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POWER QUALITY (PQ) GUIDELINES

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HEALTH + SAFETY

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ASSET MANAGEMENT

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PROF DEVELOPMENT

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NCLW + LIVE WORK

Power Quality (PQ) Guidelines

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This guide is intended to provide general guidance on the management of power quality (PQ) disturbances, in order to ensure that they are acceptably small and do not interfere with customer equipment. It is not a substitute for specialist engineering advice

If there is uncertainty on what technical or legislative requirements should apply in any particular situation, specialist engineering advice, including legal advice, should be sought.

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Status of Examples and Case Studies

Examples, including calculations, and case studies in this guide are included to assist in how to access Power Quality, determine the impacts and allocate harmonics are outlined in this document. The examples or case studies are not a comprehensive statement of matters to be considered, nor steps to be taken, to comply with any statutory obligations pertaining to the subject matter of this guide but they do illustrate how the electricity distribution sector has applied in practice the issues in managing Power Quality on electrical networks.

Foreword

This second revision of the Power Quality Guidelines is an update of the 2013 revision and features new material on high frequency harmonics or supra-harmonics, inter-harmonics and flicker, ferroresonance and geo magnetically induced currents. The Guide's revision is largely the work of Professor Neville Watson of University of Canterbury, with assistance from Michael Whaley (M W Consultants) and Robin Pittwood (Powerco) and their efforts are gratefully acknowledged.

The guide's original version was prepared for the Electricity Engineers' Association of New Zealand with funding from Foundation for Research in Science and Technology (FRST), which is now the Ministry of Business, Innovation and Employment.

Power Quality is an essential aspect of electrical power distribution and consumption, and it encompasses a wide range of parameters that impact the performance, reliability, and safety of electrical equipment. Most electrical and electronic equipment requires high-quality power to function correctly, and poor power quality can result in loss of efficiency, damage and in some cases complete equipment failure.

Continued adoption of non-linear appliances is bringing a different power quality landscape to electricity distributors and connected consumers from that experienced, say, 20 years ago. A wide range of appliances such as Light Emitting Diodes (LED) lighting, variable speed drives, electric vehicle chargers and solar panel inverters chop our electricity supply's sine wave voltage waveform generating harmonic currents that affect the voltage waveform. Some appliances have switching transients that cause momentary voltage dips.

The future road with supraharmonics is predicted to be an interesting one. Appliances including variable speed drives, active power factor correction devices, storage commutation devices and self-commutating inverters operate at increasingly higher switching frequencies, not necessarily multiples of the fundamental, as their manufacturers seek to improve their efficiency and comply with harmonic limits. The interactions between multiple devices with supra switching frequencies can manifest in quirky appliance behaviours such as intermittent flickers, audible noise or equipment malfunction. Much research has been underway in the last ten or so years and continues, particularly in Europe, on the effects of high frequency harmonics on the operation of LV networks and on supply quality to end use consumers. This version of the guide captures some of the current state of play.

The intent of the PQ Guidelines is to set out good practice in a field where developments are occurring rapidly. The statutory environment relating to Power Quality has some vagueness and perhaps has had difficulty keeping pace with the developments. For instance, *Electrical Code of Practice (ECP) 36*, referenced by *Electricity (Safety) Regulation 31* as an "applicable standard", has a higher status in statute than the national and international standards, but its technical context on copper wire telephony has largely been superseded. Likewise, the *Electricity Industry Participation Code* limits its coverage of power quality to a discretionary part of the *Default Distributor Agreement.*

The guide provides a comprehensive coverage of power quality issues faced by the electricity supply industry without extending into temporary or sustained interruptions to supply from faults or shutdowns. Much of the guide's coverage is necessarily technically detailed and mathematical and it is hoped that there are enough pointers to international standards if users need to delve more deeply. Nevertheless, it is planned that the EEA will supplement the guide's publication with group forums to help members to become acquainted with the topics the guide covers.

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Preface

This guide has been written to provide guidance on electrical power quality based upon research and international standards.

Introduction

This guide is intended to provide general guidance on the management of power quality (PQ) disturbances, to ensure that they are acceptably small and do not interfere with customer equipment.

Purpose

The purpose of this guide is to give guidance and advice on power quality for alternating current (AC (a.c.)) power systems adequate to meet the requirements of *Electricity (Safety) Regulations 2010*.

Scope

This document provides guidance on power quality in general for public a.c. power systems. This guide does not apply to dedicated and special a.c. power systems.

Interpretation

In this guide, unless the context requires otherwise, the following definitions apply.

Agreed Power	the apparent power of the disturbing installation on which the customer and utility agree.
Background distortion	the existing distortion, caused by the existing sources, present on the electrical system prior to the connection of a new load.
Characteristic harmonics	harmonics produced by a device, such as a semiconductor converter, under normal operation. A p-pulse converter is expected to produce harmonics of the order h = kp±1 (i.e. for 6-pulse 5th, 7th, 11^{th}, 13^{th}, 17^{th}, 19^{th} …) where k is any positive integer and p the pulse number of the converter.
Choke	an inductor.
Compatibility level	electromagnetic disturbance level used as a reference level in a specified environment for co-ordination in the setting of emission and immunity limits
Customer	a person, company or organisation that operates an installation connected to, or entitled to be connected to, the electrical supply system.
Disturbance level	the amount or magnitude of an electromagnetic disturbance, when measured and evaluated in a specified way.
Electromagnetic compatibility (EMC)	the ability of equipment or system to function satisfactorily in its electromagnetic environment without introducing intolerable electromagnetic disturbances to anything in that environment.
Fundamental component	component whose frequency is the fundamental frequency.
Fundamental frequency	nominal system frequency (50 Hz in New Zealand).
Harmonic component	any of the components having a harmonic frequency. Its value is normally expressed as a Root Mean Square (r.m.s.) value
Indicative	a recommended level but can be varied after due consideration to local conditions.

Informative	the information provided is only for guidance and is not a mandatory requirement of the guide.
Interharmonic	frequencies that are not integer multiples of the fundamental frequency.
May	means that a provision is truly optional. Some implementers may choose to include the measure because it serves a particular local requirement, while others may omit the same measure and still comply with this guide.
Non-characteristic harmonics	harmonics that are not characteristic harmonics (e.g., the 5^{th} and 7^{th} are non-characteristic for a 12-pulse converter).
Planning Level	level of a particular disturbance adopted as a reference value for the limits to be set for the emissions.
Subharmonic	interharmonic that is at a frequency below the fundamental frequency.
Voltage unbalance	condition in a three-phase system in which the r.m.s. values of the line-to-line voltages (fundamental component), or the phase angles between consecutive line-to-line voltages, are not all equal.

Referenced Acts and Regulations

Electricity (Safety) Regulations 2010

New Zealand Electrical Code of Practice (NZECP) 36

Electricity Governance Rules 2003 (*revoked in 2010*)

Referenced and Other Relevant Standards and Documents

IEC 61000 series of Standards and Technical reports

IEC 61000-2-2:2002 Electromagnetic compatibility (EMC) - Part 2-2: Environment - Compatibility levels for low-frequency conducted disturbances and signalling in public low-voltage power supply systems

IEC 61000-2-12:2003 Electromagnetic compatibility (EMC) - Part 2-12: Environment - Compatibility levels for low-frequency conducted disturbances and signalling in public medium-voltage power supply systems

IEC 61000-3-6:2008 Electromagnetic compatibility (EMC) - Part 3-6: Limits - Assessment of emission limits for the connection of distorting installations to MV, HV and EHV power systems

IEC 61000-3-7:2008 Ed. 2 Electromagnetic compatibility (EMC) - Part 3-7: Limits - Assessment of emission limits for the connection of fluctuating installations to MV, HV and EHV power systems

IEC 61000-3-13:2008 Electromagnetic compatibility (EMC) - Part 3-13: Limits - Assessment of emission limits for the connection of unbalanced installations to MV, HV and EHV power systems

IEC 61000-3-14:2011 Electromagnetic compatibility (EMC) - Part 3-14: Assessment of emission limits for harmonics, interharmonics, voltage fluctuations and unbalance for the connection of disturbing installations to LV power systems

IEC 61000-3-15:2011 Ed. 2 Electromagnetic compatibility (EMC) - Part 3-15: Limits - Assessment of low frequency electromagnetic immunity and emission requirements for dispersed generation systems in LV network

IEC 61000-4-7:2009 Electromagnetic compatibility (EMC) – Part 4-7: Testing and measurement techniques – General guide on harmonics and interharmonics measurements and instrumentation, for power systems and equipment connected thereto.

IEC 61000-4-30:2015+AMD1:2021 CSV, Consolidated version, Electromagnetic compatibility (EMC) - Part 4-30: Testing and measurement techniques - Power quality measurement methods

AS/NZS 61000 series of Standards

AS/NZS 61000.3.2:2013 Harmonic current emission limits for equipment input current ≤16 A /phase

AS/NZS 61000.3.4:2007 Harmonic current emission limits for equipment input current >16 A /phase

AS/NZS 61000.3.6:2012 Emission limits (harmonic) for installations (MV, HV and EHV)

AS/NZS TR IEC 61000.3.7:2012 Emission limits (fluctuations) for installations (MV, HV and EHV)

AS/NZS 61000.3.12:2013 Harmonic current emission limits for equipment input current >16 A & ≤75 A /phase)

AS/NZS 61000.4.7:2012 General guide on harmonics and interharmonics measurements

AS/NZS 61000.4.15:2012 Testing and measurement techniques - Flickermeter

AS/NZS 61000.4.30:2012 Testing and measurement techniques - Power quality measurement methods

Institute of Electrical and Electronics Engineers

IEEE 1159, IEEE Recommended Practice for Monitoring Electric Power Quality, 2019

IEEE Standard 519, IEEE Standard for Harmonic Control in Electric Power Systems, 2022

IEEE Standard 519-2005, Recommended Practices and Requirements for Harmonic Control in Electric Power Systems, 2005

Standards Australia

The Standards Australia HB 264-2003 Power Quality: recommendations for the application of AS/NZS 61000.3.6 and AS/NZS 61000.3.7 has been withdrawn and replaced by:

ENA DOC 033-2014, Guideline for Power Quality: Harmonics. Recommendations for the application of the Joint Australian/New Zealand Technical Report TR IEC 61000.3.6:2012

ENA DOC 034-2014, Guideline for Power Quality: Flicker - Recommendations for the application of the Joint Australian/New Zealand Technical Report TR IEC 61000.3.7:2012

ENA DOC 037-2015, Power Quality: Voltage Unbalance - Recommendations for the application of the Joint Australian / New Zealand Technical Report TR IEC 61000.3.13:2012

European Standard

EN50160 Voltage characteristics of electricity supplied by public distribution

Glossary of Abbreviations

AC (a.c.) Alternating Current

[Note that "AC" (written with upper-case letters, without any dots and language independent) is a letter symbol in accordance with IEC 61293. The established abbreviation, on the other hand, for "alternating current" is "a.c." (with lower-case letters and dots). Source: IEC 60617-2019.]

CCVT Capacitor Coupled Voltage Transformer

CT Current Transformer

CUF Current Unbalance Factor

DC (d.c.) Direct Current

[Note that "DC" (written with upper-case letters, without any dots and language independent) is a letter symbol in accordance with IEC 61293. The established abbreviation, on the other hand, for "direct current" is "d.c." (with lower-case letters and dots). Source: IEC 60617-2019]

DG Distributed Generation

DVR Dynamic Voltage Restorer

EDI Equivalent Distributing Current (this term is used in NZECP36)

EDV Equivalent Distributing Voltage (this term is used in NZECP36)

EMF Electro Magnetic field

EMI Electromagnetic interference

EMT Electromagnetic Transient

GIC Geomagnetic Induced Current

HV High Voltage, representing an operating voltage that is greater than 35 kV but not mor than 230 kV

HVDC High Voltage Direct Current

Hz Hertz

IEC International Electrotechnical Commission

IEEE The Institute of Electrical and Electronics Engineers

IET The Institution of Engineering and Technology

ITIC Information Technology Industry Council

kV Kilo v (1 kilovolt being equivalent to Volts (1,000 volts)

kVAr	The kilovolt ampere measure of Reactive Power
LED	Light Emitting Diodes
L-G	Line to Ground (referring to voltage measurement between a phase conductor of an electrical circuit and the ground)
L-L	Line to Line (referring to voltage measurement between two phase conductors of an electrical circuit)
L-N	Line to Neutral (referring to voltage measurement between a phase conductor and the neutral conductor of an electrical circuit)
LV	Low Voltage representing an operating voltage that is greater than 50V but not more than 1000V.
MV	Medium Voltage representing an operating voltage that is greater than 1000V but not more than 35kV
MVAr	Megavolt ampere measure of Reactive Power
NEMA	National Electrical Manufacturers Association (USA)
NZECP	New Zealand Electrical Code of Practice
PCC	Point of Common Coupling
PCE	Percentage of core excited - the percentage of a transformer core that is being excited under ferroresonant conditions.
pfc	Power-Factor Correction
PLC	Power Line Communication or Power Line Carrier
POC	Point of Connection
POE	Point of Evaluation
pu	Per Unit
PV	Photo-Voltaic
PWM	Pulse-width modulation which is a method of power conversion in inverters and rectifiers.
RCD	Residual Current Device
r.m.s.	Root Mean Square
RMU	Ring Main Unit
SCR	Short Circuit Ratio
SEMI	Semiconductor Equipment and Materials International group

SMPS Switched-Mode Power Supply

STATCOM Static Compensator (also called STATCON – Static Condenser)

SVC Static Var Compensator

t Time (in seconds)

THD Total Harmonic Distortion $THD = \sqrt{\sum_{h=2}^{n} \left(\frac{Q_h}{Q_1}\right)^2}$ where Q can be current or voltage

TIF Telephone Interference Factor

TOV Temporary Overvoltage

Triplen Harmonic orders that are odd multiples of 3 (i.e. 3,9,15,21,..)

UIE International Union for Electricity Applications

UPS Uninterruptible Power Supply

VA Volt-Amperes, a unit of apparent power (generally otherwise expressed in kVA or MVA)

VAr Volt-Amperes Reactive, a unit of reactive power (generally otherwise expressed in kVAr or MVAr)

VFD Variable Frequency Drive

VN The negative sequence component voltage

VP The positive sequence component voltage

VSD Variable Speed Drive (same as ASD)

VT Voltage Transformer, a transformer used for voltage measurement on MV, HV and EHV circuits

VUF Voltage Unbalance Factor

XLPE Cross-linked Polyethylene, an insulation material often used in electrical cables

List of Symbols

$\boldsymbol{\alpha}$	Summation exponent (diversity factor)
E_{Ihi}	Allocated harmonic current of order h for customer *i*
$E_{IWTHD.i}$	Allocated current weighted THD
E_{Vhi}	Allocated harmonic voltage of order h for customer *i*
E_{VTHDi}	Allocated voltage THD
h	Harmonic order
i	Subscript for installation ‘i’
I_h	Harmonic current
I_{WTHD}	Current weighted THD
L_h	LV planning level for harmonic ‘h’
L_{THD}	LV planning level for voltage THD
$Margin_{h.ideal}$	Margin for strict IEC conditions
$Margin_{hm}$	Margin as measured
M_h	Correction for measured harmonic levels (individual)
M_{THD}	Correction for measured harmonic levels (THD)
S	Maximum demand
S_i	Maximum apparent power of consumer *i* in MVA or pu
S_T	Firm capacity
S_F	Fault power (same as Fault Level (FL)) in MVA or pu
V_d	Voltage droop
V_h	Harmonic voltage (order h)
V_{hm}	Measured harmonic voltage
$V_{x\%}$	Voltage percentile where x is the time percentile (between 0 and 100%). The voltage level at which the voltage is below x% of the time
Y_C	The r.m.s. value of the spectral components of voltage (*V*) or current (*I*)
$Y_{C,(N\times h)+k}$	r.m.s value of the spectral component. N is the number of fundamental cycles in DFT window and k the ordinal number.

$\boldsymbol{Y_{ig,h}}$	Interharmonic group between harmonic orders *h* and *h+1*
$\boldsymbol{Y_{isg,h}}$	Interharmonic centred subgroup between harmonic orders *h* and *h+1*
$\boldsymbol{Y_{C,(N\times h)+k}}$	The r.m.s value of the spectral component (N × h) +k. N is the number of fundamental cycles in DFT window, harmonic order of fundamental frequency, and k the ordinal number.
$\boldsymbol{Y_{sg,h}}$	Harmonic subgroup for harmonic order *h*

SECTION 1 - General

1. Definition of Power Quality

The geometry of the ac generators results in a sinusoidal Electro Magnetic Field (EMF) being produced at the generator and hence electrical equipment is designed to operate from a sinusoidal supply voltage of the appropriate magnitude and frequency. Any voltage, current or frequency deviations can adversely affect customer equipment and constitutes a power quality problem.

2. Emission and Immunity

PQ disturbances are caused by a combination of utility, customer and outside actions. Equipment can be damaged or may not operate as intended if PQ disturbance levels are too high. Hence satisfactory operation can only be guaranteed if limits are imposed on PQ disturbances and therefore on the separate utility and customer contributions. Outside contributions, for example lightning strikes, can be limited by appropriate design, construction and maintenance standards.

The contribution to a PQ disturbance from equipment is called its emission level and can be measured by a voltage or current parameter, for example voltage flicker P_{st} or current Total Harmonic Distortion THD. The minimum level of a PQ parameter which can cause equipment to malfunction is its immunity level. It can be measured, for example, by the level of a particular harmonic voltage or the depth and duration of a voltage dip.

It is not economically possible to eliminate PQ disturbances completely. However, they cannot be allowed to become too large, otherwise equipment costs would have to increase to account for the increased immunity. The appropriate *International Electrotechnical Commission* (IEC) standards committee has agreed to limit values for equipment emission in a way that is believed to minimise the cost to the community.

The principles of EMC (electromagnetic compatibility) are used to develop a process by which equipment can be guaranteed to operate satisfactorily on the supply network. The basic idea is that, for each disturbance type, a value called the compatibility level is established and that:

- All equipment should have immunity levels greater than the compatibility level.
- The PQ disturbance level on the network has to be constrained to be less than the compatibility level.

The compatibility level can be seen to be the boundary between the possible choices of immunity level and the possible disturbance levels appearing on the network.

The network owner achieves satisfactory PQ levels by designing to a target value less than the compatibility level. This level is the utility's internal limit for PQ disturbances and is called the planning level (Figure 1). The planning level should only be reached by the PQ disturbance when the network is fully loaded, and all installations are taking their full allocation of emission. Hence PQ disturbances are normally less than the planning level at most sites. The disturbance level is a result of the emissions of equipment acting on the system; therefore, limiting emission levels is the main way of controlling disturbance levels. Figure 2 illustrates the trade-off between emission limits and cost. Specifying low emission levels will result in a very high cost for equipment while the cost incurred by system (in extra losses, loss of equipment lifetime or disturbance mitigation) will be minimal. Allowing high emission levels will allow cheaper equipment to be deployed (although this might be countered somewhat by the need to have a higher immunity level), but a high cost will be incurred by the system (in extra losses, loss of equipment lifetime and mitigation).

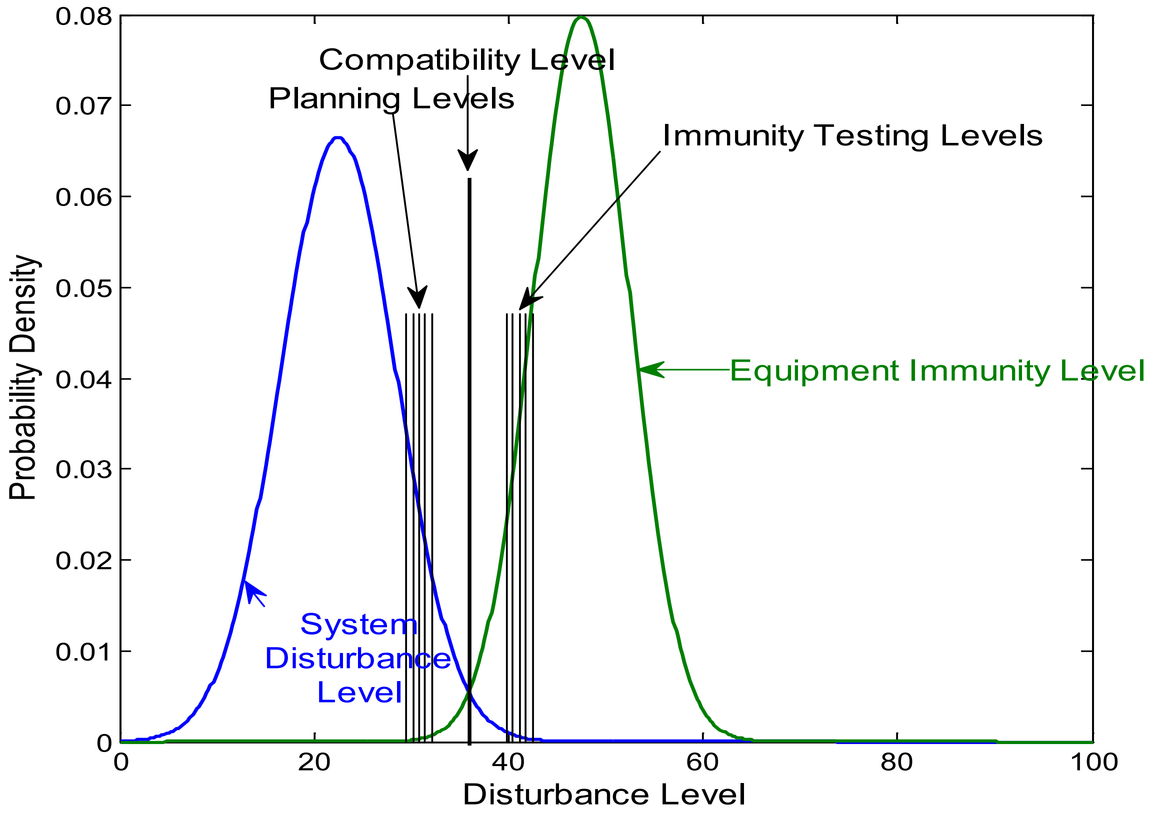


Figure: 1 Concept of Disturbance Level and Immunity Level

The management of utility emission levels is broadly similar for all disturbance types. The treatment given below is particularly relevant to harmonics. Different approaches are adopted for Low Voltage (LV) and Medium Voltage (MV) installations. For LV, many consumers cannot be expected to understand or implement measures to limit emissions. Instead equipment emission limits are defined.

These limits are designed to ensure that equipment connected to the LV network will not lead to power quality levels which exceed compatibility limits. It is the responsibility of the manufacturer to design and construct equipment to meet these limits. At MV, installation limits are determined by the utility following these PQ Guidelines . The customer attempts to meet this limit by the specification of appropriate equipment, sometimes with additional filters or other mitigation measures.

Recently it has been found that some LV installations can produce power quality problems even though every item of equipment in the installation complies with equipment standards. This problem occurs at installations which contain a much greater concentration of equipment than was considered when the equipment limits were determined. Standards for LV installation limits are now being developed and will apply to installations which exceed a certain size (which is determined to exclude most residential installations) .

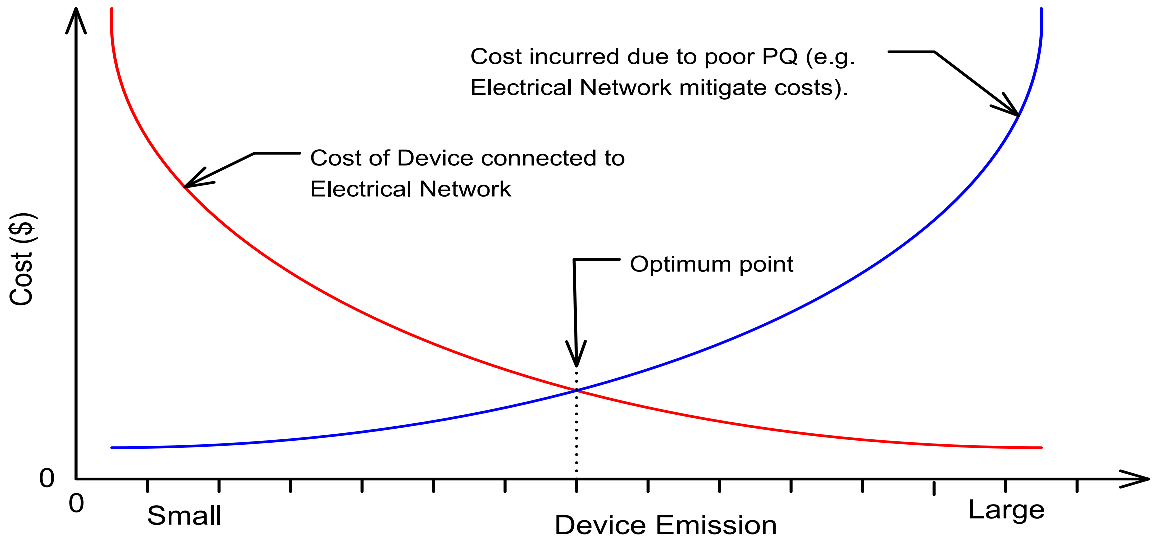


Figure: 2 Trade-off between Device Emission levels and Costs (Device & Network)

3. Types of PQ Disturbances

3.1 Variations and Events

PQ disturbances can be broadly classified into two categories. These are variations and events. Variations are disturbances which have an effect on every cycle, such as harmonics or voltage unbalance. Events are disturbances which last for a time, from a fraction of a cycle to several cycles, and then may not repeat for several hours or days, for example transients and voltage dips. Some important differences between the two are given in Table 1.

Table: 1 Comparison of one type of PQ Variation and PQ Event

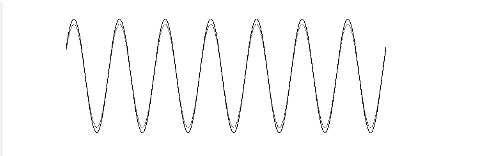
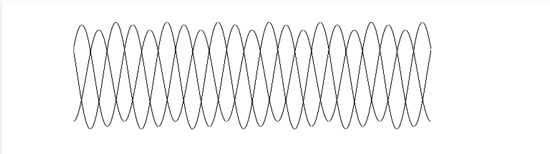
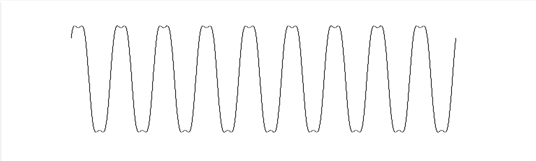
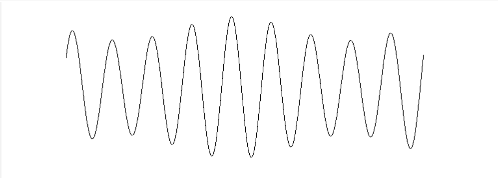
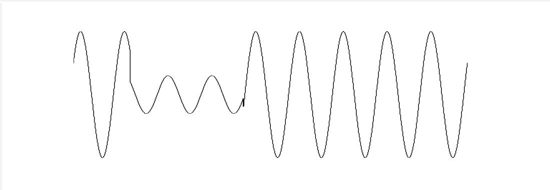
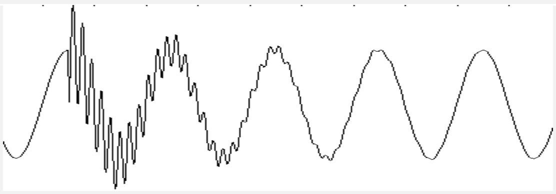
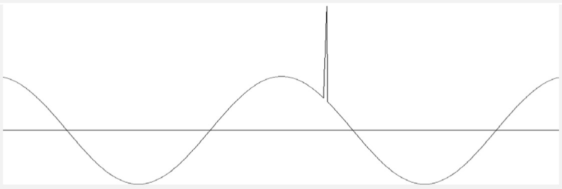
	Variation	Event
Example	Unbalance	Sags
Time nature	Present at all times	Occur as separate, independent events
Equipment impact	Thermal, cumulative	Mal-operation or destruction, instantaneous
Limits	Statistical	Not well developed; limit applied to worse case

Different approaches are required in monitoring, reporting and in the setting of standards for acceptable levels for these different disturbance categories.

3.2 Disturbances

The most important PQ disturbance types are shown in Table 2, classified by the major headings of Classification, Waveform and Type. Figure 3 shows the classification used to distinguish between voltage dip/sag and under-voltage. A voltage dip is typically caused by a fault on the system or a large motor starting. The large current flowing through the system impedance causes a depressed voltage until the fault is cleared or the motor gets up to speed. If the retained voltage is very low (<10% Institute of *Electrical and Electronics Engineers* (IEEE) or 1% IEC) it is classed as an interruption. If the retained voltage is between 10% and 90% and the duration is less than 1 minute it is then classed as a voltage dip; otherwise, if the duration is longer than 1 minute it is classed as an under-voltage condition.

Table: 2 Disturbance Types

Classification	Waveform	Type
Steady-state r.m.s. voltage (under- or over-voltage)		Variation
Steady-state voltage unbalance		
Harmonics		
Voltage fluctuations		
Short-term interruption, sag (dip) or swell		Event
Transient – (a) Oscillatory		
(b) Impulsive		

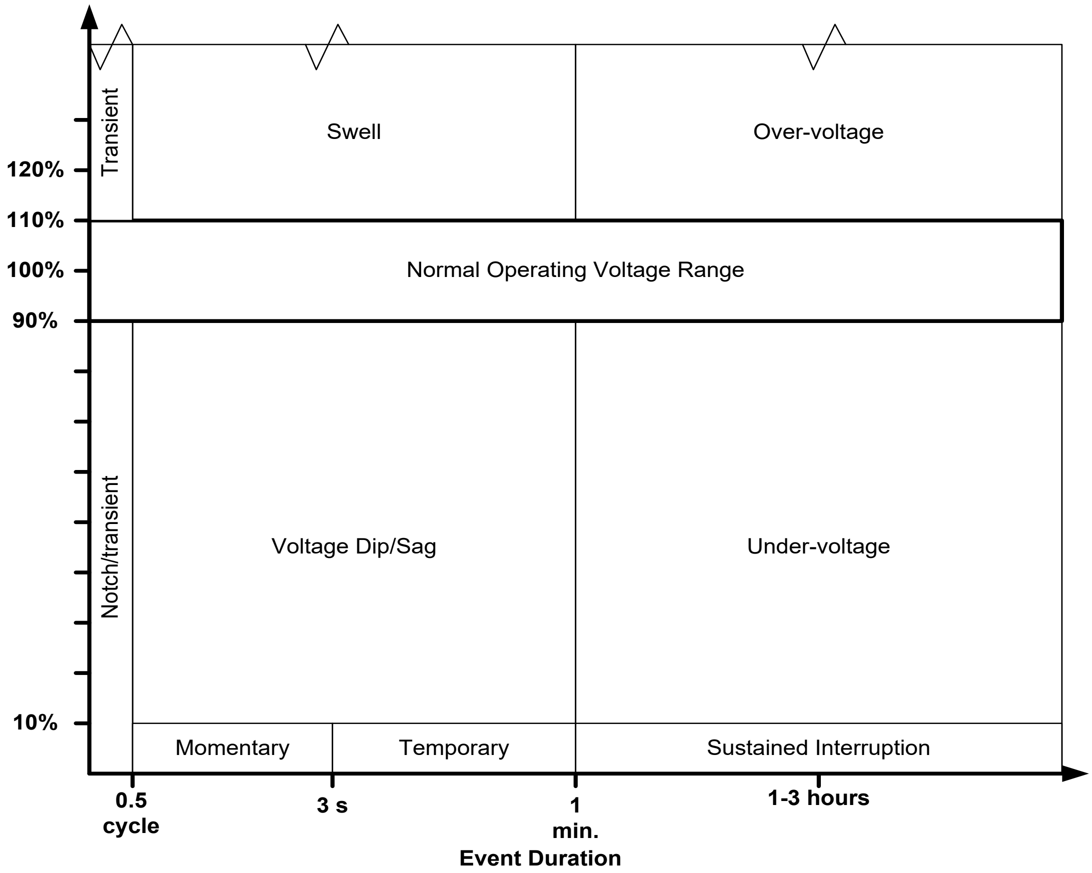


Figure: 3 Definition of Voltage Magnitude Events according to IEEE Std. 1159-1995

4. PQ Assessment Procedure

Figure 4 illustrates a typical PQ assessment procedure. Identifying the PQ concern is not always straightforward and sometimes site inspection and preliminary measurements are required to identify the PQ issue. Once the PQ problem is identified, measurements are required to quantify the phenomenon. A simulation model is normally developed so that the effectiveness of prospective mitigation techniques can be determined. The measurements are used to verify the model and to give confidence that the simulation model can correctly represent the situation. The solution is trialled, if this is possible, before full-scale deployment. Measurements are then made to verify that the mitigation works as predicted and hence satisfactory PQ levels are achieved.

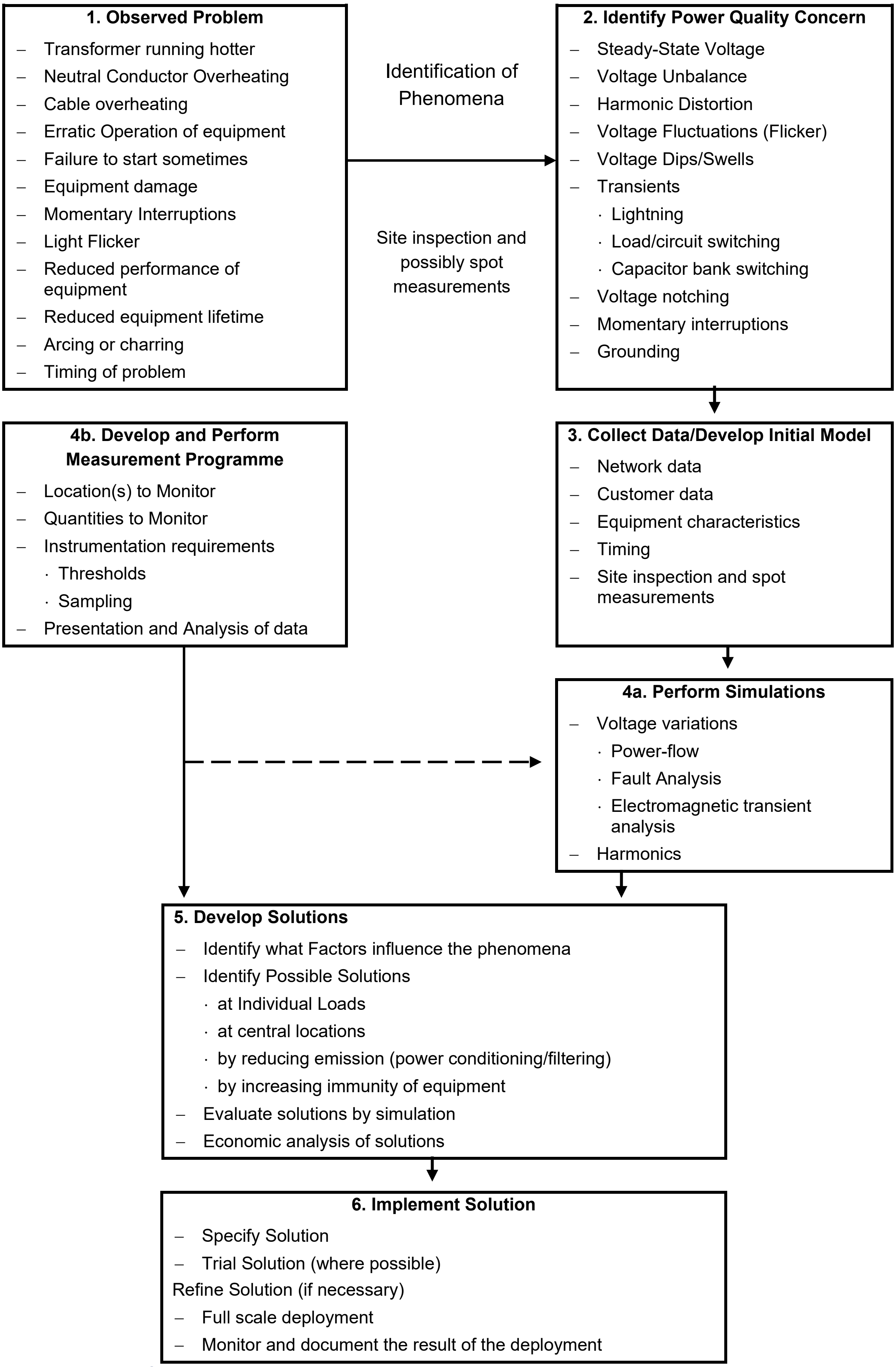


Figure: 4 PQ Assessment Procedure

5. Point of Compliance

The *Point of Evaluation* (POE) is the point where the emission levels of a given customer's installation are assessed for compliance with the emission limits. The point of evaluation will be either the *Point of Common Coupling* (PCC), *Point of Supply* , *Point of Connection* (POC) of the disturbing installation, or any other point agreed upon by the system operator/owner and installation.

The PCC is the point in the power supply network, electrically nearest to a particular load, at which another customer is supplied through. The POE is an agreed boundary, whether POC or some other point in the power system. For most customers the PCC will be the point of compliance, however, for some customers this does not give enough certainty. This is because the location of the PCC will depend on the location of the nearest neighbour, which can change over time and a customer has no control over where the PCC is, and when it changes. To give certainty, in these *PQ Guidelines* the point of compliance is the agreed point, which will be either; the PCC for most cases, or alternatively an agreed place closer to the installation where compliance can be checked (e.g., ownership boundary between customer and Electricity Distributor or tariff metering point). The latter will ensure that the point of compliance will not change with time without mutual agreement.

Note: More than one point of evaluation may also be specified for a given customer's installation depending on the system structure and characteristics of the installation; in this case, the evaluation should be made considering the system characteristics and agreed powers applicable to the different points of evaluation.

6. New Technologies

The purpose of this PQ Guidelines and *LV Device Standards* is to set emission levels that, if adhered to, will allow acceptable operation of all equipment connected. Besides ensuring adequate rating for the fundamental current that will occur with widespread adoption of new technologies (e.g., Photo-Voltaic (PV) inverters, electric vehicle charges, inverter-based fridge/freezers, heat-pump hot-water heaters, Light Emitting Diodes (LED) and fluorescent lighting etc.), provided the devices (and installations) comply with suitable standards, PQ problems will be avoided.

Concerns regarding the present device standards are:

- Enforcement of device standards is very poor.
- The emission levels need to be checked for their appropriateness (as some are designed for a European grid).
- Standards do not address some of the issues that need addressing with newer technologies.

