PROTECTIVE RELAYING AND POWER QUALITY

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IEEE PSRC Working Group Report

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IEEE PSRC Working Group Report

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1. SCOPE

Power quality is an area of growing interest in electric utilities. This IEEE PSRC Working Group document presents the aspects of power quality that relates to protective relaying. This document includes:

- An overview on power quality issues related to protective relaying using relevant standards/recommended practices
- Impact of protective relaying practices on power quality
- Impact of power quality on protective relaying
- Power quality monitoring functions in the protective relays
- Summary

2. INTRODUCTION

The document is divided into the four major sections identified above. Each of the relevant standards that proscribe "Power Quality" specification will be reviewed for those aspects that impinge on protective relaying practices. The impact that those standards have on protective relaying and the corresponding impact that protective relaying will have on those standards will be discussed in this document.

There are five major standards that have been identified as relevant that have the greatest interaction with protective relaying. Those standards are: 1) IEEE 1159 *Recommended Practice for Monitoring Electric Power Quality*, 2) IEEE 519 *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*, 3) ITIC (CBEMA) Curve, 4) IEC 1000-4-7 *General Guide On Harmonics And Interharmonics Measurements And Instrumentation, For Power Supply Systems And Equipment Connected*, and 5) EN 50160 *Voltage Characteristics Of Electricity Supplied By Public Distribution System*.

The IEEE 1159 *Recommended Practice for Monitoring Electric Power Quality* defines "power quality" in section 4.1 as:

> *Power Quality refers to a wide variety of electromagnetic phenomena that characterize the voltage and current at a given time and at a given location on the power system.*

As can be seen by this definition, protection relaying is more closely related to power quality than might at first be evident. Protection relaying is primary concerned with clearing faults while power quality is concerned with the delivering of reliable power within certain parameters.

The protective relaying fault clearing result in voltage sags that affect power quality. Protective relays detect faults under the assumption that conditions on the power system (i.e. voltages and currents) are within the requirement that define good power quality. When the steady state conditions on the power system are such that power quality parameters could be defined as poor power quality, protective relays can have problems making the correct decisions on tripping or not tripping.

This report will discuss the relationships between these two issues. The discussion will point out issues that protection engineers need to be aware in dealing with the effects of poor power quality. Also, power quality engineers will be made aware of the functions of protective relays and issues that could affect power quality.

3. Power Quality Standards Related to Protective Relaying

This section provides a summary of the power quality definitions and terms as outlined in standards or recommended practices.

3.1 Recommended Practice for Monitoring Electric Power Quality [IEEE Std 1159-1995]

The IEEE 1159 document [B1.1] outlines several key areas specifically related to power quality monitoring. Key areas include:

- Power Quality Phenomena
- Monitoring Objectives
- Measurement Instruments
- Application Techniques
- Interpreting Power Monitoring Results

This overview will focus on the power quality phenomenon. The power quality phenomenon is divided into several categories: transients, short duration variations, long term variations, voltage imbalance, waveform distortion, voltage fluctuations, and power frequency variations. The events are put in a particular category based on spectral content, duration, and/or voltage magnitude.

Some characteristics of these power quality events, as defined by IEEE 1159, are outlined below. Most power quality events are classified using two criteria: time duration and magnitude deviation. This section provides a summary of the functions by time duration.

Table 3.1. Transient Power Quality Events

Category	Typical Spectral Content	Typical Duration	Typical Voltage Variation
1.0 Transients			
1.1 Impulsive			
1.1.1 Nanosecond	5 ns rise	< 50 ns	
1.1.2 Microsecond	1 us rise	50ns-1ms	
1.1.3 Millisecond	0.1 ms rise	>1ms	
1.2.0 Oscillatory			
1.2.1 Low Frequency	<5 KHz	0.3-50 ms	0-4 pu
1.2.2 Medium Frequency	5-500 KHz	20us	0-8 pu
1.2.3 High Frequency	0.5-5MHz	5 us	0-4 pu

Voltage sags and interruptions are a common phenomena resulting from network faults and load energizing. Voltage sags are rms reductions in the ac voltage for a duration ranging from a half-cycle to a few seconds. Voltage interruptions represent the complete loss of voltage for similar time periods. Faults and fault clearing are a major source of voltage amplitude variations and interruptions. The phenomena and duration are dependent on the location of the fault, the type of fault, the network topology, and the protection coordination. Loads located on the down side of a faulted feeder undergo interruptions, whereas loads connected to lateral feeders or on the supply side of a faulted feeder sense a voltage sag for the duration of the fault. Voltage swells are rms increases in the ac voltage for duration ranging from a half-cycle to a few seconds. Often they appear on the unfaulted phases of feeders with ground faults in association with voltage sags or interruption on the faulted phase. Other times, they are present during changes in loading. These types of short-term events are summarized below.

Table 3.2. Short Term Variations

Categories	Typical Spectral Content	Typical Duration	Typical Voltage Variation
2.0 Short Duration Variations			
2.1 Instantaneous			
2.1.1 Sag		0.5-30 cycles	0.1-0.9 pu
2.1.2 Swell		0.5-30 cycles	1.1-1.8 pu
2.2 Momentary			
2.2.1 Interruption		0.5 cycles-3 s	<0.1 pu
2.2.2 Sag		30 cycles -3 s	0.1-0.9 pu
2.2.3 Swell		30 cycles –3 s	1.1-1.4 pu
2.3 Temporary			
2.3.1 Interruption		3s-1m	<0.1 pu
2.3.2 Sag		3s-1m	0.1-0.9 pu
2.3.3 Swell		3s-1m	1.1-1.2 pu

Sustained voltage interruptions represent the complete loss of voltage for a time greater than 1 minute. Undervoltages and overvoltages are the equivalent of sustained voltage sag or swell for greater than 1 minute, within a tighter bandwidth. These types of long-term events are outlined in the table below.

Table 3.3. Long Term Variations

Category	Typical Spectral Content	Typical Duration	Typical Voltage Variation
Interruption, Sustained		> 1 min	0.0 pu
Undervoltage		> 1 min	0.8-0.9 pu
Overvoltage		> 1 min	1.1-1.2 pu

Large amounts of network harmonics are generated by power electronic equipment. Low order harmonics up to the 40th harmonic can cause undesirable effects. Nonlinear loads draw harmonic currents from the power system, even if the power system voltage is a perfect sine wave. These currents produce harmonic voltage drops by way of the network impedances.

