telephone circuits to be unusable.

12.5 Distribution Screening

It is not feasible to model distribution systems in detail, other than by generic approximations, in bulk transmission system harmonic analysis. Except that failure of distribution capacitors can increase transmission system reactive power demand, distribution issues are not germane to bulk system security assessment. It is recommended that bulk system (fundamental frequency) voltage stability assessments use a slightly reduced load power factor assumption to represent distribution capacitor fuse-outs.

Section 13: Relay and Protection Systems

Relay and protection systems have often been cited as vulnerable to harmonics produced during a GMD, with much of the focus on false relay operation (insecurity). To a great extent, this focus has been driven by relay operations that occurred during the March, 1989 GMD event. The most significant of these relay operations were those that tripped static var compensators (SVCs) resulting in a blackout of the Hydro Quebec system, and numerous transmission capacitor bank tripouts across the Northeast of the U.S. The SVC trips were found to have not been not due to relay misoperations, but rather to overly-conservative settings that did not allow utilization of the inherent harmonic overload capabilities of the protected equipment. The capacitor bank trips were due to the characteristics of certain capacitor protection schemes commonly used in 1989, but used less frequently today for transmission capacitor banks.

While the focus on relays as the transmission system component most vulnerable to GMD-related harmonic distortion may be somewhat disproportionate, the response and lack of response of protective relay systems to harmonics are issues that must be addressed in order to evaluate system GMD vulnerability. The system protection issues related to GMD harmonics are in three forms:

1. Insecurity, or the false operation of relays as a result of harmonic currents and voltages when operation is neither desired nor appropriate.
2. Un-dependability, where harmonics prevent the operation of a protective relay that should operate.
3. Lack of protection where the design of the protection scheme, including the characteristics of the protective relays, do not adequately protect critical system equipment from the stresses caused by GMD harmonics. (This section on relay and protection systems was intentionally placed near the end of this guide so that the impacts of harmonics on equipment could first be addressed before discussion of the protections required to address these impacts.)

The discussions of relay scheme performance in this guide are limited to the impacts of harmonic currents caused by saturation of power transformers. GIC may also saturate instrument transformers (current transformers, magnetic voltage transformers), diminishing their accuracy and increasing susceptibility of the protection schemes to insecurity and undependability. These direct impacts of GIC on instrument transformers, and the resulting impacts on protection system performance are not within the scope of this guide.

13.1 Harmonic Response Characteristics of Relays

There are three types of protective relays in use on transmission systems: digital, static (solid state), and electromechanical. Digital relays, also known as numeric relays, use software running on microprocessor platforms that numerically analyze current and voltage signals in order to make tripping decisions. Digital relays, a technology introduced in the past couple of decades, have largely replaced the other two legacy relay types in most bulk transmission applications. Static relays use analog electronic components to process the inputs. Each of these technologies has its own inherent responses to harmonics.

Digital Relays

Except where a relay is intentionally designed to respond to harmonics (e.g., second harmonic restraint on a transformer differential relay), the operation of digital relays is typically based on the fundamental frequency components of the input voltages and currents. The fundamental components are identified from sampling of the input values at a specified number of times per fundamental cycle, typically 32 or 64. To avoid the creation of aliasing artifacts, the signal is preconditioned prior to sampling by a low-pass analog filter that has a cutoff frequency at typically one-third of the sampling frequency. This is equates to cutoff frequencies near the tenth or twenty-first harmonics for 32 and 64 samples per cycle, respectively. After sampling, a digital filter may be used to attenuate signals with frequencies above the fundamental. A discrete Fourier transform (DFT) filter is used to extract the fundamental component of the signal, using either a full-cycle or a half-cycle algorithm. The inherent nature of the DFT filters out all integer harmonics, in the case of a full-cycle algorithm, or all odd harmonics in the case of a half-cycle algorithm as shown in Figure 13-1 and Figure 13-2.

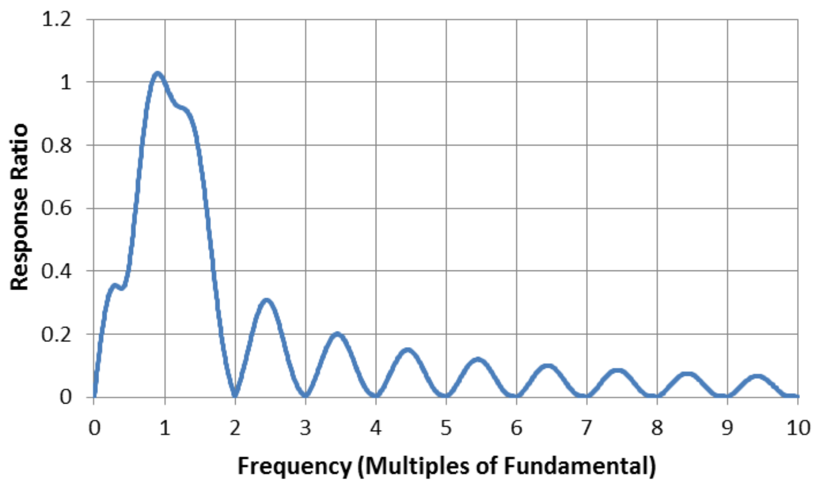

Figure 13-1
Frequency response of discrete Fourier transform (DFT) using a full fundamental-cycle algorithm.

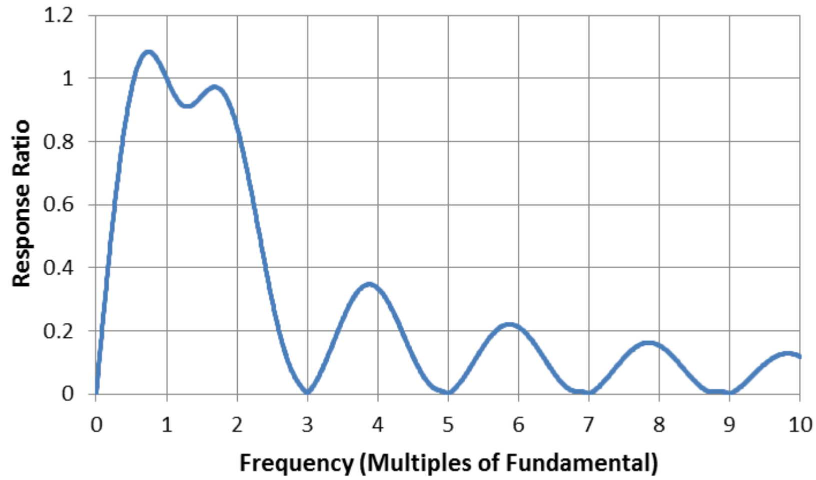

Figure 13-2
Frequency response of discrete Fourier transform (DFT) using a half fundamental-cycle algorithm.