Hence, suitable standards for grid interfaces for distributed generation (such as PV inverters) [*EEA2018*], electric vehicle (EV) chargers, inverter-based fridge/freezers, heat-pumps, hot-water heaters, washing machines and clothes dryers as well as LED and fluorescent lighting, etc are needed. Inrush current limits need to be incorporated as tests on new technologies have shown a peak inrush current of 180 times the nominal steady-state current.

SECTION 2 - Steady-state Voltage

7. Introduction

Any steady-state voltage outside of its prescribed limits (whether under-voltage or over-voltage) is a power quality issue.

8. Sources

Long term steady-state voltage is a change in the *Root Mean Square* (r.m.s.) voltage over many cycles and can be due to:

- Low short-circuit ratio (high load relative to the upstream impedance).
- Wrong transformer tap.
- Failure to switch in power-factor capacitor banks.
- Embedded generation generating at times of light load.

9. Effects

The main effects of steady-state voltage excursions are:

- High voltage: reduction in lifetime for incandescent globes and SMPS filtering capacitors.
- Low voltage: motor current increase and possible stalling and burnout of motor if prolonged.
- Some equipment may not operate as intended if the voltage is too low.

10. Limits

10.1 Low Voltage

The statutory requirement in New Zealand (NZ) is that, except for momentary fluctuations, the voltage magnitude supplied to an installation must be kept within ±6% of the standard nominal voltage (230 V for phase-to-neutral LV) [*Regulation 28 (1); Electricity (Safety) Regulations 2010*]. Hence the maximum range is 216.2 Volts to 243.8 Volts. Note that these limits apply to the *Point of Supply*[1] , which maybe different from the Point of Common Coupling (PCC) or the switchboard.

Note: This differs from AS 61000.3.100:2001. Some regions in Australia previously had 240 V as their nominal voltage. These regions now have 230 V (-6% to +10%) as their limits to reflect actual network operating conditions, but define 230 V (-2% to +6%) as their preferred operating zone. AS 61000.3.100 has the concept of Preferred Operating Zone (-2% to +6%), Lower Operating Zone (-6% to -2%) and Upper Operating Zone (6% to +10%).

[1] *Electricity Act 1992* states the "*point of supply, in relation to a property, means the point or points on the boundary of the property at which exclusive fittings enter that property, except that…*" and that "*exclusive fittings mean's fittings that are used or intended to be used for the purpose of supplying electricity exclusively to that property*". There are exceptions, for example when both high voltage lines and a transformer owned by the electricity distributor are located on the customer property, or if there is a specific agreement in place.

10.2 Medium Voltage

Limits for steady-state voltage at MV are defined in *AS/NZS 61000.3.100* and are reproduced in Table 3.

11. Mitigation

Over-voltage problems have been experienced with widespread use of PV generation in Australia. This problem has been recognised and grid interfaces for DG, whether at LV or MV, should have the ability to control power-factor leading or lagging to help support voltage regulation (c.f. Germany's regulations)[1]. Without this ability additional reactive power compensation may be required to regulate the Voltage level.

Table: 3 MV Steady-state Voltage Limits [AS/NZS 61000.3.100]

Nominal Voltage (kV)	Phase-to-phase Voltage Limits (10 minute rms)	
	Minimum, $V_{1\%}$ (kV)	Maximum, $V_{99\%}$ (kV)
6.6	6.20	7.00
11	10.34	11.66
22	20.68	23.32
33	31.02	34.98

12. Emission Assessment

Assessment is made using standard 10-minute recordings of r.m.s. values. Ideally, measurements shall be made using monitoring equipment compliant with the requirements of *AS/NZS 61000.4.30 Class A*. Flagged data as defined in *AS/NZS 61000.4.30* should be removed before assessment. Assessment is made of the 99th percentile and 1st percentile of 10-minute r.m.s. readings over a one-week period. The 99th percentile value is compared to the upper limit for steady-state voltage (e.g., 230 V + 6% for LV) and the 1st percentile value is compared to the lower limit for steady-state voltage (e.g., 230 V – 6% for LV).

[1] "Technical Regulation for Generating Plants in the Medium Voltage Grid" issued by the German Federal Association of Energy and Water Industries (BDEW) came into force on 1 January 2009.

SECTION 3 - Voltage Unbalance

13. Introduction

Voltage unbalance is when the three phase voltages differ in r.m.s. value and/or do not have a relative phase angle of 120°.

There are two definitions for unbalance factor, the IEC definition and the *IEEE / NEMA* definition. The *IEC* definition is becoming widely adopted and is given here. If a three-phase set of voltages has positive and negative sequence components VP and VN[1], then the unbalance factor can be calculated as:

$$\text{Negative sequence Voltage Unbalance Factor} = \frac{V_N}{V_P} \tag{3.1}$$

Strictly this definition of unbalance is called *Negative Sequence Voltage Unbalance Factor* and is also commonly known as the *Voltage Unbalance Factor* (*VUF*) for the reason that the zero sequence unbalance factor given by the ratio V_0/V_P (where V_o is the zero sequence voltage) is not relevant to the current flow in three wire loads[2].

The *VUF* can also be calculated using line-to-line readings as follows[3]:

$$\beta = \frac{V_{\mathrm{ab}}^4 + V_{\mathrm{bc}}^4 + V_{\mathrm{ca}}^4}{(V_{\mathrm{ab}}^2 + V_{\mathrm{bc}}^2 + V_{\mathrm{ca}}^2)^2} \tag{3.2}$$

$$VUF = \sqrt{\frac{1-\sqrt{3-6\beta}}{1+\sqrt{3-6\beta}}} \tag{3.3}$$

Where V_{ab}, V_{bc}, V_{ca} are the line-to-line voltage magnitudes.

Special care should be taken in calculating unbalance as studies have shown that incorrect calculation methods can lead to significant errors [Gosbell 2002].

---

1 The phase-to-sequence transformation is given by:

$$\begin{pmatrix} V_0 \\ V_p \\ V_N \end{pmatrix} = \frac{1}{3}\begin{bmatrix} 1 & 1 & 1 \\ 1 & a & a^2 \\ 1 & a^2 & a \end{bmatrix}\begin{pmatrix} V_a \\ V_b \\ V_c \end{pmatrix} \quad \text{where } a = 1\angle 120° = \frac{-1}{2} + j\frac{\sqrt{3}}{2}$$

2 For systems with the neutral point directly connected to earth, the zero-sequence unbalance ratio can be relevant.

3 The voltage unbalance caused by a single-phase load connected line-to-line is in practice equal to the ratio of the load power to the network three-phase short circuit power (see equation 3.5). Another approximation that gives reasonably accurate results for the levels of unbalance normally encountered is [IEC 61000-2-2 & IEC 61000-2-12]:

$$VUF = \sqrt{\frac{6\left(V_{ab}^2 + V_{bc}^2 + V_{ca}^2\right)}{\left(V_{ab} + V_{bc} + V_{ca}\right)^2} - 2}$$

14. Sources

At a *Point of Common Coupling* (PCC) or *Point of Evaluation* (POE) the voltage unbalance arises due to one or more of three reasons:

1. Unbalanced load currents in the three-phase network (unbalanced load or poor apportioning of single-phase loads or single-phase DG generation).
2. Unbalanced system impedances (e.g., transmission lines not transposed in upstream network).
3. High background unbalance voltages from upstream system or transmission system.

Due to the geometry and the phase conductor positioning of overhead transmission lines the electrical parameters are different for the different phases unless transpositions are used. Even with transpositions unequal loading can create unbalanced voltages. One major cause of unbalance, particularly in residential areas is the uneven distribution of loads across the phases. There is often a tendency for more single-phase connections to be made to some phases due to their position on pole cross-arms and hence reach-ability for connection.

15. Effects

One major effect of voltage unbalance is the heating of rotors in three-phase induction motors. If unbalance levels are high enough motor derating will be required. Another effect of unbalance is that when supplied by unbalanced voltages, three phase diode rectifier systems will draw unbalanced currents containing uncharacteristic harmonics.

16. Limits

16.1 New Zealand Limits

Electricity Governance Rules 2003 (Part C Common Quality) used negative sequence as the measure of Voltage unbalance. These Rules were revoked in 2010 but they are stated here because they give useful guidance:

> “*2.3.1.3 Voltage imbalance of less than 1%*
>
> *The requirement to use reasonable endeavours to maintain negative sequence voltage at less than 1% and to ensure that negative sequence voltage will be no more than 2% in any part of the grid.*”

16.2 IEC Limits

The compatibility limits for voltage unbalance factor as specified in *IEC 61000-2-2 and IEC 61000-2-12* is 2% for both MV and LV systems. However, it is stated that voltage unbalance levels up to 3% may occur in areas where predominantly single-phase loads are connected.

The indicative planning levels as per *IEC 61000-3-13* are given in the Table 4.

Table: 4 Indicative Planning Levels

Voltage level	VUF - Planning level (%)
MV	1.8
HV	1.4
EHV	0.8

17. Emission Assessment

The unbalance emission level is specified as the magnitude of the voltage unbalance which an installation gives rise to at the *Point of Evaluation* (POE).

Assessment should be made of 10 minute and/or 3 second values over a one-week period. The minimum unbalance measurement period is 1 week of normal operation of the installation. However, this period should capture highest level of unbalance emission that can be caused by the installation. More than one index can be used to assess an installation:

- 95% probability weekly value of voltage unbalance factor ($U2_{sh}$) measured using 10 minute windows should not exceed a given emission allocation.
- The largest 99% probability daily value of voltage unbalance factor ($U2_{vs}$) measured using 3 second windows should not exceed the given emission allocation multiplied by factor in the range 1.25 to 2. This factor needs to be specified by the network operator depending on system characteristics, very short-term capability of equipment and protection devices.

Measurements should ideally be taken using monitoring devices which fulfil the requirements of *AS/NZS 61000-4-30* Class A monitors. All flagged data must be removed and should not be incorporated in the assessment of the installation.

Voltage unbalance emission assessment in cases where the load is the only contributor to voltage unbalance at a point of evaluation (U_{2load}) can be calculated using:

$$U_{2-load} = Z_{22} I_{2-load} \tag{3.4}$$

Where:

Z_{22} - is the negative sequence impedance of the supply system.

I_{2load} - is the negative sequence current drawn by the asymmetrical load.

Noting that the positive sequence impedance Z_{11} of the supply system is equal to the negative sequence impedance Z_{22}, it can be shown that:

$$VUF = \frac{S_{load}}{S_{sc}} C_{load} \quad (3.5)$$

Where:

S_{load} – VA capacity of the load,

S_{sc} – three-phase short circuit capacity of the PCC,

C_{load} (I_2/I_1) – current unbalance factor measured at the PCC.

It is worth noting that for both situations where (a) a load is connected between line and neutral or (b) a load is connected line to line, the value of C_i = 1.0. The value of C_i can be established for other load connection types easily using symmetrical components.

When both the upstream and load contribute to voltage unbalance at the POE, then the assessment method depends on whether phase angle information is available.

If phase angle measurements are available with the pre and post connection voltage unbalance measurements, the voltage unbalance emissions arising from the load can be established using:

$$|V_{2-load}| = |V_{2-postconnection} - V_{2-preconnection}| \quad (3.6)$$

If the phase angle information is not available, as directed by *IEC/TR61000-3-13*, the summation law can be used for separation as given by:

$$|V_{2-load}| = (|V_{2-postconnection}|^{\alpha} - |V_{2-preconnection}|^{\alpha})^{\frac{1}{\alpha}} \quad (3.7)$$

Where:

α is the exponent that represents diversity.

The exponent α depends on (a) the chosen value of the probability for the actual value not to exceed the calculated value, (b) the degree to which individual voltage unbalances vary randomly in terms of magnitude and phase, and (c) the number of random variations considered (either the number of summated sources or the variation in time). Generally, a value of 1.4 is used. When it is known that the unbalances are likely to be in phase and coincident in time, a value closer to 1 is used.

The derivation given above is only approximate as the post connection measurement will incorporate contributions made by the upstream asymmetrical network (can be considered as one network) and any upstream unbalanced sources (can be considered as a single voltage source). The separation exercise is much more complex if the POE post connection voltage unbalance measurements must be separated to determine its constituent components that arise because of (a) upstream voltage source, (b) network, and (c) the load.

To determine approximately the voltage unbalance contribution made at the POE by the upstream asymmetrical network the following equation can be used:

$$VUF_{network} = \frac{S_{load}}{S_{sc}} \left| \frac{Z_{12}}{Z_{11}} \right| \tag{3.8}$$

Where:

Z_{12} - is the negative sequence-positive sequence coupling impedance of the upstream network,

Z_{11} - is the positive sequence impedance of the upstream network,

S_{load} – is the VA capacity of the load,

S_{sc} – is the three-phase short circuit capacity (VA) of the PCC.

Equation 3.8 gives the voltage unbalance at the PCC, when the three-phase load is balanced, and is a result of the network asymmetry only.

18. Allocation

The procedure for allocation of unbalance emission levels to installations is defined in *IEC 61000-3-13:2008.*

Example 3.1: Calculation of Voltage Unbalance Factor (using Sequence Voltages)

Table 5 gives details on three line-to-neutral voltages as obtained from a power quality instrument. Calculate the magnitudes of the negative and positive sequence voltage and hence the magnitude of the negative sequence unbalance factor.

Table: 5 Line-to-neutral voltages

LINE TO NEUTRAL VOLTAGES		
	Magnitude (V)	Angle (deg)
V_{an}	210	0
V_{bn}	240	-121
V_{cn}	240	120

Using the phase-to-sequence transformation the sequence components are given by:

$$V_N = \left|\left(\frac{1}{3}\right)(V_{an} + a^2V_{bn} + aV_{cn})\right|$$

$$= \left|\left(\frac{1}{3}\right)(210\angle 0^0 + 1\angle 240^0 \times 240\angle -121^0 + 1\angle 120^0 \times 240\angle 120^0)\right|$$

$$= 8.81\,V$$

$$V_P = \left|\left(\frac{1}{3}\right)(V_{an} + aV_{bn} + a^2V_{cn})\right|$$

$$= \left|\left(\frac{1}{3}\right)(210\angle 0^0 + 1\angle 120^0 \times 240\angle -121^0 + 1\angle 240^0 \times 240\angle 120^0)\right|$$

$$= 229.99\,V$$

Hence the Voltage Unbalance Factor (VUF) is:

$$VUF = \frac{8.81}{229.99} = 3.83\%$$

Example 3.2: Calculation of Voltage Unbalance Factor (using Line-to-Line Voltages)

Using the same three line-to-neutral voltages as in example 3.1 (Table 5), calculate the magnitude of the line-line voltages and calculate the VUF using equations 3.2 and 3.3:

$$V_{ab} = |V_{an} - V_{bn}| = |(210\angle 0^0 - 240\angle -121^0)| = 391.94\,V$$

$$V_{bc} = |V_{bn} - V_{cn}| = |(240\angle -121^0 - 240\angle -120^0)| = 413.58\,V$$

$$V_{ab} = |V_{cn} - V_{an}| = |(240\angle 120^0 - 210\angle 0^0)| = 390.00\,V$$

Hence:

$$\beta = 0.334309$$

$$VUF = 3.83\%$$

Example 3.3: Calculation of Current Unbalance Factor

A single-phase resistive load is connected line-to-line, and the corresponding line current is 60 A. Calculate the magnitude of the positive and negative sequence currents and hence the current unbalance factor.

$$I_N = \left|\left(\frac{1}{3}\right)(I_a + a^2 I_b + aI_c)\right|$$

$$= \left|\left(\frac{1}{3}\right)(60\angle 0^0 + 1\angle 240^0 \times 60\angle - 180^0 + 1\angle 120^0 \times 0\angle 120^0)\right.$$

$$= 34.64\ A$$

$$I_P = \left|\left(\frac{1}{3}\right)(I_a + aI_b + a^2 I_c)\right|$$

$$= \left|\left(\frac{1}{3}\right)(60\angle 0^0 + 1\angle 120^0 \times 60\angle - 180^0 + 1\angle 240^0 \times 0\angle 120^0)\right.$$

$$= 34.64\ A$$

Giving:

$$CUF = \frac{34.64}{34.64} = 100\%$$

Example 3.4: Negative sequence Voltage Unbalance Factor using line current measurements

A three-phase ungrounded load draws the line currents in phases ‘a’ and ‘b’ as shown in Table 6. Determine the current in phase ‘c’ (including its angle). Determine the magnitude of positive and negative sequence currents and hence the negative sequence unbalance factor.

Table: 6 Line currents

LINE CURRENTS		
	Magnitude (*A*)	Angle (deg)
I_a	50	0
I_b	40	-110
I_c		

Since ungrounded the vector sum of the current in phases ‘a’ and ‘b’ must return in phase ‘c’, hence:

$$I_c = -(I_a + I_b) = 52.27\angle 134.02^0 A$$

Converting to sequence components:

$$I_N = \left|\left(\frac{1}{3}\right)(I_a + a^2 I_b + aI_c)\right|$$

$$= \left|\left(\frac{1}{3}\right)(50\angle 0^0 + 1\angle 240^0 \times 40\angle - 180^0\right.$$

$$\left.+ 1\angle 120^0 \times 52.27\angle 134.02^0)\right| = 7.32A$$

$$I_P = \left|\left(\frac{1}{3}\right)(I_a + aI_b + a^2 I_c)\right|$$

$$= \left|\left(\frac{1}{3}\right)(50\angle 0^0 + 1\angle 120^0 \times 40\angle - 180^0\right.$$

$$\left.+ 1\angle 240^0 \times 52.27\angle 134.02^0)\right| = 47.16\ A$$

$$CUF = \frac{7.32}{47.16} = 15.52\%$$

Example 3.5

The load considered in Example 3.4 can be considered to have a rating of 32 kVA whereas the point to which it is connected in the distribution system, which can be considered as balanced, has a symmetrical fault level of 200 kVA. Determine the negative sequence voltage unbalance factor that will be developed when the load is connected.

Using equation 3.5 yields:

$$VUF = \frac{32}{200}(15.52\%) = 2.48\%$$

SECTION 4 - Harmonics

19. Introduction

Harmonics in power systems are sinusoidal waveforms whose frequencies are integral multiples of the supply frequency. They affect voltage or current waveforms in such a way as to distort the shape from a pure sinewave. An important aspect is that adjacent cycles of the supply are distorted similarly. It is generally accepted that the range of most interest is from 2 to 50 times the supply frequency (100 Hz to 2.5 kHz), however for new converters with high switching frequencies harmonics up to 150 kHz may be observed.

Harmonic distortion is to be distinguished from other types of distortion such as inter-harmonics, high frequency noise and transients.

- Inter-harmonic distortion is caused by sinusoidal waveforms whose frequencies are not integral multiples of the supply frequency, for example 175 Hz. This results in adjacent cycles of the supply being distorted differently.
- High frequency noise is generally caused by switching devices which may or may not be synchronised with the supply frequency, for example switching transistors in power inverters. Their frequency range of interest can extend up to 10 kHz, or beyond.
- Transients are short term disturbances which usually decay to a negligible value within a few cycles, for example fault and capacitor switching transients.

In general, each cycle is distorted similarly to its neighbours.

Fourier Series:

$$f(t) = a_0 + \sum_{n=1}^{\infty} \left(a_n \cos\left(\frac{2\pi n}{T} t\right) + b_n \sin\left(\frac{2\pi n}{T} t\right) \right)$$

$$= a_0 + \sum_{n=1}^{\infty} (a_n \cos(n\omega t) + b_n \sin(n\omega t))$$

Where:

$$a_0 = \frac{1}{\mathrm{T}} \int_{-T/2}^{T/2} f(t)\, dt$$

$$a_n = \frac{2}{\mathrm{T}} \int_{-T/2}^{T/2} f(t) \cos\left(\frac{2\pi n}{T} t\right) dt = \frac{2}{\mathrm{T}} \int_{-T/2}^{T/2} f(t) \cos(n\omega t)\, dt$$

$$b_n = \frac{2}{\mathrm{T}} \int_{-T/2}^{T/2} f(t) \sin\left(\frac{2\pi n}{T} t\right) dt = \frac{2}{\mathrm{T}} \int_{-T/2}^{T/2} f(t) \sin(n\omega t)\, dt$$

Using:

$$c_n\, cos(n\omega t - \phi) = \overbrace{c_n\, cos(\phi)}^{a_n}\, cos(n\omega t) + \overbrace{c_n\, sin(\phi)}^{b_n}\, sin(n\omega t)$$

$$f(t) = \frac{c_0}{2} + \sum_{n=1}^{\infty} (c_n\, cos(n\omega t - \phi_n))$$

$$\phi_n = tan^{-1}\left(\frac{b_n}{a_n}\right)$$

$$|c_n| = \sqrt{a_n^2 + b_n^2}$$

The complex Fourier series is:

$$f(t) = \sum_{n=-\infty}^{\infty} \left(c_n e^{i\frac{2\pi n}{T}t}\right)$$

Where:

$$c_n = \frac{1}{T}\int_{-T/2}^{T/2} f(t) e^{j\frac{2\pi n}{T}t} dt$$

20. Sources

The main sources of harmonic distortion are:

- Nonlinear power-electronic loads.
- Saturation of iron cores.

Most harmonics today are caused by switching devices such as diodes, thyristors, and insulated-gate bipolar transistors (IGBT), which are synchronised with the supply frequency. The front-end of many electronic devices, especially those using a diode rectifier, as in variable speed drives; compact fluorescent lamps and switch mode power supplies are examples of switching devices which cause harmonics.

Resonances between capacitors and power system impedance can amplify the harmonic voltages or currents to unacceptable levels. This effect can be reduced to very low levels by adding an inductor in series with the capacitor so that the combination is inductive at all harmonic frequencies of importance.

21. Effects

The main effects of harmonics on the system are:

- Heating of rotor of three-phase induction motors.
- Heating of capacitors not fitted with an appropriate series detuning inductor.
- Mal-operation of electronic controlled equipment.
- Destruction of equipment due to increased r.m.s. currents and voltages (particularly capacitor banks).
- Telephone interference.
- Cogging and crawling of induction motors.
- Acoustic noise from equipment and vibrations.
- Mal-operation of test equipment, such as *in situ* Residual Current Device (RCD) testers.

Harmonic issues can be either thermal issues or short-term effects (interfering with the operation of equipment). The high frequency sinusoidal components can have an adverse effect on induction motors, capacitors, and electronic equipment. In some situations, it is too expensive or impractical to modify the equipment to make it insensitive to harmonics. Hence limits are set to allow equipment suppliers to have some confidence regarding the environment in which their equipment will need to operate.

22. Limits

22.1 Voltage Harmonics (10 minute Values)

The *Electrcity (Safety) Regulations* allow NZECP36 as a means of complying with the requirements for quality of supply. However, this is an *old Code of Practice* and its effectiveness at prescribing the controls needed to maintain quality of supply in the face of modern appliances is diminishing.

Since equipment is now sold on a world market, a new set of limits for LV systems that are better aligned with international standards is required. Any limits must be based on the compatibility levels as shown in Table 7. Based on Table 7, the LV planning limits are given in Table 8. These planning levels must not be exceeded in LV systems, and generally occur towards the end of heavily loaded or long LV feeders. The planning level at LV is set to 90% of the compatibility level (shown in Table 7) to give a 10% margin. All these values are based on engineering recommended practice and should be observed very closely (exceptions may be granted under special circumstances). These are the values which are used to determine how much harmonic current to allocate to a customer.

The values shown in Tables 9 - 12 must not be exceeded in MV and HV / Extra High Voltage (EHV) systems[1], and generally occur towards the end of heavily loaded or long feeders.

Table: 7 Compatibility levels for harmonic voltages (RMS values as percentage of r.m.s. value of the fundamental component) in LV & MV power systems

ODD HARMONICS NON-MULTIPLE OF 3		ODD HARMONICS MULTIPLE OF 3		EVEN HARMONICS	
Order h	Harmonic Voltage %	Order h	Harmonic Voltage %	Order h	Harmonic Voltage %
5	6	3	5	2	2
7	5	9	3.0	4	1
11	3.5	15	2.0	6	0.5
13	3	21	1.5	8	0.5
$17 \leq h \leq 49$	2.27 x (17/h) -0.27	$21 < h \leq 45$	1.5	$10 \leq h \leq 50$	0.25 x (10/h) +0.25
Note: Total Harmonic Distortion (THD): 8%					

Table: 8 Planning levels for harmonic voltages (RMS values as percentage of r.m.s. value of the fundamental component) in LV power systems

ODD HARMONICS NON-MULTIPLE OF 3		ODD HARMONICS MULTIPLE OF 3		EVEN HARMONICS	
Order h	Harmonic Voltage %	Order h	Harmonic Voltage %	Order h	Harmonic Voltage %
5	5.4	3	4.5	2	1.8
7	4.5	9	2.7	4	0.9
11	3.15	15	1.8	6	0.45
13	2.7	21	1.35	8	0.45
$17 \leq h \leq 49$	2.04 x (17/h) -0.24	$21 < h \leq 45$	1.35	$10 \leq h \leq 50$	0.225 x (10/h) +0.225
Note: Total Harmonic Distortion (THD): 7.2%					

[1] Based on reference impedances obtained from surveying the various distribution systems in New Zealand and obtaining the average.

Table: 9 Planning levels for harmonic voltages (RMS values as percentage of r.m.s. value of the fundamental component) in MV power systems (1 kV < V_n < 25 kV)

ODD HARMONICS NON-MULTIPLE OF 3		ODD HARMONICS MULTIPLE OF 3		EVEN HARMONICS	
Order h	**Harmonic Voltage %**	**Order h**	**Harmonic Voltage %**	**Order h**	**Harmonic Voltage %**
5	5.2	3	4.2	2	1.7
7	4.3	9	2.6	4	0.8
11	3.1	15	1.7	6	0.4
13	2.6	21	1.4	8	0.4
17 ≤ h ≤ 49	1.88 x (17/h) -0.22	21 < h ≤ 45	1.2	10 ≤ h ≤ 50	0.21 x (10/h) +0.21
Note: Total Harmonic Distortion (THD): 6.8%					

Table: 10 Planning levels for harmonic voltages (RMS values as percentage of r.m.s. value of the fundamental component) in MV power systems (25 kV < V_n < 45 kV)

ODD HARMONICS NON-MULTIPLE OF 3		ODD HARMONICS MULTIPLE OF 3		EVEN HARMONICS	
Order h	**Harmonic Voltage %**	**Order h**	**Harmonic Voltage %**	**Order h**	**Harmonic Voltage %**
5	4.3	3	3.3	2	1.3
7	3.6	9	2.2	4	0.7
11	2.7	15	1.5	6	0.4
13	2.3	21	1.2	8	0.4
17 ≤ h ≤ 49	1.5 x (17/h) -0.18	21 < h ≤ 45	1.0	10 ≤ h ≤ 50	0.16 x (10/h) +0.16
Note: Total Harmonic Distortion (THD): 5.3%					

Table: 11 Planning levels for harmonic voltages (RMS values as percentage of r.m.s. value of the fundamental component) in MV power systems (45 kV < V_n < 100 kV)

ODD HARMONICS NON-MULTIPLE OF 3		ODD HARMONICS MULTIPLE OF 3		EVEN HARMONICS	
Order h	Harmonic Voltage %	Order h	Harmonic Voltage %	Order h	Harmonic Voltage %
5	4.1	3	3.0	2	1.2
7	3.4	9	2.0	4	0.6
11	2.6	15	1.5	6	0.3
13	2.2	21	1.2	8	0.3
17 ≤ h ≤ 49	1.35 x (17/h) -0.16	21 < h ≤ 45	1.0	10 ≤ h ≤ 50	0.15 x (10/h) +0.15
Note: Total Harmonic Distortion (THD): 4.9%					

Table: 12 Planning levels for harmonic voltages (RMS values as percentage of r.m.s. value of the fundamental component) in HV/EHV power systems (100 kV < V_n)

ODD HARMONICS NON-MULTIPLE OF 3		ODD HARMONICS MULTIPLE OF 3		EVEN HARMONICS	
Order h	**Harmonic Voltage %**	**Order h**	**Harmonic Voltage %**	**Order h**	**Harmonic Voltage %**
5	2.1	3	1.2	2	0.5
7	1.7	9	1.0	4	0.2
11	1.6	15	0.9	6	0.2
13	1.4	21	0.7	8	0.2
17 ≤ h ≤ 49	0.6 x (17/h) -0.07	21 < h ≤ 45	0.5	10 ≤ h ≤ 50	0.07 x (10/h) +0.07
Note: Total Harmonic Distortion (THD): 2.7 %					

22.2 Current Harmonics (10 minute Values)

Current harmonic limits are calculated through the harmonic current allocation process (section 24).

22.3 Short-term Harmonic Limits

Some equipment can generate harmonics for short-periods of time (e.g. motor soft-starters). The short-term impacts of such equipment relate to the harmonic voltages produced. The short-term effects relate mainly to possible disturbing effects on neighbouring equipment rather than long-term thermal effects. This is termed shape-effects and includes voltage notches. The harmonic voltage effects due to shape-effects have a time-scale of cycles and are linked to 3 second values. However, equipment is not a single thermal mass and during transients there is likely to be a restricted region of high initial heating before the heat redistributes through the bulk of the equipment. Short-term thermal effects have a time-scale of minutes to hours.

To assess the harmonic current limits the impact of current on voltage must be considered, which will lead to larger short-term current limits for small installations.

To assess whether intermittent harmonics are being generated the maximum and average values for a 10 minute period are compared. If the ratio is above 1.37 then a short burst of harmonics is indicated. The maximum value must be compared to the allocation for short bursts of harmonic current.

Voltage

The short-term harmonic voltage limit is 150% of the steady-state value. Many instruments give the ratio of the maximum 3 second value to the average for each 10-minute reading, hence the maximum (i.e. 100%) 3 second value is available. Hence, the limit for 100% 3 second values is 150% of the steady-state limit.

If 10 minute readings are taken, the average of any 10 minute reading must be no greater than 1.1 times the planning level (i.e. the average harmonic voltage value can be 10% larger than the planning level over a 10 minute period). This is based on limiting the voltage harmonics to 150% of planning level for 2 minutes out of every 10 minutes which yields an average of 110% over the 10 minutes. This may not be adequate in all circumstances and verification that the level is below 150% of planning level may require 3 second recordings over the transitional period. Each 3 second recording must be below 150% of the steady-state limit.

Current

In order to limit the short-term THD level, the short-term harmonic current emission must be limited. As an approximation, a multiplication factor (*F*) is defined that is the ratio of overcurrent limit to overvoltage limit and is dependent of S_i/S_t. The multiplication factor for short-term harmonic current emission is:

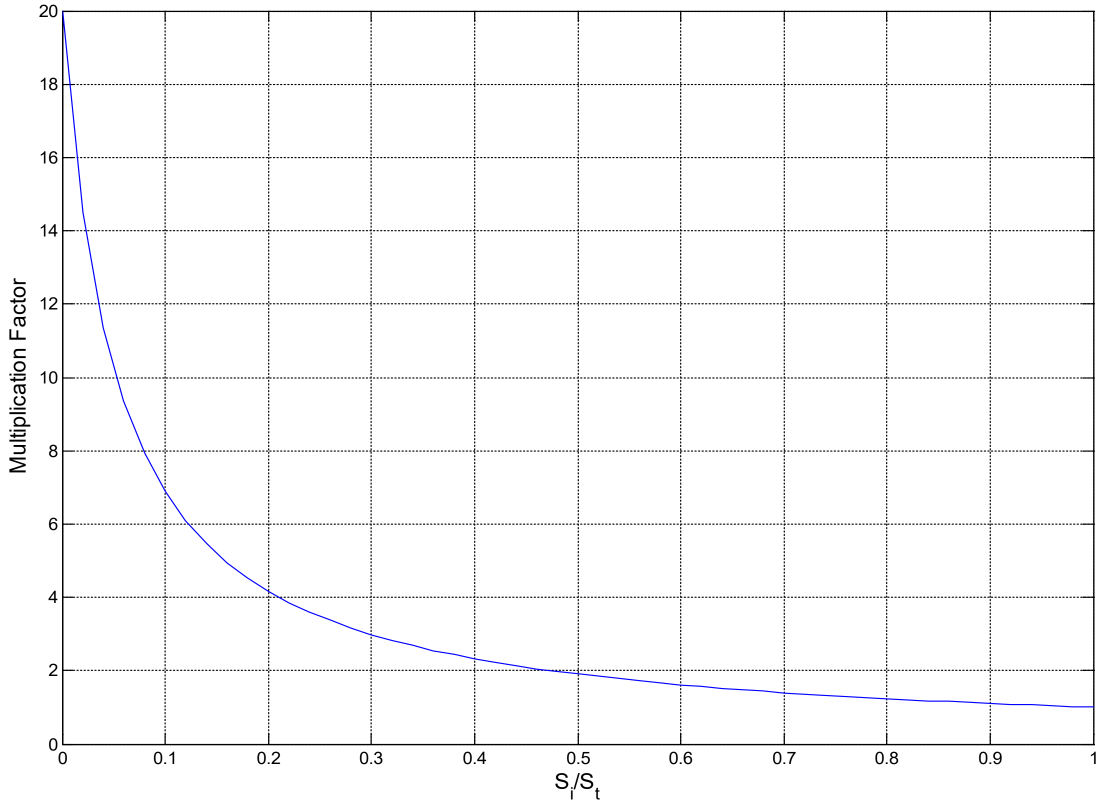
$$F = \frac{20}{1 + 19 * \left(\frac{S_i}{S_t}\right)} \tag{4.1}$$

Where S_i/S_t is the ratio of the installation size to supply capacity (varies from 0 to 1). The multiplication factor (*F*) is plotted in Figure 5. With an aim of limiting the harmonic voltage to 1.5 times the steady-state limit, if five 10 minute readings are at the limit and one at 1.5 times the limit then the r.m.s. of the values is approximately 1.10 times the limit (with rounding).

The r.m.s is: $\frac{\sqrt{(5\times100^2+1\times150^2)/6}}{100} = \frac{\sqrt{72500/6}}{100} = \frac{109.9\%}{100} \approx 1.10$).

Therefore, if a load is very small then *F* is approximately 20 and the short-term harmonic current limit is 20 × 1.10 = 22.0 times their steady-state limit. If a load is large the *F* is approximately 1 and their short-term limit is 1 × 1.10 = 1.10 times their steady-state harmonic current limit.

Figure: 5 Allowance above the steady-state limit for short-term harmonics



23. LV Customers

At LV level it is generally acceptable for consumers to install small appliances without specific evaluation of harmonic emission by the supply company. Manufacturers of such appliances are responsible for limiting the emissions to the relevant standards. For instance, *AS/NZS 61000.3.2* is a product family standard which defines emission limits of harmonics for equipment connected to LV systems and less than 16 Amps per phase. *AS/NZS 61000.3.12* specifies limits for harmonic emission for devices with input current > 16 A and ≤ 75 A per phase. This supersedes *AS/NZS 61000.3.4* in this region thus resulting in the latter applying to devices with input current > 75 A (even though its title states that it applies to devices with an input current > 16 A per phase).

24. Allocation for MV-HV-EHV Customers

24.1 Introduction

The approach for allocation of harmonic current is based on principles contained in *AS/NZS 61000.3.6 and AS/NZS 61000.3.7*. Customer installations are given harmonic current allocations by utilities in three stages:

Stage 1: The connection of small consumers or consumers with only a limited amount of distorting load can be approved without detailed evaluation of the emission characteristics or the supply system response. If the condition:

$$\frac{S_i}{S_{SC}} < 0.2\%$$

is fulfilled (S_i = agreed power of consumer i (MVA), and S_{sc} = fault level[1] (MVA) at the point of evaluation), then any distorting load may be connected within the consumer facilities without further examination.

Stage 2: installations are given a harmonic current allocation which is simple to determine and depends mainly on their maximum demand and the fault level[1] at the point of connection. The installation can be connected if the customer can demonstrate that the installation harmonics currents do not exceed the Stage 2 values (see section 24.2).

Stage 3: installations which fail Stage 2 need a more accurate and necessarily more complex assessment than is given under Stage 2. Stage 3 assessments require many assumptions which may not hold in the long term. Hence the allocation is necessarily temporary and needs to be reviewed at regular intervals.

[1] The minimum fault level that occurs over a reasonable percentage of the time (values that occur for less than one week a year should be ignored).

24.2 Stage 2 Allocation

The recommended approach is based on the Voltage droop approach *[Barr 2010, Gosbell 2010a, Gosbell 2010b]*. The allocation is based on the upstream supply point capacity and fault level, and the installation maximum demand and fault level at the point of connection. Allocations are made to limit individual voltage harmonics and to limit the voltage THD. Some special cases, such as embedded generation and a group of installations having no diversity with each other are treated later. Figure 6 illustrates some of the concepts and symbols used in harmonic allocation studies.

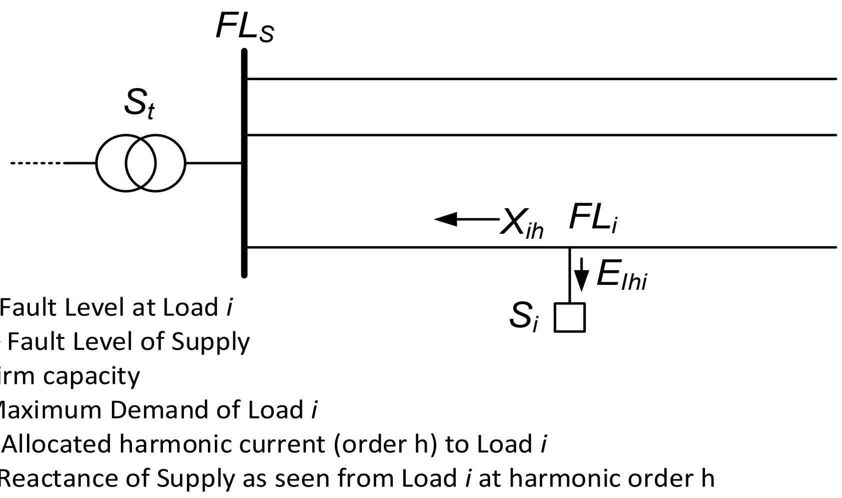


Figure: 6 System under study

(A) Individual voltage harmonic limits

1. For each harmonic order h, determine the LV limit (L_h) (Table 8) and the diversity factor α (Table 13). Note that the diversity factors given in Table 13 are based on both phase angle and time diversity in a typical network with a variety of nonlinear devices. This diversity does not exist when all the nonlinear devices are the same, such as in a solar or wind farm or in a Data Centre. In such cases there is no diversity and hence α = 1 must be used.

Table: 13 Diversity factor for combining harmonics using the summation law

HARMONIC ORDER (*h*)	DIVERSITY FACTOR (α)*
H < 5	1
5 ≤ h ≤10	1.4
H > 10	2

* *Note:* When it is known that the harmonics are likely to be in phase (i.e., phase angle differences less than 90°), then the exponent α = 1 should be used for order 5 and above.