Table 3.4. Other Variations

Category	Typical Spectral Content	Typical Duration	Typical Voltage Variation
4.0 Voltage Imbalance		Steady state	0.5-2%
5.0 Waveform Distortion			
5.1 DC Offset		Steady state	0-0.1%
5.2 Harmonics	0-100th	Steady state	0-20%
5.3 Interharmonics	0-6 kHz	Steady state	0-2%
5.4 Notching		Steady state	
5.5 Noise	Broad-band	Steady state	0-1%
6.0 Voltage Fluctuations	<25 Hz	Intermittent	0.1-7%
7.0 Power Frequency Variations		< 10 s	

3.2 IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems [IEEE Std 519-1992]

The IEEE 519 document [B1.2] is intended to establish waveform distortion goals for the design of electrical systems that include both linear and nonlinear loads. The document provides guidelines and limitations for the quality of steady-state power at the Point of Common Coupling (PCC - the interface between sources and loads) recommended for "worst case" normal operation conditions. "Worst case" meaning conditions lasting longer than one hour. The document addresses the following salient topics:

- Sources of harmonics (converters, arc furnaces etc.)
- Effects of harmonics on various equipment (motors, generators, transformers, relays etc.)
- Harmonic control (reactive power compensation, control of harmonic currents)
- Analysis Methods (calculation and modeling guidelines)
- Measurements (instrument requirements, guidelines for presentation of data)
- Recommended practices for individual consumers and utilities

This overview will focus on the recommend voltage distortion limits, the effects of harmonics on protective relays and measurements of harmonics. Section 11 of the document specifies limits that should be used as system design values for the "worst case" for normal operation. For shorter periods, during start-ups or unusual conditions, the limits may be exceeded by 50%. Below is a mimic of table 11.1 from IEEE 519:

Table 3.5 Voltage Distortion Limits

Bus Voltage at PCC	Individual Voltage Distortion (%)	Total Voltage Distortion THD (%)
69 kV and below	3.0	5.0
69.001 kV through 161 kV	1.5	2.5
161.001 kV and above	1.0	1.5

NOTE: High-voltage systems can have up to 2.0% THD where the cause is an HVDC terminal that will attenuate by the time it is tapped for a user.

The IEEE 519 document refers to a published report (84 TH 0115-6 PWR) entitled "Sine Wave Distortions on Power Systems and the Impact on Protective Relaying" prepared by the Power System Relaying Committee of the IEEE Power Engineering Society. This report points out the impossibility of defining how protective relays will respond to harmonics due to the variety of relays and the methods they use. The report states:

> "Protective relays generally do not respond to any one identifiable parameter such as the rms value of a primary quantity or the fundamental frequency component of that quantity. As a related consideration, the performance of a relay to a range of single frequency inputs is not an indication of how that relay will respond to a distorted wave containing those frequencies. Superposition does not apply. Multi-input relays may be more unpredictable than single input relays in the presence of wave distortion. Relay response under distorted conditions may vary among relays having the same nominal fundamental frequency characteristics, not only among different relay manufacturers, but also among different vintages of relays from the same manufacturer."

IEEE 519 states, "Distortion factors of 10-20% generally are required to cause problems in relay operation." These levels are higher than the recommend limits given in Section 11 of the document.

The document discusses the various devices used to measure voltage and current harmonics and the goals of these measurements. Below are selected items from a list given in section 9.1 of IEEE 519 that relate to protective relays and their possible use for these purposes.

- Monitoring existing harmonic levels and comparing to recommended or admissible levels.
- Observing/trending existing background harmonic levels (daily, monthly, seasonal trends).
- Measuring harmonic levels to compare to harmonic load flow study results.
- Measuring harmonic current and voltage phase angles with respect to the fundamental. Such measurements can help determine the harmonic driving point impedance at a location for use in studies.

The document points out the limitation that existing digital protective relays generally have in regards to measuring harmonic quantities:

> "The techniques used for harmonics measurements differ from those used for ordinary power system measurement. The frequency bandwidth of the ordinary measurements of voltage, current, and power can be accomplished with attention to a narrow band of frequencies near the distribution frequency. Substantially wider bandwidths (up to 3kHz) are required in the study of power system harmonics."

IEEE 519 specifies requirements that must be met for accurate harmonic measurements:

> "Accuracy. The instrument must perform the measurement of a constant (stead-state) harmonic component with an error compatible with the permissible limits. It is reasonable to use an instrument with an uncertainty no larger than 5% of the permissible limit. For example, assume a 480V, three-phase system in which the 11th harmonic should be less than 0.70%. The line-neutral 11th harmonic, V_{11}, is less than 1.94V. This indicates that the instrument should have an uncertainty of less than $\pm(0.05)(1.94) = \pm 0.097$ V."
>
> "Bandwidth. The bandwidth of the instrument will strongly affect the reading, especially when harmonics are fluctuating. It is recommended that instruments with a constant bandwidth for the entire range of frequencies be used. The bandwidth should be 3 ± 0.5Hz between the –3 dB points with a minimum attenuation of 40 dB at a frequency of f_h + 15 Hz. In situations in which inter-harmonics and transients are present, a larger bandwidth will cause large positive errors."
>
> "Current Transformers. For measurements of harmonic currents in the frequency range up to 10 kHz, the normal current transformers that are used for switchgear metering and relaying have accuracies of better than 3%. If the CT burden is inductive, there will be a small phase shift in the current."
>
> "Magnetic Voltage Transformers. Magnetic voltage transformers, which are most easily available, are designed to operate at fundamental frequency. Harmonic frequency resonance between winding inductances and capacitances can cause large ratio and phase errors. Fig 9.6 presents typical variations of transformer ratio vs. frequency. For harmonics of frequencies less than 5 kHz, the accuracy of most potential transformers is within 3%, which is satisfactory."

> "Capacitive Voltage Transformers. Capacitive voltage transformers cannot be used for voltage harmonic measurements because, typically, the lowest frequency resonance peaks appear at frequencies of less than 200 Hz."

IEEE 519 Figure 9.6 is reproduced below:

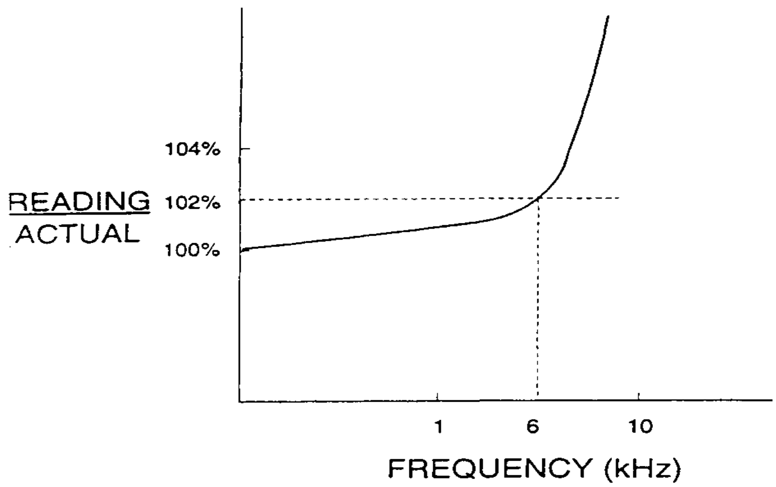


Figure 3.1. IEEE 519 figure showing relationship of reading to frequency

3.3 ITIC (CBEMA) Curve

The Information Technology Industry Council (formerly known as the Computer & Business Equipment Manufacturer's Association, or CBEMA) represents leading U.S. providers of information technology products and services. One of their technical committees has published a curve which "describes an AC input voltage boundary which typically can be tolerated (no interruption) in function by *most* Information Technology Equipment (ITE)." This curve covers both steady state and transient conditions and characterizes the susceptibility of ITE to possible damage from disturbances in the AC supply. The curve relates to 60 Hz systems with nominal voltages of 120V, 208Y/120V, and 120/240V.