The filtering effect of a full-cycle DFT eliminates any response to the harmonics caused by a GMD event. A half-cycle DFT, however, is responsive to even harmonic distortion that can be very substantial during a GMD. The greatest vulnerability is for the second harmonic because digital filtering should substantially attenuate higher-order even harmonic distortion.

Electromechanical Relays

The responsiveness of electromechanical relays to harmonic distortion of the measured quantity (i.e., current or voltage) is dependent on the details of the relay design. A comparison of the sensitivity of two different induction disk type electromechanical overcurrent relays to harmonic currents, provided in [28] and shown in Figure 13-3, shows a rather striking difference between two different relays of the same type. Tests of electromechanical relay response to harmonic currents superimposed onto fundamental frequency operating quantities can actually decrease sensitivity [29].

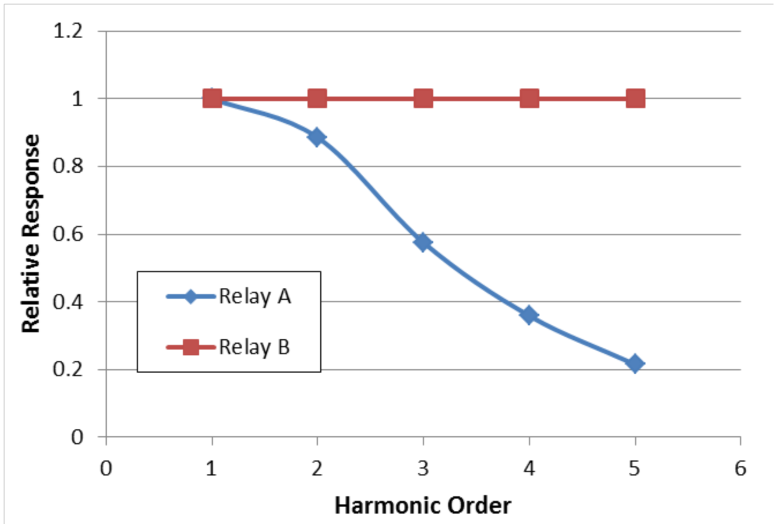

Figure 13-3
Frequency response test results for two different induction-disk electromechanical relays, from [27].

Electromechanical negative sequence relays use passive components (i.e., resistors, inductors, and capacitors) to create the phase shifts necessary to derive a negative sequence quantity from phase quantities. The impedances of inductors and capacitors are proportional and inversely proportional, respectively, to frequency. Therefore, these phase shifting networks only create the desired phase shift at the fundamental frequency. Input phase quantities at harmonic frequencies are transformed to a meaningless quantity.

Electromechanical relays have been largely replaced in critical HV and EHV transmission applications.

Static Relays

Static relays must transform an input ac quantity to a dc quantity in order to be compared by a reference value in an electronic comparator device. How this ac to dc transformation occurs, along with any signal filtering, determines the relay's responsiveness to harmonic distortion of the input quantity. These characteristics are at the discretion of the relay designer, and generalizations are not useful. Where these relays are used in locations where high levels of harmonic distortion are expected on the relays' measured quantities, and the relay performance (security and dependability) affect the system security or protection of critical components, the manufacturer should be contacted to determine the impacts of the distortion.

Like electromechanical relays, static relays use passive circuit components to create the phase shifts needed to derive a negative sequence quantity from phase quantities. The phase shifts at harmonic frequencies are not the correct shifts needed to correctly derive the negative sequence quantity. Therefore, these relays also do not correctly respond to harmonic quantities that are not filtered out prior to the negative sequence transformation circuit.

Static relays had only a short period of substantial usage prior to the widespread acceptance of digital relay technology. There are relatively few static relays remaining in service.

13.2 Capacitor Bank Protection

In the March 1989 severe GMD event, there were numerous trips of transmission shunt capacitor banks. Capacitor bank trips during GMD can be the result of protection system misoperation, but they also may be the result of correct operation to protect the bank from excessive duty or as the result of excessive numbers of capacitor units fusing out or failing as a result of the harmonic stress.

Bank Imbalance Detection

Transmission shunt capacitor banks are composed of series and parallel connections of capacitor units. Unit failures, resulting in operation of fuses in internally- and externally-fused banks or packet short circuiting in a fuseless bank, result in increased stress on the other units of the bank that remain in operation. In order to avoid cascading failure of the bank, sensitive bank imbalance protection is required detect unit failures. It is typical to alarm when a certain number of unit failures are detected, and to trip the bank at a higher threshold.

There are a number of different capacitor bank protection schemes in use, and these vary in their sensitivity to harmonic distortion. In general, schemes that detect imbalances within a phase are less vulnerable than schemes that perform failed unit detection based on imbalances between phases.

One scheme for grounded-wye capacitor banks (HV and EHV capacitor banks are almost always in a grounded-wye configuration) uses voltage transformers connected to tap points within each phase of the bank as shown in Figure 13-4. The secondaries of the voltage transformers are connected in broken delta and connected to an overvoltage relay. Alternatively, each phase's voltage transformer secondary can be connected to a neutral overvoltage relay that sums the phase inputs internally.