2. Determine the Short-Circuit Ratio (*SCR*)[1] at the installation point of connection and at the nearest upstream supply point. For mesh systems, an average *SCR* value can be obtained by dividing the sum of the fault levels at upstream supply points by the sum of the supply point capability values.

$$SCR_i = \frac{FL_i}{S_t} \tag{4.2}$$

$$SCR_s = \frac{FL_s}{S_t} \tag{4.3}$$

3. Determine the voltage droop value (V_d) using:

$$V_d = \max(0.3, 2/SCR_s) \tag{4.4}$$

4. Determine the allocated harmonic voltage (E_{Vhi}) for the installation using:

$$E_{Vhi} = \frac{L_h}{(V_d SCR)^{1/\alpha}} \tag{4.5}$$

5. Determine the network harmonic impedance (X_{ih}) seen at the installation's point of connection. The Stage 2 allocated current is then:

$$E_{Ihi} = \frac{E_{Vhi}}{X_{ih}} \tag{4.6}$$

6. If there are no harmonic resonances due to non-detuned power-factor correction capacitors or significantly long transmission lines or cables, the harmonic impedance can be expressed in terms of the fault level at the point of connection (FL_i)[2]. For all situations other than Triplen harmonics in LV:

$$X_{ih} = \frac{h}{FL_i} \tag{4.7}$$

Where FL_i and X_{ih} are expressed in pu. For triplen harmonics in LV systems, X_{ih} can be about three times higher than this value.

7. It is possible to combine these three equations into one expressing the harmonic current as a percent of the maximum demand current (using $FL_i = SCR \times S_i$)[3]. For all situations other than triplen harmonics in LV[4]:

[1] In calculating the allocations the minimum fault level that occurs over a reasonable percentage of the time (less than one week a year should be ignored) are to be used.
[2] In cases of resonance the harmonic impedance must be assessed and used instead of *h/FL$_i$* (see Resonance section).
[3] Note that when pu or % values are used then S_i and I_i are the same as the voltage is assumed to be at its nominal value (1 pu). I_i being the nominal rated fundamental current of the installation.
[4] In exceptional cases harmonic current levels above those provided by this allocation method can be approved when it is clearly shown that the phase angle of the emission of harmonic currents will cancel other sources and thereby reducing the voltage harmonics all the time (not just at one point in time) [Watson2010].

$$\frac{E_{Ihi}}{I_{1max}} = \frac{L_h SCR^{(1-1/\alpha)}}{hV_d{}^{1/\alpha}} \tag{4.8}$$

For triplen harmonics in LV systems, E_{Ihi} can be about three times smaller than this value.

8. If there are harmonic resonances, X_{ih} may require detailed investigation. Where capacitance is significant, X_{ih} can have a value of up to three times the value given by equation 4.7. As a guide, overhead line capacitance can be ignored when h × length < 300 m while underground capacitance can be ignored when h × length < 60 m.

where:

h - the harmonic order (dimensionless)

length - the line length (metres)

FL_i - fault level (MVA)

SCR – Short Circuit Ratio (dimensionless)

E_{Vhi} – allocated harmonic voltage (%)

E_{Ihi} – allocated harmonic current (%)

V_d – Voltage droop parameter (dimensionless)

L_h - Harmonic voltage Planning level (%)

α - Diversity factor (also called summation law) (dimensionless)

X_{ih} - Source Impedance (i.e. reactance) at load i and harmonic order *h*

Example 4.1: Allocation of 5th harmonic

Consider a factory with an agreed maximum loading of 3 MW which is supplied directly from an 11 kV busbar with a fault capacity of 180 MVA. What is the maximum permissible 5th harmonic current emission?

The diversity factor α =1.4 for 5th harmonic. Voltage droop value V_d = 0.3

$$SCR = \frac{180 \times 10^6}{3 \times 10^6} = 60$$

The allocated harmonic voltage (E_{Vhi}) for the installation is (equation 4.5)

$$E_{Vhi} = \frac{5.2\%}{(0.3 \times 60)^{\left(\frac{1}{1.4}\right)}} = 0.66\ \%$$

The allocated harmonic current as percentage of maximum demand is (equation 4.8)

$$\frac{E_{Ihi}}{I_{1max}} = \frac{L_h SCR^{1-1/\alpha}}{hV_d{}^{1/\alpha}} = \frac{5.2 \times 60^{\left(1-\frac{1}{1.4}\right)}}{5 \times 0.3^{\left(\frac{1}{1.4}\right)}} = 7.917\%$$

Maximum fundamental current:

$$I_{1max} = \frac{S_i}{\sqrt{3} \times V_{ph-ph}} = \frac{3 \times 10^6}{\sqrt{3} \times 11 \times 10^3} = 157.46 \text{ Amps}$$

The allocated harmonic current in Amperes:

$$I_{5\max} = \frac{7.917}{100} \times 157.459 = 12.47 \text{ Amps}$$

Although the factory loading will vary as a function of time, the maximum allowable 5th harmonic current emission is 12.47 Amps (regardless of factory loading).

Table 14 gives the calculated current allocations for connected voltages between 25 kV and 45 kV, as a percentage of fundamental, for various short-circuit ratios. These values are graphically displayed in Figure 7.

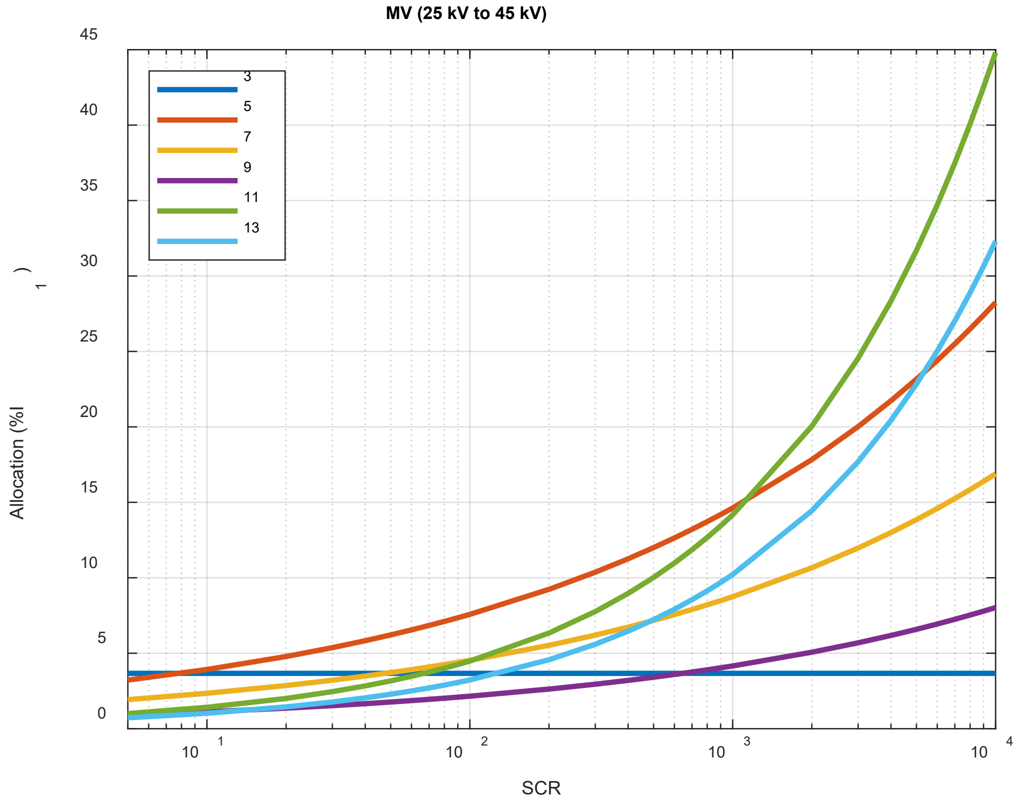


Figure: 7 Allocated Current as a function of SCR (using L_h for MV 25kV to 45 kV system and V_d = 0.3)

Table: 14 Current Allocation (% Fundamental) as a Function of SCR (L_h for MV 25kV to 45 kV system and V_d=0.3)

		Order											
		3	5	7	9	11	13	15	17	19	21	23	25
L_h		3.3	4.3	3.6	2.2	2.7	2.3	1.5	1.32	1.16	1.2	0.93	0.84
SCR	**5**	3.67	3.22	1.92	0.91	1.00	0.72	0.41	0.32	0.25	0.23	0.16	0.14
	10	3.67	3.92	2.35	1.12	1.42	1.02	0.58	0.45	0.35	0.33	0.23	0.19
	20	3.67	4.78	2.86	1.36	2.00	1.44	0.82	0.63	0.50	0.47	0.33	0.27
	30	3.67	5.37	3.21	1.53	2.45	1.77	1.00	0.78	0.61	0.57	0.40	0.34
	40	3.67	5.83	3.49	1.66	2.83	2.04	1.15	0.90	0.71	0.66	0.47	0.39
	50	3.67	6.21	3.72	1.77	3.17	2.28	1.29	1.00	0.79	0.74	0.52	0.43
	60	3.67	6.55	3.92	1.86	3.47	2.50	1.41	1.10	0.86	0.81	0.57	0.48
	70	3.67	6.84	4.09	1.94	3.75	2.70	1.53	1.19	0.93	0.87	0.62	0.51
	80	3.67	7.11	4.25	2.02	4.01	2.89	1.63	1.27	1.00	0.93	0.66	0.55
	90	3.67	7.35	4.40	2.09	4.25	3.06	1.73	1.34	1.06	0.99	0.70	0.58
	100	3.67	7.58	4.53	2.15	4.48	3.23	1.83	1.42	1.12	1.04	0.74	0.61
	200	3.67	9.23	5.52	2.62	6.34	4.57	2.58	2.00	1.58	1.48	1.04	0.87
	300	3.67	10.37	6.20	2.95	7.76	5.59	3.16	2.46	1.93	1.81	1.28	1.06
	400	3.67	11.26	6.73	3.20	8.96	6.46	3.65	2.84	2.23	2.09	1.47	1.23
	500	3.67	12.00	7.18	3.41	10.02	7.22	4.08	3.17	2.50	2.33	1.65	1.37
	600	3.67	12.64	7.56	3.59	10.98	7.91	4.47	3.47	2.74	2.56	1.81	1.50
	700	3.67	13.21	7.90	3.75	11.86	8.55	4.83	3.75	2.95	2.76	1.95	1.62
	800	3.67	13.72	8.21	3.90	12.68	9.14	5.16	4.01	3.16	2.95	2.09	1.74
	900	3.67	14.19	8.49	4.03	13.44	9.69	5.48	4.25	3.35	3.13	2.21	1.84
	1000	3.67	14.63	8.75	4.16	14.17	10.21	5.77	4.48	3.53	3.30	2.33	1.94
	2000	3.67	17.83	10.66	5.07	20.04	14.45	8.16	6.34	4.99	4.67	3.30	2.74

Note that diversity was used in calculation the values in Table 14. With no diversity, the harmonic current allocations (% Fundamental) are constant for different SCR levels, however, the actual current increases linearly with S_i as one would expect for α = 1. The 5th harmonic current allocation without diversity is 2.87% (regardless of SCR), as shown below. This compares to 3.22% for SCR=5 with diversity.

h	3	5	7	9	11	13	15	17	19	21	23	25
L_h (%)	3.3	4.30	3.60	2.20	2.70	2.30	1.50	1.32	1.16	1.20	0.93	0.84
I_h (%)	3.67	2.87	1.71	0.81	0.82	0.59	0.33	0.26	0.20	0.19	0.13	0.11

(B) Voltage THD limits

There is a need to impose *THD* limits as the wave-shape would be unacceptable if all the individual harmonics were at their maximum permissible level. The procedure is:

1. Begin as for the first three steps above in determining the short-circuit ratios and the voltage droop.
2. Determine the installation's allocated voltage THD (E_{VTHDi}) as:

$$E_{VTHDi} = \frac{L_{THD}}{\sqrt{V_d SCR}} \tag{4.9}$$

3. This does not translate into a direct limit on current THD. Where there are capacitive resonances, it is difficult to determine how the current should be limited to meet this voltage *THD* allocation. Where there are no resonances, the voltage THD translates into a limit on the weighted current *THD* (I_{wTHD}) where higher frequency currents are given a higher weight.

$$I_{wTHD} = \frac{\sqrt{\sum (hI_h)^2}}{I_1} \tag{4.10}$$

4. Where there are no resonances, the limit on current weighted *THD* (E_{wTHD_i}), relative to the maximum demand current (I_i) is:

$$\frac{E_{wTHD_i}}{I_i} = L_{THD}\sqrt{\frac{SCR_i}{V_d}} \tag{4.11}$$

Example 4.2: Calculation of THD Limits:

Assuming SCR = 25, V_{droop} = 0.3, E_{V5} = 5.4 (Planning Level for 5th harmonic Voltage in an LV system), E_{VTHD} = 7.20 (Planning Level V_{THD}).

Calculate the new I_5 limit and I_{THD} limit given that the spectrum has the proportions given by: I_5 = 30%, I_7 = 21%, I_{11} = 14.7%, I_{13} = 10.3%, I_{17} = 7.2%, I_{19} = 5.04%.

The spectrum up to 19th will be considered and is normalised as shown in Table 15.

Table: 15 Normalised Spectrum

h	I_h	$(I_h)^2$	$h*I_h$	$(h*I_h)^2$
5	1.00	1.00	5.00	25.00
7	0.70	0.49	4.90	24.01
11	0.49	0.24	5.39	29.05
13	0.34	0.12	4.46	19.88
17	0.24	0.06	4.08	16.66
19	0.17	0.03	3.19	10.20
Total	**0.00**	**1.93**	**0.00**	**124.80**

For the normalised Spectrum

$$I_{THD} = \sqrt{1.93} = 1.391$$

$$I_{wTHD} = \sqrt{124.8} = 11.172$$

$$I_{5n}/I_{wTHD} = 1.0/11.172=0.090$$

$$I_{THD}/I_{wTHD} = 1.391/11.172 = 0.124$$

Where:

I_{5n} – Normalised I_5

I_{THD} – THD

I_{wTHD} – weighted THD

The individual harmonic current limit for I_5 is given by using equation 4.8 i.e.

$$\frac{E_{Ihi}}{I_{1max}} = \frac{5.4 \times 25^{(1-1/1.4)}}{5 \times 0.3^{1/1.4}} = 6.4\%$$

This has to be lowered to ensure the voltage THD is not excessive. This is achieved by restricting the current THD.

First calculating the weighted current THD for the installation (equation 4.11) i.e.

$$\frac{E_{wTHD_i}}{I_i} = 7.2\sqrt{\frac{25}{0.3}} = 65.727\%$$

Hence current wTHD limit = 65.727 %

If only the 5th harmonic is present, then the I_5 limit to ensure this current wTHD limit is not breached is:

$$I_5 = \frac{E_{wTHD_i}}{5} = 13.145\%$$

Hence the I_5 limit = 13.145%

Now considering the proportion of the 5th of the spectrum allows the new I_5 limit to be calculated:

$$I_5 = E_{wTHD_i} \times I_{5n} = 65.727 \times 0.09 = 5.88\%$$

Hence the I_5 limit with the prescribed spectrum = 5.88% (c.f. 6.4% being the individual limit).

Now calculating the current THD limit to ensure the voltage THD planning level is not breached gives:

$$I_5 = E_{wTHD_i} \times \frac{I_{THD}}{I_{wTHD}} = 65.727 \times 0.124 = 8.18\%$$

Hence the I_{THD} limit with the prescribed spectrum = 8.18%

(C) Special cases

Embedded generation

Embedded generation is considered as a load for harmonic allocation purposes. Hence the supply capacity (S_t) is increased above the supply capacity without embedded generation. Consider first the case of no embedded generation and ignoring diversity as depicted in Figure 8. The Allocation Constant is the multiplier for the calculated harmonic allocation using the Voltage Droop method. As the loading increases towards the supply capacity the harmonic voltage will increase (assuming each load takes their full allocation) and the harmonic voltage will be proportional to the area under the horizontal allocation constant line for a given loading level. With embedded generation, the supply capacity can be greater than 100%. The planning level must now be reached when S_t reaches its limit, and since the harmonic voltage is proportional to the integral of the allocation constant, the allocation constant must be reduced so that this is achieved.

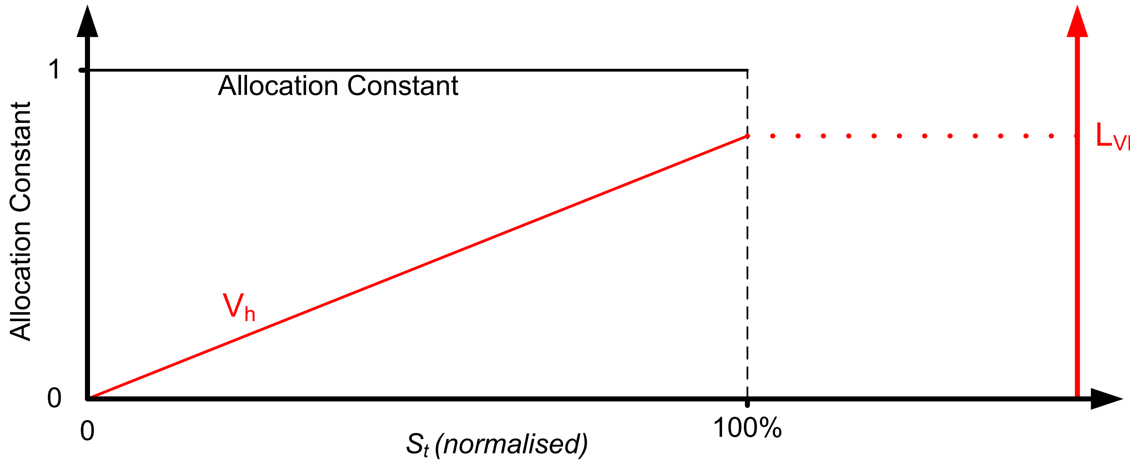


Figure: 8 Allocation Constant with no embedded generation

Figure 9 illustrates the case when the embedded generation is 20% of the firm supply capacity (without embedded generation). Since the planning level must just be reached at 120% the allocation constant is 0.833, which implies the harmonic allocation will be 83.3% of allocation without embedded generation.

If diversity is now considered and assuming α = 1.4 then the allocation constant is 87.8% ($(100/120)^{1/1.4}$ = 0.878) of allocation without embedded generation. This procedure gives an allocation to the generation even though it may seldom reach its full generation potential. Hence the allocation to definite loads has to be reduced to give reserve which may never be used.

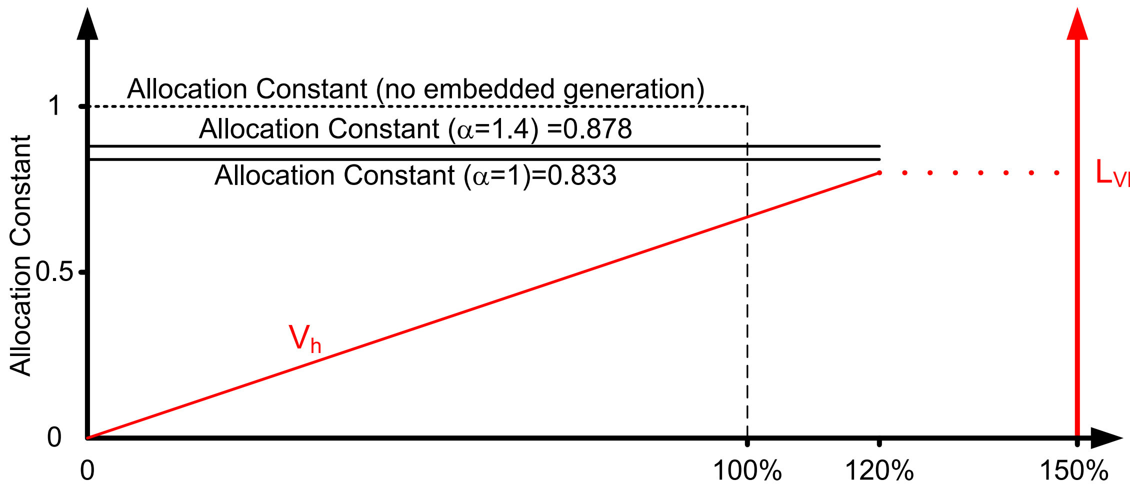


Figure: 9 Allocation Constant with embedded generation

If the probability distribution of the network's ultimate supply capacity including embedded generation (S) can be developed a more elaborate allocation is possible, which gives a smaller allocation for loads with a smaller probability of being connected. As an illustration Figure 10 shows an example probability profile. In this the probability of reaching S = 130% is 20% and reaching S = 150% is 0%. The expected load is the area under the graph, hence:

S_t (expected) = 100*1+(100+20)/2*0.3+(20)/2*0.2 = 120%.

Without diversity the allocation for the definite load must be 1/1.2 = 0.8333 (83%).

If diversity of 1.4 is assumed this increases to 0.878.

Hence the procedure is:

1. Determine the Load before addition of a new load (S_0).
2. Calculate the average loading for before and after adding new load ($S = S_0 + S_i/2$).
3. Calculate S/S_t and look up the Allocation Constant on the appropriate graph (e.g. Figure 11).

This procedure will minimise the reduction in allocation for definite loads. As the system is loaded up the allocation constant reduces (in the tail region) so as to ensure the planning level is not breached. Each load in this region will receive a slightly lower *Allocation Constant* than the load before, so no gross inequity occurs.

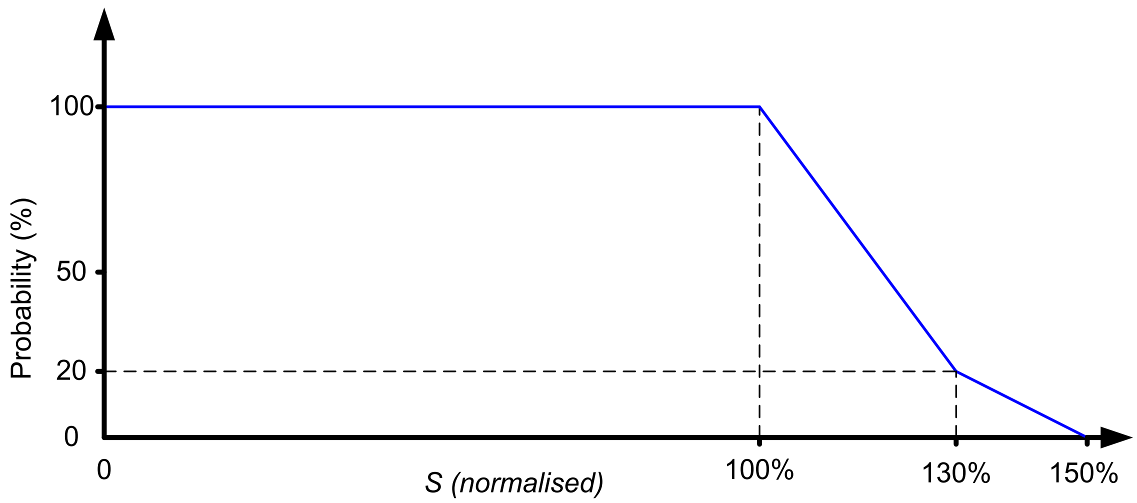


Figure: 10 Probability of S

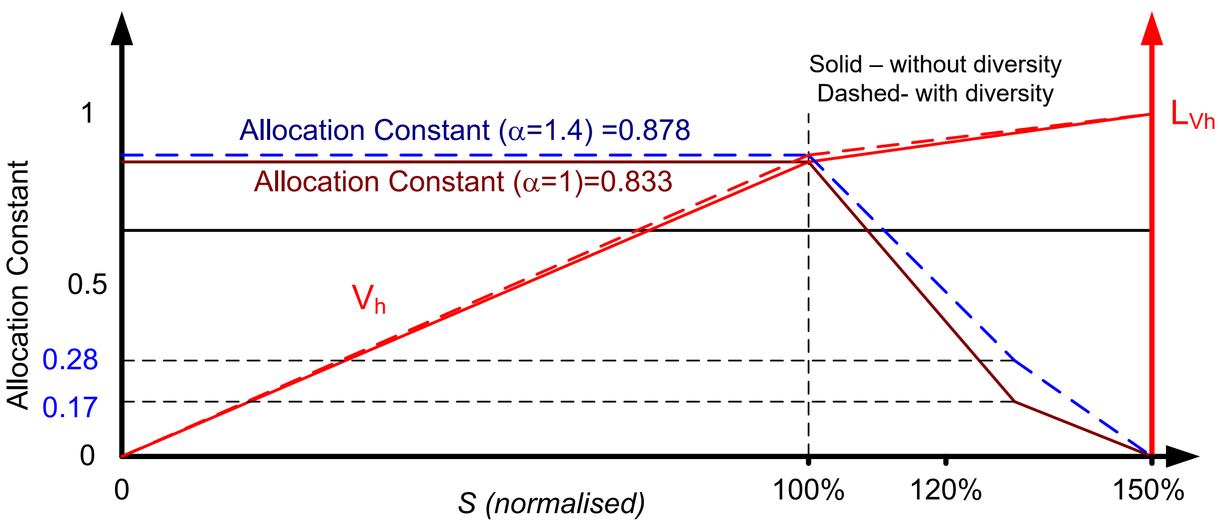


Figure: 11 Allocation Based on Probability Function

Similar Equipment Installed

A group of installations having no diversity with each other occurs when equipment with similar characteristics is installed. For example this can be the case for a group of irrigation pumps which operate roughly at the same time.

The steps in a Stage 1 allocation are as follows:

- Determine the SCR for each installation in the group.
- Determine the SCR for the group as the "parallel combination" of the separate SCR values.
- Determine the harmonic voltage allocation to the group from equation 4.5.
- Apportion this harmonic voltage to the individual installation by the inverse of the SCR.
- Determine the harmonic current allocation to each installation from the harmonic impedance at the point of connection.

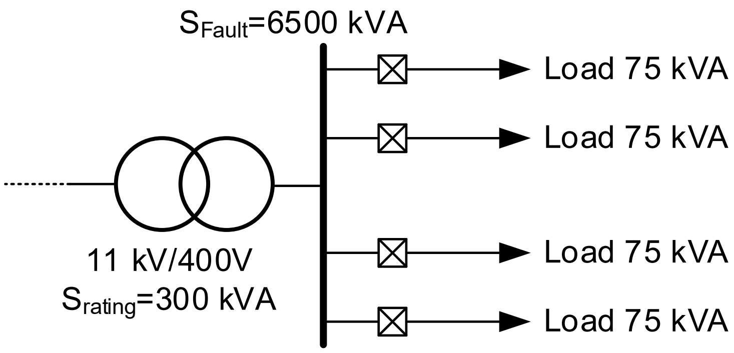


Figure: 12 Example Test System

Example 4.3: Similar equipment of the same size:

First consider the allocation of 5th harmonic to four 75 kVA loads fed from common busbar with a fault level of 6500 kVA and planning level of 4% as shown in Figure 12.

Then for each load:

$$SCR_i = \frac{6500}{75} = 86.667$$

$$I_{1i} = \frac{\frac{75 \times 10^3}{3}}{230} = 108.25 \text{ Amps}$$

$$\frac{E_{Ihi}}{I_{1i}} = \frac{L_h \times SCR_i^{\left(1-\frac{1}{\alpha}\right)}}{hV_d^{\left(\frac{1}{\alpha}\right)}} = \frac{4 \times 86.667^{\left(1-\frac{1}{1.4}\right)}}{5 \times 0.3^{\left(\frac{1}{1.4}\right)}} = 6.765\%$$

Converting to Amperes gives for the 5th harmonic allocation:

$$E_{Ihi} = \frac{6.765\%}{100} \times I_{1i} = 7.323 \text{ Amps}$$

This result assumes diversity between the loads.

If two loads are of the same type, then for the combination of these two loads:

$$SCR_i = \frac{6500}{150} = 43.333$$

$$I_{1i} = \frac{\frac{150 \times 10^3}{3}}{230} = 216.5 \text{ Amps}$$

$$E_{Vhi} = \frac{L_h}{SCR^{\left(\frac{1}{\alpha}\right)} V_d^{\left(\frac{1}{\alpha}\right)}} = \frac{4}{43.33^{\left(\frac{1}{1.4}\right)} \times 0.3^{\left(\frac{1}{1.4}\right)}} = 0.64\%$$

Since these two loads are identical the harmonic voltage allocation for each is 0.64/2 = 0.32%. This gives a harmonic current allocation per load of:

$$\frac{E_{Ih1}}{I_1} = \frac{E_{Vh1} \times SCR_i}{h} = \frac{0.32 \times 43.333}{5} = 2.775\%$$

$$E_{Ih1} = \frac{2.775\%}{100} \times I_1 = \frac{2.775\%}{100} \times 216.5 = 6.0 \text{ Amps}$$

The same harmonic allocation can be achieved by calculating the harmonic current allocation for the group and proportion this harmonic current allocation amongst the loads, i.e.

$$\frac{E_{Ihi}}{I_1} = \frac{L_h \times SCR_i^{(1-1/\alpha)}}{hV_d{}^{(1/\alpha)}} = \frac{4 \times 43.333^{(1-1/1.4)}}{5 \times 0.3^{(1/1.4)}} = 5.549\%$$

$$E_{Ihi} = \frac{5.549\%}{100} \times I_1 = 12.01 \text{ Amps}$$

This is shared between the two similar loads giving 6.0 Amps each. Table 16 shows how an individual load's allocation varies depending on the number of similar loads.

Table: 16 Example 5th Harmonic Allocation Table

DIVERSITY BETWEEN THE FOUR LOADS.	Combine 75 kVA Loads that are similar		Individual 75 kVA Loads	
	SCR_i	I_5 (Percentage)	I_5 (Percentage)	I_5 (Amps)
Full	86.67	6.765	6.765	7.323
None between two loads	43.33	5.550	2.775	6.032
None between three loads	28.89	4.942	1.647	5.372
No Diversity	21.67	4.552	1.138	4.928

Example 4.4: Similar equipment of unequal size.

Assume Load1 = 60 kVA and Load2 = 15 kVA what is the allocation of each.

$$SCR_1 = \frac{6500}{60} = 108.33$$

$$SCR_2 = \frac{6500}{15} = 433.33$$

$$SCR_T = \frac{SCR_1 SCR_2}{SCR_1 + SCR_2} = \frac{6500}{75} = 86.67$$

The harmonic Voltage allocation to the combined loading is:

$$E_{Vhi} = \frac{L_h}{SCR^{(1/\alpha)} {V_d}^{(1/\alpha)}} = \frac{4}{86.667^{(1/1.4)} \times 0.3^{(1/1.4)}} = 0.39\%$$

Proportioning this harmonic voltage gives:

$$E_{Vh1} = 0.39 \times \frac{60}{75} = 0.312\%$$

$$E_{Vh2} = 0.39 \times \frac{15}{75} = 0.078\%$$

For Load 1:

$$\frac{E_{Ih1}}{I_1} = \frac{E_{Vh1} \times SCR_i}{h} = \frac{0.312 \times 86.667}{5} = 5.41\%$$

$$E_{Ih1} = \frac{5.41\%}{100} \times I_1 = \frac{4.437\%}{100} \times 108.25 = 5.86 \text{ Amps}$$

For Load 2:

$$\frac{E_{Ih2}}{I_1} = \frac{E_{Vh1} \times SCR_i}{h} = \frac{0.078 \times 86.667}{5} = 1.35\%$$

$$E_{Ih2} = \frac{1.35\%}{100} \times I_1 = \frac{1.35\%}{100} \times 108.25 = 1.465 \text{ Amps}$$

Alternatively calculating a total harmonic current allocation and then proportioning this:

$$\frac{E_{Ihi}}{I_{1i}} = \frac{L_h \times SCR_i^{(1-1/\alpha)}}{h{V_d}^{(1/\alpha)}} = \frac{4 \times 86.667^{(1-1/1.4)}}{5 \times 0.3^{(1/1.4)}} = 6.765\%$$

Converting to Amperes gives for the 5th harmonic allocation of the combination:

$$E_{Ihi} = \frac{6.765\%}{100} \times I_{1i} = 7.323 \text{ Amps}$$

Now proportioning this to the two loads:

$$E_{Ih1} = \frac{60}{75} \times 7.323 = 5.86 \text{ Amps}$$

$$E_{Ih1} = \frac{15}{75} \times 7.323 = 1.465 \text{ Amps}$$

Resonances

The *Voltage Droop* method assumes that the system is mainly inductive and that the *Voltage Droop* is a reasonable proxy for system impedance. The presence of capacitors in the network causes resonances which may amplify harmonic levels. To avoid these resonances the use of detuned capacitor banks (series choke installed) is recommended. This ensures the capacitor bank is inductive at the characteristic harmonics and hence not amplified. Where resonance is an issue detailed studies are required to determine the true system harmonic impedance, and this is then used to calculate a harmonic current allocation that will not result in a breach of the planning level for harmonic voltages.

Care is needed in choosing the tuned frequency of these detuned capacitor banks as they may form a low impedance path to ripple signals thereby reducing the developed ripple voltage. Consider for example a power-factor correction bank consisting of two 234.81 μF capacitors in parallel and a 1.5 mH detuning choke in series with the capacitors. The essential parameters are shown in Table 17.

Table: 17 Basic Parameters of Power-Factor Correction Bank

BASIC PARAMETERS	CALCULATED PARAMETERS
V_1 (phase-to-phase) = 415 Volts	X_L/X_c = 0.070
C_{Total} = 469.62 uF	X_1 = 6.31 Ohms
L = 1.5 mH	Q = 27.308 kVAr
	I_1 = 38.0 Amps
	f_{res} = 189.63 Hz

This gives a tuned to frequency of h ≈ 3.8 (190 Hz), which is reasonably common. A frequency scan of the capacitor bank is shown in Figure 13, and this shows that the impedance is low at 175 Hz and may cause a problem if 175 Hz is the ripple frequency. The tuned frequency of the capacitor bank must be such that the ripple control is not adversely affected. Studies have shown the desirability of always using a detuning capacitor to minimize alteration of the system's frequency response and hence likelihood of unwanted harmonic resonances.

When harmonic resonances exist then the harmonic voltage allocation per normal (using equation 4.5) is determined; however, the assessed harmonic impedance is used instead of h/FL_i to convert this to a harmonic current allocation (equation 4.6).

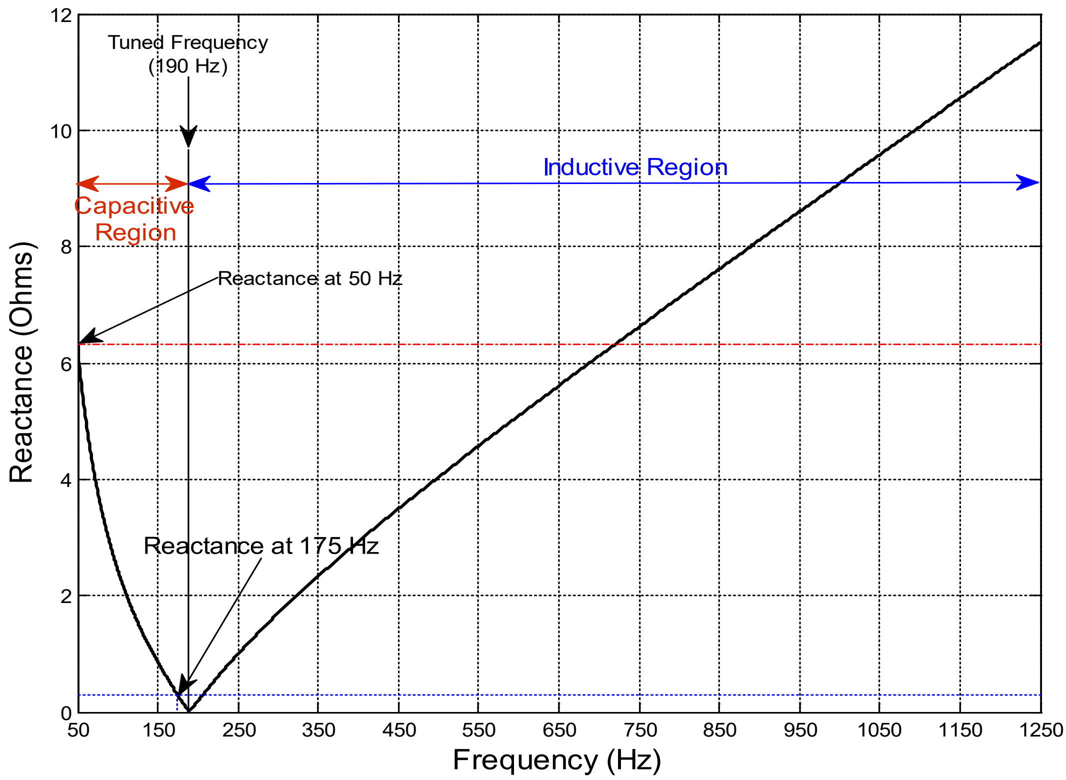


Figure: 13 Reactance Magnitude of a Capacitor Bank with Detuning Choke

Example

$Q = \frac{V^2}{X_T}$ where X_T is the capacitive reactance of the branch at 50 Hz and Q the desired reactive power (negative as capacitive).

If $X_L = kX_C$ then it can be shown that $f_{res} = \frac{f}{\sqrt{k}}$ and hence $k = \left(\frac{f}{f_{res}}\right)^2$

Choosing a resonant frequency of 189 Hz (below all the major characteristic harmonics), then:

$$X_L = 0.07X_C$$

$$X_T = X_L - X_C = (0.07 - 1)X_C = -0.93X_C \quad and \quad X_T = \frac{V^2}{Q} = -0.93X_C$$

$$X_C = \frac{V^2}{-0.93Q} = \frac{1}{2\pi fC}$$

and rearranging this yields:

$$C = \frac{-0.93Q}{2\pi fV^2} \tag{4.12}$$

As

$$2\pi fL = \frac{0.07}{2\pi fC}$$

then:

$$L = \frac{0.07}{(2\pi f)^2 C} \tag{4.13}$$

Just to check that the calculations are correct, ensure the resonant frequency is as designed:

$$2\pi f_{res} = \frac{1}{\sqrt{LC}}$$

$$(2\pi f_{res})^2 = \frac{1}{\left(\frac{0.07}{(2\pi f)^2 C}\right)C} = \frac{(2\pi f)^2}{0.07}$$

$$f_{res} = \frac{f}{\sqrt{0.07}} = 3.7996f = 189Hz$$

Example 4.5

If 10 MVAr is required on a 66 kV system (4.12) yields a capacitance of 6.796 μF and (4.13) an inductance of 104.4 mH. X_L =3 2.79 Ω, X_C = 468.4 Ω and X_T = -435.6 Ω.