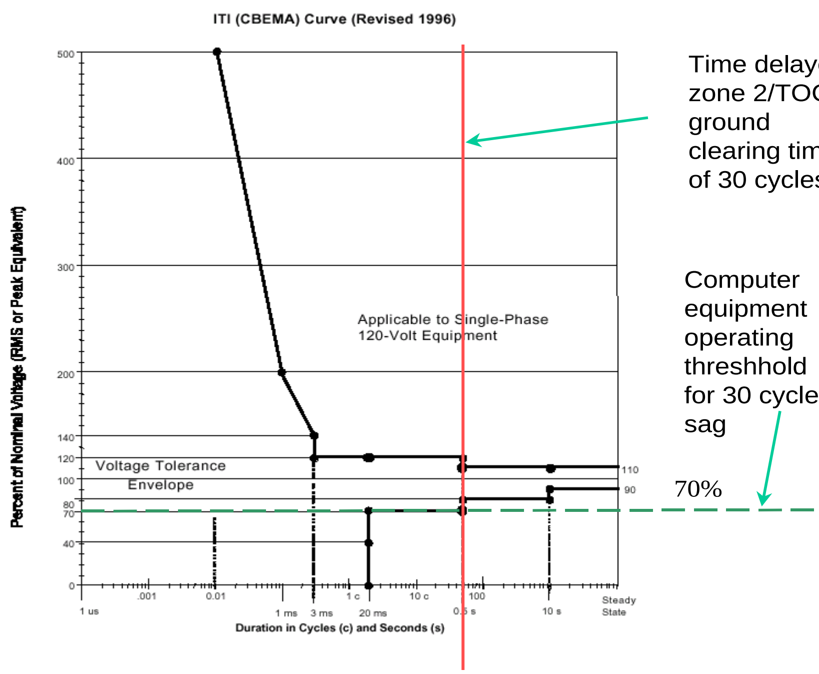


Figure 3.2. ITI curve

The curve has six salient regions:

Range	Duration	Magnitude	Typical cause(s)
Steady-state	10 s or longer	+/-10% around 120V nominal	Normal loading/losses
Voltage swell	Up to 0.5 s	Up to 120% of nominal	Loss of large load
High-frequency Impulse/Ringwave	1.2/50 microseconds	*	Lightning
Low-frequency Decaying Ringwave	200Hz to 5kHz	140%** for 200Hz, 200% for 5kHz, linear	Cap bank switching
Voltage sag - category 1	Up to 10 s	80% of nominal	Application of heavy load, fault conditions
Voltage sag - category 2	Up to 0.5 s	70% of nominal	Application of heavy load, fault conditions
Dropout	Up to 20 msec	Near to complete zero voltage	Fault clearing

*See C62.41-1991 – IEEE Recommended Practice on Surge Voltages in Low-Voltage AC Power Circuits
**Expressed as a percentage of peak

References

1. ITIC Curve Application Note: http://www.itic.org/iss_pol/techdocs/curve.pdf
2. IEEE Std 1100-1992 (Emerald Book)

3.4 IEC [IEC 1000-4-7] General guide on harmonics and interharmonics measurements and instrumentation, for power supply systems and equipment connected

The objective of this standard is to define how to measure and analyze the harmonics in power supply systems. This guide is applicable to instrumentation intended for measuring voltage or current components with frequencies in the range of dc to 2500 Hz that are superimposed on the voltage or current at the power supply frequency.

This guide classifies the instrumentation in frequency-domain instrumentation and time-domain instrumentation.

The instrumentation may be differentiated according to the characteristics of the signal to be measured, according to the accuracy classes of instrumentation and according to the type of measurement (voltage, current or another magnitude).

According to the characteristics of the signal to be measured four types of harmonics can be found:

- Quasi-stationary harmonics
- Fluctuating harmonics
- Quickly changing harmonics
- Interharmonics and other spurious components

Depending on the characteristics of the signal the analysis will be continuous or not (the more fluctuating the signal is the more continuous the analysis will be).

According to the accuracy classes of instrumentation two types are considered (A or B). Type A instruments are more accurate and are used for emission tests according to IEC 555-2.

According to the type of measurement recommendations for voltage and current harmonic measurements are given separately. Special cases of measurements (phase angle of harmonics, total harmonic distortion, weighted harmonic distortion, symmetrical components measurements, etc.) are also considered.

3.4.1 Common requirements for all types of instrumentation

There are some requirements that are applicable to all types of instrumentation, whether operating in frequency-domain or in time-domain. They are valid for steady state, fluctuating or very fast changing harmonics and interharmonics. These requirements refer to the input circuits and the accuracy. Regarding input circuits voltage input circuits and current input circuits are differentiated. In both cases the power absorption shall not exceed 3 VA.

The voltage input circuit of the measuring instrument shall be adapted to the nominal voltage and frequency of the supply voltage to be analyzed and shall keep its characteristics and accuracy unchanged up to 1,2 times this nominal voltage. A crest factor of at least 1,5 is considered sufficient for measurements except for highly distorting loads in industrial networks when a crest factor of at least 2 may be necessary. An overload indication is required in any case. It is suggested that stressing the input for 1s by an a c voltage of four times the input voltage setting or 1 kV_{rms} whichever is less, should not lead to any damage in the instrument. To permit a relatively universal use of the instrument for most supply systems, it may be advisable for the input circuit to be designed for the following nominal voltages: 115, 230, 400 V.

The current input circuit should be adapted to the currents to be analyzed. It should provide the direct measurement of the harmonic currents and, besides, should have a low-voltage high impedance voltage input, which may be associated with external resistive shunts. Appropriate input circuits range from 0.1 to 1 V. For direct current measurement it is advisable to provide input circuits, fitted for several of the nominal input currents: 0.1, 0.2, 0.5, 1, 2, 5, 16 A (and 10 A if required). Every measuring input circuit shall be able to be continuously stressed by 1.2 I_N and a stressing by 10 I_N for 1 s shall not lead to any damage.

Two classes of accuracy are suggested for instrumentation measuring voltage and current harmonics. The maximum allowable errors in Table 3.4.I refer to single-frequency and constant signals, in the operating frequency range, applied to the instrument under rated operating conditions to be indicated by the manufacturer (temperature range, humidity range, instrument supply voltage, etc.).

TABLE 3.4.I. Maximum measurement errors

Class	Measurement	Conditions	Maximum allowable error
A	Voltage	$U_m \geq 1\%\ U_N$ $U_m < 1\%\ U_N$	$5\%\ U_m$ $0.05\%\ U_N$
	Current	$I_m \geq 3\%\ I_N$ $I_m < 3\%\ I_N$	$5\%\ I_m$ $0.15\%\ I_N$
B	Voltage	$U_m \geq 3\%\ U_N$ $U_m < 3\%\ U_N$	$5\%\ U_m$ $0.15\%\ U_N$
	Current	$I_m \geq 10\%\ I_N$ $I_m < 10\%\ I_N$	$5\%\ I_m$ $0.5\%\ I_N$

U_m, I_m are the measured values corresponding to the f_m frequency value
U_N, I_N are the nominal input ranges of the instrument

The accuracy of voltage-transformers and current-transformers shall match the accuracy requirements for measurement instruments, i.e. the relative error (related to the measured value) shall not exceed 5%. When testing appliances according to IEC 555-2, the relative error of the total measurement equipment shall not exceed 5% (see Table 3.4.I).