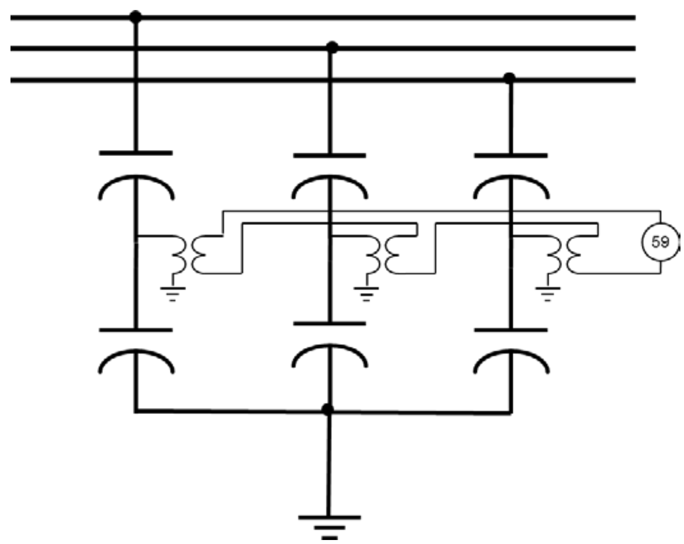

Figure 13-4
Zero-sequence overvoltage scheme for detecting failed capacitor units in a grounded single-wye capacitor bank.

A similar scheme is functionally a neutral overcurrent scheme implemented using a resistive burden applied to the neutral CT secondary with the voltage across this burden detected by an overvoltage relay (device 59). This scheme is illustrated in Figure 13-5.

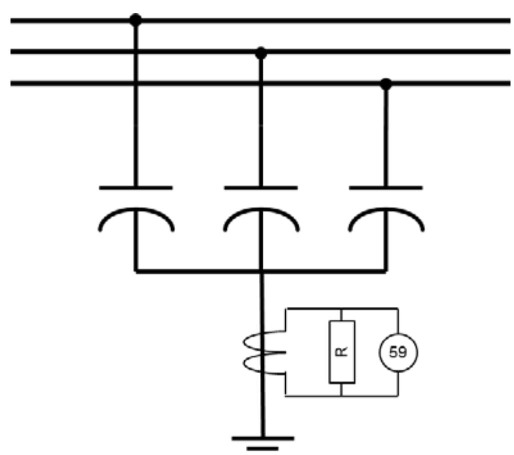

Figure 13-5
Ground overcurrent scheme for detecting failed capacitor units in a grounded single-wye capacitor bank.

Both of these schemes are based on detecting imbalances between the impedances of the capacitor bank phases by detecting zero sequence voltage or current within the bank. Therefore, they are both vulnerable to misoperation due to neutral voltages or currents resulting from a zero sequence component of the bus voltage. The zero sequence bus voltage component could be at the fundamental or harmonic frequencies.

Where electromechanical or static relays are used for these schemes, a common practice is to use a third harmonic filter because the zero sequence harmonics are overwhelmingly third order under normal conditions. Even triplens (multiples of third order) such as the sixth harmonic are not significantly produced during non-GMD conditions, except on a transient basis during transformer inrush. Higher order triplens, such as the ninth harmonic, generally have a much smaller magnitude than the third harmonic. However, under GMD conditions, the zero sequence quantities may consist of other harmonic orders. GIC-saturated transformers inject high magnitudes of even-order harmonic currents. Thus, a potentially significant sixth harmonic component may be present on the bus voltage during a GMD. Three-phase 5-leg and shell form transformers are magnetically imbalanced, and as a result they inject zero sequence currents at all harmonic orders [30]. For relays that are sensitive to harmonic quantities, elimination of only the third harmonic may not be sufficient to avoid insecurity (false operation) during a GMD.

A digital relay with a half-cycle DFT algorithm would be vulnerable to insecurity if applied to these schemes due to the presence of even-order harmonics. These schemes should not be vulnerable to harmonics if a digital relay using a full-cycle DFT algorithm is applied. However, GIC saturation of magnetically imbalanced transformers (i.e., 5-leg core form and shell form) will also increase fundamental-frequency zero-sequence voltages, so there is some potential for insecurity even with a digital relay. Some digital relays incorporate both a half-cycle DFT for speed and a full-cycle DFT for security, with higher thresholds used for the quantities resolved by the former. Vulnerability of such relays in this capacitor protection application depends on the setting used for the half-cycle-derived capacitor bank neutral current or burden voltage.

An improvement of the neutral current scheme is obtained by compensating for the zero-sequence voltage component of the bus voltage, based on the fundamental-frequency impedance of the bank. Such a scheme mitigates the potential insecurity due to fundamental-frequency zero sequence voltage only. Because resistive impedance is used as the neutral CT burden (impedance constant for all frequencies) and the capacitive impedance of the bank decreases with frequency, this scheme does not provide correct compensation for zero-sequence harmonic components. Therefore, this improvement eliminates the concern for false operation during a GMD if a digital relay (with a full-cycle algorithm) is used, but does not eliminate the problem if an electromechanical or static relay is used unless the relay is adequately filtered such that it responds only to fundamental frequency voltages.

For large capacitor banks, with many elements in parallel and in series, the phase imbalance schemes described above are unlikely to be sufficiently sensitive to detect individual capacitor unit failures without being excessively susceptible to false operation due to bus voltage imbalance. A voltage differential scheme applied individually to each phase, such as illustrated in Figure 13-6, is often used today for large transmission capacitor banks. This scheme is based on imbalance within the phase, responding to changes in the relative impedances of the bank above and below the tap point, and can be very sensitive while not vulnerable to bus voltage zero sequence components. This type of scheme should not be vulnerable to insecurity during GMD, unless the voltage transformers used for the bus voltage and the capacitor bank tap voltage have substantially diverse frequency response characteristics (e.g., a CCVT used for the bus and magnetic PTs for the tap), and the voltage relay is responsive to harmonics. Application of a digital relay with a full-cycle DFT algorithm should eliminate this vulnerability, even if the voltage transducers are mismatched on a harmonic response basis.