As a check:

$$Q = \frac{V^2}{X_T} = \frac{(66 \times 10^3)^2}{435.6} = 10 \times 10^6 = 10\ MVAr$$

Atypical Supply Impedance

Equation 4.7 (i.e. X_{ih} = h/FL_i) assumes the network impedance is mainly inductive which is a good approximation until the higher frequencies (1000 Hz) where the system capacitances (in the lines and cables) become more significant and limit the increase in impedance with frequency. Hence at high frequencies h/FLi may be a conservative estimate of the system impedance.

In exceptional cases more detailed harmonic studies may be required to ensure the planning levels are not exceeded by evaluating a more accurate representation of harmonic impedance to be used in converting from harmonic voltage to harmonic current allocation (equation 4.6). This may be required because of the presence of resonances or the assumption that the impedance adequate represented by X = h/*FLi* is invalid.

24.3 Stage 3

The emission determined by Stage 2 is based on all planned consumers being connected and making use of their full harmonic current allocation. Circumstances where this is not the case may include:

1. The supply will not be fully utilized for a given period into the future.
2. The existing consumers are not drawing their full harmonic allocation and their harmonic emission is known to be stable for a given period into the future.

Both conditions give additional harmonic allowances which can be allocated to a customer for a period of time. Under stage 3 the utility and the customer may then agree on a higher emission allocation than determined in Stage 2, with the understanding that it is temporary and will be reviewed at a later stage.

25. Emission Assessment

25.1 Introduction

Assessment is a potential source of conflict between customer and utility and the procedure needs to be tightly specified. It needs to:

- Be fair.
- Well defined.
- Have a sound technical basis.
- Be practicable.

Ideally, measurements shall be made using monitoring equipment compliant with the requirements of *AS/NZS 61000.4.30 Class A*. Flagged data as defined in *AS/NZS 61000.4.30* should be removed before assessment.

Customers and equipment manufacturers can control the time variation of their installations/products better than utilities can control their harmonic voltages. Because of this, it is justified to compare the installation/product 100% current with the allocated value whereas the harmonic voltage is based on the 95% level.

25.2 Harmonic Voltage

The 95% value of 10 minute readings over a week is compared to the voltage planning level to determine compliance.

This assumes that utility harmonic voltage measurements:

- Are a well-behaved distribution.
- Do not contain sustained short periods of high harmonic levels. If this is the case, short-term harmonic levels will need to be assessed and compared to the relevant limits.
- Allow dispensation for ripple control (duration less than 3 minute of any 10 minute period and magnitude less than the signal level specified by the Meister curve)[1].

[1] AS/NZS 61000.2.12:2003

25.3 Installation/Device Harmonic Current Assessment

The maximum value of the 10 minute readings are compared to calculated harmonic current allocation (Section 24, Allocation for MV-HV-EHV customers).

Some equipment generate harmonics for short periods of time (e.g., motor soft-starters) and the short-term harmonic current limits are discussed in section 22.3, Short-term harmonic levels.

Note: Some equipment have process cycles where the harmonic current emissions vary greatly throughout the stages in the cycle. If each stage is sufficiently long, then the harmonic levels are compared to the steady-state limits. Otherwise, short-term limit is applicable.

25.4 Mitigation

If the values in Tables 8 - 12 are exceeded, steps need to be taken to reduce them to acceptable levels. Generally a number of alternatives are possible, with modification being made to the network, installation or to specific equipment. Depending on the mitigation measure adopted, there can be associated costs borne by the distributor, customer or equipment supplier. Utilities need to have a harmonic management process in place so that it is possible to identify clearly the party responsible for harmonic limits being exceeded. This is the party responsible for the cost of remedial measures and their identification will lead to a narrowing in the choice of mitigation.

25.5 Principles of Harmonic Management

Limits are set on harmonic voltage determined by what is cost-effective for the community as a whole. Limits are set on individual harmonics up to the 50th harmonic and also on THD and vary within the power system, being generally larger towards the LV part of the system. There is some scope for the utility to determine its own limits as it deems appropriate, providing they do not exceed the LV compatibility levels.

Harmonic voltages are the response of harmonic currents flowing in the network harmonic impedance. Control of harmonic voltage requires limits to be placed on customer harmonic current and network harmonic impedance.

LV customers cannot be expected to be responsible for their installation's harmonic behaviour. LV harmonic emission is controlled by generic limits on equipment current emission determined according to the equipment's pattern of use and its power rating. These limits have been determined by the IEC and are given in *AS/NZS 61000.3.2, AS/NZS 61000.3.4* and *AS/NZS 61000.3.12.*

Good use can be made of the MV system's harmonic absorption capacity if installation limits are tailored for installation. Standards such as *AS/NZS 61000.3.6* give general guidelines as to how this should be done with the aim of ensuring that the maximum harmonic voltage is close to but does not exceed harmonic limits when all projected customers are drawing their full harmonic allocation.

25.6 Compliance Checking

Once harmonic allocations are made the harmonic currents of an installation are compared to the allocation (using the statistical measure). The harmonic currents injected by nonlinear loads are dependent to varying degrees on the harmonic voltages at its terminals. It is not feasible to test customer compliance in isolation from the influence of other customer nonlinear loads and even if possible it is undesirable if a load is only compliant when it is the only nonlinear load on the system. Therefore, compliance is tested *in situ* with background distortion (provided background distortion is within planning levels).

25.7 Existing Installations

The *PQ Guidelines* are based on giving equitable harmonic allowance to every user. However, there is the issue of harmonic levels exceeding these *PQ Guidelines* in installations built before the *PQ Guidelines* were developed.

This needs to be addressed when:

1. The installation is being altered.
2. Other customers want to use their allocation (and PQ levels are likely to exceed the planning levels).

Taking remedial action to address identified PQ issues takes time and the grace period given to a customer to continue operating before implementing a solution to resolve the PQ issue is at the discretion of the Electricity Distributor supplying the customer. The Electricity Distributor will take into account the severity of the breach, the impact other customers are experiencing, as well as the difficulty in resolving the issue.

25.8 Responsibilities

Utilities are responsible for keeping network harmonic voltage levels at or below limits, especially at MV and above. Utilities are also responsible for supplying the fault level information required for determining the maximum harmonic current allocation to all customers connected to MV and above. This is usually performed in three stages and may become part of a connection agreement. As part of harmonic management, they may choose to limit the network harmonic impedance by planning and installation practices such as having detuning chokes fitted for all power-factor correction capacitors.

Equipment suppliers should ensure that their equipment meets the appropriate equipment standard for harmonic current emission. These include:

- *AS/NZS 61000.3.2* Limitation of voltage change equipment connected at LV with low (less than 16 A per phase) current.
- *AS/NZS 61000.3.4* harmonic current emission limits for equipment connected at LV with high (more than 16 A per phase) current.
- *AS/NZS 61000.3.12* harmonic current emission limits for equipment connected at LV with input current > 16 A and ≤ 75 A per phase.

Customers connected to MV and above are responsible for ensuring their installation harmonic currents remain within the limits set by utilities[1]. They also need to follow utility guidelines for installations, especially with regards to power-factor capacitor installations.

Large customers connected to LV may become responsible for meeting installation harmonic current limits in the future by following guidelines such as *IEC 61000-3-14* if adopted by New Zealand.

25.9 Harmonic Standards

A summary of the international standards for harmonics is given in the full *PQ Project Report*.

25.10 Monitoring

This *PQ Guideline* document is based around using 10 minute recordings and avoids the use of 3 second recordings due to the greatly increased data and processing requirements. However, when dealing with transient and short-term harmonics a shorter period may be required. Monitoring requirements are given in the *PQ Project Report*.

25.11 High Frequency Harmonics

The trend is for equipment manufacturers to move to higher switching frequencies for compliance to standards and regulations without the need for bulky and expensive low order harmonic filters. Moreover, the magnetics devices can be smaller and lighter at higher frequencies. However, the higher frequencies result in current paths through stray capacitances and these paths are often undesirable. These high frequency harmonics (called supraharmonics by some) can also excite resonances at these high frequencies.

[1] It is in the interest of Utilities to ensure the harmonic currents injected into their network comply with the PQ Guidelines. Some Utilities have the necessary equipment for checking their customers' harmonic emissions and may provide this service to their customers.

Effects of High Frequency Harmonics

1. Tripping of RCDs due to increased leakage currents [Rönnberg 2017].
2. Nuisance tripping of protection equipment (circuit breakers).
3. Malfunction of equipment (mainly through affecting their control system).
4. Shortened equipment lifetime.
5. Elevated PE to Neutral voltage.

Higher frequency harmonics are illustrated in the recordings displayed in Figures 14 to 19. Figure 14 displays an example of voltage waveforms caused by inverter-based equipment unfiltered in the time domain. Figure 15 shows the spectrum and duration of these waveforms in the frequency domain, highlighting rather significant voltages at a frequency of around 50 kHz. Figure 16 displays example voltage and current waveforms unfiltered in the time domain from an electric vehicle charger connected to a three-phase AC supply. Figure 17 shows their spectrum in the frequency domain and a congregation of currents at around 10 kHz. Figures 18 and 19 show current and voltage waveforms measured from a factory where a resonance was excited. As more power electronic equipment using kHz switching frequencies enter the power system more high frequency disturbances are expected.

The high inductive reactance of transformers and internal stray capacitances hinders these high frequency harmonics propagating to other voltage levels, with the transformer acting as a low pass filter. However, high frequency harmonics can reduce the life of the transformer significantly and affect other equipment connected to the same part of the network.

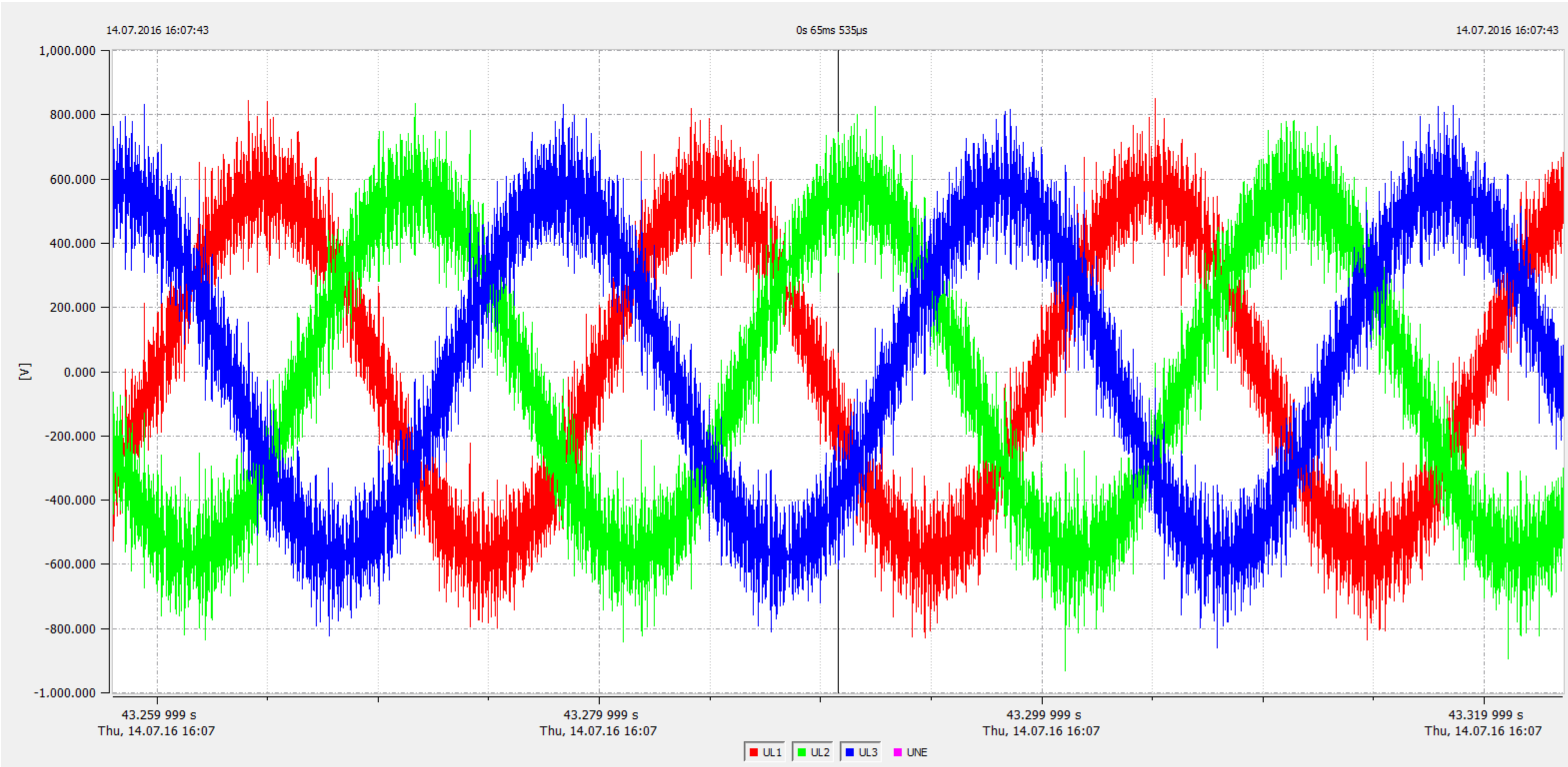


Figure: 14 Example of high frequency harmonic components in voltage waveforms from inverter-based equipment

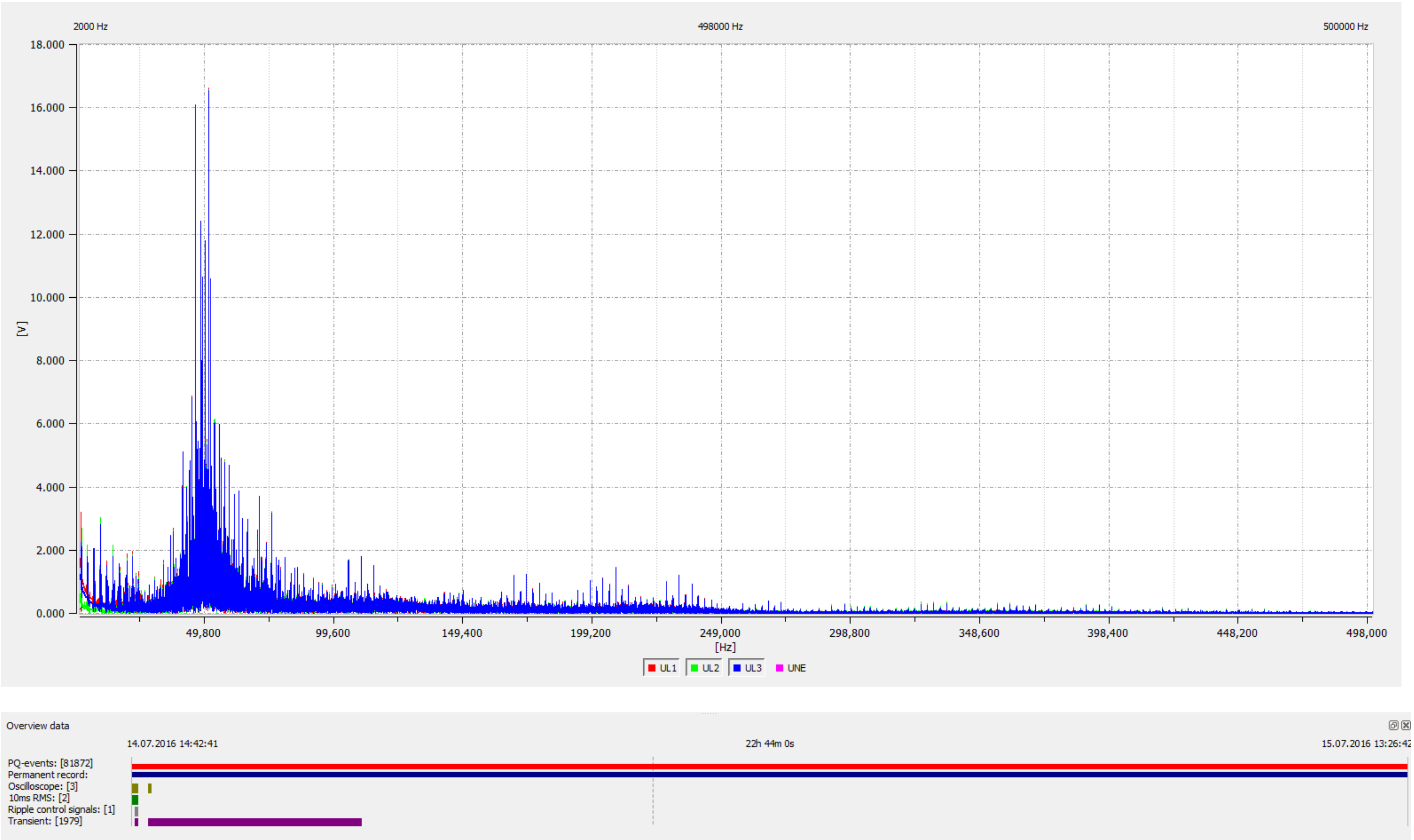


Figure: 15 Example of frequency components in voltage waveforms from inverter based equipment

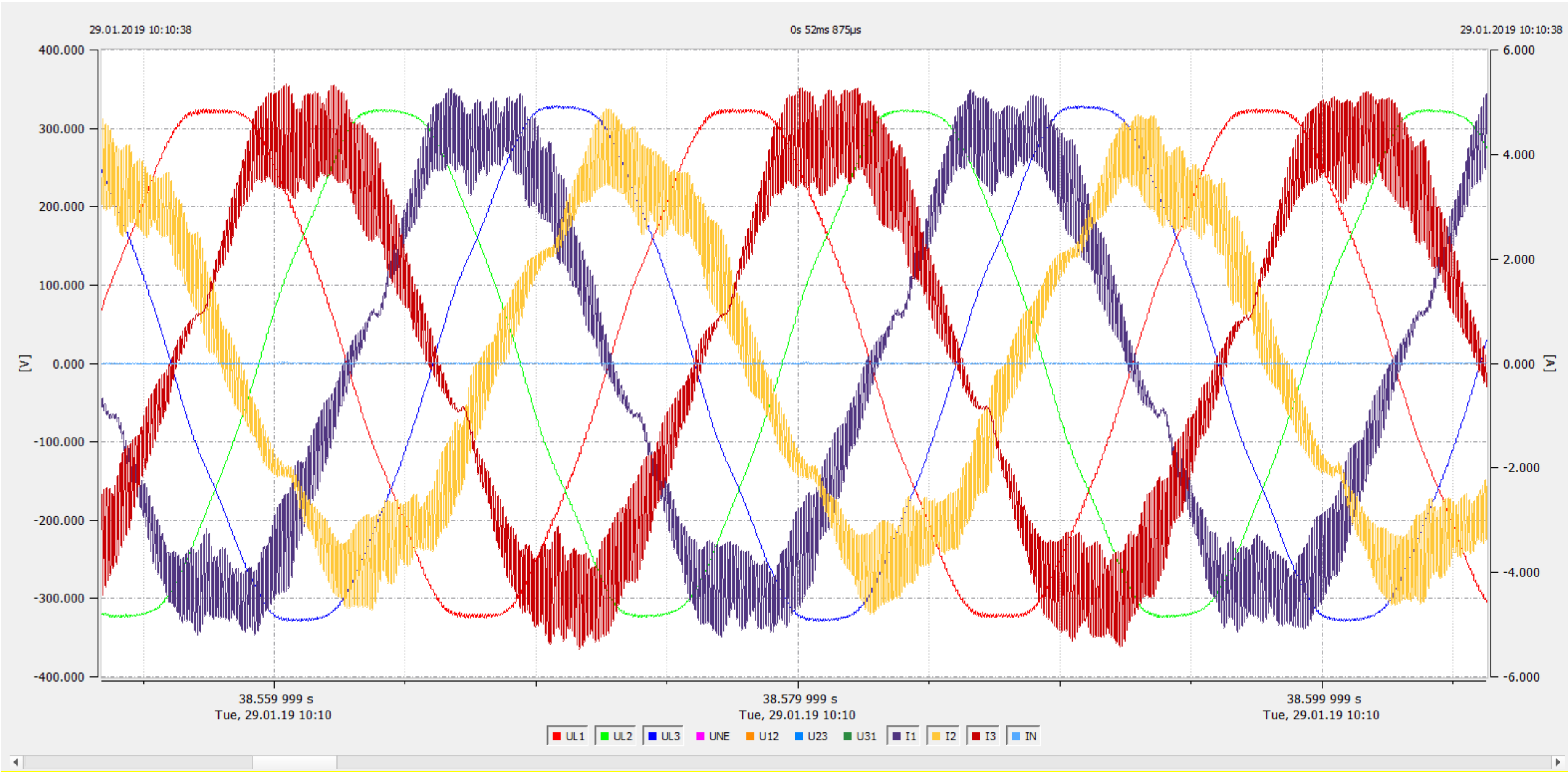


Figure: 16 Example of high frequency harmonic components in voltage and current waveforms due to electric vehicle charging

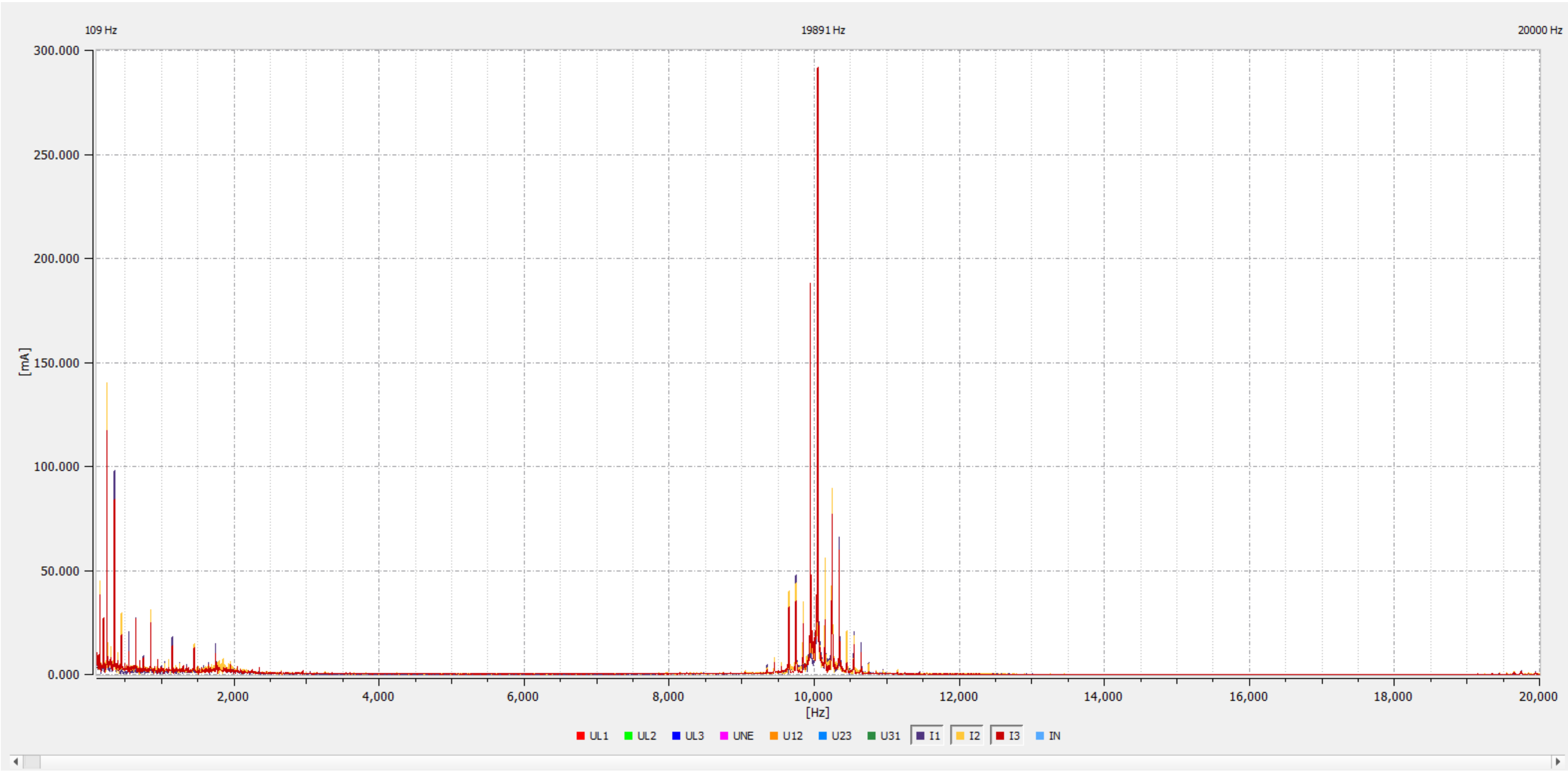


Figure: 17 Example of high frequency harmonic components in current waveforms due to electric vehicle charging

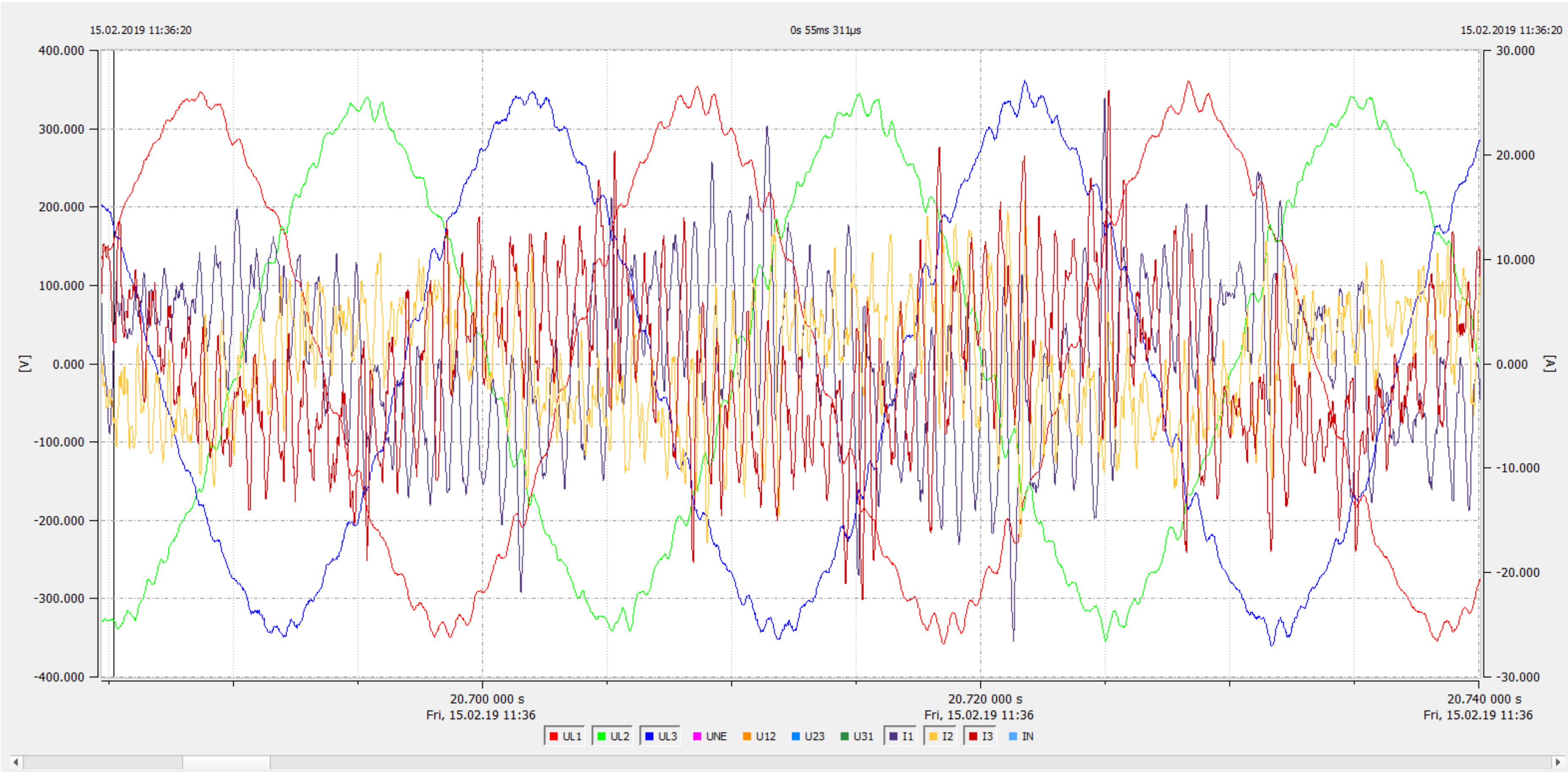


Figure: 18 Example of harmonic components in voltage and current waveforms with resonance excitement

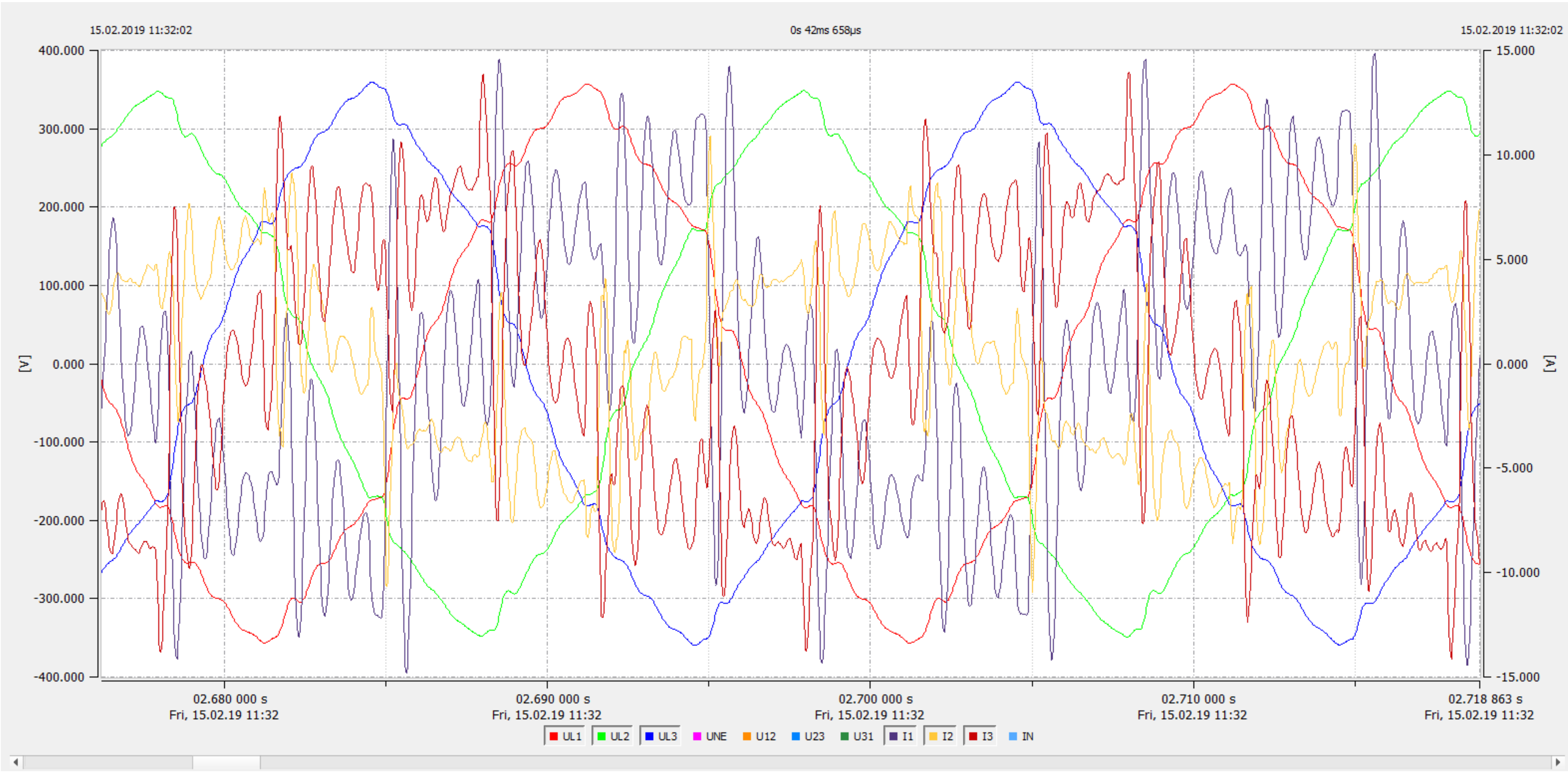


Figure: 19 Example of harmonic components in voltage and current waveforms with resonance excitement

25.12 Pseudo-harmonics

There are two techniques for giving lower harmonic emission levels when testing for compliance. They are based on the fact that Fourier theory assumes a waveform is in steady-state. The window used is multiple periods of the fundamental to allow better resolution in the frequency domain and some averaging of multiple cycles is used to overcome the fact that the system is never truly in the steady-state.

The first technique is to use a spread spectrum approach. Instead of using a fixed switching frequency it is varied within the cycle. This gives a far lower amplitude of emission but spreads it over many frequencies.

The second technique is illustrated in Figure 20 which shows consecutive cycles are not the same.

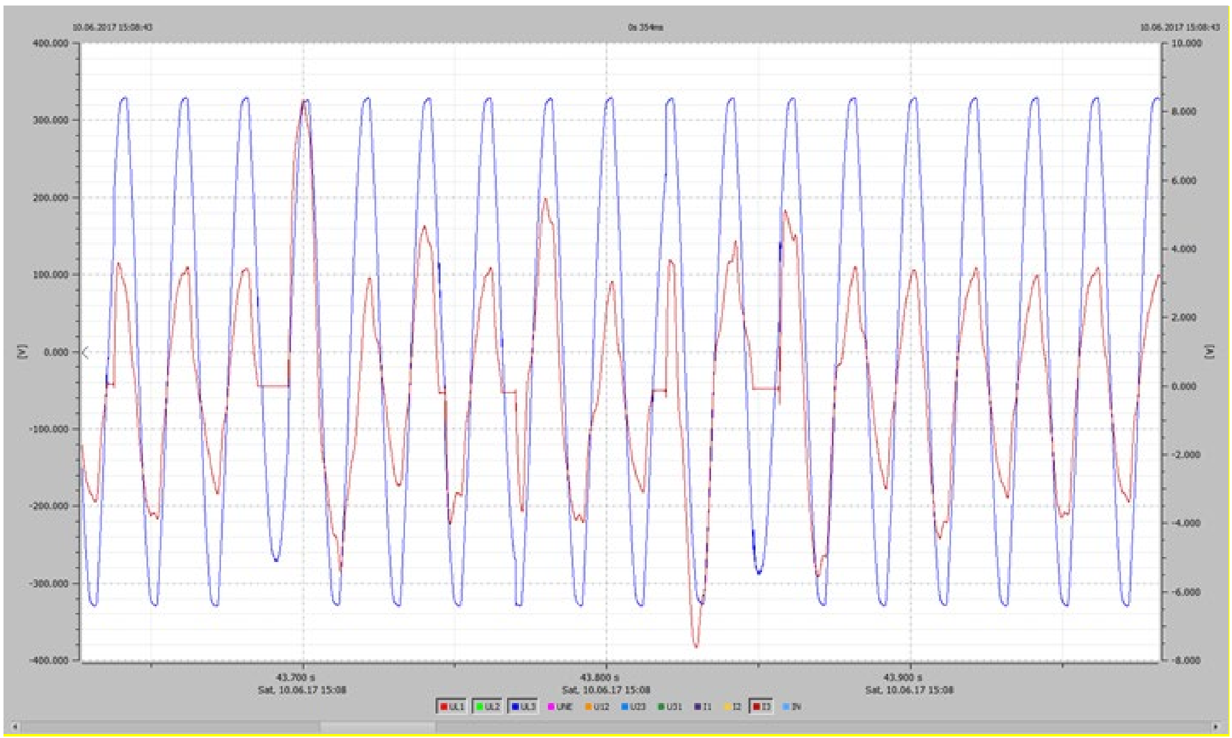


Figure: 20 Example of a current waveform where there is no apparent repetition

SECTION 5 - Interharmonics

26. Introduction

Interharmonics are waveform components that are at frequencies that are not an integer multiple of the supply frequency. Interharmonics that are below the supply frequency are called subharmonics. Normally interharmonics up to the 50th harmonic are considered separately to the harmonic frequencies. When the voltage harmonics are above the 50th harmonic it is generally not significant whether they are harmonics or interharmonics. The main frequency divisions are[1]:

- <50 Hz (subharmonics).
- 50 to 2.5 kHz.
- 2.5 to 9 kHz.
- 9 to 150 kHz.
- >150 kHz.

27. Sources

The main sources of interharmonics are:

- Electric arc furnaces.
- Arc welding machines.
- Power supply to traction systems (e.g., 16.7 Hz).
- Power electronic converters.

(a) When the end-use of the electricity requires an a.c. voltage at a frequency other than at the network (fundamental) frequency (e.g., VSD and Cycloconverter),

(b) When the PWM converters on the network side have no synchronism with the network frequency (the harmonics of the modulation frequency will be interharmonics),

(c) Switched-mode power supply for rectification:

- Induction motors which can draw an irregular magnetising current due to the slots in the stator and rotor, possibly in association with saturation of the iron.
- Ripple control (mains signalling) is also a source of interharmonic voltages, but in this case the emissions are intentional and carefully managed to ensure compatibility.

[1] In Europe the division is at 2 kHz (rather than 2.5 kHz) as they consider first up to the 40th harmonic rather than 50th.

- Automatic meter reading (AMR) systems that use Power-Line Communications (PLC).
- Series compensated transmission lines.

Disturbances in the frequency range 2.5 to 150 kHz are classified as:

- Narrowband.
- Broadband.
- Recurring oscillations.

Narrowband disturbance, mainly in the form of individual frequencies, is due to fixed-frequency end-user equipment and power-line communication. Broadband disturbances are caused by end-user equipment with active power-factor correction. The emission from active power-factor correction circuits shows complex time-frequency behaviour and the voltage distortion caused by the sum of many individual devices has more of a broadband character. This is expected to increase in the future with the deployment of more wind and PV systems, chargers for electric and hybrid vehicles and energy efficient equipment with active power-factor correction circuits. Recurring oscillations are caused by power electronic converter operation and are very common. Examples of such devices are large converters and fluorescent lamps. When a change of state occurs an oscillatory transient is initiated. For example in a fluorescent lamp with a high frequency ballast, near the voltage zero cross there is *"zero-crossing distortion"* (also called cross-over distortion). The notching around the voltage zero-crossing occurs due to the oscillatory current setup when the current restarts (conduction begins again). A similar phenomenon is observed in large HVDC converters when a thyristor is fired, and commutation is initiated.

Subsynchronous resonances occur when one or more of the mechanical resonant frequencies of a turbine-shaft-generator system coincide with fundamental minus the electrical resonant frequency of the capacitor in series with the total system impedance, such as in series compensated power systems. There is sustained exchange of energy between the mechanical shaft and the electrical system which puts torsional stress on the turbine generator shaft which can cause metal fatigue.