The manufacturer shall specify the rated operating conditions and possibly the magnitude of error introduced by changes in:

- Temperature: operating temperature range (+5 ºC to +40 ºC), storage temperature range (-10 ºC to +55 ºC)
- Humidity: 40% to 95 %.
- Instrument supply voltage and related series interferences: deviation from the rated frequency (±2%), deviation from the rated voltage (±15%), total distortion (up to 10% for normal use), or interruption (10 ms).
- Common mode interference voltage up to 420 Vrms between the earth connection of the instrument, its input circuits and the auxiliary supply voltage.
- Static electricity discharges: Test according to IEC 801-2. Test voltage 15 kV air discharge.
- Radiated electromagnetic fields: The influence error shall be indicated under the effect of a magnetic field of 100 A/m at mains frequency.

3.4.2 Special requirements for frequency-domain instrumentation

The measurement of quasi-stationary harmonics is based on the rejection of fundamental and other harmonic components. These requirements define the minimum attenuation with reference to f_n ($f_n = nf_1$; f_1: fundamental supply frequency) that is the frequency of the harmonic of order n to be measured and for which the instrument is set. The attenuation is measured with reference to the value at frequency f_n, when a single frequency signal, at a harmonic frequency different from f_n is applied to the input of the instrument. The values of Table 3.4.II are applicable for voltage and current measurements.

TABLE 3.4.II. Attenuation requirements

Single frequency injected signal	Value of f_n	Minimum attenuation dB
Neighboring harmonic $f_n - f_1$ and $f_n + f_1$	$2 f_1 \le f_n \le 12 f_1$ $12 f_1 < f_n \le 20 f_1$ $20 f_1 < f_n \le 50 f_1$	30 20 15
Frequency $\le 0.5 f_n$	Any value of f_n	50
Fundamental (supply) frequency f_1	Any value of f_n	60* 70**

* For all current measurements and class B voltage measurements
** For voltage measurement with class A instrumentation

The bandwidth at –3 dB shall be included between 3 Hz and 10 Hz for measurements of fluctuating harmonics. For the case of quickly changing harmonics it is not recommended to measure them with frequency-domain instruments.

3.4.3 Special requirements for time-domain instrumentation

The guide defines two approaches for the measurement of current and voltage harmonics. One is based on the Fourier transform and the other on digital filters.

Instruments that realize the Fast Fourier Transform consist mainly of:

- Anti-aliasing filter
- A/D converter including sample and hold unit
- Synchronization and window-shaping unit if necessary
- FFT processor
- Arithmetic processor providing the harmonics and possibly their phase-lag

The required characteristics depending on the harmonic type are summarized in Table 3.4.III.

TABLE 3.4.III. Basic requirements for FFT-instrumentation

Category of harmonics	Recommended window width	Additional requirements
Quasy-stationary	T_W = 0.1 – 0.5 s	Gaps between windows may exist
Fluctuating (according to IEC 555-2)	T_W = 0.32 s (rectangular) T_W = 0.4 – 0.5 s (Hanning)	No gap Overlapping half by half
Quickly changing	T_W = 0.08 – 0.16 s (rectangular)	No gap

Instead of performing the FFT, the analog band-pass defined according to Table 3.4.II can be reproduced using digital filters, taking care that the high quality factors required are met. The requested 40 are calculated in parallel. Whilst these harmonics are of primary importance, facilities should be provided to obtain the full spectral content of the power supply including interharmonics.

In addition, this guide refers to the importance of measure other magnitudes apart from the voltage and current harmonics. Theses magnitudes are the phase-lags between harmonic currents and voltages of all considered orders, the harmonic distortion, the symmetrical components and the interharmonics.

Some of these magnitudes can give information about the presence of faults or abnormalities in the network. For example, the phase-lags between harmonic currents and voltages can be used to evaluate the load-flow of harmonics in supply systems or to detect and localize disturbing harmonic sources. The direction of the active power flow of the harmonic order of interest may help in finding the origin of the disturbances: if the active power flows into the public system, the plant causes the current; otherwise it is the mains system itself.

Deviation from symmetry in three phase electrical equipment may be an indication that a fault has occurred. Symmetry is strongly affected by small failures, for example one failed element of a capacitor bank, particularly in the harmonic frequency range. Therefore, its supervision may help to detect these failures.

3.5 Voltage characteristics of electricity supplied by public distribution system [EN 50160:1999]

European Standard EN 50160 defines the main characteristics of the voltage at the customer's supply terminals in public low voltage and medium voltage distribution system. This standard gives the limits or values within which any customer can expect the voltage characteristics to remain under normal operating conditions. Standard does not apply under abnormal operating conditions like conditions arising as a result of a fault or a temporary supply arrangement, in case of non-compliant customer installations or equipment. Main object is to describe voltage characteristics concerning frequency, magnitude, waveform and symmetry of the three phase voltages. Power quality focus is in longer period characteristics of the voltage.

Nature of the standard is to give limits for measured indices during a long period like one week. The index itself is measured as average value over a period varying between 10 seconds and 10 minutes. Limits are given with two categories. First, maximum limits are given - all measured values shall be under the given limit. Then another limit is given so that small percentage of the measured values is allowed to be between given limit and the maximum limit.

Short time events and rapid changes like voltage sags, swells and interruptions are described. As these mostly are results form abnormal conditions, there are not given limits to fulfill, but normative values a customer can expect to happen are given. Indices described are:

- Voltage sags
- Voltage swells
- Interruptions
- Transients
- Interharmonics

As summary this standard is ignoring the short time events that are affected by relay operations. Instead it is concentration to long period power quality measurement and monitoring. This standard includes the following definitions:

3.5.1 Definitions

Voltage variation: increase or reduction in the amplitude of the voltage normally caused by variations in the load

Fast voltage variation: a variation in the voltage rms value between two consecutive levels and maintained during defined time intervals.

Voltage fluctuation: a series of voltage variations or a cyclic variation of the voltage enveloping

Flicker severity: intensity of the nuisance caused by the flicker, measured as defined by UIE-CEI and evaluated as:

- Short term severity (P_{st}) measured in a 10 minute period
- Long term severity (P_{lt}) defined as $P_{lt} = \sqrt[3]{\sum_{i=1}^{12} \frac{P_{st}^3}{12}}$

Voltage sag: sudden reduction in the rms voltage to a value between 90% and 1% of the declared value (usually the nominal value) and a duration between 10 ms and 1 min.

Interruption: voltage bellow 1% of the declared value. An interruption is classified in:

- Short term interruption: duration till 3 min.
- Long term interruption: duration over 3 min.

Temporary overvoltage (industrial frequency): overvoltage of a relative long duration usually caused by switching or faults

Transient overvoltage: oscillatory or non-oscillatory overvoltage with a maximum duration of several milliseconds.