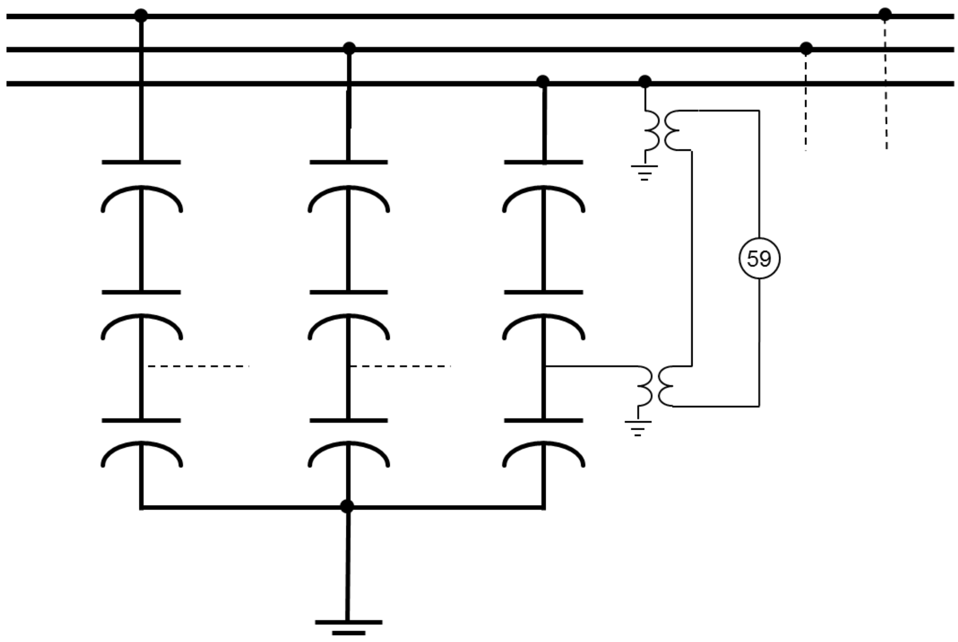

Figure 13-6
Phase voltage differential scheme for detecting failed capacitor units in a grounded single-wye capacitor bank.

Large transmission shunt capacitor banks are sometimes divided into two parallel sub-banks on each phase (double-wye banks). Failed capacitor units in these banks are typically detected by the schemes depicted in Figure 13-7 or Figure 13-8. Both schemes are based on detecting dissimilarity in the impedances of the bank legs connected to the same phase. I.e., the scheme is applied on a phase-by-phase basis. These schemes have no particular vulnerability to insecurity due to GMD-produced harmonic distortion.

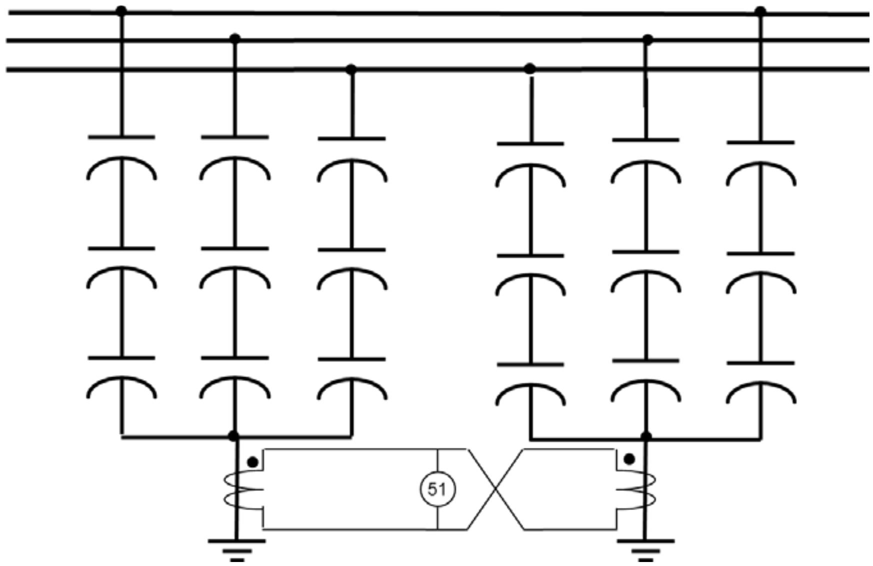

Figure 13-7
Differential ground current scheme for detecting failed capacitor units in a grounded double-wye capacitor bank.

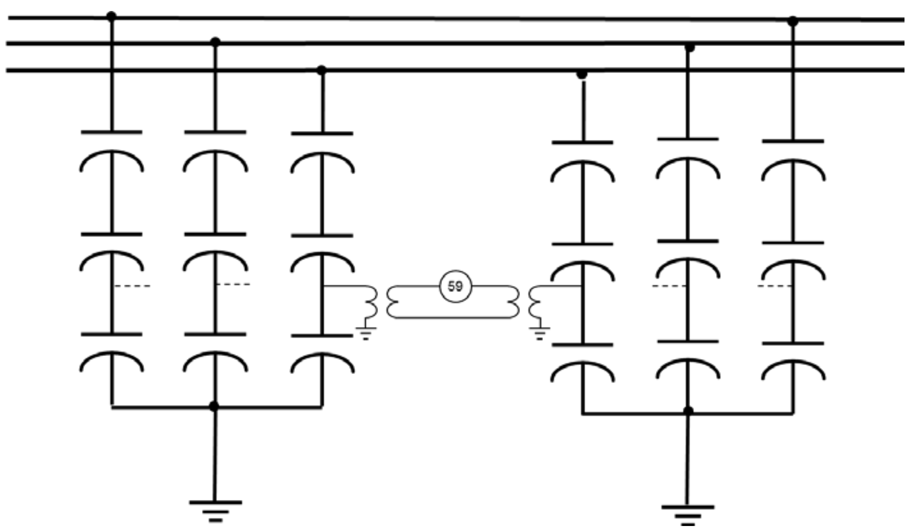

Figure 13-8
Differential phase voltage scheme for detecting capacitor units in a grounded double-wye capacitor bank.

In addition to the schemes for detecting failed capacitor units, discussed above, transmission capacitor banks also typically have phase and ground overcurrent or directional overcurrent protection to detect faults on the bus between the capacitor breaker and the bank itself. Typically, the pickups for this protection are set quite high, at multiples of the capacitor bank rated current, so insecurity due to GMD-produced harmonics should not be a concern.