Take for example the simple case of a sinusoidal modulation of the voltage envelope of a 50 Hz system. Mathematically this can be expressed as:

$$v(t) = \sqrt{2}(1 + m\,cos(\omega_2 t))\,cos(\omega_1 t + \phi_1)$$

$$= \sqrt{2}\,cos(\omega_1 t + \psi_1) + \frac{m}{2}[cos((\omega_1 + \omega_2)t + \phi_1) + cos((\omega_1 - \omega_2)t + \phi_1)] \qquad (5.1)$$

This highlights that there are three spectral components, one at the fundamental frequency and on either side. A case of a 5 Hz modulation of the 50 Hz voltage waveform is depicted in Figure 21 and the corresponding spectral components in Figure 22. Note that a 0.2 s window is used to give a 5 Hz resolution in the frequency domain. Harmonic order 10 (10 $\times$ 5 Hz = 50 Hz) thus the fundamental spectral component. Harmonic orders 9 and 11 are the 45 Hz and 55 Hz spectral components.

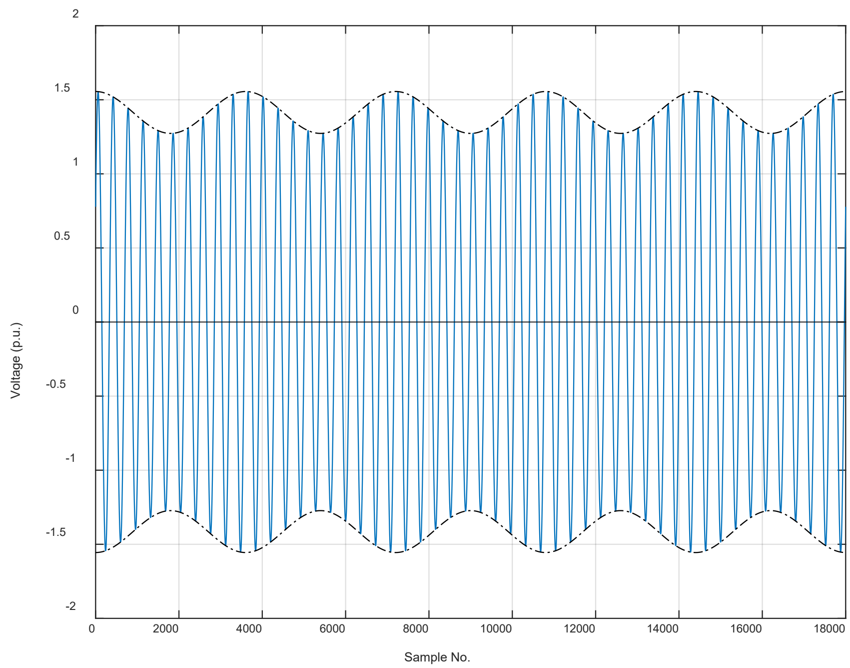


Figure: 21 Sinusoidal amplitude modulation

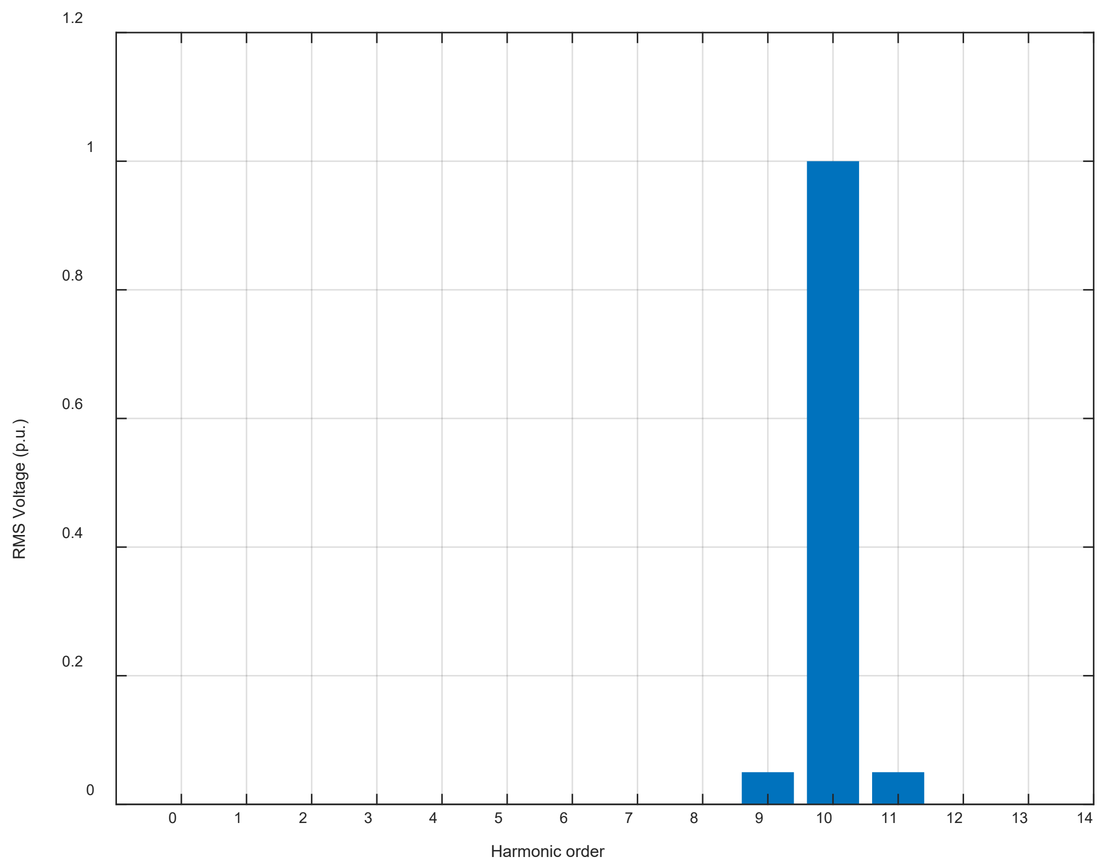


Figure: 22 Spectral components for sinusoidal amplitude modulation

Another standard modulation is square-wave modulation as illustrated in Figure 23. The mathematical form is:

$$v(t) = \sqrt{2}\big(1 + m \times SIGN(\omega_2 t)\big)\,cos(\omega_1 t + \phi_1)$$

Where:

$$SIGN(\omega_2 t) = \begin{cases} 1 \ \text{when} & \text{remainder}(t/T_2) < T_2/2 \\ -1 \ \text{when} & \text{remainder}(t/T_2) > T_2/2 \end{cases}$$

, $T_2 = 1/f_2$ and *m* the depth of modulation

The frequency of the modulation is 5 Hz giving a fundamental period of 0.2 s which the waveform repeats over. This is highlighted in Figure 24 which shows the period over which the spectral components are calculated (that is 0.2 s). The spectral components for this waveform are given in Figure 25. Since the time window is 0.2 s the harmonic orders are of 5 Hz (10 harmonic order is 50 Hz component). The spectral components of the modulating waveform itself are shown in Figure 26. From theory the r.m.s. Fourier components for a square wave are given by:

$$C_n = \frac{4}{n\pi}, \; n \text{ odd}$$

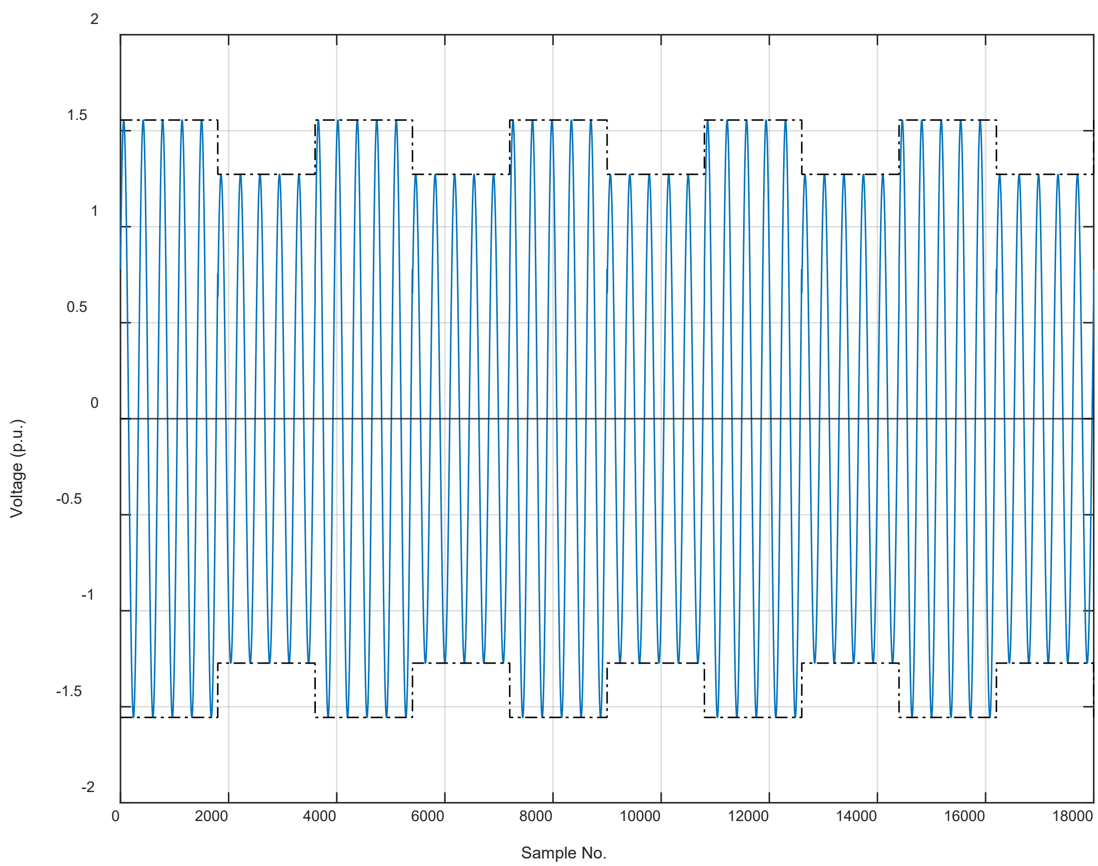


Figure: 23 Square-wave amplitude modulation

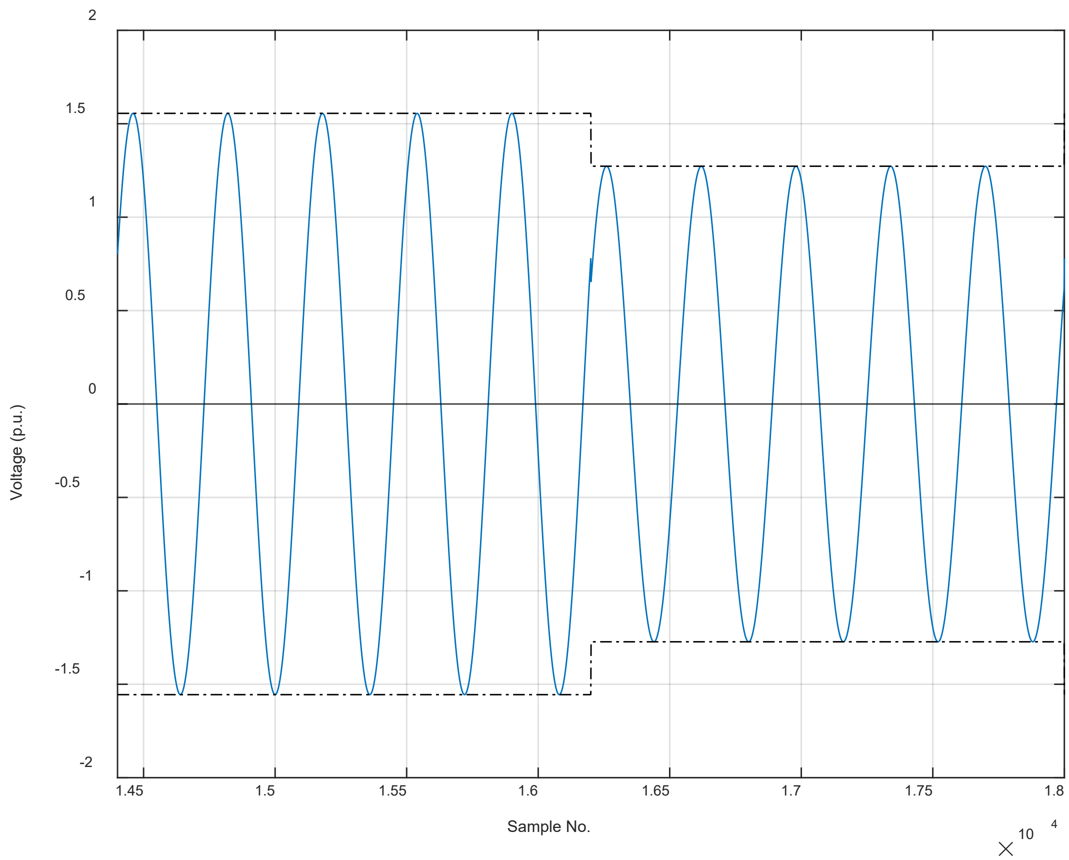


Figure: 24 One cycle for obtaining the spectral components

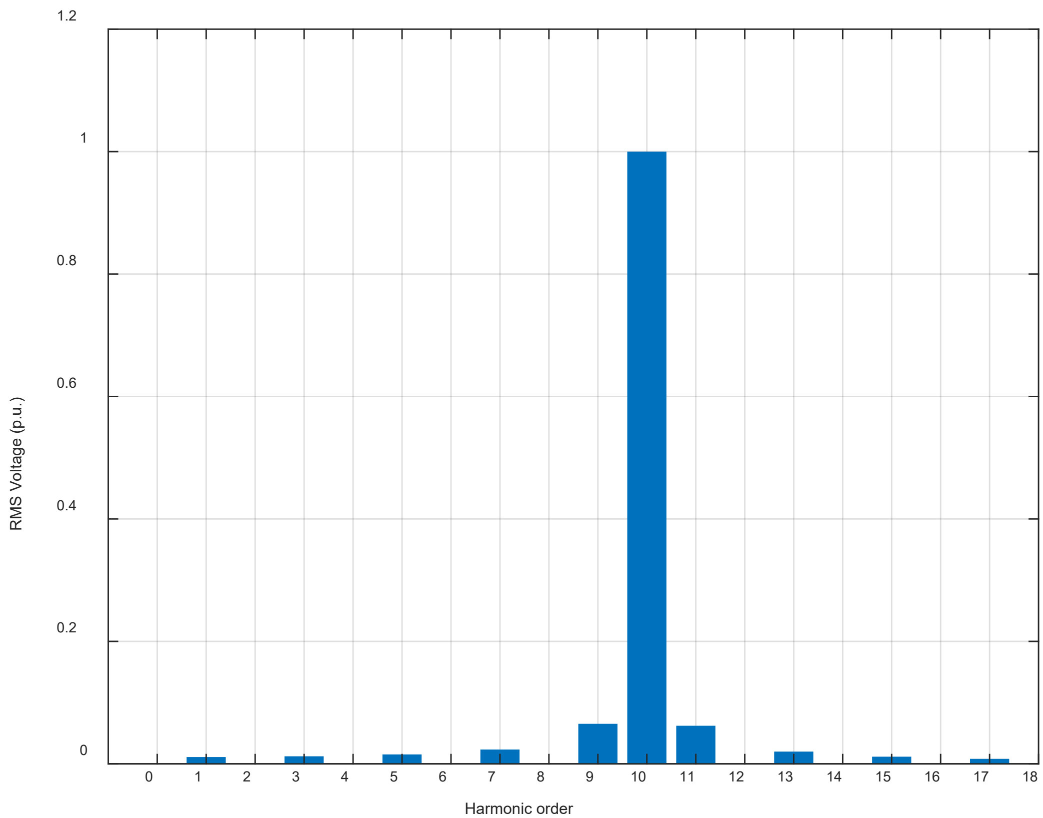


Figure: 25 Spectral components for square-wave amplitude modulation

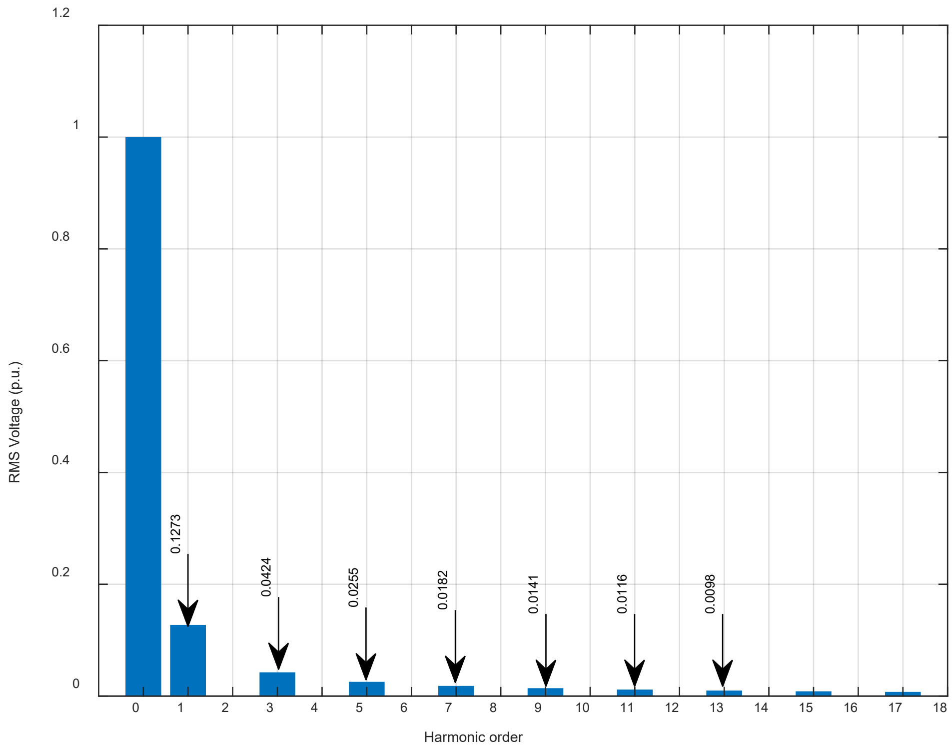


Figure: 26 Spectral components for modulating square-wave waveform

28. Effects

The main effects are:

– Light flicker. The two mechanisms are;

(a) the interharmonic voltages combining with the fundamental (or occasionally harmonics) to give rise to a beat frequency with a modulation frequency in the visible range and

(b) the frequency translation that naturally occurs between the ac side and dc side of a power electronic converter (i.e. electronic ballast) causing modulation of the light output in the perceivable frequency range.

– Unwanted currents in the supply network generating additional energy losses.

– Disturbed operation of electronic equipment such as fluorescent lamps and television receivers. Devices which use the crest voltage, or the zero-crossing can be disturbed if the combination of unwanted frequencies present alters these attributes of the supply voltage (e.g., dimmers).

– Acoustic noise and vibrations (e.g., in inductive coils due to magnetostriction).

– Temperature increase and unwanted torques in induction motors.

- Interference causing maloperation of equipment (e.g., ripple control receivers).
- Overloading or disturbance of equipment due to amplified voltage distortion. With a greater range of frequencies there is a greater the risk of resonant effects.
- Interference with the operation of protection relays (alteration of operating time or pickup current). Both electro-mechanical and solid-state protection relays may be affected [Fuchs2004].
- Metal fatigue in turbine shafts.
- For historical reasons main interharmonic effects, separated into the effect of lighting and non-lighting equipment,

29. Limits

Both IEC and IEEE working groups have been developing limits for interharmonics and assessment methods (see [*IEEE 519:2020, Drapela2020, IEC 61000-4-7 Ed. 2*]). An interharmonic task force has reviewed existing standards and recommendations from around the world. Most standards use fixed interharmonic voltage limits based on the sensitivity of lighting and non-lighting equipment. The task force recommend using the interharmonic subgroup concept of *IEC 61000-4-7*. The benefits are the reduced number of limits required and the ability to contain the amount of data to handle. The disadvantages are, that it can be unnecessarily conservative in some frequency ranges (e.g., around even harmonics) and difficult to measure very low voltage magnitudes around the fundamental with available instruments.

Between d.c. and 40 Hz a limit of 0.1% is imposed to address flicker. From 40 Hz to 60 Hz a limit of 0.2% due to the reduced sensitives at these frequencies. For frequencies between 100 Hz to 2.5 kHz, although a level of 0.5% may be tolerable, this needs to be reduced for frequencies within 10 Hz of harmonic frequencies due to light flicker and possible interference with PLC if present and coinciding with the signal frequency and light flicker. For discrete frequencies between 50th harmonic and 9 kHz the reference value (expressed as the ratio of the r.m.s. value of the voltage at that frequency to the r.m.s. value of the fundamental component) is 0.2%.

When considering a band of frequencies and using a 200 Hz bandwidth, the reference value which should not be exceeded is 0.3%. This is evaluated using equation 5.2. Frequency components in the range 9 to 150 kHz have caused significant problems internationally and must be limited in a similar way as the 2.5 to 9 kHz frequency band.

$$V_b = \frac{1}{V_1}\sqrt{\frac{1}{200Hz}\int_{F-100Hz}^{F+100Hz}\left(V_f^2\right)df} \qquad (5.2)$$

Where:

V_b is the normalised r.m.s voltage within the 200 Hz frequency band.

Table: 18 Interharmonic and High Frequency Limits (See Figure 28)

FREQUENCY	APPLIED TO		REFERENCE LEVEL (%V1)
0 – 40 Hz	Interharmonics	Discrete frequency	0.1%
40 – 60 Hz	Interharmonics	Discrete frequency	0.2%
60 – 90 Hz, 110-140 Hz, 160 -190 Hz, etc	Interharmonics	Discrete frequency	0.5%
H × 50 ±10 Hz range (h odd)	Interharmonics	Discrete frequency	0.3%
H × 50 ±10 Hz range (h even)	Interharmonics	Discrete frequency	0.35%
Ripple frequency		Discrete frequency	0.1%[1]
100 Hz - 2.5 kHz	Interharmonics	Discrete frequency	0.5%
2.5 - 9 kHz	Harmonics / interharmonics	Discrete frequency	0.2%
2.5 - 9 kHz	n/a	Band of frequencies	0.3%
9 - 150 kHz	Harmonics / interharmonics	Discrete frequency	0.2%
9 - 150 kHz	n/a	Band of frequencies	0.3%

[1]Note: While IEC 61000-2-2 recommends a reference level of 0.2%, reference levels for ripple control were still being finalised at the time of writing. For this reason, the level of 0.1% has been retained. Refer to Section 29.1.

The reference value (limit) is determined by the following considerations:

- Light Flicker: This involves looking at the frequencies generated and the perceptibility of these frequencies (see Flicker section).
- Acoustic Noise and vibrations: in the frequency range 1 kHz to 9 kHz the limit is 0.5%. Although the level of disturbance depends on the type of equipment and frequency, above this value the disturbance is likely to be noticeable.
- Compatibility with ripple control: As ripple receivers may respond to as little as 0.3% of the nominal supply voltage any interharmonics above this level can disturb their operation if the frequencies are the same as the operational frequency of the receivers. Hence the reference value is set to 0.2% of the nominal supply voltage. This limit is location specific as different regions will have different ripple frequencies.
- Destruction of thyristor-based equipment due to false-triggering.
- Malfunction of equipment.

The international community is moving towards the use of the interharmonic subgroup concept of *IEC 61000-4-7 Ed. 2* instead of individual interharmonic components. At present *IEC* compliant equipment use a time window of 200 ms (10 fundamental cycle for 50 Hz system and 12 cycles for a 60 Hz system) which gives 5 Hz resolution in the frequency domain[1]. The non-stationary nature of the signal, uncertainty in synchronisation, spectral leakage due to frequency components that are not multiples of 5 Hz (picket fence effect), aliasing all result in inaccuracies in the spectral component magnitudes (e.g., spill-over to neighbouring spectral components either side of the harmonic). The use of subgroups collects the major portion of the energy in the signal in a band of frequencies (illustrated in Figure 27).

[1] Note: there are plans to move to a 320 ms time window giving a resolution of 3.125 Hz.

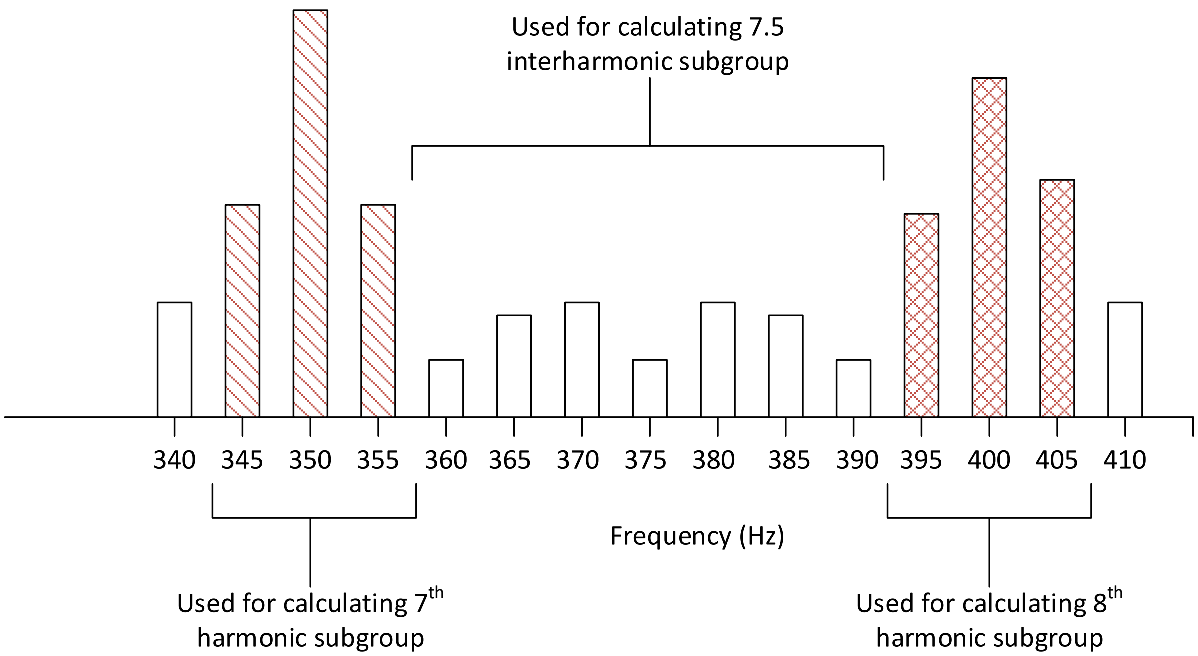


Figure: 27 Concept of subgroups for harmonics and interhamonics

It should be noted that this is more restrictive than limiting individual interharmonic frequencies but given the difficulty of accurately measuring frequency components that are not integer multiples of 5 Hz it is more practical.

The grouping of the spectral components in the interval between two consecutive harmonic components forms an interharmonic group. The r.m.s value of the interharmonic group between orders *h* and *h+1* is designated as $Y_{ig,h}$. Y_C represents the spectral components of voltage (*V*) or current (*I*). For example, the group of interharmonics between *h* = 5 and *h* = 6 is designated as $Y_{ig,5}$ [IEC61000-4-7:2019].

$$Y_{ig,h} = \sqrt{\sum_{k=1}^{N-1} Y^2_{C,(N\times h)+k}}$$

Where:

- *N* is the number of fundamental periods within the window width.
- *k* is the ordinal number (order of the spectral component) based on the frequency resolution *($f_{C,1}$ =1/ T_N). For example, if N=10 then T_N=0.2 s* and *$f_{C,1}$=5 Hz.* Each spectral component is separated by 5 Hz. Therefore $Y_{ig,5}$ involves summing the squares of the 9 spectral/harmonic components of $f_{C,1}$ (5Hz), order 51 to 59. These correspond to 255Hz to 295 Hz (in 5 Hz steps).
- T_N is the width of the time window.

- *h* represents the harmonic order (of the fundamental frequency).
- $Y_{C,n}$ is the r.m.s. value of the corresponding spectral component with frequency $f_{C,n} = \frac{n}{N} f_{H,1}$.

The effect of fluctuations of harmonic amplitudes and phase angles are partially reduced by excluding the spectral components immediately adjacent to the harmonic frequencies (shown in Figure 27). This gives interharmonic centred subgroup, designated $Y_{isg,h}$:

$$Y_{isg,h} = \sqrt{\sum_{k=2}^{N-2} Y_{C,(N\times h)+k}^2}$$

Equally, to improve the assessment accuracy in fluctuating conditions the spectral components on each side of the harmonic (usually 5Hz) shall be grouped to give the harmonic subgroup designated by $Y_{sg,h}$ (shown in Fig. 27).

$$Y_{sg,h} = \sqrt{\sum_{k=-1}^{1} Y_{C,(N\times h)+k}^2}$$

29.1 Ripple control

Ripple control signalling (carrier signal amplitude-modulated by set of rectangular pulses, i.e. telegram) is widely used and uses carriers at harmonic or interharmonic frequencies. The ripple control receiver can response to a signal as low as 0.3% of the nominal supply voltage, therefore, interharmonic voltage in excess of this value can cause disturbance if its frequency is the same as the operational frequency of the receivers. For this reason *IEC 61000-2-2* recommends the reference level of 0.2% of the nominal supply voltage as the interharmonic limit at the defined frequency, in the geographical region that this signalling is used[1].

[1] While Table 18 cites 0.1%, the key objective is to ensure that ripple systems are not compromised in their operation. At the time of writing, the reference levels for ripple control have not yet been finalised. IEC 61000-2-2 recommends the reference level of 0.2% of the nominal supply voltage at the defined ripple frequency. This level is justified considering that ripple control receiver's response level can be as low as 0.3% of the nominal supply voltage; therefore, an unintended interharmonic voltage in excess of this value can cause a disturbance if its frequency is the same as the defined operational frequency of the receivers (IEEE 519:2020). IEEE 519 states: The numerical values reported in the limit curves, as well as the frequency range represented, are not to be intended as prescriptive. Appropriate numbers should be based on specific needs (local, country, conditions, etc.)

29.2 Light flicker

When two frequencies exist there are modulation products that can cause light flicker. For example the beat product of 3rd harmonic and interharmonic can cause light flicker. Since the even harmonic levels are lower than odd harmonics the interharmonic levels surrounding even can be higher than those around the odd harmonics.

Figure 28 shows two interharmonic sensitivity levels. The red lines show the sensitivity to incandescent lights and other traditional appliances, while the black line the indicative limits for interharmonics. The indicative limits (represented by the black lines) of 0.1% from DC to 40 Hz takes into account possible effects on incandescent lighting and non-lighting equipment. A second level of 0.3% has been fixed in a ±10 Hz range around the odd order harmonic frequencies, while a higher level of 0.35% around the even harmonics, in order to take into account the sensitivity of modern lighting equipment. The sensitivity of non-lighting equipment requires a restrictive limit (0.1%) for interharmonics in the subharmonic range. Outside these regions a 0.5% limit is tolerable.

29.3 Non-lighting equipment

IEC 61000-3-6 has suggested that a level of 0.5% for the remaining interharmonic frequencies is tolerable because this should avoid problems with non-lighting equipment (e.g., with televisions, induction rotating machines audible noise and vibrations and under-frequency relays).

The numerical values in this section are not intended as “prescriptive”. Instead they are indicative levels that may be appropriate. Appropriate numbers should be based on location and conditions (whether ripple control is used and at what frequencies).

For regions that do not use ripple control a limit of 0.5% for interharmonic subgroups except around odd order harmonics (0.3%) and fundamental (0.2%) [e.g. Figure 28].

Reference [IEEE 519:2020] indicates that testing the sensitivity of lighting equipment (LEDs) to single interharmonic components (i.e. voltages magnitudes and frequencies producing Pst = 1) has shown that in a range around the system fundamental frequency strict limits (e.g., 0.2% of the rated power frequency voltage at the PCC) should be applied. It was evident that over twice the system fundamental frequency, interharmonic voltages should be limited to values up to 0.3% in a proper range around odd harmonics. Analysing the sensitivity of non-lighting equipment, it was evident that even more restrictive limits (e.g., 0.1%) should be applied in the subharmonic range (i.e. below the system fundamental frequency).

In summary, taking into account these consideration the interharmonic voltages should be limited to:

(a) 0.1% in the subharmonic range.

(b) 0.2% around the fundamental (at a proper distance away of about +/-10 Hz).

(c) 0.3% around odd harmonics (at a proper distance away of about +/-10 Hz).

(d) > 0.35% around even harmonics.

These limits are displayed graphically in Figure 28. These limits are very restrictive so they should be applied if equipment is installed that requires such limits. An investigation needs to be performed to demonstrate their necessity. The magnitude of even order harmonics is lower than odd order harmonics, which justifies the higher interharmonic limit around even order harmonics (the beat products of the harmonic and interharmonic important).

Rather than setting limits to accommodate the most sensitive devices, work on the lack of immunity for some devices (e.g., new lighting technologies) is necessary.

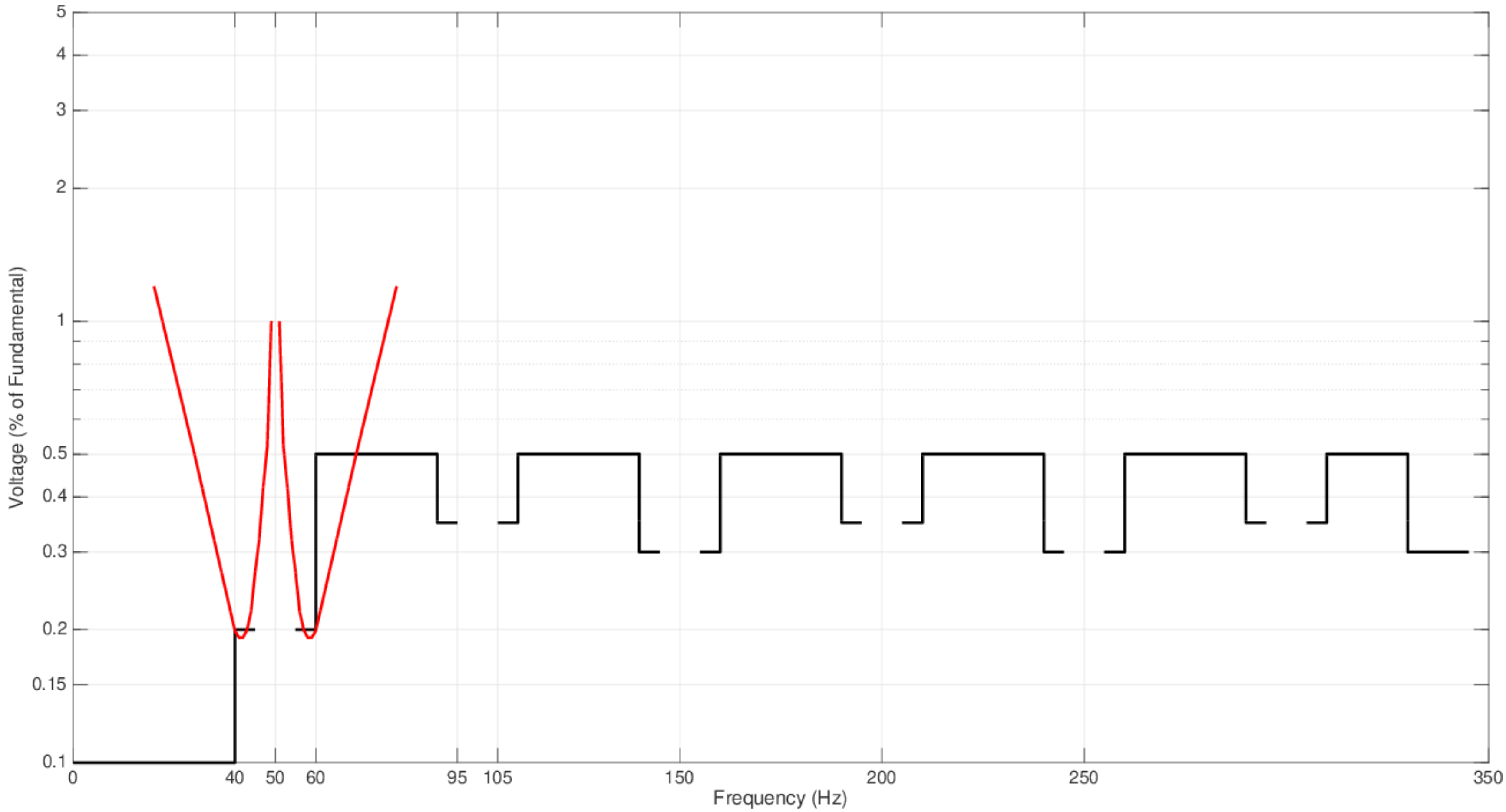


Figure: 28 Displays an example of a limit curve using a combination of IEC interharmonic subgroups limited and the IEC Flickermeter characteristics

30. Emission Assessment

Ideally, measurements shall be made using monitoring equipment compliant with the requirements of *AS/NZS 61000.4.30 Class A.* Flagged data as defined in *AS/NZS 61000.4.30* should be removed before assessment. Measured values are compared with the limits in Table 18 to determine compliance.

31. Mitigation

31.1 Subharmonic (f < 50 Hz)

Mitigation methods depend on the source and whether or not the frequency components are always at the same frequency. If they are, as in traction power supplies, passive filtering can be performed.

If the frequencies involved change with change in operating point, as in the case of cycloconverters, these low frequencies are particularly hard to filter. This often makes passive filtering impractical, and some form of active filtering is required.

31.2 Interharmonics above fundamental frequency (50 < f ≤ 2500 Hz)

The need to avoid light flicker often creates the most stringent restriction on interharmonic levels as the transfer of these through electronic ballasts creates visible flicker. Again the stability of the frequencies involved will dictate the most cost effective solution.

31.3 High frequency Emissions (Harmonics and Interharmonics above 2.5 kHz)

High frequency emissions may be caused by devices which are not synchronised with the supply frequency (high frequency noise) or synchronised with the supply frequency. The frequencies of interest can extend up to 10 kHz and often beyond. Switching frequencies of 10 - 40 kHz are not uncommon.

The use of PWM techniques in inverters and rectifiers greatly reduces the low order harmonics. However it causes distortion at higher frequencies, with sidebands around multiples of the carrier frequency. Processes that have a chaotic characteristic such as discharge lamps and arc furnaces generate high frequency noise. Although the conducted emissions from these higher frequency components do not propagate far into the electrical network they can still constitute a compatibility problem with nearby equipment and therefore these emissions should be limited. Broadband passive filtering is often the most economical solution.

The other restriction is the resulting d_v/d_t caused by the emission as this can cause false triggering of semiconductor devices (e.g. thyristors) and thereby destruction of equipment. This is remedied by the use of RC filters to limit the d_v/d_t.

With the increasing use of voltage source converters the level of high frequency emissions is expected to increase over time.