Harmonic voltage: sinusoidal voltage with a frequency which is a multiple of the fundamental frequency mainly caused by non-linear loads

Interharmonic voltage: sinusoidal voltage with a frequency which is not a whole number multiple of the fundamental frequency

Voltage imbalance: in a three-phase system when voltage rms values or phase angle differences are not equal

Information signal transmitted along the network: the public distribution network allows three types of signals:

- Remote control signals: sinusoidal signals with a frequency range of 110 to 3000 Hz
- Carrier: sinusoidal signal with a frequency range of 3 kHz to 148,5 kHz
- Wave marked signals: short duration transients superimposed to the voltage in specified instants.

3.5.2 Voltage characteristics in public distribution networks

Frequency: nominal frequency must be 50 Hz. In normal operating conditions the fundamental frequency, measured in 10 s periods, must be situated in the following intervals:

- Interconnected networks: 50 Hz ± 1% during 99.5% of the year
  50 Hz + 4% - 6% during 100% of the year,
- Islanded networks: 50 Hz ± 2% during 99.5% of the year
  50 Hz ± 15% during 100% of the year.

Voltage amplitude: for MV networks is the declared voltage U_c. For LV networks the normalized nominal value is:

- 4 conductors: 230 V phase to neutral,
- 3 conductors: 230 V phase to phase.

Voltage variations: for a week period, 95% of rms values (averaged in 10 min intervals) in the interval U_n ± 10%. For every 10 min period, average rms values must be in the interval U_n + 10% - 15% (only in LV networks).

Fast voltage variations: are usually caused by fast variation in the load. In normal operating conditions fast variations are usually under 5% of U_n for LV networks and 4% for MV networks. But, in certain conditions, can reach 10% of U_n in LV networks and 6% in MV networks. During a week period, flicker severity caused by voltage fluctuations should be ≤ 1 (P_{lt}) during 95% of the time.

Voltage sags: these phenomena are fundamentally random and its frequency depends on the type of distribution network and the observation point. Indicative values in normal operating conditions for a year vary from several tens to a thousand. The greatest parts of the sags have duration of less than a second and a depth bellow 60%.

Short-term interruptions: Annually, the number of short-term interruptions can vary from several tens to several hundreds. Over 70% of them are below 1 second in duration.

Long-term interruptions. Indicative values for a year, and for accidental interruptions, can be less than 10 or reach to 50 depending on the region.

Temporary phase to ground overvoltages: are usually due to faults in the network or in a client installation. Generally, the overvoltage can reach the phase-to-phase voltage value due to the displacement of the neutral. For LV networks, indicative values are normally less than 1.5 kV for faults in the HV side of a distribution transformer. For MV networks, it depends on the grounding method. For solidly grounded or impedance grounded networks, the overvoltage must not exceed 1.7 U_c. For ungrounded or resonant grounded systems the overvoltage must not exceed 2 U_c.

Transient phase-to-phase overvoltages: For LV networks, generally, they have a peak value less than 6 kV but sometimes it can be higher. Rise time can vary between less than a μs to several ms.. For MV networks, switching overvoltages generally have a lower amplitude than lightning overvoltages, but their rise time can be faster and their duration longer.

Voltage imbalances: for every week period, 95% of the inverse voltage component rms values averaged in 10 min. must be between 0% and 2% of the direct component value. In regions with single phase or two-phase supply imbalances can reach 3%.

Harmonic voltages: for every week period, 95% of the rms values of each harmonic voltage averaged in 10 min. cannot exceed the values shown in the table 3.5.I.

Table 3.5.I

Odd harmonics				Even harmonics	
Non-multiples of 3		Multiples of 3			
Order	Individual Distortion	Order	Individual Distortion	Order	Individual Distortion
5	6%	3	5%	2	2%
7	5%	9	1,5%	4	1%
11	3,5%	15	0,5%	6 … 24	0,5%
13	3%	21	0,5%		
17	2%				
19	1,5%				
23	1,5%				
25	1,5%				

Values corresponding to harmonics of an order above 25, which generally are weak and very unforeseeable due to resonant effects, are not indicated in this table

Also, Total Harmonic Distortion (THD) cannot exceed 8%.

Interharmonic voltages: due to the few experience in this field, the level of interharmonic voltages is left for further study.

Information signals: the value of the transmitted signals averaged every 3 s cannot exceed the levels indicated in figures 3.3 and 3.4 during 99% of the day.

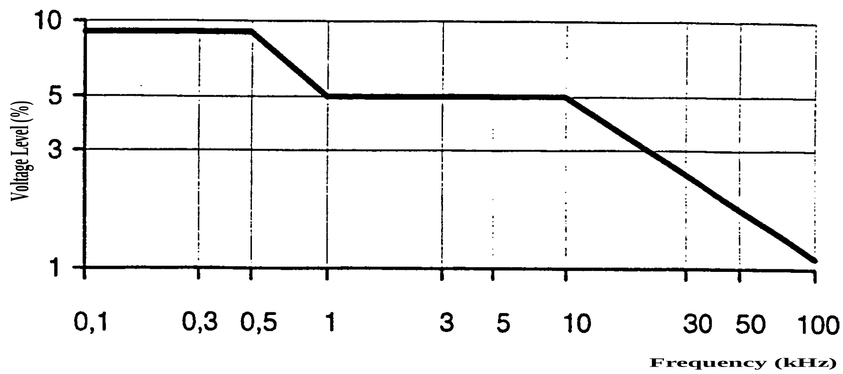


Fig.3.3. Information signal voltage level in LV networks

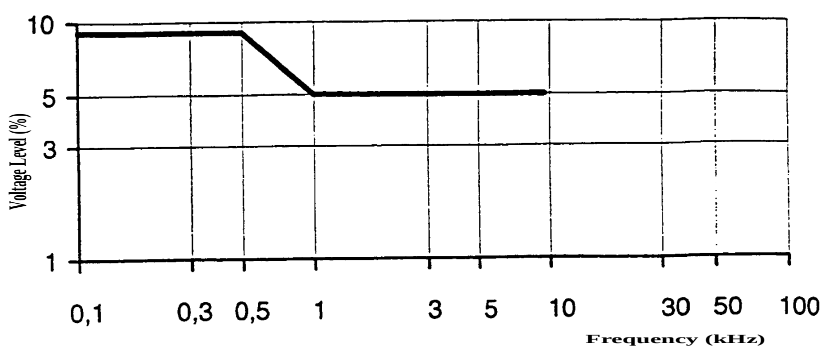


Fig.3.4. Information signal voltage level in MV networks

3.6 Application of Power Quality Standards to Protective Relaying

3.6.1 Application of Power Quality Definitions to Protective Relaying

The application of power quality functions in protective relaying is possible due to the increased functional capability of modern microprocessor protective relays. This results from the continuous consolidation of secondary equipment functions into a single Intelligent Electronic Device (IED). Multipurpose IEDs permit the coexistence of the PQ functions to monitor power system reliability as well as provide the protective relaying for primary equipment protection. The purpose of power quality monitoring is to observe the power system behavior and capture critical data that can be used to assist in explanation of this behavior or phenomena. Likewise, the protection functions digital fault recorders also provide a means of capturing critical data for postmortem root cause analysis in both PQ and fault events.