Capacitors may also be protected from harmonic overload. There are dedicated-purpose relays offered for capacitor protection, and some of these offer overload protection elements. One relay uses current input applied to a filter that has an attenuation directly proportional to frequency, in the same manner that capacitor impedance is inversely proportional to frequency, such that the operating quantity represents voltage across the capacitor [31]. Another capacitor relay uses the true rms value of current in order to detect harmonic overload, as well as the root-sum-square or arithmetic summation of inferred capacitor voltage derived from current, or direct phase voltage inputs as capacitor overvoltage protection [32]. And the documentation for yet another dedicated capacitor protection relay does not mention any harmonic overload functionality [33].

Capacitor banks in typical transmission applications are subjected to little harmonic duty relative to the capacitor unit withstand capabilities during normal, non-GMD conditions. Except for harmonic filters, harmonic overload protection is infrequently applied to transmission shunt capacitor banks. During a severe GMD, however, capacitor banks may be subjected to unusual harmonic duty to the degree where capacitor unit failure could potentially occur. Where harmonic overload protection is applied, the protection may trip the bank. If the overload protection is correctly coordinated with capacitor capabilities, then such tripping is correct and can prevent equipment damage. If the protection is set too conservatively, the capacitor bank may be tripped unnecessarily and deprive the system of reactive power support when it may be most needed. If capacitor harmonic overload protection is not applied (the usual case), or if overload protection setting are too high, capacitor units could fail during a GMD event and result in tripping due to bank imbalance. Thus, with regard to performance during GMD, there is a balance between insecurity and lack of protection, with either outcome having essentially the same functional impact on the bulk transmission system which is loss of reactive compensation resources at a time when the grid is likely to be dependent on those resources to counteract the reactive power demand of widespread saturation of transformers by GIC.

13.3 Harmonic Filter Protection

Harmonic filters are always applied at conventional line-commutated (LCC) HVDC converter stations and with SVCs using thyristor-controlled reactors (TCR). Filters are also applied at certain types of industrial facilities having distorting loads (e.g., arc furnaces, railway power converters, etc.). Transformer saturation during a GMD can produce harmonic currents in filters that far exceed the harmonic current duty due to the device (e.g., HVDC converter, SVC) to which the filter is applied. This is particularly true of filters tuned to frequencies in the low-order harmonic range (less than 10th order). Filter designs consider a certain degree of background harmonic distortion in the transmission grid, but the assumed distortion used as a design basis can be an order of magnitude less than what may be present during a GMD. Also, the distortion may include frequencies (e.g., even order harmonics) that are not present to any substantial degree during normal system conditions.

In addition to filters applied to mitigate specific sources of distortion, some shunt capacitor banks installed for reactive compensation have tuning reactors in series for the purpose of detuning these banks to avoid parallel resonance at harmonic orders normally encountered on a steady-state basis in the transmission system. These banks are typically tuned slightly below the fifth harmonic. A parallel resonance will always appear at a frequency below the series-tuned frequency of a filter applied to an inductive power system. Therefore, it is quite possible for these de-tuned capacitor banks to be parallel resonant near the fourth harmonic. This harmonic is not normally present to any significant degree, but can be very large during a GMD.

Protection of harmonic filters is similar to that of a capacitor bank, except that prudent filter protection design dictates application of harmonic overload protection. In addition to the protection of the capacitors in the filters, protection may also be applied to the tuning reactors and damping resistors of a filter. Utilization of protective relays with appropriate harmonic response is obviously desirable for filter overload protection functions. Harmonic responsiveness, however, may not be desirable for protection intended for detection of capacitor unit failures. It is reasonable to assume that the overall filter protection design considers the presence of harmonic distortion, and that protection trip points are adequately coordinated with equipment capabilities. Therefore, it should be expected that the operational concern during GMD is not so much with protection misoperation (insecurity) but rather correct operation of the protection due to excessive loading from the distortion present. Tripping of the filter removes the filtering function, which may increase harmonic distortion, and deprives the grid of a reactive resource. The controls of HVDC converters and SVCs may be programmed to trip the entire installation if an excessive number of filter banks trip or become unavailable.

13.4 Generator Protection

The only common generator function having relevance to GMD-caused harmonics is stator current imbalance, or negative sequence overcurrent, protection. Where electromechanical or static relays are applied, harmonic distortion of the generator stator current can cause an operating quantity that neither is related to the negative-sequence component of the harmonic currents nor the impact that the currents have on the generator. This stems from three different reasons:

1. The phase shifting networks used in these relays do not provide the correct phase shifts at harmonic frequencies to translate the phase current inputs into a negative sequence quantity.
2. Even if the harmonic negative sequence components are correctly resolved, the rotor heating impact of harmonic currents is not limited to negative sequence components, but also includes all positive sequence currents as well.
3. Just the negative, or positive, sequence current magnitudes are not sufficient to reflect the generator impact of the harmonic current; the harmonic quantities must also be appropriately weighted as a function of the rotor reference frame frequency.

Electromechanical and static relays are susceptible to both providing inadequate protection against rotor heating, and also potential insecurity due to harmonic currents being incorrectly transformed to an apparent negative sequence quantity.

Digital generator protection relays that are presently available do not include harmonic currents in the negative sequence overcurrent protection. While these relays are not vulnerable to insecurity as the result of GMD harmonics, there is no protection of generators from generator rotor heating due to harmonics. As discussed in section 5, this heating effect can be significant, with potentially very severe consequences if generator heating limits are exceeded.

Generator protection schemes often include third harmonic undervoltage and low-frequency injection methods to detect stator faults. These operate only on zero-sequence quantities. Because the generator is isolated from zero sequence harmonics in the grid by the grounded-wye delta step-up transformer, GMD harmonics are not expected to affect or interfere with these schemes.

13.5 Transformer Protection

Two different types of transformer protections are potentially vulnerable to GMD-related harmonics. These protections are transformer differential and negative-sequence overcurrent and overvoltage. Current differential schemes are almost universally used as the primary means for internal fault detection on major power transformers. Negative sequence protections are occasionally used for backup protection against internal faults, open phase conditions, and other specialized applications.