Interference and mal-operation has been reported between power line communication equipment and household equipment. The main solution is by improving the immunity of the equipment being affected to these frequencies (i.e. installing a filter on the equipment). Equipment immunity standards in the 6 to 150 kHz frequency range are lacking.

SECTION 6: Voltage Fluctuations and Flicker

32. Introduction

Voltage fluctuations are repetitive or random variations in the magnitude of the supply voltage which arise due to fluctuations in the real and reactive power ($\Delta P, \Delta Q$) drawn by loads. The per unit change in voltage at a point can be expressed as:

$$\frac{\Delta V}{V} = -(\Delta P.R + \Delta Q.X) \quad (6.1)$$

Where R, X are the per unit real and reactive components of the impedance seen by the fluctuating source and $\Delta P, \Delta Q$ are the per unit values of the changes in real and reactive power respectively. If the resistive part R is negligible the above can be expressed as:

$$\frac{\Delta V}{V} = -\frac{\Delta Q}{FL} \quad (6.2)$$

Where *FL* is the fault level in per unit.

The two main problems associated with voltage fluctuations are: (a) light flicker and (b) rapid voltage changes, even within the normal operational voltage tolerances.

33. Sources

Voltage fluctuations are caused by:

- Arc furnaces.
- Frequent motor starts.
- Woodchippers.
- Mine hoists.
- Rolling mills.
- Car shredders.
- Arc welders.
- Intermittent generation (e.g. PV and wind generation).

34. Effects

The main effect of voltage fluctuations is light flicker in lighting equipment causing eye irritation. Flicker occurs as result of amplitude modulation of the voltage envelope. The human eye-brain connection has different sensitivity to different modulation frequencies, hence there is the need to weight these voltage fluctuations based on frequency (repetition rate). The human perceptibility to fluctuations has been evaluated using a large sample group and this found fluctuations in the range 1 to 35 Hz were significant and the human eye is most sensitive to light fluctuations at a modulation frequency of 8.8 Hz (~16 changes/second). Other effects of voltage fluctuations include: voltage being outside accepted normal tolerance, interference with communication equipment, spurious tripping of relays and electronic equipment and mal-operation of equipment with control systems which depend on the phase angle of voltage waveform.

35. Limits

The compatibility levels of P_{st} and P_{lt} for LV power systems as defined in *IEC 61000-2-2* are given in Table 19. Such values are not defined for MV, HV or EHV systems.

Table: 19 Compatibility levels for P_{st} and P_{lt} in LV and MV power systems

P_{st}	1.0
P_{lt}	0.8

Planning levels are levels that are used for planning purposes to limit the impact of the combined effect of customers loads have on the supply system. Planning levels are specified by the supply utility for all voltage levels and can be considered as internal quality objectives. Planning levels are specified equal to or lower than compatibility levels. Only indicative values may be given because planning levels will differ from case to case, depending on network structure and circumstances. As an example, see the planning levels for P_{st} and P_{lt} presented in Table 20 (from *IEC 61000.3.7:2008).*

Table: 20 Indicative values of planning levels for P_{st} and P_{lt} (LP_{st} and LP_{lt}) in MV, HV and EHV power systems

	MV	HV & EHV
L_{Pst}	0.9	0.8
L_{Plt}	0.7	0.6

Like many power quality phenomena, flicker also propagates from one voltage level to another voltage level. With regard to propagation of flicker in radial power systems (where no measured values exist otherwise), it is assumed that;

- The flicker level at a given voltage level will transfer to lower voltage levels with no attenuation (field measurements indicate that the associated transfer coefficients (TP_{stML} or TP_{stHL}) are lower than unity, e.g., 0.8).
- Flicker from lower voltage systems does not transfer to higher voltage systems i.e. the transfer coefficient is zero.

Flicker transfer coefficients can be established by carrying out synchronised flicker measurements. Appendix B of *AS/NZS TR IEC 61000.3.7:2012* gives further details on this topic including example values based on measurements.

In developing the values in Table 20 it has been assumed that the flicker transfer coefficient between MV or HV power systems and LV systems is unity (i.e. T_{PstML} or T_{PstHL} = 1.0).

36. Emission Assessment

36.1 Introduction

The international flickermeter also known as the *IEC* flickermeter (see *IEC 61000-4-15:Ed. 2, 2010-08)* is used to assesses the light flicker by directly measuring the voltage. Embodied in the flickermeter is the transfer characteristic of a 60 W incandescent lamp (voltage fluctuations to light fluctuations) along with synthesis of the eye-brain response to light fluctuations. The flickermeter gives a quantitative statistical measure of the irritation caused by light flicker. However, for newer lighting technologies (e.g. compact fluorescent lamps) the *IEC* flickermeter is not an appropriate device for assessment as the transfer from voltage fluctuations to light flicker is different to an incandescent lamp and hence the irritation is different. Another issue is that due to the transfer characteristics of power electronic ballasts, frequencies in the electrical network well outside the perceptible frequency range can couple to light fluctuations within the perceptible frequency range.

For example 175 Hz voltage fluctuation can cause 25 Hz light flicker. This transfer is very much dependent on the design of the electronic ballast and using a different design will often eliminate the transfer causing the light flicker in the perceptible frequency range.

At present light-based flickermeters are still being researched and developed and hence *IEC 61000-4-15:Ed. 2, 2010-08* is still the best standard to use.

IEC 61000-4-15 gives two quantities to characterise flicker severity. The first is the short term flicker severity index P_{st}, which is measured over a period of 10 minutes. The second is the long term flicker severity index P_{lt} obtained over each 2 hour period and is evaluated using 12 consecutive values of P_{st} (j = 1,2, …12) as given below:

$$P_{lt} = \sqrt[3]{\frac{1}{12}\sum_{j=1}^{12} P_{stj}^{3}} \qquad (6.3)$$

The general summation law for flicker allows summation of flicker caused by different sources using:

$$P_{st} = \sqrt[\propto]{\sum\nolimits_{j} \quad P_{stj}^{\propto}} \qquad (6.4)$$

Where P_{st} is the resultant flicker level, P_{stj} is the flicker produced by the j^{th} flicker source (N is the number of flicker sources) and α is the summation exponent. In general, α = 3 and other suitable values are listed in *IEC 61000.3.7.* α is selected depending on the nature of operation of the fluctuating loads. For example, in relation to coincident motor starts α = 1.0 (and α = 4 if simultaneous voltage fluctuations are unlikely).

Compliance for flicker is determined by comparing the measured flicker values with planning limits.

The minimum flicker measurement period is 1 week of normal but worst operation of the installation considering contingencies. More than one index can be used to assess an installation:

- 95% probability weekly value of P_{sti} should not exceed the planning level.
- 99% probability weekly value of P_{sti} may exceed the planning level by a factor in the range 1 -1.5. This factor needs to be specified by the network operator.
- 95% probability weekly value of P_{lti} should not exceed the planning level.

The measurements methods should be in line with *IEC 61000-4-15* and *IEC 61000-4-30 Class A*. Any data flagged in accordance with the latter standard should be removed from the data (i.e. not incorporated in the assessment).

36.2 Flicker Emission allocation – MV Systems

Emission allocation is carried out in three stages. In Stage 1, small fluctuating loads are connected without detailed evaluation. In Stage 2, the global flicker absorption capacity is apportioned to individual customers based on their size in relation to system capacity. Stage 3 covers customers who require emission allocation allowances that exceed the Stage 2 limit.

Stage 1

In Stage 1 the customer's apparent power variation (ΔS) is compared with the short-circuit capacity (S_{sc}) at the point of common coupling (PCC) together with the corresponding number of voltage changes. The ratio ($\Delta S/S_{sc}$) is approximately equal to the relative voltage change at the PCC. The number of changes per minute can be estimated from the load type or measured from the voltage/current waveform (a voltage dip followed by a recovery gives two changes). This stage effectively assesses if the impact of the disturbing load on the system is small and can be neglected. It is to be noted that the (ΔS) can be lower, equal or greater than the rated power of the load under consideration (e.g., a direct on-line started induction motor can draw 3 - 8 times rated current)

Table: 21 Stage 1 limits for relative changes in power as a function of the number of changes per minute variation limits

Number of changes per minute	Ratio Limit ($\Delta S/S_{sc}$)max
R > 200	0.1
10 ≤r≤ 200	0.2
R < 10	0.4

Example 6.1 (reference AS HB264-2003):

A mini-rolling mill that is connected to an MV system leads to the voltage profile shown in Figure 29. Determine whether the rolling mill can be connected under Stage 1.

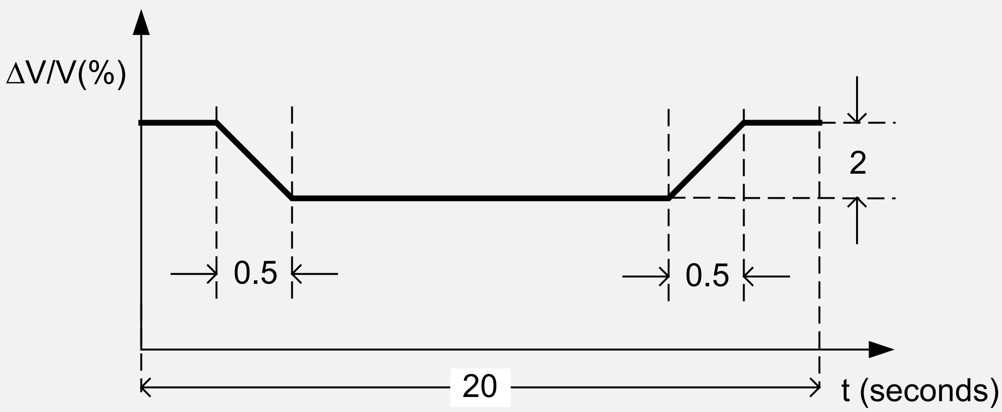


Figure: 29 Time variation of r.m.s. Voltage

The number of voltage changes per minute is 6. From Table 21 the allowable voltage change is only 0.4% (for $r < 10$) which is less than the voltage change of 2% (equal to $\Delta S/S_{sc}$) produced by the mill and hence cannot be connected under Stage 1.

Stage 2

For customers at the MV level, the calculated global absorption capacity of the MV system determines the flicker allocation that is shared between them taking into account the flicker that may propagate from the HV system. In the flicker allocation process the general rules governing flicker propagation listed in Section 35 are applied.

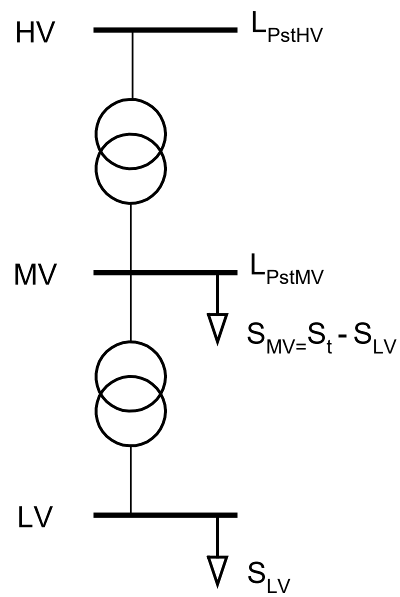


Figure: 30 Time variation of r.m.s. Voltage

Considering the system shown in Figure 30, while ignoring the flicker propagating from the LV loads to the MV levels and taking into account flicker propagating from the HV system to the MV level, the global emission capacity of the MV level is given by:

$$G_{PstMV} = \sqrt[\alpha]{L_{PstMV}^{\alpha} - T_{PstHM}^{\alpha}\ L_{PstHV}^{\alpha}} \tag{6.5}$$

Where:

G_{PstMV} - maximum global contribution (could be P_{st} or P_{lt}) of the local loads to the flicker level in the MV system.

L_{PstMV} - flicker planning level (could be P_{st} or P_{lt}) in the MV system.

T_{PstHM} - flicker transfer coefficient from the upstream HV system to the MV system.

L_{PstHV} - flicker planning level (could be P_{st} or P_{lt}) in the upstream HV system.

α - summation exponent (e.g. 3).

The global emission capacity G_{PstMV} (or G_{PltMV}) is then allocated to individual installations using equations 6.6 and 6.7.

$$E_{Pst} = G_{PstMV} \sqrt[\alpha]{\frac{S_i}{(S_t - S_{LV})}} \tag{6.6}$$

$$E_{Plt} = G_{PltMV} \sqrt[\alpha]{\frac{S_i}{(S_t - S_{LV})}} \tag{6.7}$$

Where:

S_i – agreed power of the i^{th} customer installation.

S_t – total supply capacity of the MV system taking into account future system and load growth.

S_{LV} – total power of the LV installations considering future load growth.

There may be situations where the existing flicker level may be more than that which should have been allocated using the above approach. In such cases:

(a) the emission limits to new installations can be reduced or

(b) some of the unused flicker emission allowances at HV levels can be reallocated to MV voltage levels or

(c) the flicker absorption capacity of the MV level can be increased.

Appendix C of *AS/NZS TR IEC 61000-3-7:2012* gives some examples detailing (b) above.

For users with comparatively low agreed power the imposed emission levels based on the above approaches may be too restrictive. The recommended minimum emission levels can be selected by the user to allow a reasonable level for special cases. Table 22 gives default emission limits E_{Pst} and E_{Plt} that can be considered.

Table: 22 Minimum emission limits

E_{Psti}	E_{Plti}
0.35	0.25

Example 6.2: (reference AS HB264-2003):

Assuming the planning levels of Table 20 and a unity HV to MV flicker transfer coefficient, determine the global emission allowance for an MV system.

$$G_{PstMV} = \sqrt[3]{0.9^3 - 1.0^3 0.8^3} = 0.60$$

Assuming the planning levels of Table 20 and a HV to MV flicker transfer coefficient of 0.8, determine the global emission allowance for an MV system.

$$G_{PstMV} = \sqrt[3]{0.9^3 - 0.8^3 0.8^3} = 0.78$$

Example 6.3:

A rolling mill with an agreed MVA rating of 3 MVA is connected to a MV busbar with a capacity of 30 MVA. Calculate the emission allowance for the rolling mill assuming global emission capacity of 0.78. Assume no LV load is connected to the MV busbar.

$$E_{Pst} = 0.78\sqrt[3]{\frac{3}{30}} = 0.36$$

Stage 3

Stage 3 allows allocation of flicker levels that exceed Stage 2 levels. The possible reasons for Stage 3 allocation that can be used by a utility are listed below:

(a) Some customer installations do not contain significantly fluctuating components in the power they draw although they are given the full emission allowance based on the agreed power and hence system flicker absorption capacity is not utilised fully.

(b) The general summation law may be conservative, i.e. there may be loads which do not operate simultaneously.

(c) Higher global emission capacity can be established by reallocating some of the unused flicker emission allowance from the HV system to the MV system and/or the actual HV to MV flicker transfer coefficient can be smaller than a default value of 1.0.

(d) Considering possible variations to network configurations it is possible that a load exceeds the Stage 2 limits only under a degraded network condition that prevails only occasionally.

The utility must undertake careful network studies considering the pre-existing flicker levels. Higher than normal flicker emission levels can be allocated on a conditional basis.

A summary of the flicker emission allocation processes described above is given in the flowchart of Figure 31 [*AS/NZS TR IEC 61000-3-7:2012].*

36.3 Flicker Emission allocation - HV Systems

As in the case of MV systems emission allocation is carried out in three stages. In Stage 1, small fluctuating loads are connected without detailed evaluation. In Stage 2, the global flicker absorption capacity is apportioned to individual customers based on their size in relation to system capacity. Stage 3 covers customers who require emission allocation allowances that exceed the Stage 2 limit.

Stage 1:

Allocation in Stage 1 is similar to the methodology adopted under Stage 1 for MV systems.

Stage 2:

The allocation for each customer is determined by their demand in relation the total demand of all the customers on the HV system. The '*total available power*' (S_{tHV}) does not include the loads on MV and LV systems as their flicker contributions can be neglected. Noting that S_t is the total power available for all HV customers the ratio S_i/S_t is the basic quantity which determines the allocation under Stage 2. To find the 'total available power' one of three methods are available depending on the data and assessment level.

The **first approximation** (method 1) simply sums the agreed power of each HV customer connected or to be connected to the PCC. This approximation is considered to be conservative and may lead to incorrect results if important fluctuating loads are present in the vicinity of the HV busbar to which a new installation is to be connected.

The **second approximation** (method 2) incorporates connecting busbars by finding the influence coefficients. The loads at each connecting busbar are referenced back through these coefficients to the PCC. Details of this process can be found in *AS/NZS TR IEC 61000-3-7:2012* including a more rigorous third method that is based on short circuit studies.

The individual emission limits are calculated using:

$$E_{Psti} = G_{PstHV} \sqrt[\alpha]{\frac{S_i}{S_{tHV}}} \tag{6.8}$$

$$E_{Plti} = G_{PltHV} \sqrt[\alpha]{\frac{S_i}{S_{tHV}}} \tag{6.9}$$

Where:

E_{Psti}, E_{Plti} - emission limit for customer i.

G_{PstHV}, G_{PltHV} - global emission capacity of the flicker level in the HV system.

G_{PstHV}, G_{PltHV} can be determined as in the case of MV systems by considering planning levels and the flicker transfer coefficients. Further discussion on this topic is given in *AS/NZS TR IEC 61000-3-7:2012.*

Customers with low agreed power can be given flicker emission allowances as given in Table 20 as the above approaches may be too restrictive.

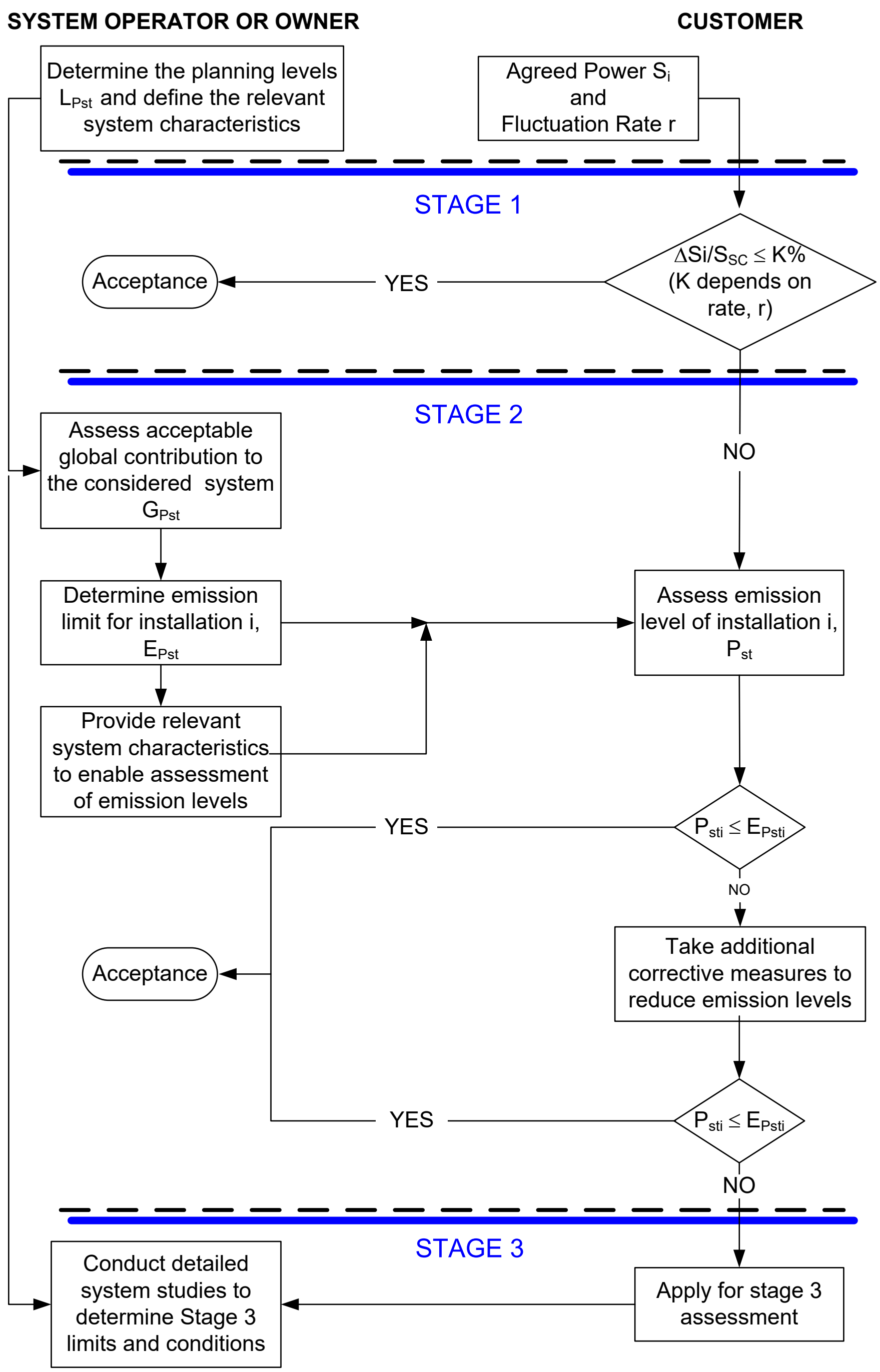


Figure: 31 Diagram of evaluation procedure [AS/NZS TR IEC 61000-3-7:2012]

Stage 3

The discussion given under Stage 3 for MV systems applies equally here.

36.4 Emission assessment

The emission level is specified as the magnitude of the flicker which an installation gives rise to at the point of evaluation.

The minimum flicker measurement period is 1 week of normal but worst operation of the installation considering contingencies. More than one index can be used to assess an installation:

- 95% probability weekly value of P_{sti} should not exceed the emission allocation EP_{sti}.
- 99% probability weekly value of P_{sti} may exceed the emission allocation EP_{sti} by a factor in the range 1 -1.5. This factor needs to be specified by the network operator.
- 95% probability weekly value of P_{lti} should not exceed the emission allocation EP_{sti}.

The measurement methods should be in line with *IEC 61000-4-15* and *IEC 61000-4-30 Class A.* Any data flagged in accordance with the latter standard should be removed from the data (i.e. not incorporated in the assessment) and in working out the indices listed above.

36.4.1 Pre-connection assessment

It is advisable to carry out pre-connection studies on flicker emission using available network and installation data. *Appendix E* of *AS/NZS TR IEC 61000-3-7:2012* gives simplified approaches that can be used to determine (at the pre-connections stages) the emission caused by installations which lead to periodic and aperiodic voltage fluctuations. For the application of these methods known shapes of voltage changes (e.g., ramp, double step, sinusoidal and triangular) and their magnitudes are required.

With regard to a new arc furnace connection, knowing the measurement results of similar furnaces already in operation, short circuit level (S_{sc}) at the point of connection where the new furnace is to be connected and the short circuit power of the new furnace (S_{scf}) (i.e., from the short circuited electrode test), the flicker emission by the new furnace can be predicted using:

$$P_{st95\%} = K_{st}\frac{S_{scf}}{S_{sc}} \qquad (6.10)$$

Where:

K_{st} – is the characteristic flicker emission factor (recommended values are given in *Appendix E* of *AS/NZS TR IEC 61000-3-7:2012*)

36.4.2 Post-connection assessment

Measurement of flicker emission level where the background levels are low (P_{st} < 0.5) can be carried out using two sets of measurements:

(a) with the installation and compensating equipment connected and

(b) with the installation and any compensating equipment disconnected.

The second value is subtracted from the first value using a suitable summation law (e.g. α = 3) to determine the emission by the installation as given below:

$$E_{Psti-load} = (P_{st-postconnection}{}^{\alpha} - P_{st-preconnection}{}^{\alpha})^{\frac{1}{\alpha}} \quad (6.11)$$

For situations where the background level is high (P_{st} > 0.5) more refined methodologies should be used to assess an installation. *Appendix E of AS/NZS TR IEC 61000-3-7:2012* gives several of these approaches (both simplified and complex).

36.5 Rapid Voltage Changes

The need to maintain the voltage magnitude within narrow limits dictates that customers should not produce significant voltage variations, even if they are tolerable from the point of view of flicker levels. In this context rapid voltage changes are changes in fundamental frequency r.m.s. voltage over several cycles. The mechanisms for this change are detailed in Section 43 (e.g., motor starting and capacitor bank switching).

36.5.1 Compatibility levels and planning levels

Under normal operating conditions, in MV networks rapid voltage changes (*ΔV/V*) should be limited to 3%. However, voltage changes exceeding 3% can occur infrequently.

No summation laws exist for rapid voltage changes as the coincidence of voltage changes has a very low probability. Indicative planning levels for rapid voltage changes are given in Table 23.

36.5.2 Emission limits

The individual emission must be derived based on the adopted planning levels on a case by case basis. When all installations are operating together the combined effects should not cause voltage changes that exceed the adopted network planning levels.

36.5.3 Emission assessment

No standardised methods exist for measurement of individual emission levels. It is recommended that assessment be based on the measurement of r.m.s. voltage changes considering only the fundamental frequency (i.e., transients removed) where shortest possible multi-cycle window is used to avoid excessive smoothing of the fundamental frequency voltage changes.

The measurement period is one week covering normal operation of an installation and the emission level should be based on the worst case value (not the emission level that prevails over 95% of the measurement period).

Table: 23 Indicative Planning Levels for Rapid Voltage Changes as a Function of the Number of such Changes in a given Period

Number of changes (*n*)	**$\Delta V/V_N$ (%)**	
	MV	HV/EHV
n ≤ 4 per day	5-6	3-5
n ≤ 2 per hour and >4 per day	4	3
2 < n ≤ 10 per hour	3	2.5
10 < n ≤ 100 per hour	2	1.5
100 < n ≤ 1000 per hour	1.25	1.0

Note: The last two rows of Table 23 (covering frequent fluctuations of more than 10 per hour) are no longer part of *IEC TR 61000.3.7:2008* or its derivatives like *AS/NZS 61000.3.7:2012*, but they were part of the first edition of this standard, and are included here in case limits need to be set by a utility as it seeks to fulfil or prescribe its default distributor agreement obligations.

High values may be permissible under abnormal system conditions. In addition to the above planning levels, engineering assessment is required in the case of motor starting. The large permissible voltage range at HV/EHV is due to large range of voltage levels covered.

IEC TR 61000.3.7:2008 (and *AS/NZS 61000.3.7:2012*) make the distinction between r/min values to denote changes in power for flicker emission (refer to Table 21), and n values to denote rapid voltage changes for planning levels.

Although there is no standardised measurement method for rapid voltage changes the following should be considered:

- Only the power frequency is considered (the oscillatory transients are removed).
- The shortest possible multi-cycle window should be used to avoid artificially smoothing the r.m.s. fundamental frequency voltage change.
- The minimum measurement period is one week of normal business activity.
- The worst case of the rapid voltage changes is considered when assessing emission level (not based on 95% of time).

36.6 Perceptibility of Voltage Fluctuations

Figure 32 displays an idealised sinusoidal modulation of the fundamental voltage. The perceptibility curves (Figure 33~~)~~ show that the human eye-brain are very sensitive to small variations at sub-synchronous frequencies. The UIE Flicker-meter *(IEC 61000-4-15 Flicker-meter)* is based on voltage measurements as these are easy to take. It contains blocks that model the low pass characteristics of a 60 W incandescent lamp as well as an eye-brain model. This gives quantitative measurements of the short-term (P_{st}) and long-term (P_{lt}) light flicker that would be experienced in a 60W incandescent lamp. However, this flicker-meter is not appropriate for other lighting technologies as the voltage to illuminance is different. The transfer from voltage fluctuations to light flicker is very dependent on the design of the power electronics (controls, DC capacitor size, etc) and varies greatly from model to model. A light-based flicker-meter can measure the light flicker irrespective of the lighting technology. However, these suffer from size (testing chamber) and in-situ measurements are influenced by the surrounding surfaces. Different levels will be measured for a luminary depending on the environment.

The human eye can perceive light flicker in the range 1 – 35 Hz approximately. If a sinusoidal modulation (frequency ω_m) of the fundamental voltage (ω_1), as shown in Figure 32, is applied to a resistive element (filament) the power has frequency components at DC, ω_m, (ω_m+2ω_1), (ω_m-2ω_1), 2ω_m, 2(ω_m+ω_1), 2(ω_1-ω_m). The last three terms are generally negligible as their magnitude is proportional to the square of the modulation amplitude, which is small. The ω_m term gives the direct sensitivity between 1 - 35 Hz. The (ω_m-2ω_1) term gives a sensitivity for a modulation frequency between 50 and 100 Hz and 100 to 135 Hz as these result is visual components in the 1 - 35 Hz range. This is clearly seen in Blue line representing the incandescent lamp in Figure 34. No modulation of a frequency greater than approximately 135 Hz is perceptible. However, power electronics driving modern luminaries have a different transfer between voltage and luminance. Light variation in the perceptible 1-35 Hz range occur with high modulation frequencies due to modulation products around harmonic frequencies caused by the switching action of the power electronic converters.

This is clearly evident in the Green and Red lines in Figure 34 which are measurements for two LED lamps. Most work has been focused on visible perception, however, ocular micro tremor (OMT) and eyestrain due to long-term exposure to fluctuating illuminance should be considered in selecting lighting equipment (e.g., considering the switching frequency and hence modulating frequency, capacitance on DC bus, and sensitivity of the controller).

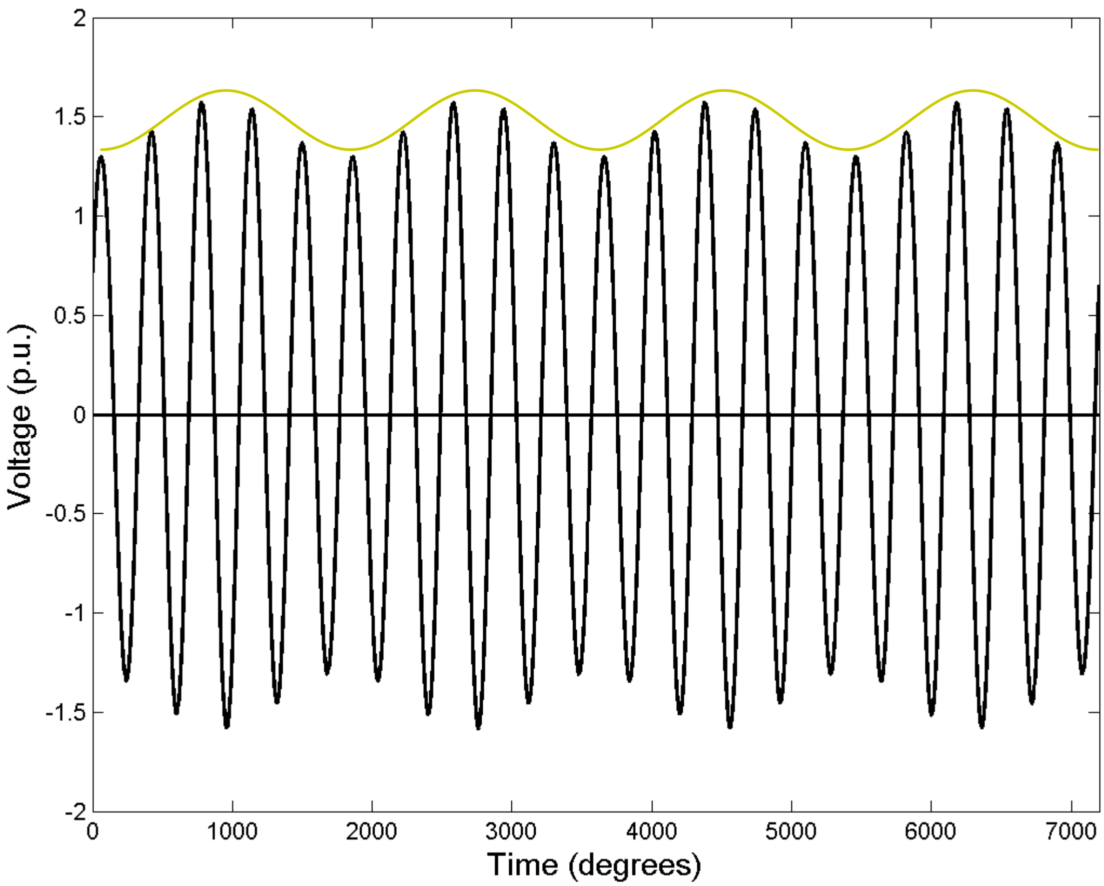


Figure: 32 Voltage fluctuations due to sinusoidal modulation

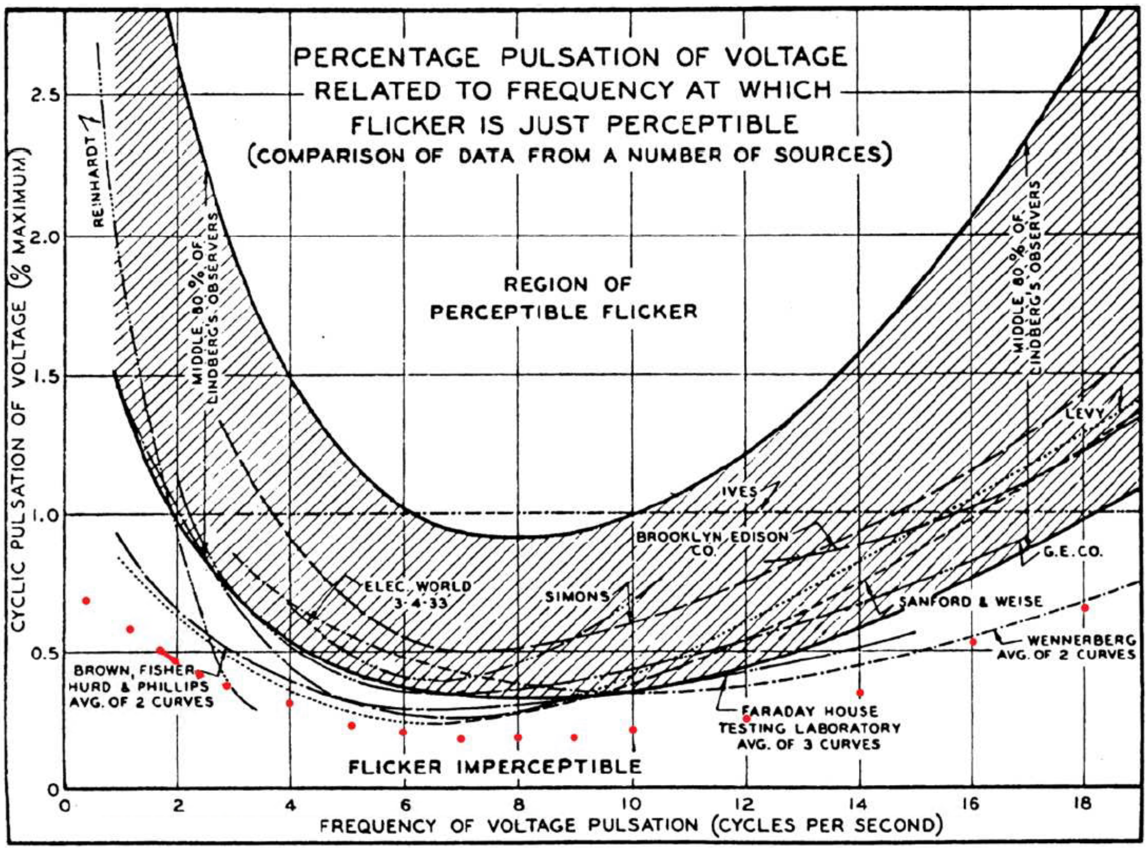


Figure: 33 Perceptibility to voltage fluctuations (Red markers indicating IEC levels).

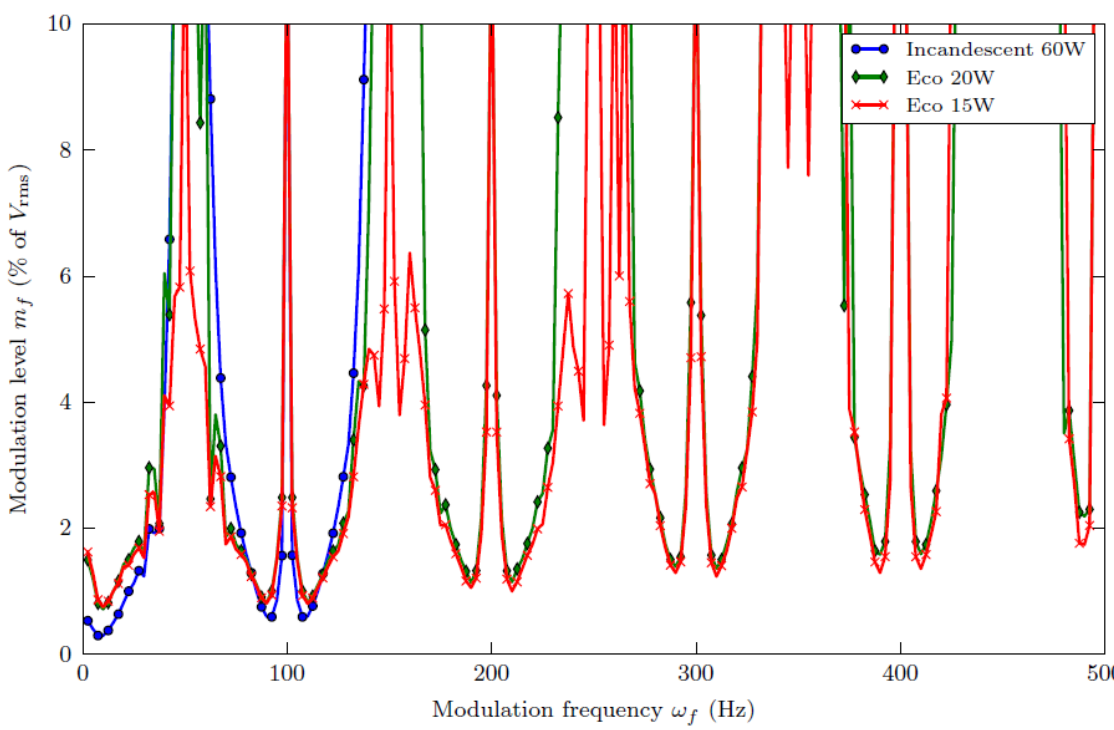


Figure: 34 Modulation level (square) limit for Perceptibility

SECTION 7 - Voltage Dips/Sags

37. Introduction

Voltage dip/sag is when the r.m.s. voltage falls to less than 90% of nominal for a period of 1 minute or less. Allowable voltage dips/sags are closely linked to the immunity of equipment. The ITIC curve (shown in Figure 35) is a voltage tolerance curve which shows the region for which equipment should be able to tolerate. It covers both voltage dips and voltage swells.

38. Sources

The main sources of voltage dips are:

- Transmission system faults (generally limited to several cycles duration).
- Parallel MV feeder faults (0.5 - 1 second duration).
- Supply feeder with successful reclose (voltage falls to very low value).
- Nearby motor starting (shallow dip of long duration).