In principle, the power quality definitions do not have a direct relationship to the protective relaying. When an IED is reacting to a power system fault or load shedding scenario, a downstream or adjacent lines IEDs could observe the faulted line's IEDs action as a power quality event. For example, the faulted IEDs trip and reclose sequence will be observed in another IEDs power quality voltage interruption.

The power quality categories and their relationship to protective relaying are summarized below:

<u>Transients</u> – a condition that exist for a very short time interval and would not typically have any application on protective relaying.

<u>Short duration variations</u> - a condition that could result from a faulted feeder operation and subsequent breaker reclose and would typically be a result from protective relaying operation.

<u>Long-term variations</u> – a condition that could result from a permanent fault on a feeder with the breaker going to lockout and would typically be a result from a protective relaying operation.

<u>Voltage imbalance</u> – a condition that could result from non-linear loads on a single phase circuit where conventional protective relaying applications could detect this unbalance in the sequence component calculations. The definition of the voltage imbalance is 0.5-2% which in effect not be observed by any sequence component protection application.

<u>Waveform distortion</u> – a condition that is present when harmonics are present in the fundamental sine wave. The impact of the waveform

distortion from protective relaying applications that deploy fundamental measurement only could result in marginal operations. Typically, the distortions are magnitudes less than 20% harmonic content.

Power frequency variations – a condition that could result from many sources including motor startup or other from coupling two independent power systems. These frequency variations, since they are typically less than 10 seconds in duration, would typically not have an impact on protective relaying or load shedding schemes.

In summary, the application of power quality definitions in protective relaying will be viewed as complimentary functions in the consolidation of secondary equipment protection, control, metering and monitoring into a single IED. The PQ functions can and will be very useful to the power system engineers in the identification and postmortem analysis of intermittent operations as well as other power system phenomena.

3.6.2 Application of IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems [IEEE Std 519-1992] to protective relaying

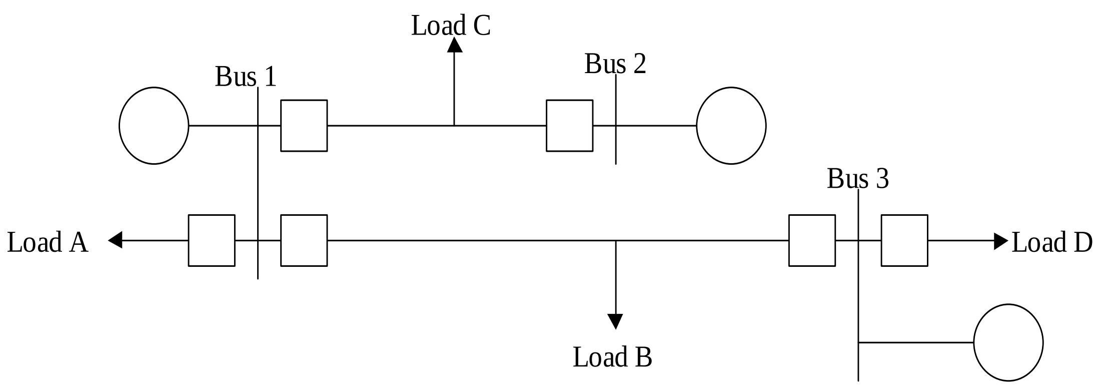
Since the IEEE 519 document provides guidelines and limitations for steady state and "worst case" ("worst case" meaning conditions lasting longer than 1 hour) conditions it doesn't pertain to the general application of protective relays or automatic reclosing. IEEE 519 does mention that harmonics may affect relay performance, "Distortion factors of 10-20% generally are required to cause problems in relay operation." These levels are higher than the recommended limits given in the document such that if the IEEE 519 limits are violated it may impact operation of protective relays. Aside from general information on how harmonics (power quality) may affect relay performance IEEE 519 is not relevant to the application of protective relays.

3.6.3 Application of ITI Curve to Protective Relaying

The voltage sag and dropout categories of the ITI curve seem to have the most relevance when discussing protective relaying. Referring to the ITI curve, a transmission system fault cleared in typical zone 2 clearing time of 30 cycles requires that the fault produce a sag at the customer bus no less than 70% of nominal. If the sag is lower than that, it can be expected that at least some ITE may shut down. For this reason, pilot relaying, which can provide high-speed (5 cycles or less) fault clearing for 100% of the protected line, might be considered for transmission lines in areas around customers with a large portion of sensitive ITE.

For example, consider the system single-line diagram below: For a fault on the line from buses 1 and 3, load B will necessarily be interrupted during the process of clearing the fault. However, during the fault, the voltage at buses 1, 2, and 3 will all drop to some value, depending on the length of the lines and the strength of the equivalent sources. The duration of the fault is dependent on the speed of the relay scheme for the faulted line added to the switchgear interrupting time.

It is evident that pilot protection will not help stations tapped from the faulted line, since according to the ITI curve, zero-voltage dropouts can only last up to 20 msec, or a little more than one 60 Hz power cycle. This is a seemingly impractical goal for conventional transmission and distribution switchgear. But pilot protection along with fast (2-3 cycle) switchgear could give sensitive loads on adjacent or nearby buses a chance to ride through a power system fault.



3.6.4 Application of Standard IEC 1000-4-7 to Protective Relaying

The standard IEC 61000-4-7 gives some recommendations about how the devices should be used to measure harmonic distortion. For the point of view of digital relays, the main interest is that the harmonic distortion does not interfere in the measurement (i.e. introducing errors). For that reason, the relays should complete some characteristics that come defined by the standard IEC 61000-4-7, as recommendations, to make signal measures.

The main negative influence that harmonic distortion can have on the digital relays (and all type relays in general) is that they can act without fault situation. This action would be as consequence of: the peak value of the resulting wave and/or the shift. For that reason, when measuring currents and voltages, the relays must measure alone the fundamental component of the signal. To get this, a software filter is usually used.

According to the characteristics of the signal to be measured four types of harmonics can be found: quasi-stationary harmonics; fluctuating harmonics, quickly changing harmonics and interharmonics and other spurious components. In the case of relays, it is considered the worst case (those harmonics, which vary quickly). For this type of harmonics, it is recommended to make a continuous measure of the signal to detect any possible harmonic distortion. Besides, it is necessary to filter the harmonic and to obtain the rms value of the fundamental frequency signal. For this purpose, the standard recommends to use the Fourier transform. It is the more used algorithm to filtrate the harmonic distortion.

Finally, we must have in mind that there are some cases in which the presence of harmonic distortion can be interesting. One example is the case of differential relays of transformers.

3.6.5 Application of Standard EN 50160 to Protective Relaying

The standard EN 50160 defines the characteristics that the voltage wave should have, defining some acceptable ranges for the different distortions that can appear in the signal.

- Frequency variations

As we have seen previously, the standard EN 50160 settles down some limits among the frequency can vary. Inside these limits, it is considered that the quality of the voltage wave is acceptable. But, these variations can influence in the measures of the digital relays and include some distort in the measurement of some magnitudes. However, as they are acceptable inside a range, it is necessary to be sure that the relay is able to support these variations without its influence is noticed.