Phase differential relays operate on the phasor difference between transformer primary and secondary currents, adjusted for the transformer turns ratio. Transformer saturation, due to energization (inrush), energization of an adjacent transformer (sympathetic inrush), overexcitation, and GIC flow will cause a differential current and thus tend to operate the relay. To make the protection secure from false trips due to saturation, various methods are used. Offset (or dc) saturation is characterized by even-order harmonics. Therefore, second and sometimes fourth harmonic components of differential current are used as indicators of the saturation, and used to either restrain or block differential operation. In some transformer protection schemes, harmonic blocking is enabled, or enabled with an adjusted threshold, for a defined period after transformer energization. Restraint or blocking based on fifth harmonic differential current may also be used to avoid operation due to transformer overexcitation.

Harmonic currents from external sources (e.g., other saturated transformers) will not affect transformer differential protection, except where transformer primary and secondary current transformers respond differently to harmonics. Unlike potential devices such as CCVTs, the frequency response characteristics of current transformers are quite good through the low-order harmonic range that is relevant to GMD. Therefore, the harmonic issue for differential protection during GMD is limited to harmonics produced by GIC saturation of the protected transformer. GIC saturation is identical in nature to transformer energization inrush, although generally less severe. Unlike energization inrush, which attenuates over a period of seconds, GMD persists for a very much longer duration.

Harmonic restraint (typically second, fourth, or fifth harmonics) may de-sensitize transformer differential protection during GIC saturation and thus may decrease the ability of the protection to detect a low-current internal fault (high-impedance ground fault or a turn-to-turn fault) before it evolves into a more severe fault. This is not different than the situation during energization inrush, except that the period of vulnerability is extended when the saturation is caused by GIC, and there is the arguable possibility that GIC saturation might increase the probability of a transformer internal fault occurring during a GMD event. Harmonic blocking removes the blocked differential function completely when differential harmonic quantities exceed the setting. Blocking or restraining the sensitive transformer phase differential element does not leave a transformer unprotected from internal faults, however. Prudent transformer protection design typically includes other functions that provide internal fault protection, albeit at a reduced sensitivity in some cases. Other typical internal fault detection schemes that should not be affected by GIC saturation include unrestricted phase differential, restricted earth fault protection, and sudden pressure or Bucholz relays. Unrestricted phase differential protection will see the transformer saturation, should have a pickup greater than differential current for the worst-case inrush. Worst case inrush, considering the most adverse point of voltage wave energization and maximum flux residual, should always be greater than GIC saturation. While restricted earth fault protection is not susceptible to harmonics, it is susceptible to misoperation due to current transformer saturation.

In some transformer phase differential schemes, harmonic blocking is only enabled for a defined period following transformer energization. This period is typically limited to a few seconds in order to accommodate ordinary transformer inrush. During a GMD, the transformer may be saturated for an extended period, and these periods are not necessarily preceded by the transformer energization event that enables the blocking function. Therefore, the phase differential protection is potentially vulnerable to false operation due to GIC saturation. This is the case even when a digital relay is used because the exciting current of the GIC-saturated transformer will have a substantial fundamental component, in addition to the harmonic components.

The vulnerability of negative sequence schemes to GMD harmonics is limited to electromechanical and static relays, due to the incorrect response to harmonic quantities of the phase shifting networks used to generate the negative sequence operating quantity. These relays generally have filtering to decrease the sensitivity to harmonics. Digital relays, at least those based on full-cycle DFT algorithms, perform sequence transformation on only the fundamental quantity and are not sensitive to harmonics. The use of negative sequence elements for transformer protection was uncommon prior to the introduction of digital relays.

13.6 Line Protection

There are a wide variety of transmission line protection schemes. Most schemes, such as those based on impedance relay elements, are not particularly vulnerable to low-order harmonic distortion such as might be present during a GMD. The response of electromechanical relays to harmonic distortion, however, is complex and largely undocumented. There is potential for incorrect operation of any electromechanical relay under very high levels of distortion.

Line protection schemes based on zero crossings and negative sequence quantities are particularly vulnerable to harmonics when electromechanical and static relays are applied. The phase shifting networks used to transform input quantities into negative sequence quantities do not provide the correct phase shifts at other than the fundamental frequency.

Harmonics can distort zero crossing times. When even harmonics are present, such as during a GMD, the positive and negative half cycles may have unequal time periods between zero crossing points. One scheme that is based on zero crossings is phase comparison protection. Most often, this scheme is based on negative sequence current phase comparison. When implemented by static relays (this scheme is not implemented using electromechanical relays), both the sequence transformation and the zero crossings are both potentially affected by harmonic distortion. Static relays employ filtering to minimize the impact of harmonics, but performance may be degraded by very high levels of distortion. Digital relays allow the phase comparison to be based on only the fundamental-frequency component of current, eliminating harmonic distortion issues for phase comparison protection implemented with digital relays.

13.7 Shunt Reactor Protection

Shunt reactors implemented at transmission voltages are iron core reactors, in contrast with air core reactors used at lower voltage levels. Although they have iron cores, EHV/HV shunt reactors are not realistically vulnerable to GIC saturation. This is because their cores are gapped, and thus have a far smaller magnetizing reactance than power transformers. In addition, they are typically designed with a lower flux density (higher saturation level) than transformers. Harmonic currents in shunt reactors during a GMD are the result of external sources – saturated transformers in the transmission system. Because the impedance of a reactor increases with frequency, harmonic current flow is limited, and is weighted toward the lowest harmonic orders.

The typical protections used for these reactors include phase overcurrent, winding differential, and restricted earth fault protection. None of these elements are particularly vulnerable to harmonic currents in this application. In order to detect inter-turn faults, a neutral overcurrent element may be applied. In order to avoid false operation due to zero sequence bus voltages forcing zero sequence current, the neutral overcurrent may be supervised by a zero-sequence voltage polarized directional element. Typical setting is on the order of 5%-10% of rated reactor current. If implemented using digital relays, the inter-turn fault protection should be immune to harmonics. With electromechanical or static relays that are not adequately filtered to reject harmonics, there is a theoretical possibility of false response to grid zero-sequence harmonics. However, this is unlikely because a very large zero sequence harmonic bus voltage component would be required to force enough neutral current through the reactor's impedance at those harmonic frequencies.