39. Effects

The main affect is the loss of production due to one or more of the following:

- Digital clocks reset.
- Computers and PLCs reset.
- AC contactor drop-out.
- VSDs stopping.
- Incorrect deposition in manufacturing.
- Product outside acceptable manufacturing tolerance.

40. Limits

A measure of the immunity of computer equipment to voltage dips is given by the lower limit of the *ITIC Curve* (Figure 35). Although designed for computer equipment, the immunity of other equipment is often tested against the ITIC Curve. This is due to the lack of internationally accepted limits for immunity of other class of equipment to voltage dips[1].

Many sources of voltage dips are unplanned events in which an emission allocation is inappropriate. However, for events for which an emission allocation is appropriate (e.g., motor starting)[2], in accordance with the practice of 10% margin between the compatibility limit and planning level, the deviation from nominal voltage is multiplied by 0.90 to give a planning level as a deviation from nominal voltage. This is then converted to a retained voltage limit (see Table 23).

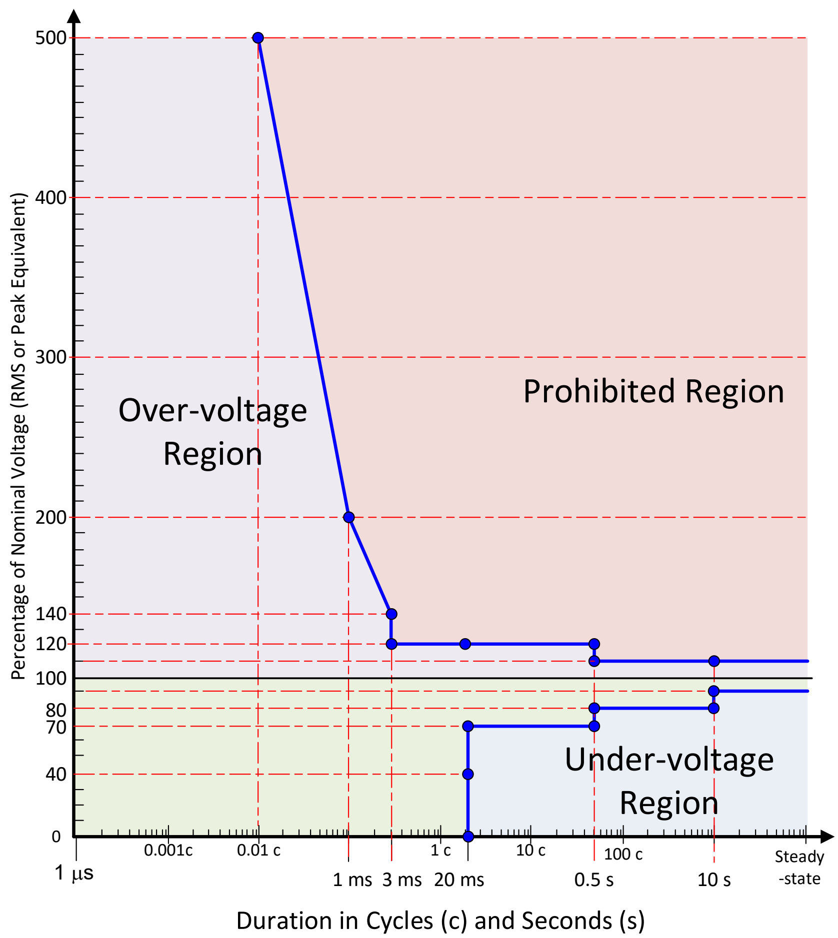


Figure: 35 ITIC Curve

[1] One exception is SEMI 47 which specifies the immunity of semiconductor manufacturing equipment. Semiconductor Equipment and Materials International (SEMI) group have been developing their own standards for their industry.
[2] Must also comply with Rapid Voltage Changes limits (Section 36.5).

Table: 24 Voltage Dip Limits

DURATION OF EVENT	DEVIATION FROM NOMINAL		RETAINED VOLTAGE	
	Immunity (ITIC Curve)	Planning Level	Immunity (ITIC Curve)	Planning Level
< 2 ms	100%	90%	0%	10%
20 ms - 0.5 s	30%	27%	70%	73%
0.5 ms -10 s	20%	18%	80%	82%
> 10 s	10%	9%	90%	91%

41. Emission Assessment

The trigger level should be set to 90% of the nominal voltage (230 V for phase-to-neutral LV), hence 207 V for LV[1]. The event when plotted on the ITIC curve should be within allowable region.

41.1 Voltage Dip/Sag Time and Phase Aggregation

One of the complications of assessment and reporting of voltage dips/sags is the fact that they may occur on multiple phases at the same time with each phase potentially having different sag characteristics (depth and duration). In order to combine these multiple sags into a single event a process known as phase aggregation is performed. Phase aggregation is defined as follows:

For dips/sags occurring at the same timestamp across multiple phases, the lowest retained voltage and longest duration data across all events is retained. All other data is discarded.

This is illustrated in Table 25.

[1] If planning limit is set as trigger level then 209.3 V is used.

Example 6.1: Phase aggregation of Dip/Sag

Table: 25 Voltage Dips/Sags seen on phases

Phase	Retained Voltage	Duration
A	88%	0.10s
B	76%	0.15s
C	59%	0.08s
Aggregated Value	59%	0.15s

Furthermore, an initial voltage sag event may lead to further events, for example, in the case of recloser operations. It is not desirable that multiple events due to the same root cause result in the reporting and assessment of multiple voltage sags. Time aggregation involves aggregating all dips/sags occurring within a certain time period of each other into one event. In general, a one minute window may be sufficient time for all recloser and other operations to have taken place (although a utility may wish to vary this window based on local practices). The process for dip/sag time aggregation is as follows:

Time aggregation is performed after phase aggregation. A fixed window beginning from the timestamp of the first sag to be aggregated is applied. The lowest retained voltage and longest duration observed within the window is retained. All other data is discarded. This event aggregation is illustrated in Table 26.

Example 6.2: Time aggregation of Dip/Sag Events

Table: 26 Voltage dips seen on events

Event	Retained Voltage	Duration
1	88%	0.4s
2	62%	0.35s
3	43%	0.3s
Aggregated Value	43%	0.4s

The above phase and time aggregation process will result in the very worst case scenario.

41.2 Mitigation

There are a number of ways of mitigating voltage dips. The first is by reducing the number of incidences by preventative maintenance such as vegetation clearance. The second is by using power electronic devices such as dynamic voltage restorers *Dynamic Voltage Restorer* (also known as *Voltage Conditioner*) (DVR), *Static Compensator* (also called STATCON – *Static Condenser*) (STATCOM) or *Uninterruptible Power Supplies* (UPS) to reduce the voltage dip seen by equipment. Another mitigation method is device hardening of equipment susceptible to voltage dips. This involves identifying part susceptible to the voltage dip/sag (often the control system) and hardening it. Often this is achieved by increasing the storage on the DC bus by increasing the DC capacitor size.

SECTION 8 - Transients

42. Introduction

An electrical transient occurs every time the circuit is changed in some way. This change may be due to normal switching operation (circuit breaker or switch opening or closing) or abnormal conditions caused by inception and clearance of system faults. Transients can be classed in different ways. Common classifications are:

(a) Shape of transient (oscillatory or impulsive).

(b) Source of energy for the interaction (electromagnetic transient or electromechanical transient). Electromagnetic transients involve the interaction between magnetic and electrostatic energy stored in the inductance and capacitance of the network. Electromechanical transients involve the interaction between the mechanical energy stored in rotating machines and the electrical energy stored in the power system (often termed transient stability).

(c) Time-scale of the phenomena (fast, medium or slow transient), which is linked to the objective of the analysis (insulation coordination, switching study, over-voltage study, transient stability).

43. Causes

Oscillatory transients: ringing in the frequency range 500 Hz-15 kHz, usually starting with a sudden fall of the instantaneous voltage towards zero. This may be caused by:

- Capacitor bank switching.
- Switching of transformers or transmission lines.
- Switching of thyristors (e.g. at the initiation of commutation).
- Ferroresonance.
- Circuit breaker restrike.

Impulsive transients: short-lived transient spike

- Lightning strike.
- Inrush transients.
- Clashing of MV conductors onto LV conductors.

A description of these phenomena is given in the *PQ Project Report*.

44. Effects

The effects can be attributed to three mechanisms:

- Increased component and insulation stress due to elevated crest voltage. This will cause degradation of the insulation and components in equipment. Repetition of these events will shorten the life-time of equipment.
- Malfunction due to high *dv/dt*.
- Multiple zero-crossings causing timing issues.

44.1 Oscillatory transients

The effects of oscillatory transients can be:

- VSDs can be tripped off.
- False firing of thyristor based equipment.
- Malfunction of Programmable Logic Controllers (PLCs).
- Destruction of equipment due to insulation level being exceeded.
- Malfunction of equipment using voltage zero-crossings for timing.

The rate of change of the voltage waveform (*dv/dt*) is an important parameter as it results in charging currents in capacitances in the system. This can cause false turn-ON of thyristor based equipment and hence its destruction. Cables can be damaged by a high *dv/dt*.

44.2 Impulsive transients

The main issue is damage due to exceeding insulation rating. This includes damage to lights, semiconductor-based equipment and other equipment due to insulation rating being exceeded. Blowing of inbuilt fuses in distribution transformers and internal flashovers have also been experienced.

45. Limits

Due to the diversity of transient responses, there is not straightforward way of specifying and imposing transient limits. The closest is the voltage notching limits in *IEEE 519 (IEEE 519:2020)*. This is a steady-state condition but rather than limiting the harmonics the shape of the voltage notch in the voltage-time waveform is limited. The voltage notch is caused by the commutation process in power electronic converters. For switching transients, the peak voltage should not exceed the recommended levels shown in Table 27.

Table: 27 Recommended limits on peak voltages

Peak as percentage of normal steady-state crest voltage	Duration of event
200	< 1 ms
140	1 to 3 ms
120	3 ms to 0.5 s
110	> 0.5 s

The frequency of oscillation needs to be estimated and dv/dt compared to the immunity of all equipment subjected to it. Likewise, the immunity of equipment to multiple zero crossings needs to be ascertained. Figure 36 displays a particularly bad capacitor switching transient with an extremely high peak voltage as well as multiple zero-crossings. For impulsive transients, as indicated by the ITIC curve, a peak voltage of less than 5 times normal voltage is appropriate[1].

46. Assessment

Measurement of transient events requires instrumentation that has a sampling frequency sufficiently high to capture the features of the transient and can be triggered to capture at the right time. As a rule-of-thumb the sampling must be a least ten times the Nyquist rate for the highest frequency of interest. A trigger level of 900 V/ms is recommended for a 230 V system. Due to capacitive nature of electrical systems at higher frequencies these frequency components in the transient voltage can be amplified as they propagate, resulting in equipment experiencing a high transient voltage than measured upstream in the system. Therefore, measurement at or close to susceptible equipment is advised.

[1] More tests on equipment immunity are needed to confirm modern equipment meet this.

47. Mitigation

The appropriate mitigation is dependent of the type of transient and its source. For more information refer to *PQ Project Report*, November 2011, EEA.

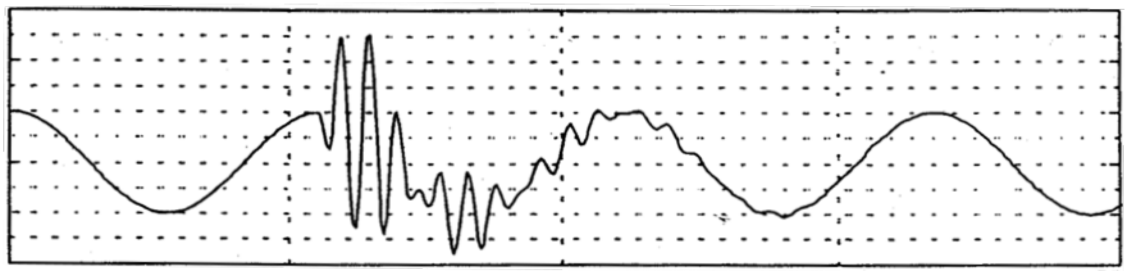


Figure: 36 Voltage Capacitor switching transient

48. Immunity

Testing both the insulation system of the *Device Under Test* (DUT) and the ability of the device to withstand lightning and switching transients is important. Internationally, many standards that define testing of specific products reference *IEC 60060-1*[1] (when testing insulation systems) and *IEC 61000-4-5*[2], (when testing switching and lightning-transient immunity). The standard lightning waveform is 1.2/50 µs (i.e. 1.2 µs to rise from 30% to 90% of peak ± 30%, and time to half value is 50 µs ± 20%). The standard switching waveform is 250/2500 µs (i.e. 250 µs to rise from 30% to 90% of peak, and time to half value is 2500 µs).

[1] IEC 60060-1 "High Voltage Test Techniques"
[2] IEC 61000-4-5, "Testing and Measurement Techniques - Surge Immunity Test,"

SECTION 9 - Voltage Swells and Temporary Overvoltages

49. Introduction

Voltage swells occur when the r.m.s. voltage rises to more than 110% of nominal for a period of ½ cycle to 1 minute (note *that IEEE 1159:2019* uses the terms; Instantaneous, Momentary and Temporary swells to differentiate the swells of duration ½ cycle to 30 cycles, 30 cycles to 3s and >3 sec to 1 minute, respectively). The term Temporary Overvoltage (TOV) is used when the increase in voltage magnitude is sustained for more than 1 minute.

50. Sources

The main sources are:

- Load rejection (i.e. Sudden loss of a large load).
- Voltage rise on healthy phase during unbalanced fault. This has been experienced on MV systems with delta-windings on all the interconnecting transformers. The capacitance present and type of grounding employed (details of any neutral earthing transformers) are important.
- Energisation of equipment.
- Resonances [*CIGRE-TB913*].
- Ferro-resonance.

51. Effects

The main effects are:

- Electronic component damage.
- Overheating and equipment damage.
- Unwanted tripping of equipment.
- Tripping of upstream protection.

52. Limits

The immunity of equipment to voltage swells is given by the upper limit of the ITIC Curve (Figure 35).

Many sources of voltage swells and temporary overvoltages are unplanned events in which an emission allocation is inappropriate. However, for events for which an emission allocation is appropriate (e.g. Load rejection)[1], in accordance with the practice of 10% margin between the compatibility limit and planning level, the deviation from nominal voltage is multiplied by 0.90 to give a planning level as a deviation from nominal voltage. This is then converted to a percentage voltage level limit (see Table 28).

Table: 28 Voltage Swell Limits

DURATION OF EVENT	DEVIATION ABOVE NOMINAL		PERCENTAGE VOLTAGE LIMITS	
	Immunity (ITIC Curve)	Planning Level	Immunity (ITIC Curve)	Planning Level
0.1 ms to 1 ms	[2] $\Delta V_{ITIC} = m \times \log_{10}(x) + C$	$\Delta V_{PL} = 0.9 \times \Delta V_{ITIC}$	$V = \Delta V_{ITIC} + 100\%$	$V_{PL} = \Delta V_{PL} + 100\%$
1 ms to 3 ms	[3] $\Delta V_{ITIC} = m \times \log_{10}(x) + C$	$\Delta V_{PL} = 0.9 \times \Delta V_{ITIC}$	$V = \Delta V_{ITIC} + 100\%$	$V_{PL} = \Delta V_{PL} + 100\%$
3 ms to 0.5 s	20%	18%	120 %	118%
> 0.5 s	10%	9%	110%	109%

53. Assessment

The trigger level should be set at 110% of the nominal voltage (230 V for phase-to-neutral LV). Hence 253 V for LV[4]. The event when plotted on the ITIC curve should be within allowable region.

[1] Must also comply with rapid voltage change limits (Section 36.5)
[2] m = -300 %/log(sec), C = -800 %
[3] m = -125.75 %/log(sec), C = -277.26 %
[4] If planning limit is set as trigger level then 250.7 V is used.

54. Mitigation

Mitigation employed depends on the sources of the voltage swell or temporary overvoltage. Some of the possible remedies are:

- Limit the size of possible load rejection events or apply protection to alter the system to compensate for the load rejection (e.g. use protection or controls to switch out harmonic filters when a HVDC pole drops off).
- Change the characteristics of the system to eliminate resonances.
- Employ a different grounding system or alter the grounding resistance.
- Apply surge suppression (e.g. surge arrestors).
- Alter the way energisation is preformed.

SECTION 10 - Frequency Deviations

55. Introduction

Whenever there is a mismatch between the mechanical power delivered by the turbines and electrical output power then the difference changes the kinetic energy of the system. This either speeds up or slows down the generator and hence the frequency changes.

56. Source

Imbalance between generation and loading due to sudden change in generation or load (e.g., due to generator tripping or load rejection).

57. Effects

The main effects are:

- Unwanted deviation in clock-based equipment which rely on frequency for time keeping.
- Possible black-out if power balance cannot be restored quickly.
- Tripping of protection relays.

58. Limits

The frequency of supply is to be maintained within 1.5% of 50 Hz, except for momentary fluctuations.

59. Assessment

Measurement equipment must be compliant with *IEC 61000-4-30.*

60. Mitigation

To minimise frequency excursions the generation must be matched to loading and losses. Two provisions to achieve this are:

- Adequate mix of reserve generation (spinning reserve, 6 second- and 6-minute reserves) and interruptible load alleviates frequency excursions. As more distributed generation is embedded into the network it is important that this operates to compensate for frequency excursions[1].

[1] Frequency response of grid connected energy system inverters is prescribed in *AS/NZS 4777.2: 2020.*

- Requirement for active power reduction depending on frequency. This will aid controlling frequency whether it is distributed generation feeding into the network or loads connected to the network[1].

[11] See "Technical Regulation for Generating Plants in the Medium Voltage Grid" issued by the German Federal Association of Energy and Water Industries (BDEW) came into force on 1 January 2009.

SECTION 11 - Ferroresonance

61. Introduction

For a circuit to exhibit ferroresonance the following four elements are needed:

1. Nonlinear inductance.
2. Capacitance.
3. Low losses.
4. A source of energy.

The series resonant circuit of Figure 37 and graphical construct shown in the diagram Figure 38 is often used to give an Intuitive insight into the features such as: existence of multiple steady-states, jump phenomena, importance of capacitance, factors influencing risk of ferroresonance. For the circuit of Figure 37 the fundamental equation is:

$$v_S(t) = V_s \sin(\omega t) = v_C(t) + v_L(t) + v_R(t) \tag{11.1}$$

However, equation 11.1 is an oversimplification and does not provide a real understanding of the mechanisms driving a ferroresonant oscillations. This will be achieved using Figure 39. Note that the inductor is nonlinear, and its reactance is a function of current.

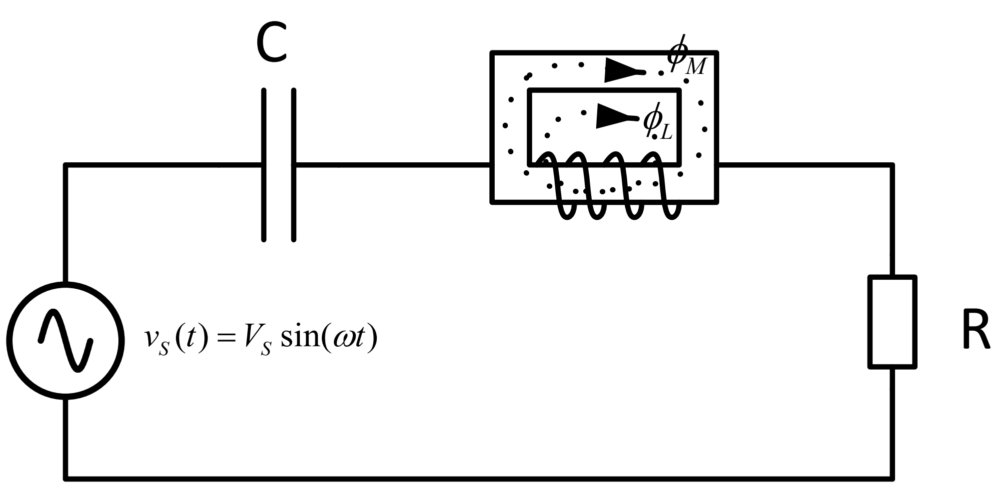


Figure: 37 Resonance circuit

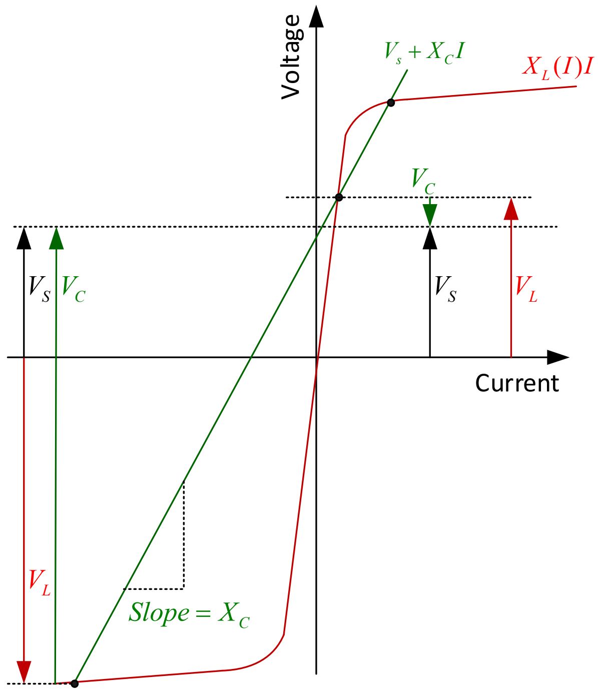


Figure: 38 Resonance circuit

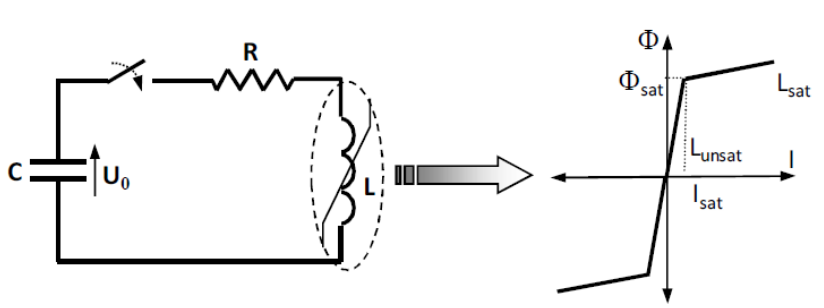


Figure: 39 Resonance circuit

The circuit losses are initially ignored for simplicity and a two-segment piecewise linear representation is used for the magnetising impedance. The expected current and voltage waveforms with these simplifications are presented in Figure 40. The circuit behaves like a two-state oscillator switching between two frequencies, depending on whether the inductor is in or out of saturation. Initially, the capacitor charge is equal to V_0. At $t = 0$ sec the switch is closed, and the capacitor C starts discharging very slowly (magnetising impedance is large) through the inductor working in its linear region, L_{unsat}. The frequency of this oscillation is:

$$f_1 = \frac{1}{2\pi\sqrt{L_{unsat}C}} \tag{11.2}$$

Nevertheless, the flux linkage slowly builds up in thsye magnetic core until saturation is reached. This is shown in Figure 40 at $t = t_1$, when the magnetizing reactance drops to its saturated value, L_{sat}. Since L_{sat} is a few orders of magnitude smaller than L_{unsat} the capacitor discharges very rapidly. The frequency of this new oscillation is:

$$f_2 = \frac{1}{2\pi\sqrt{L_{sat}C}} \tag{11.3}$$

The change in flux linkage at any time can be calculated as the area under the voltage-time curve, and hence since going from saturated in one direction to the other, then:

$$\Delta\phi = \int_{t_3}^{t_5} v_L dt = 2\phi_{sat} \tag{11.4}$$

Using rectangular integrator and that t_5-t_3 is half the period an estimate of the period for the unsaturated part of the cycle is:

$$T_{unsat} \approx 2\left(t_5 - t_3\right) = 4\frac{\phi_{sat}}{V_0} \tag{11.5}$$

Period for the saturated part is:

$$T_{sat} = \frac{1}{f_2} = 2\pi\sqrt{L_{sat}C} \tag{11.6}$$

Putting equations 11.5 and 11.6 together gives:

$$T_{ferro} = T_{sat} + T_{unsat} = 2\pi\sqrt{L_{sat}C} + 4\frac{\phi_{sat}}{V_0} \tag{11.7}$$

Equation 11.7 shows that the frequency of oscillation is directly linked to the circuit capacitance, *C*, the initial charge of the capacitor and the nonlinear characteristics of the magnetic core.

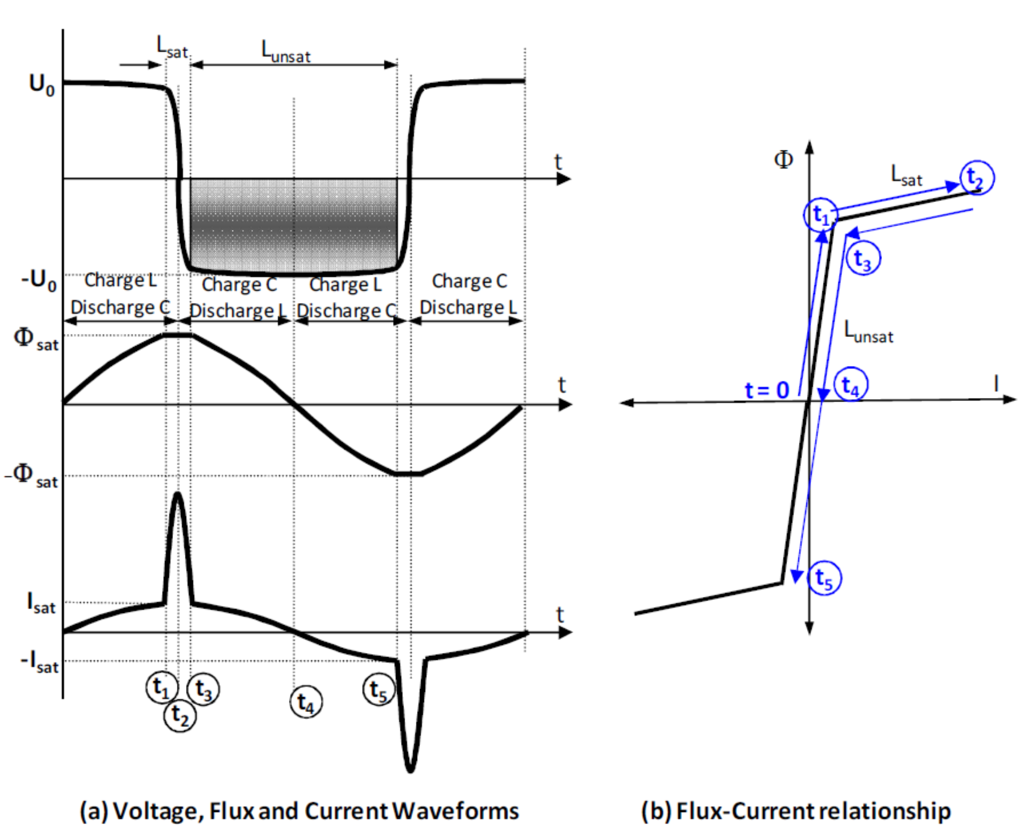


Figure: 40 Physical Behaviour of a Ferroresonant Circuit without Losses [CIGRE WG C4.307]

The effect of circuit losses is to cause the amplitude of the oscillation to decay. The lower amplitude will result in a longer time to reach saturation and hence lower the frequency of the ferroresonant oscillation, which will decrease gradually. If an external source of energy exists to counter the losses the oscillation can be maintained indefinitely.

62. **Effects**

The main effects are:

1. Tripping of protection devices.
2. Overheating and if prolonged damage to the insulation.
3. Gassing of transformers and other by-products.
4. Destruction of surge arresters.
5. Reduced equipment lifetime. Operating a solid dielectric system above its normal stress level for an extended period is expected to shorten the lifetime of the equipment.

Ferroresonance has been reported in both transmission and distribution systems as well as in Capacitor Coupled Voltage Transformer (CCVT). In transmission systems shunt compensation is a common cause of ferroresonance. Ferroresonance can involve the inter-phase capacitive coupling, either between phases or phase-to-earth, or between phases in different circuits in a multi-circuit right of way. The latter can exhibit ferroresonance even for balanced operation. However, more often unbalanced operation instigates ferroresonance and this may be due to single-phase switching or due to stuck poles in a circuit breaker. In distribution systems the main cause of ferroresonance is unbalanced operation, due to switching or dropout fuse operation, in conjunction with a cable connected to an unloaded/lightly loaded transformer. Therefore, it will be the focus of the treatment given here. It should be noted that voltage transformers are also prone to ferroresonance and are normally fitted with anti-ferroresonance circuitry.

$$V_S = IX_L\left(t\right) - IX_C \tag{11.8}$$

Ferroresonance waveforms for the different modes (characterised by their periodicity) are shown in Figure 41:

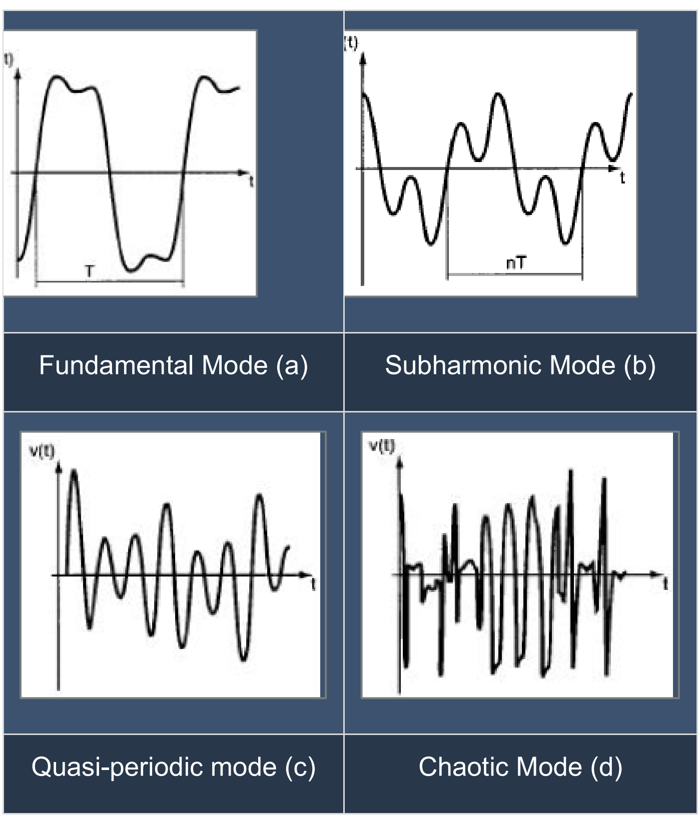


Figure: 41 Ferroresonance Modes

63. Typical Network conditions

The origin of the series resonant circuit during uneven open-phase operation is linked to the unequal compensation of positive and zero-sequence line capacitances (i.e. C_0/C_+ ratio). Potentially ferroresonance can occur whenever single-phase switching is performed leaving a cable connected to an unloaded transformer.

Single-switching – one phase connected. This circuit is shown in Figure 42 while Figure 43 displays the equivalent circuit.

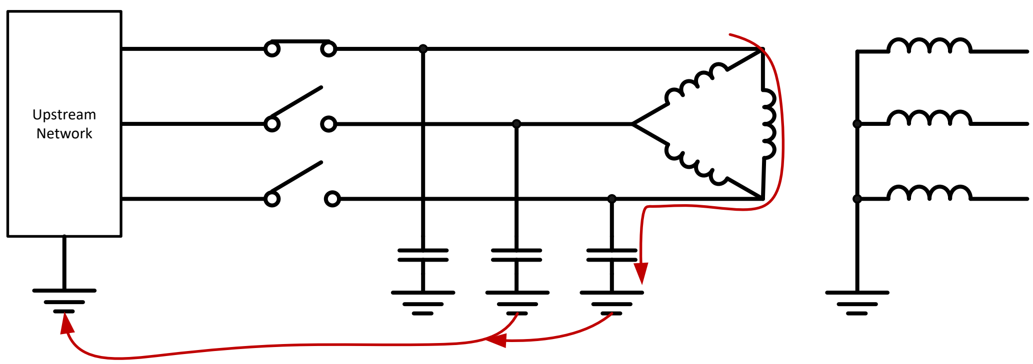


Figure: 42 One Phase connected

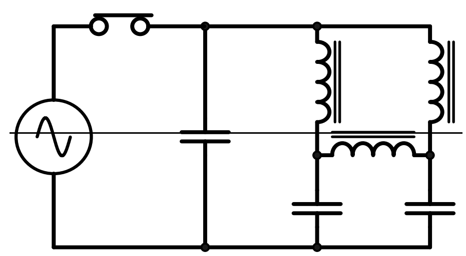


Figure: 43 Equivalent circuit for One phase connected

Single-phase switching – Two phase connected. This circuit is shown in Figure 44 while Figure 45 displays the equivalent circuit.

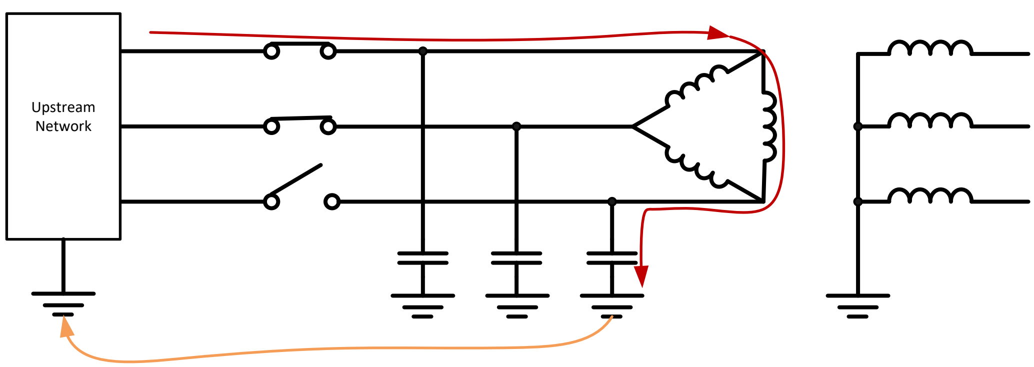


Figure: 44 Two phases connected

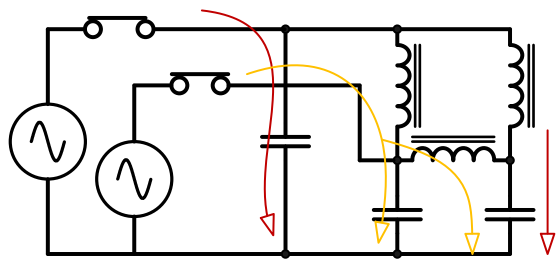


Figure: 45 Equivalent circuit for two phases connected

Figures 46 and 47 show switching operations in a cable network that can lead to ferroresonance.

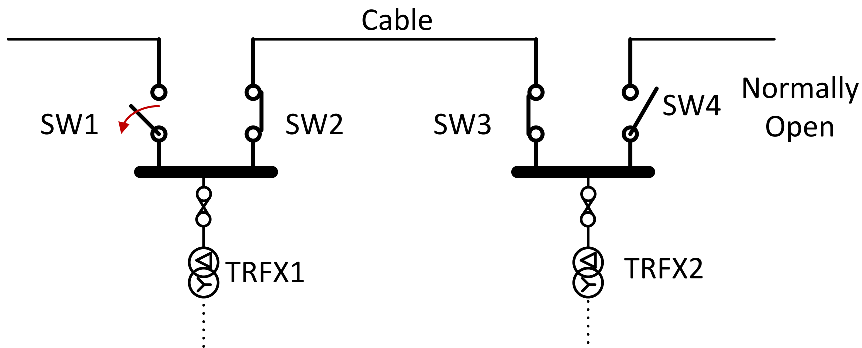


Figure: 46 Single-phase switching on a cable network

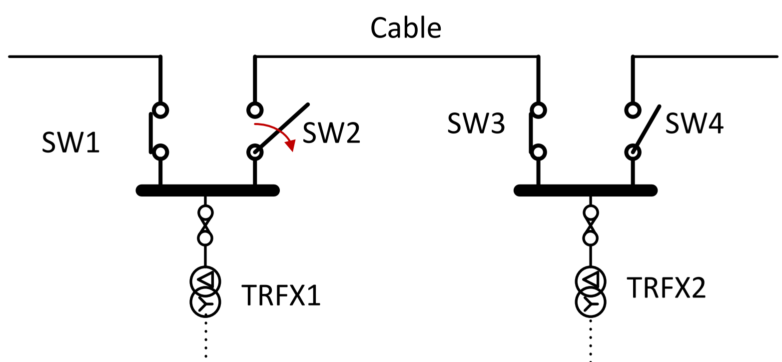


Figure: 47 Single-phase switching on a cable network

Even with Y (Wye) connected primary on a transformer unbalanced operation can cause ferroresonance as illustrated in Figure 48.

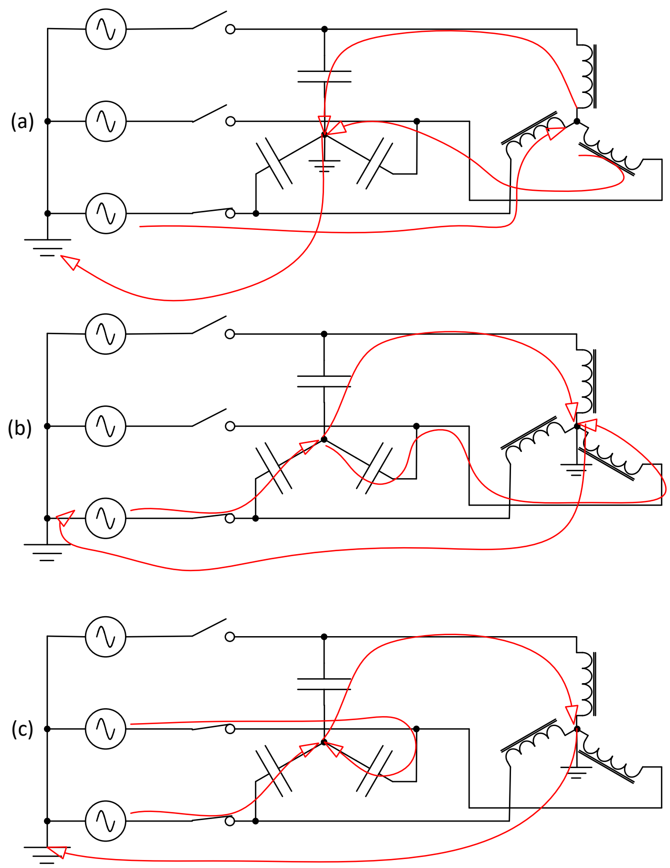


Figure: 48 Ferroresonance in a transformer with a Y-G (Wye)-connected primary

64. Critical Cable Lengths

A number of attempts have been made to develop tables of critical cable lengths, above which ferroresonance will occur. Some have derived these lengths from equations and others via simulation. All of these rely of assumptions regarding the nature of the nonlinearity of the core and the system capacitances that may or may not be accurate. The most notable is the *Baitch* equation, which is *[Baitch 1979, Baitch 2000]:*

$$L_{Critial} = \frac{PCE / 2 \times I_{\mathrm{Im}ag}(\%) \times kVA_R}{(1.58 + C'_{CC} / C'_{CS}) \times \dfrac{\omega}{10} \times kV_R^2 \times C'_{CS} \times 1000} \qquad (11.8)$$

Where:

$L_{critical}$ is the critical cable length in metres

PCE is the percentage of the core that is excited under ferroresonant condition. This depends on whether the flux path is through the outer two legs of the core (0.85) or the centre and outer leg (0.6).