The magnitudes measurement of a relay (voltage, current) is based on making a sampling. This sampling has a defined number of samples (i.e. from 8 to 64), during one period (20 ms for 50 Hz). From this sampling, the rms value of the signal will be obtained.

Let us suppose a case of 12 samples per cycle. If an increase of the frequency takes place and we maintain the sampling period of time fixed (20 ms), when obtaining the rms value there will be an error. This error is due to the fact that we would be obtaining the rms value taking 12 samples to make the calculation, but we would really be taking more than one cycle. Therefore, the calculated rms value would be erroneous.

On the other hand, a decrease of the frequency would cause a contrary effect. So, using periods of 20 ms, we would be calculating the rms value from a wave piece of less than a cycle, which would cause errors equally in the measure.

To avoid this type of errors, the digital relays must adapt the sampling frequency to the network frequency, in each moment. This way, we can be sure that the calculated rms value is good. To get this one, we should know in each moment, which the network frequency is and adapt the sampling frequency to it.

- Voltage fluctuations, swells and interruptions

The standard EN 50160 establishes that the voltage fluctuations should not be bigger than 10% of the nominal voltage. This phenomenon type does not have influence on the correct operation of the digital relays. On the other hand, this standard does not settle down a limit for the voltage swells and interruptions, since they usually take place as consequence of faults. But, these phenomena have not a significant influence on digital relays because the feeding of the digital relays usually comes from batteries or sources of uninterrupted feeding.

- Voltages imbalances

This standard settles down that for every week period, 95% of the inverse voltage component rms values averaged in 10 min. must be between 0% and 2% of the direct component value. Although this type of distortion does not affect the correct operation of the relay, it is necessary to control and maintain it inside the margins that the standard demands. Thus, derived problems of this network distortion will not affect the relay performance. Also, although the standard speaks of direct sequence voltage, digital relays usually use homopolar or inverse sequence currents. They usually have overcurrent units adjusted with a small starting, but temporized at a long time. This way, if an imbalance is detected during a long period of time, finally the relay trips.

4. IMPACT OF PROTECTIVE RELAYING ON POWER QUALITY

This section provides an overview of the impact of protective relaying on power quality.

When considering the impact of relaying, or any protective device application, on power quality, it must first be understood that power quality means many things to different classes of electrical customers. Traditional reliability attributes associated with sustained outages or momentary interruptions certainly apply in most cases. Non-voltage zero dips, swells, or transients, as well as harmonic content also are of significance in many cases.

This understood it is of interest to review the effects of different types of protective devices and applications and their effects, both pro and con, on power quality. The use of protective relays and circuit breakers in substations to sense and interrupt faults quickly obviously affects the number of sustained and momentary outages on the feeder that they protect. Electromechanical relays have the advantage of simplicity in application, likely leading to few misoperations with negative effects on power quality. Microprocessor-based or digital relays have other advantages including self testing features to avoid misoperations, faster reset characteristics, flexibility to program better coordination to reduce trip operation times and event recording capabilities to aid in the analysis of system operations, possibility resulting in better system designs, relay settings, and identification of recurring field problems. Each of these is a potential advantage when considering power quality.

Reclosers, whether hydraulic or electronic with intelligent controls, have similar effects on power quality. The selection of proper line and tap fusing, both in size and in type, will also affect power quality by providing adequate overcurrent device coordination and acting to reduce the effect of faults to as few customers as possible, while also limiting the duration of voltage dips, especially in the case of current limiting fuse applications.

In each of these cases it is important to note that proper coordination is of great significance. If coordination is not achieved, larger portions of the electric system may be subjected to unnecessary outages. Transmission system misoperations can affect many distribution customers. Tripping a transformer or bus in a distribution substation when a feeder breaker or recloser should have tripped has the same effect.

Speed of operation of any protective device is of great significance when considering effects on power quality. Protective devices should operate as fast as possible to limit the effects of faults to upstream customers and customers on adjacent feeders fed from the same bus. Instantaneous or fast definite time operations will have fewer effects than delayed or time-overcurrent operating times. Where practical, communications-assisted schemes can be used to reduce operating time rather than relying on other methods such as zone 2 impedance relays.

The use of line reclosing, whether via reclosing relays and breakers or self-contained reclosers, also affects power quality. Successful reclose operations can reduce outage durations significantly, resulting in fewer sustained outages but actually increasing the number of momentary interruptions experienced by customers. The number of reclose operations or 'shots' affects the likelihood of reclose success, but also impacts the number of voltage dips seen by customers on adjacent feeders. Reclose interval times also affect the likelihood of success, and while it might seem that instantaneous reclosing might be the best approach to addressing power quality issues, in many cases a short time delay actually results in a better success rate.

Fuse Saving is a practice sometimes applied whereby an upstream overcurrent device, typically a relayed breaker or recloser, is set to trip and reclose prior to a tap fuse operation for a fault downstream from the fuse. This practice has both advantages and disadvantages when considering power quality. When it is applied it tends to subject larger numbers of customers to momentary interruptions. When it is not applied temporary faults can turn into sustained outages for those customers downstream from a tap fuse that is allowed to operate. It is best to evaluate the application of fuse saving on a case-by-case basis, considering customer needs.

Single phase tripping, through the use of single-phase reclosers or other devices, may offer some advantages over three-phase tripping in some aspects. If a single phase to ground fault occurs on a system and single phase tripping is in place, the outage can be limited to only the customers served by the phase of the circuit experiencing a fault. Care must be taken to assure that three phase customers have in place loss of voltage protection so that they do not suffer the effects of 'single phasing' which could be considered a power quality issue from the customer perspective.

Relay misoperations, either failure to trip for a fault and 'cascading' the event to an upstream protective device thus affecting more customers, or tripping when no fault is present, have the potential to negatively affect customers. Complexity of the protective scheme, communications systems failures, use of blocking vs. unblocking schemes, and system design conditions such as sensing of ground faults on delta/ungrounded systems all come into play. System reconfiguration issues also affect relay performance. Adaptive schemes, automatic setting changes, autochangeover schemes, and the application of Distribution automation switching all point to the need to review protective schemes as the system changes, or design those schemes with enough margin to accommodate the system changes. Operating issues and maintenance of protective devices also affect their ability to respond appropriately to faults. Relay test intervals, test practices, and even settings changes and control issues come into play.

Load shed schemes, whether undervoltage, underfrequency, or a combination of both, have the ability to limit the effects and control large system disturbances. As system voltages and frequencies begin to collapse, appropriately set and applied load shed schemes can save major portions of a system, while limiting the magnitude and duration of voltage and frequency power quality excursions to the customers that stay in service.

New technologies continue to be developed and applied that can have positive effects on power quality these include:

- High impedance fault detection may be used to identify and repair the causes of arcing faults and incipient failures, thus having positive effects on the harmonic content of the distribution system.

- Load encroachment schemes that can be tailored and set to reduce the likelihood of a protective device misoperation due to heavy load conditions

- Fault location algorithms allow for identification of outage causes and faster restoration, thus reducing the duration of outages seen by customers

- The use of targets and other relay information in automation schemes such as Substation Integration or Distribution Automation also act to reduce outage times.