Section 14: Conclusions and Summary of Harmonic Screening Criteria

In the development of this guide, a number of key overall conclusions were reached:

- Many harmonic impacts are thermal in nature. The highly variable nature of the geo-electric field during a GMD means that GIC, and the harmonic currents injected by GIC-saturated transformers, are similarly variable. Many power system components have relatively long thermal time constants, relative to the GMD intensity variations. Therefore, these time constants provide a filtering effect that reduces many types of GMD harmonic impacts substantially from the severity that would occur if the harmonic currents produced at the peak GMD intensity were continuously applied. The reduction in impact is substantial in the case of transformers and cables, which have long thermal time constants.
- Many protective relaying problems that have occurred in prior GMD events can be attributed to relays that are undesirably sensitive to harmonic currents and voltages, or which have inaccurate response to these harmonics. These undesired characteristics are almost exclusively related to electromechanical and static (solid-state) relays. Modern digital relays have largely replaced these older types of relays. Digital relays that use full-cycle discrete Fourier transform (DFT) algorithms are completely insensitive to harmonics which is desirable in almost all cases.
- Some capacitor banks are susceptible to harmonics, as their impedance decreases with frequency and they can engage in resonances with the system that amplify harmonic currents and voltages. In some cases, harmonic overload protection is not applied to transmission shunt capacitor banks.
- Some generators may not be sufficiently protected from potentially damaging harmonic currents. Such currents could potentially cause excessive rotor heating and stimulate mechanical vibrations at frequencies turbine-generator designers did not anticipate.

Table 14-1 summarizes the potential impacts of GMD harmonics on electric power systems and provides thresholds that can be used for preliminary impact screening. These thresholds are intentionally conservative, and are designed to require only the harmonic current and voltage results that typical power system harmonic analysis tools provide. Where currents or voltages exceed these thresholds, further analysis is recommended using the more detailed criteria described in this guide.

Table 14-1
Summary of GMD harmonic impacts and screening thresholds

Potential Impact	Discussion	Screening Threshold[1]
TRANSFORMERS		
Winding heating due to harmonic current flow through the transformer.	Currents can be caused by saturation of other transformers. Impacts are significantly decreased by the transformer thermal time constant. Very large harmonic currents are required to create damage.	I_{rms} > 1.12 p.u. of transformer rated current (fundamental and harmonics) Root mean square current (I_{rms})
Harmonic blocking or harmonic restraint functions in differential relay schemes inhibit detection of internal faults during a GMD.	Other protection schemes will eventually detect an internal fault, but detection may be delayed and damage increased by blocking or insensitivity of the differential protection if an internal fault occurs during a GMD.	Differential second harmonic current greater than 0.1 p.u.
SHUNT CAPACITORS		
Thermal failure, fuse melting, or overload protection trip due to overcurrent.	Capacitors are likely to have high currents where they form resonances with the transmission system at integer harmonic frequencies.	I_{rms} > 1.35 p.u. (fundamental and harmonics)[2]
Dielectric failure due to excessive voltage.	Capacitor voltages may have highly amplified harmonic components due to resonances. Peak voltage is dependent on the phase relationship between harmonic and fundamental voltage components.	THD_V > 10%, and ΣV_n > 20%.[2,3] Total harmonic distortion (THD)
Capacitor bank protection false trips due to harmonic currents.	Certain protection schemes, such as zero-sequence overvoltage and ground overcurrent (with or without compensation) are vulnerable when applied using static or	Evaluate in detail any capacitor banks using zero sequence overvoltage or ground overcurrent schemes with static or electromechanical relays.

	electromechanical relays. Digital relays are generally immune.	
Capacitor banks implemented as type-C filters overloads due to excess voltage distortion.	These filters provide damping and a low shunt impedance at low-order harmonic frequencies. Their tuning sections are particularly vulnerable to the high levels of distortion during a GMD	Evaluate in detail any type-C filters tuned to the low-order harmonic range when GMD distortion exceeds the filter's design assumptions.
GENERATORS		
Harmonic current into stator can cause excessive rotor heating.	The thermal time constant of the generator rotor significantly reduces the potential impact. Generators are largely unprotected from this potential impact.	< 350 MVA, THD_i > 0.107 p.u. 350 – 1250 MVA, THD_i > 0.107 – 0.00447 × (MVA-350) > 1250 MVA; THD_i > 0.067 p.u.
Negative sequence protection incorrectly trips due to relay harmonic response	Electromechanical and static negative sequence relays are vulnerable due to the passive phase shifting networks used.	Evaluate any major generation units using static or electromechanical negative sequence relays.
Harmonic currents into the stator can cause high-frequency torque that may stimulate mechanical resonances.	Turbo-generator designers typically avoid mechanical resonances stimulated by normally-encountered harmonics (odd order). Even order (stator-side) harmonic currents are not typically a design objective.	Current standards to not specifically address this impact. Contact the turbo-generator manufacturer for guidance if the harmonic currents approach or exceed the generator thermal impact screening thresholds above.
SURGE ARRESTERS		
Harmonic voltages can cause high peak voltages, potentially causing metal oxide varistor (MOV) arrester thermal instability, placing bus faults on the transmission system.	The peak voltage depends on the phase relationships between the harmonic and fundamental voltage components. Because of the temporary nature of maximum GMD intensity, this is a temporary overvoltage rather than a continuous voltage consideration. Extremely high levels of voltage distortion are necessary	Voltage THD greater than 35%.

	for this to be an issue.	
TRANSMISSION CABLES		
Harmonic currents cause elevated cable temperature.	Due to the very long thermal time constants of cables, the thermal impacts are not deemed to be significant.	No specific screening is recommended, except for cables with multi-grounded shields and pipe-type cables. These should be evaluated in detail if heavily loaded and have substantial harmonic current flow.
Harmonic voltages cause increased cable dielectric loss heating and cable shield capacitive current heating	Due to the very long thermal time constants of cables, the thermal impacts are not deemed to be significant.	No specific screening is recommended.
Harmonic currents cause increased voltage duty on cable shield voltage limiters.	Cable shield limiter voltage ratings are defined by fault current duty, and cables tend to be applied in strong systems with high short-circuit current levels. Therefore, this issue is not deemed significant.	No specific screening is recommended.
Improper protective relay operation (false trips and failure to trip).	Negative sequence and phase comparison schemes using electromechanical or static relays are particularly vulnerable.	Evaluate in detail any negative sequence or phase comparison protection schemes using static or electromechanical relays.
OVERHEAD TRANSMISSION LINES		
Harmonic currents cause elevated conductor temperature.	Loadflow capacity of transmission lines is reduced by harmonic currents and the increased skin effect losses they produce.	I_{60} > 95% rating, or I_{60} > 90% rating and $\sqrt{\Sigma I_n^2}$ > 10%, or $\sqrt{\Sigma I_n^2}$ > 10% of line rating
Harmonic current flow in lines can make parallel telephone circuits inoperable via induction.	The parallel telephone lines do not have to be close, nor in parallel for a long distance for interference to be severe. However, the number of affected phone lines is limited and the duration of severe interference is likely to be short.	This is not a power system security issue, and does not need to be part of a bulk system GMD harmonic vulnerability assessment. Therefore, no screening criterion is suggested.