I_{mag} *(%)* is the transformer magnetising current (typically in the order of 0.8%),

kVAr is the transformer rating in kVA,

kV_R is the rated voltage in kV,

C'_{CC} is the cable's core-to-core capacitance in μF/km and C'_{CS} is the cable's core to sheath capacitance in μF/km.

Example: For a paper insulated belted cable with the following parameters the critical cable length is calculated to be 63.5 m.

kVA_R = 300 [kVA]

kV_R = 11 [kV]

I_{mag}(%) = 0.8

C'_{CC} = 0.0044 μF/km

C'_{CS} = 0.161 μF/km

PCE = 0.6 (Since 0.6 is more conservative, i.e. gives a smaller critical cable length)

Table 29 provides critical lengths (in metres) calculated using *Baitch's* equation for an 11 kV Al 3-core XLPE cable with armour. The first number is using the conservative PCE value of 0.6 and in square brackets the value if the PCE factor is 0.85. C'_{CC} assumed negligible. An attempt to verify these was made using electromagnetic transient simulation. This involved many runs with different cable lengths to estimate the onset of a ferroresonant condition. These values are given in parentheses in the table. Assumptions about the nonlinear nature needed to be made for the detailed EMT model. The results show that for the larger transformer sizes the critical cable length from *Baitch's* formula compare well with the EMT assessed lengths, however, for small transformer sizes there was a very large difference, with the *Baitch* formula being more conservative. These are theoretical results based on assumptions on the magnetic characteristics of the transformer core and ignore stray capacitance and inductive coupling as well as any residual loading on the system.

Table: 29 Critical Cable distance for 6.35/11 kV Al XLPE 3-core, Heavy Duty Screen, armoured Cable

CRITICAL CABLE LENGTH						
XX.X m is the Critical Cable distance given by Baitch's formula with **PCE = 0.6**						
[XX.X] is the Critical Cable distance given by Baitch's formula with **PCE = 0.85**						
(XX) Estimate of Critical Cable distance from EMT simulation						
CABLE			**TRANSFORMER RATING**			
Conductor cross section: (mm^2)	Conductor diameter: (mm)	Capacitance C'_{CS} (μF/km)	100 kVA	300 kVA	500 kVA	1 MVA
50	8.1	0.27	**14.8 m** [21] (42)	**44.4 m** [62.9] (72)	**74.0 m** [104.8] (104)	**148.0 m** [209.7] (184)
70	7.9	0.30	**13.3 m** [18.9] (36)	**40.0 m** [56.6] (63)	**66.6 m** [94.3] (91)	**133.2 m** [188.7] (161)
95	11.5	0.34	**11.8 m** [16.6]	**35.3 m** [49.9] (56)	**58.8 m** [83.2] (81)	**117.5 m** [166.5] (143)
120	12.9	0.37	**10.8 m** [15.3]	**32.4 m** [45.9] (52)	**54.0** [76.5] (75)	**108.0** [153.0] (132)
150	14.3	0.40	**10.0 m** [14.2]	**30.0 m** [42.5] (48)	**49.9 m** [70.8] (70)	**99.9 m** [141.4] (123)
185	16.1	0.43	**9.3 m** [13.2]	**27.9 m** [39.5] (44)	**46.5 m** [65.8] (64)	**92.9 m** [131.6] (112)
240	18.4	0.48	**8.3 m** [11.8]	**25.0 m** [35.4] (40)	**41.6 m** [59] (57)	**83.2 m** [117.9] (101)
300	20.6	0.53	**7.5 m** [10.7] (21)	**22.6 m** [32.0] (36)	**37.7 m** [53.4] (52)	**75.4 m** [106.8] (92)

65. **Mitigation**

Possible methods to mitigate Ferroresonance are:

1. Switch off load via Drop-Out Fuses at the transformer terminals and then isolate using link at tee off [Figure 49 (a)].
2. Use Ganged Drop-Out Fuse (GDOF) at tee off [Figure 49 (b)].
3. Fuse the primary of a city pad-mounted transformer [Figure 49 (c)].
4. Apply a temporary load to the transformer [Figure 49 (d)]. Great care is needed when applying a temporary load to an energised system.
5. Ring Main Unit (RMU) at tee off. RMU must have the capacity to perform this switching, e.g., Circuit breaker on the transformer circuit or fuse-switch capable to interrupt the current [Figure 49 (e)].
6. Neutral Reactors (e.g., specially selected Petersen coils).

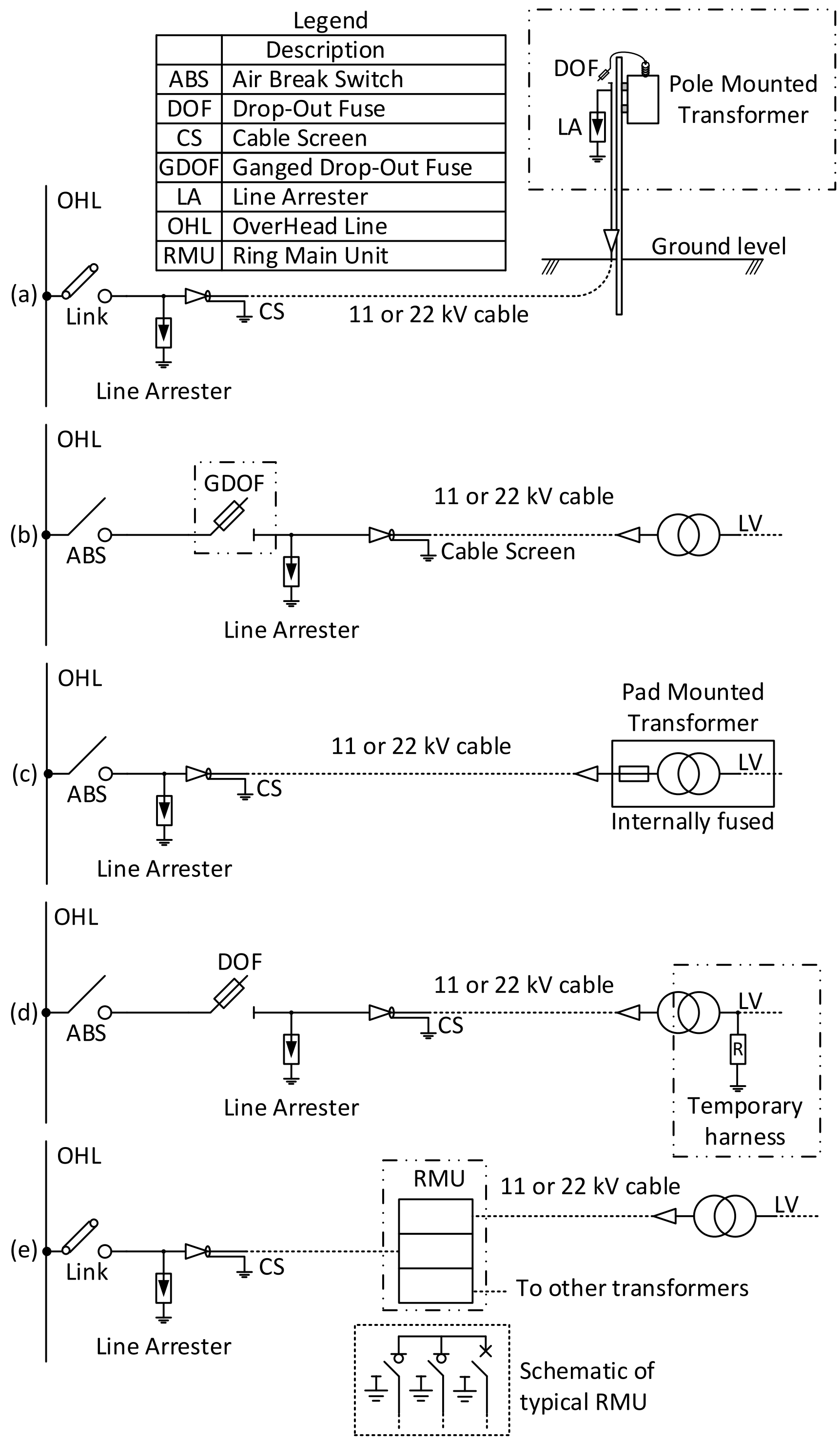


Figure: 49 Ferroresonance mitigation methods illustrated

SECTION 12 - Other Issues

66. Telephone Interference - Introduction

NZECP36 stipulates maximum levels for Equivalent Disturbing Current (EDI) and Equivalent Disturbing Voltage (EDV). These indices represent the disturbance of inductive coupling and capacitive coupling, respectively. This is based on analogue telephone circuits as it weights induced frequencies by the Psophometric weightings (which represents the sensitivity of the ear to a given frequency) to give the disturbance level to the ear. In digital telephone circuits degradation does not occur until bit errors start occurring. There is still a need to limit induction to avoid bit errors, but the EDI and EDV indices do not represent the degradation in digital telephone circuits.

The Telephone Interference Factor (TIF), C-Message Weighted Index and I.T, kI.T and V.T product, used in North America are similar in principle to EDI and EDV. Guidance is offered in a number of publications regarding appropriate limits for these indices [*IEEE 519:2020, Heydt 1991*].

66.1 Sources

Electromagnetic interference with communication systems can be either due to capacitive coupling or inductive coupling. The most common coupling between overhead transmission lines and communication circuits is inductive coupling. When harmonic/interharmonic currents flow in an overhead transmission line, this can cause a voltage to be induced into communication lines that are parallel and in close proximity to the transmission line. This is due to the magnetic field associated with the harmonic/interharmonic currents coupling with the communication lines. Proximity is an important factor and hence interference is more likely to occur when power and communication infrastructure use joint facilities (such as poles and structures).

Normally the distance between the telephone line and power line phases is greater than the distances between the three-phase conductors, in which case the zero sequence component of the current determines the level of interference. This is because the zero sequence component determines the residual magnetic field where the communications line is situated, and hence the level of induced harmonic voltage on the communication line. If the distances are comparable then even balanced currents can induce a voltage because of the differing coupling between telephone circuit and the three-phases. The arrangement of phases on double-circuit lines also greatly influences the magnetic field at a distance and hence telephone interference.

No interference is normally encountered in industrial or commercial premises between power cables and twisted pair telephone lines.

The use of ground return paths for power circuits will dramatically increase the magnetic field in the vicinity of the overhead line and hence its ability to interfere.

66.2 Effects

The main effects are noise on analogue circuits and possible errors in digital communication. This will degrade voice communications and can adversely affect control or protection circuits.

66.3 Mitigation

Normally the most cost effective solution is modification of the communication line to avoid telephone noise. This is achieved by either rerouting the communication line, changing from an analogue to a digital channel, shielding of communication line, or using wireless communication systems (e.g., optical fibre, radio or microwave).

67. D.C. Current Injection

67.1 Sources

The typical sources are:

- Non-symmetrically controlled loads (e.g., half-controlled converters).
- Uncontrollable events (such as Geomagnetically Induced Currents (GIC)).
- Grid-tie inverters.
- D.C. ground potential due to d.c. current flowing through the ground/earth (monopole operation of HVDC link with ground/earth return path, see Figure 50).

67.2 Effects

The main effect is saturation of transformers and generation of additional harmonics.

67.3 Assessment

The critical issue is the level of d.c. current and this value depends on other factors, such as the resistance of the network and source of the d.c. as well as the construction of the transformer.

67.4 Mitigation

Other than removing or reducing the disturbance level the two main approaches are application of:

– A neutral resistor.

– A series capacitor in phases.

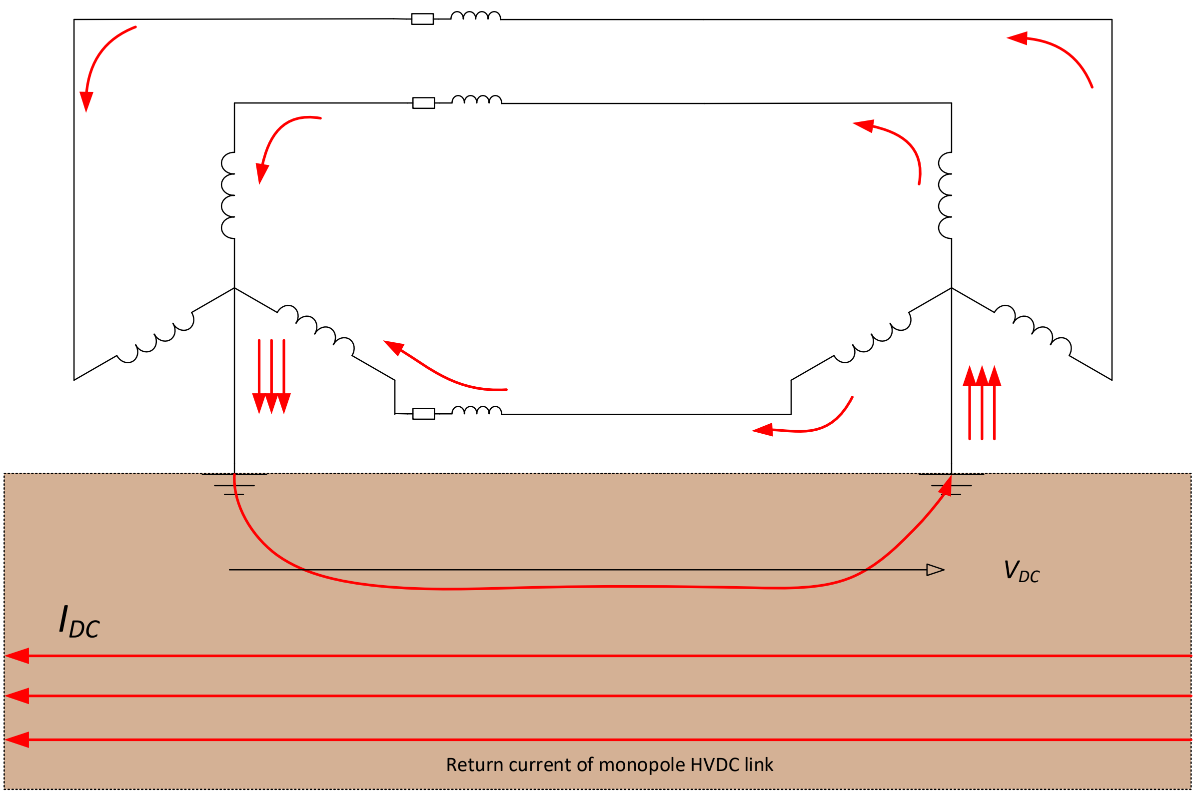


Figure: 50 DC Current due to monopole HVDC Operation

68. Geomagnetically Induced Currents

68.1 Sources

Geomagnetic disturbances (GMD) due to space weather (solar activity) cause disturbances of the Earth's magnetic field which induce an electric field at the Earth's surface, which ultimately drives GIC. GIC then flows in long conductive infrastructures, such as electrical power systems, pipelines, and railway systems. Although the Earth's magnetic field varies over a wide range of timescales, frequency components smaller than 1 Hz dominate the spectrum of the GIC, and hence it behaves like a pseudo DC current (see Figure 51).

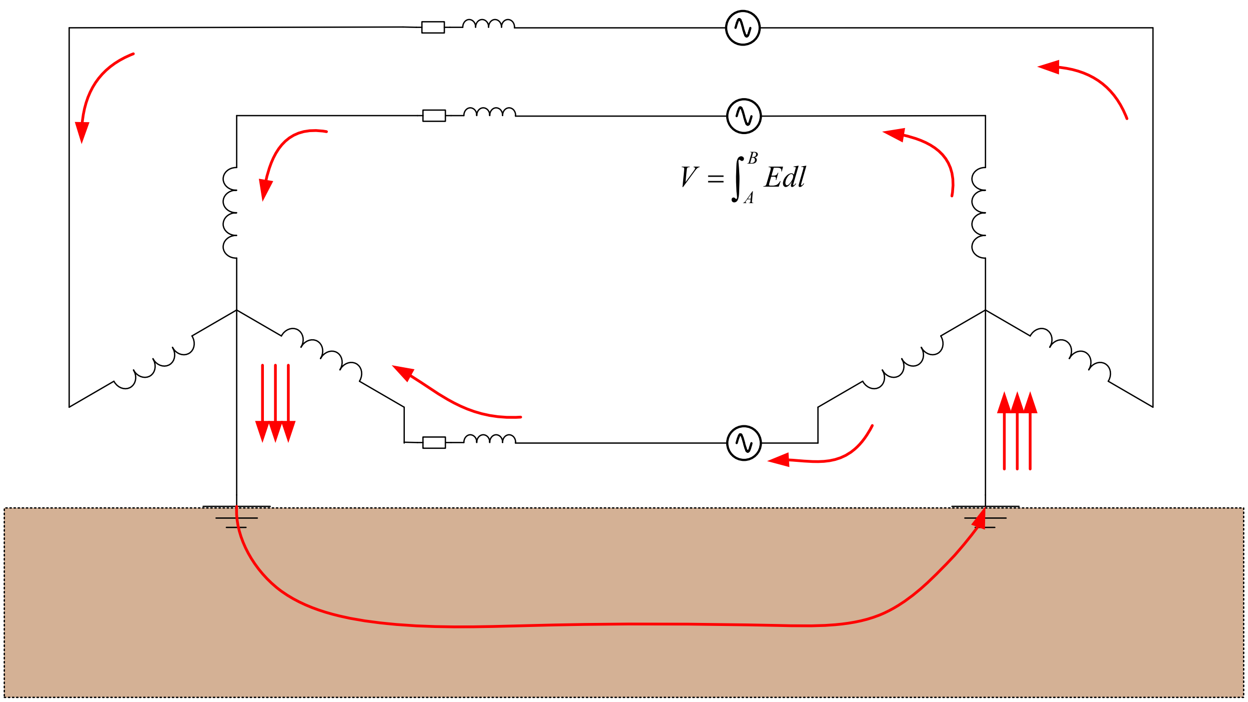


Figure: 51 Geomagnetically Induced Currents (GIC)

68.2 Effects

The main effect is the saturation of the magnetic circuit of transformers in a power system [*Girgis 2012*]. This saturation can:

- Generate harmonic currents, and heat the internal components of the transformer (can lead to gas relay alarm operation as well as possible damage).
- increase MVAr absorption of the transformers, which may lead to voltage control issues.
- Accelerate corrosion of infrastructure.

One of the more notable outages was on 13th March 1989 when a severe geomagnetic storm caused the collapse of the *Hydro-Québec* power grid and loss of supply to 6 million people in seconds. This was due to a cascading sequence of protective relay trippings.

A similar effect can occur due to the monopole operation of an HVDC link with earth return. The potential at the neutral of two transformers connected by a transmission line can differ resulting in a d.c. current flow, as illustrated previously in Figure 50.

68.3 Mitigation

The mitigation techniques as the same as for D.C. Current injection, namely:

- A neutral resistor.
- A series capacitor in phases.

Tripping/altering power system topology to minimise impact.

69. Common Mode Voltages - Introduction

Common mode voltages most commonly occur with inverter drive motors, however, common mode voltages can also exist in inverter-based energy sources connected to the grid. Even though the fundamental frequency components of the output voltages are symmetrical and balanced, it is impossible to make the sum of three output voltages instantaneously equal to zero with two possible output levels available. The resulting neutral point voltage is not zero. This voltage may be defined as a common mode voltage source. Therefore an inverter inherently has a common mode voltage, whether a VSD driving a motor, or a PV inverter connected to a grid. The common mode voltage is measurable at the star point of the motor winding if available. A two-level inverter has four voltage levels for the common mode voltage as given in Table 30, and a three-level inverter has 7 voltage levels as shown in Table 33. This is illustrated in Figure 52 which displays the phase voltages and the resulting common mode voltages. The voltage difference between the high frequency common mode voltage can result in current paths through stray capacitances as illustrated in Figure 53. These currents can adversely affect the motor and cause pitting in bearings. Motors used with VSDs need to have a winding insulation class to cope with high-frequency voltage spikes and insulated bearings to avoid bearing damage. The cable length must not be too long to avoid *dv/dt* issues, otherwise additional filters are required.

Table: 30 30 Switching-states for a 2-level converter and the corresponding common-mode voltage

2-LEVEL INVERTER OUTPUT VOLTAGE (BETWEEN INVERTER TERMINALS AND DC BUS MID-POINT)			COMMON MODE VOLTAGE
V_{AM}	V_{BM}	V_{CM}	V_{COM}
$V_d/2$	$V_d/2$	$V_d/2$	$V_d/2$
$V_d/2$	$V_d/2$	$-V_d/2$	$V_d/6$
$V_d/2$	$-V_d/2$	$-V_d/2$	$-V_d/6$
$-V_d/2$	$-V_d/2$	$-V_d/2$	$-V_d/2$

Table: 31 Switching-states for a 3-level converter and the corresponding common-mode voltage

3-LEVEL INVERTER OUTPUT VOLTAGE (BETWEEN INVERTER TERMINALS AND DC BUS MID-POINT)			COMMON MODE VOLTAGE
V_{AM}	V_{BM}	V_{CM}	V_{COM}
$V_d/2$	$V_d/2$	$V_d/2$	$V_d/2$
$V_d/2$	$V_d/2$	0	$V_d/3$
$V_d/2$	0	0	$V_d/6$
0	0	0	0
0	0	$-V_d/2$	$-V_d/6$
0	$-V_d/2$	$-V_d/2$	$-V_d/3$
$-V_d/2$	$-V_d/2$	$-V_d/2$	$-V_d/2$

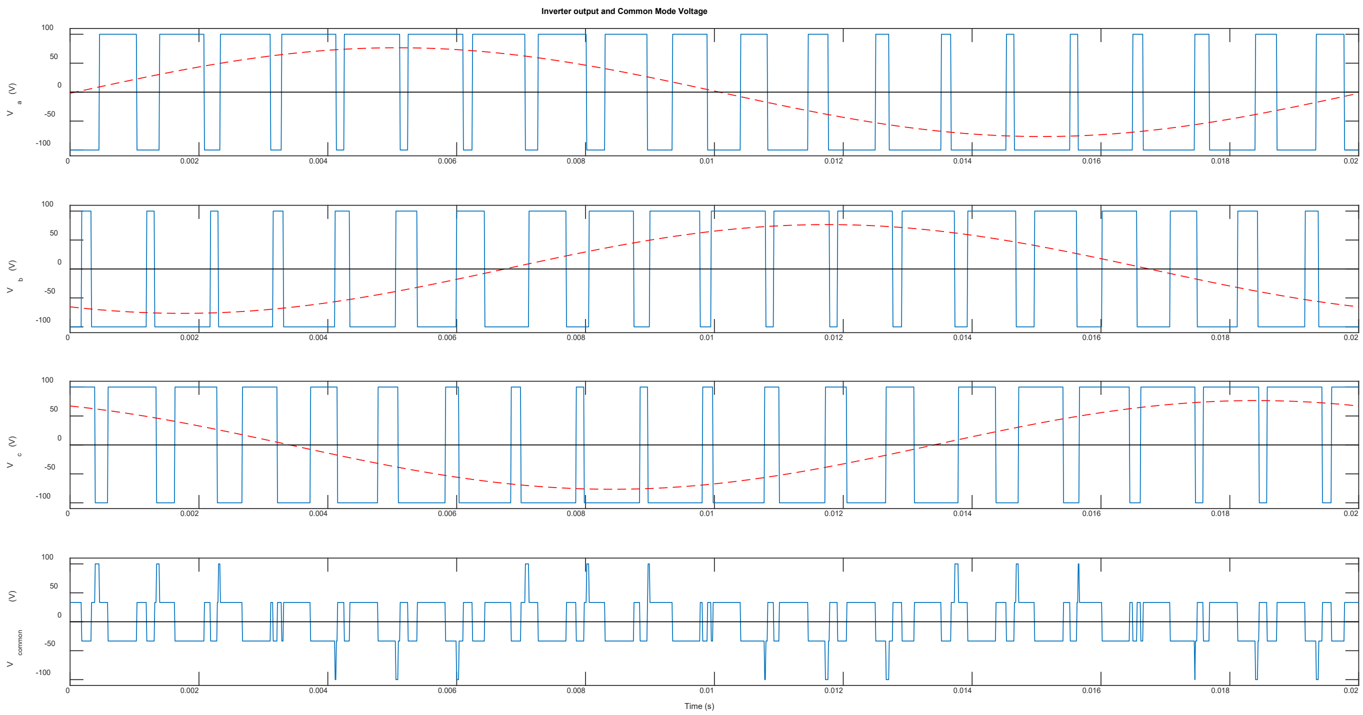


Figure: 52 Voltage Waveforms for DC/AC conversion

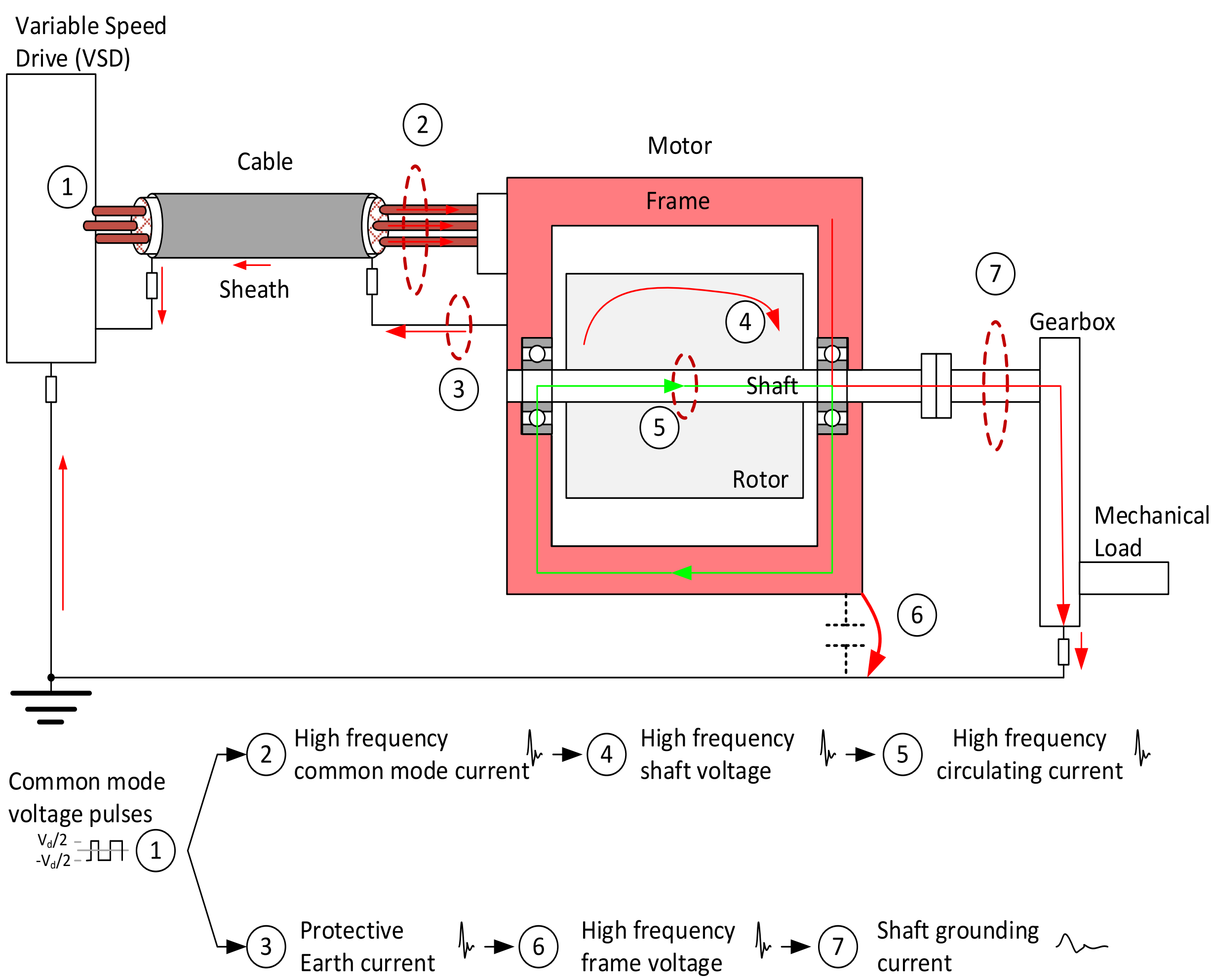


Figure: 53 Current paths

69.1 Effects

- Electromagnetic interference (EMI).
- Damage to motor bearings.
- Unexpected ground fault trips.
- Erratic behaviour of VFDs and PLCs.
- Premature motor insulation failure.
- Cable damage.

69.2 Mitigation

- Multicore motor cables.
- Short impedance path.
- Common mode choke.
- High frequency bonding connections.
- dV/dt filter.
- Shaft grounding kit to protect motor bearings.

70. Wiring and Contact Defects

70.1 Introduction

Poor PQ can be caused by poor connections in equipment or inadequate conductors

70.2 Sources

The typical sources are:

- Bad connection (loose or resistive connection).
- Missing ground path or broken neutral.
- Ground loops.
- Under-sized neutral conductor.
- Under-sized phase conductor.
- Faulty circuit breaker.
- Induction (normally due to inductive coupling) from neighbouring circuits.

70.3 Effects

The main effects are:

- Erratic voltages and sometime oscillatory transient voltage.
- Unbalanced phase-to-neutral voltages.

70.4 Mitigation

Once the root cause is identified then mitigation is achieved by eliminating the cause.

SECTION 13 - Power Quality Monitoring

71. Introduction

NZECP 36 is listed in the *Electricity (Supply) Regulations 2010* as a means of complying with the requirements relating to quality of supply. This Code prescribes methods and techniques for harmonics and flicker power quality monitoring. However the techniques it prescribes are now over 40 years' old and the national and international standards are technically more effective for monitoring the power quality issues now being encountered.

There are two main types of standards which contain content concerning power quality monitoring. These are:

Type 1: Standards which define the design and operating criteria for PQ monitoring instrumentation.

Type 2: Standards which define monitoring techniques.

The main New Zealand standards which concern the design and operating criteria for PQ monitoring instrumentation are:

- *AS/NZS 61000.4.7* (Harmonics measurement) and
- *AS/NZS 61000.4.15* (Flicker and fluctuations measurement).

The following New Zealand standards contain information related to power quality monitoring techniques:

- *AS/NZS 61000.4.30* (General testing and measurement techniques).
- AS/NZS 61000.3.6 (Harmonics).
- AS/NZS 61000.3.7 (Flicker).

The *IEC Technical Report IEC/TR 61000-3-13* contains information related to monitoring of voltage unbalance.

Of the standards which define monitoring techniques, the most important is *AS/NZS 61000.4.30.* It is impossible to discuss power quality monitoring techniques without examining the contents of this standard.

Other standards which may be useful in relation to power quality monitoring include; *EN50160, IEEE1159,* and *IEEE 519.*

72. AS/NZS 61000.4.30

AS/NZS 61000.4.30 is titled *"Testing and measurement techniques – Power quality measurement methods".* The standard aims to clearly define measurement techniques to ensure confidence in measurement outcomes regardless of the instrument used. The scope of the standard states that *"Measurement methods are described for each relevant type of parameter in terms that will make it possible to obtain reliable, repeatable and comparable results regardless of the compliant instrument being used and regardless of its environmental conditions".*

In practice this means that the standard outlines the:

- Accuracies which the instrument must achieve.
- The time intervals over which measurements should be made.
- The method of aggregation of measurements over time intervals, and
- Time clock uncertainties.

Most modern power quality implementation complies with *AS/NZS 61000.4.30* or its *IEC* counterpart *IEC 61000.4.30.*

73. AS/NZS 61000.4.30 Instrument Classes

The standard defines several instrument classes based on accuracy levels. These classes are:

- **Class A** – Highest accuracy. This class is designed for situations where very high accuracy is required, for example, contractual applications and standards compliance. The accuracy requirements for Class A instrumentation is fully outlined in the standard.
- **Class B** – This class is designed for situations where high accuracy is not required, for example, troubleshooting and statistical surveying applications. The standard does not fully detail required instrumentation accuracies. Instead, instrument accuracy is at the discretion of the instrument manufacturer within absolute boundaries specified by the standard.

> *Note:* The latest *IEC version of 61000-4-30* released in 2009 contains a third class of instrument, Class S. The requirements of this class of instrument lie between the specifications for Classes A and B.

74. Disturbances included in AS/NZS 61000.4.30

The power quality disturbances for which *AS/NZS 61000.4.30* define measurement techniques are as follows:

- Steady-state voltage
- Voltage unbalance
- Voltage and current harmonics[1]
- Voltage and current inter-harmonics[1]
- Voltage flicker[2]
- Voltage dips and swells
- Voltage transients
- Voltage interruptions
- Rapid voltage changes
- Mains signalling

75. AS/NZS 61000.4.30 Aggregation Intervals

IEC 61000-4-30 specifies a range of aggregation intervals to be used for the evaluation of power quality levels. The *AS/NZS 61000.4.30* aggregation intervals are as follows:

- 150/180 cycle (150 cycles for 50Hz systems, 180 cycles for 60 Hz systems)
- 10 minutes
- 2 hours

These aggregation intervals are all derived from a number of basic intervals. For 50Hz systems the basic interval for Class A instrumentation is 10 cycles. The basic aggregation interval for Class B instrumentation is at the discretion of the instrument manufacturer. From these basic aggregation intervals, longer evaluation periods are calculated by r.m.s. averaging.

[11] For harmonic measurements *AS/NZS 61000.4.30: 2012* refers to *IEC 61000-4-7:2002* which defines the operating characteristics of instrumentation designed for measurement of harmonics.
[2] For voltage flicker measurement *AS/NZS 61000.4.30:2012* refers to *IEC 61000-4-15: 2010* which defines the operation of the flickermeter.

76. AS/NZS 61000.4.30 Flagging Concept

The flagging concept detailed in *AS/NZS 61000.4.30* :*2012* aims to prevent one disturbance from being reported more than once – for example a sag being counted as a voltage variation as well as a sag. The flagging concept is only applicable to Class A instrumentation and states that during the survey period, if a discrete disturbance (event) is detected, the continuous data recorded during the interval in which the event was detected should be flagged. This flag allows quick identification of data that may not be reliable.

Flagging as a concept is useful in preventing a single disturbance influencing other disturbance values and to separate out discrete events from continuous data. However, application of the flagging concept may not be straightforward as the standard is silent as to how flagged data should be handled. It is recommended that all flagged data be removed before recorded data is analysed and reported.

77. Prescriptive Monitoring

List of monitoring requirements by disturbance:

Steady State Monitoring

- Limits are expressed in L-N volts for low voltage and L-L volts for MV. *AS61000.3.100: 2011* prescribes limits for both L-N and L-L quantities at LV requiring simultaneous monitoring of both L-N and L-L. Some instruments can do this – others not.
- Recommend monitoring of L-N at LV and L-L at MV is recommended. Note that most VTs on New Zealand MV systems appear to be connected in star formation, mostly L-G (although some VTs have been found to have a non-earthed star point leading to unexpected measurements).

Voltage Unbalance

- Some instruments will measure using negative a sequence method.
- If a formula is to be used then L-L values should be the input. Use of L-N values introduces (small) levels of zero sequence into the calculation.

Voltage Harmonics

- Limits are expressed as a percentage of fundamental value.
- Many instruments will measure either in % of fundamental or as a voltage.
- It is recommended that instruments are configured to measure harmonics as a percentage of fundamental voltage. Note the fundamental voltage should also be recorded. Connection at LV should be L-N. Connection at MV should be at L-L.

Current Harmonics

- Line currents should be measured either directly or using CTs and other transducers.
- At LV some instruments may be capable of whole current measurement while others will use clamp on or other types of CTs. These CTs may be current or voltage output.
- At MV CTs are used for measurement. The input to the monitoring instrument may again be either current or voltage depending on the device.

Voltage Interharmonics

- As for voltage harmonics

Flicker

- Instrumentation designed to measure flicker will include a flickermeter which is designed for flicker measurement.

Dips/Sags

- The instrument will measure based on a set trigger threshold.
- This threshold should be configured to be 90% of the nominal voltage.

Swells

- The instrument will measure based on a set trigger threshold.
- This threshold should be configured to be 110% of the nominal voltage.

Transients

- Trigger level of 900 V/ms for a 230 V system.
- Sample rate at least 10 times faster than highest frequency component of interest.

Frequency

- Measured by the instrument.

Discussion

For LV sites it is generally appropriate and simplest to connect L-N. Connection at L-N is appropriate for checking compliance with the PQ guidelines for all disturbances except where unbalance must be calculated using the formula. However, even in this case the inaccuracy introduced by using L-N values is generally small and can probably be tolerated. For simplest comparison with harmonic limits, where possible, the instrument should be configured to measure harmonic voltages as a percentage of the fundamental current. The monitoring requirements for voltage interharmonics are equivalent to those for voltage harmonics. Harmonic currents may be measured either as whole current or using either current or voltage output current transducers depending on instrumentation requirements. Harmonic currents should be measured in Amperes. Flicker will be directly measured by instruments which incorporate a flickermeter.

Voltage dips and swell characteristics will be measured directly by the instrument based on preconfigured sag and swell threshold values. These thresholds should be configured to be 90 % of nominal voltage for sags and 110 % of nominal voltage for swells.

For MV sites, connection at L-L is appropriate for checking compliance with the PQ guidelines. For simplest comparison with harmonic limits, where possible, the instrument should be configured to measured harmonic voltages as a percentage of the fundamental current. The monitoring requirements for voltage interharmonics are equivalent to those for voltage harmonics. Harmonic currents may be using either current or voltage output current transducers depending on instrumentation requirements. In some cases, it may be necessary to connect clamp on type transducer to CT secondary circuits. Harmonic currents should be measured in Amperes. Flicker will be directly measured by instruments which incorporate a flickermeter.

Voltage dips and swell characteristics will be measured directly by the instrument based on preconfigured sag and swell threshold values. These thresholds should be configured to be 90 % of nominal voltage for sags and 110 % of nominal voltage for swells.

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