Improper protective relay operation (false trips and failure to trip).	Negative sequence and phase comparison schemes using electromechanical or static relays are particularly vulnerable.	Evaluate in detail any negative sequence or phase comparison protection schemes using static or electromechanical relays.
HVDC TRANSMISSION SYSTEMS		
Filters may become overloaded and trip, increasing reactive demand on the power system.	Low-order harmonic filters ($n < 11$) are particularly vulnerable. Tripping of an excessive number of filter or capacitor banks may initiate HVDC system shutdown.	Any low-order harmonic filters should be evaluated in detail.
Harmonic distortion may cause inverter firing angle advance, increasing reactive demand.	Relatively large changes in reactive demand can be caused by harmonic distortion of the ac bus voltage. This can be critical to bulk system voltage stability analysis.	$V_{THD} > 5\%$
Harmonic distortion can interact with HVDC converters and controls.	A wide variety of interactions are possible, including saturation of the converter transformer even if GIC is blocked, as well as transfer of harmonics between systems.	The HVDC system vendor should be consulted for guidance if distortion is substantially greater than design assumptions.
STATIC VAR COMPENSATORS (SVC)		
Filters may become overloaded and trip, and may trip SVCs.	Most SVCs have low-order harmonic filters ($n < 11$) that are particularly vulnerable.	Any low-order harmonic filters should be evaluated in detail if the SVC is critical to system security.
Even-order harmonics may interact with thyristor controlled reactor (TCR) and saturate the SVC transformer	Some SVCs have flux balancing controls that avoid or minimize saturation, but interaction with severe even-harmonic distortion can cause other consequences even where flux balancing controls are used.	Evaluate any SVC that is critical to system security if even-order harmonic distortion is greater than design basis. Consult SVC vendor for guidance.
VOLTAGE SOURCE CONVERTERS IN TRANSMISSION APPLICATIONS (VSC-HVDC, STATCOM, UPFC)		
Severe harmonic distortion may overload	Tolerance of distortion depends on design.	Consult system vendor for guidance if voltage

the dc-bus or module capacitors.		distortion substantially exceeds the design basis.
WIND AND SOLAR PV PLANTS		
Severe harmonic distortion may overload the dc-bus or module capacitors.	Tolerance of distortion depends greatly on design.	Consult generating unit or inverter vendor for guidance if the plant is considered critical to system security.
Harmonic protection functions may trip the plant during a GMD.	Harmonic protection functions intended to prevent plants from exceeding current distortion limits are non-directional and may operate for grid-produced distortion during a GMD.	Current distortion exceeding 50% of trip threshold if simplistic models of voltage source converter (VSC) inverters are used.
DISTRIBUTION SYSTEMS AND LOADS		
Distribution capacitor banks may fuse out, increasing reactive demand on the transmission system.	Impact is limited to capacitors resonating at integer harmonics. It is infeasible to perform analysis of distribution systems in a bulk system study.	No screening is recommended. Instead, load power factor should be decreased in voltage stability studies to incorporate this impact.
Motors may overheat due to harmonic voltage distortion.	The thermal time constant of motors will provide some mitigation.	No screening is recommended; this is not a bulk system security issue.
Harmonic currents flowing into the distribution system can cause telephone interference.	Telephone cables are usually in close proximity to distribution feeders. Distribution harmonic flow may be particularly large between the substation and any feeder capacitors.	This is not a power system security issue and does not need to be part of a bulk system GMD harmonic vulnerability assessment. Therefore, no screening criterion is suggested.

Table notes:

1. Screening thresholds do not necessarily mean that the withstand capabilities of the components are exceeded, but further analysis as discussed in this guide is prudent.
2. The threshold shown is based on continuous duty. GMD duty is highly variable, and hence, provides an inherent safety factor. Also, the parameters and withstand capabilities of capacitors are well defined.
3. An additional safety factor is provided by the fact that the harmonic components would have to perfectly align with the peak fundamental voltage in order for the capacitor peak voltage to exceed the 1.2 p.u. limit specified in IEEE 18.

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Appendix A: Acronyms

ACCR	aluminum conductor composite reinforced
ACSR	aluminum conductor, steel-reinforced
CCVT	capacitor voltage transformer
DFT	discrete Fourier transform
EHV	extra high voltage
FACTS	flexible AC transmission system
FERC	Federal Energy Regulatory Commission
GIC	geomagnetically-induced currents
GMD	geomagnetic disturbance
HPFF	high-pressure fluid-filled
HV	high voltage
HVDC	high voltage direct current
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
LCC	line commutated converter
MCOV	maximum continuous operating voltage
MMC	modular multi-level converter
MOSA	metal-oxide surge arresters
MOV	metal oxide varistor
MVA	mega volt amp
NERC	North American Electric Reliability Corporation

POI	point of interconnection
PV	photovoltaic
PWM	pulse-width modulated
SCFF	self-contained fluid-filled
SSR	subsynchronous resonance
STATCOM	static synchronous compensators
SVC	static var compensators
TCR	thyristor controlled reactor
THD	total harmonic distortion
THDI	total harmonic current distortion
TOV	temporary overvoltages
TSC	thyristor-switched capacitors
UPFC	unified power flow control
VSC	voltage source converter
VSC	voltage-source converter
XLPE	cross-linked polyethylene

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