5. IMPACT OF POWER QUALITY ON PROTECTIVE RELAYING

This section provides an overview of the impact of power quality on protective relaying.

The influence of distorted waveforms on protective relays is not well documented because of the numerous measurement principles employed in each relay design. For example: electromechanical relays tend to respond to the fundamental frequency component of the distorted wave. However, this may vary considerably among different manufacturers electromechanical relay designs. Initially static relays were overly sensitive to high frequency components but design model revisions corrected these deficiencies.

With the advent of microprocessor relays, filtering techniques were developed to accommodate a wide variety of harmonic influences. Digital sampling and anti-aliasing filters provided a means of sampling sine wave currents and/or voltages at discrete time intervals. A fixed number of instantaneous samples are converted to digital quantities by an A/D converter and stored in memory for processing. Digital filtering is the process of combining a sequence of samples to obtain the quantities representing the phasor components of the input. This process enables the magnitude of components to change and the sampling intervals to remain fixed as the frequency of the input is varied. The resulting phasor can then vary in magnitude and phase as a function of input frequency. As a result more than two samples can be combined to obtain a more favorable frequency response. Algorithms developed around this concept are ideal for protective relay applications because they can be made to have no response to dc offsets and have no response to second-order and other even harmonics. However, the filter responds to odd harmonics that would corrupt the measurement of the fundamental. Consequently, a low pass analog anti-aliasing filter is used to eliminate the higher frequencies from the measurement. Thus, a digital filter extracts the phasor components of the analog current or voltage input. Consequently, a microprocessor relay using the digital filter is immune to the effect of harmonics in the sense that it extracts the fundamental from the waveform.

In order to determine the impact of power quality on protective relays it is in order to define some power quality components. There are three primary attributes used to differentiate between the different categories and subcategories of power quality, namely: **frequency components, magnitude, and duration.** These attributes are not equally applicable to all of the categories of power quality variations. For instance, it is difficult to assign duration to an oscillatory transient and it is not useful to assign a spectral content to variations in the fundamental frequency magnitude (sags, swells, over voltages, under voltages, interruptions). These characteristics and attributes are useful for evaluating measurement equipment requirements, system characteristics affecting the power quality variations, and possible measures to correct power quality problems.

TRANSIENTS

The term transient has been used in the analysis of Power System variations for a longtime. Broadly speaking, transients can be classified into two categories:

Impulsive and Oscillatory

Impulsive transients

An impulsive transient is considered unidirectional, that is, the transient voltage or current wave is primarily of a single polarity. Impulsive transients are often characterized by magnitude and duration. Another important component that influences the effect on many types of electronic equipment is the rate of rise. The rate of rise can be quite steep for many types of impulsive transients. The high frequency components and the high rate of rise are important considerations for monitoring impulses. Very fast sampling rates are required to characterize impulses and waveforms. The most common cause of impulses transients is lightning. For example, a 6 kA impulse transient current with a 3 microsecond rise time due to lightning may result in the conduction of a lightning arrester protecting an important piece of equipment. Protective line relays are not expected to operate for this condition. If the impulse transient results in an insulator flash over, the subsequent fundamental frequency power follow current should result in relay operation to de-energize the circuit.

Oscillatory transients

An oscillatory transient consists of a voltage or current whose instantaneous value changes polarity rapidly. Since the term "rapidly" is rather nebulous, the frequency content is used to break the oscillatory transient category into three further subcategories**,** namely: high, medium, and low frequency.

High frequency transients

Some type of switching event usually initiates these. Back-to-back (energizing a capacitor bank with a second bank in close proximity) capacitor energizing results in oscillatory transient currents in the tens of kHz. Switching circuits (lines and/or cables) results in oscillatory voltage transients in the same frequency range. These transients can last a couple of cycles. Circuit resistance typically damps these transients out quickly. Protective equipment is expected to ride through this type of disturbance.

Medium frequency transients

These transients are often associated with capacitor switching events. This type of switching operation occurs with some degree of regularity on most distribution systems and many transmission systems. Capacitor bank energization typically results in oscillatory voltage transients with a primary frequency between 300 and 900Hz and has a peak magnitude that can approach two times the normal peak and last between 0.5 and 3.0 cycles depending upon system dampening. Protective equipment is expected to ride through this type of disturbance.

Low frequency transients

Low frequency transients are generally associated with ferroresonance (a series resonant condition usually involving cable capacitance and transformer saturation when transformers are energized). Transients involving series capacitors and CCVTS can also fall under this category. They occur when the system resistance results in magnification of low frequency components, transformer inrush currents, or when unusual conditions result in ferroresonance. Voltage transformers that experience ferroresonance can adversely affect the characteristics of directional relays (refer to figure). The frequency and duration of an oscillatory transient is also related to its energy content. Protective relays cannot prevent a ferroresonance condition from starting but they may be able to detect a ferroresonance over voltage condition and isolate the trouble before damage can occur. Current transformer saturation may also fall into this category. Not only can it adversely affect a relay's directional characteristic but also its ability to coordinate with down stream devices.

SHORT DURATION VARIATIONS

Short duration voltage variations include variations in the fundamental frequency voltage that last <1 minute. The voltage variations can be a momentary low voltage (sag) or high voltage (swell).

Voltage Sags

Voltage sags are momentary undervoltage conditions that are typically caused by a fault somewhere on the power system. The voltage sag occurs over a significant area while the fault is actually on the system. As soon as a protective device clears a fault, voltage returns to normal on most parts of the system, except the specific line section that is actually faulted. The typical duration for a transmission system fault is about six cycles. Distribution system faults can last significantly longer, depending upon a utilities protection philosophy. Harmonics are usually not a problem during a sag condition.

Voltage Swells

Voltage swells are much less common than voltage sags and the magnitudes are not usually severe. The most common cause is a single line-to-ground fault condition. During a line to ground fault the voltage on the unfaulted phases can increase depending on the zero sequence impedance. On an ungrounded system, the voltage on the unfaulted phases can be in excess of 170% of nominal. This type of voltage excursion does not usually result in a relay operation unless the swell is deemed undesirable. Steps must be then be made to correct the condition. Harmonics are usually not a problem during a swell condition.

The following oscillogram depicts two types of harmonic conditions that can adversely affect the performance of relays.

1) The top trace is a voltage waveform of an unfaulted phase of the circuit in fault. The potential transformer (CCVT) connected to the line side of a breaker went into a ferroresonace condition upon reclosure. The condition lasted until the breakers tripped de-energizing the line. If this voltage were used to polarize impedance relays it may not polarize them correctly resulting in a delayed trip for internal faults and a false trip for external faults.

2) The actual fault was a phase to ground fault and the ground relay polarizing circuit was between the phase current (bottom wave form) and the station neutral current (wave form second from the bottom). It can be seen that the neutral current is badly distorted (saturated) upon reclosure. The polarizing circuit was not in the proper relationship with the phase current and the relay interpreted this to be and external fault. This resulted in a delayed trip because the carrier signal (third trace from the top) maintained a continuous "block" signal during the fault.

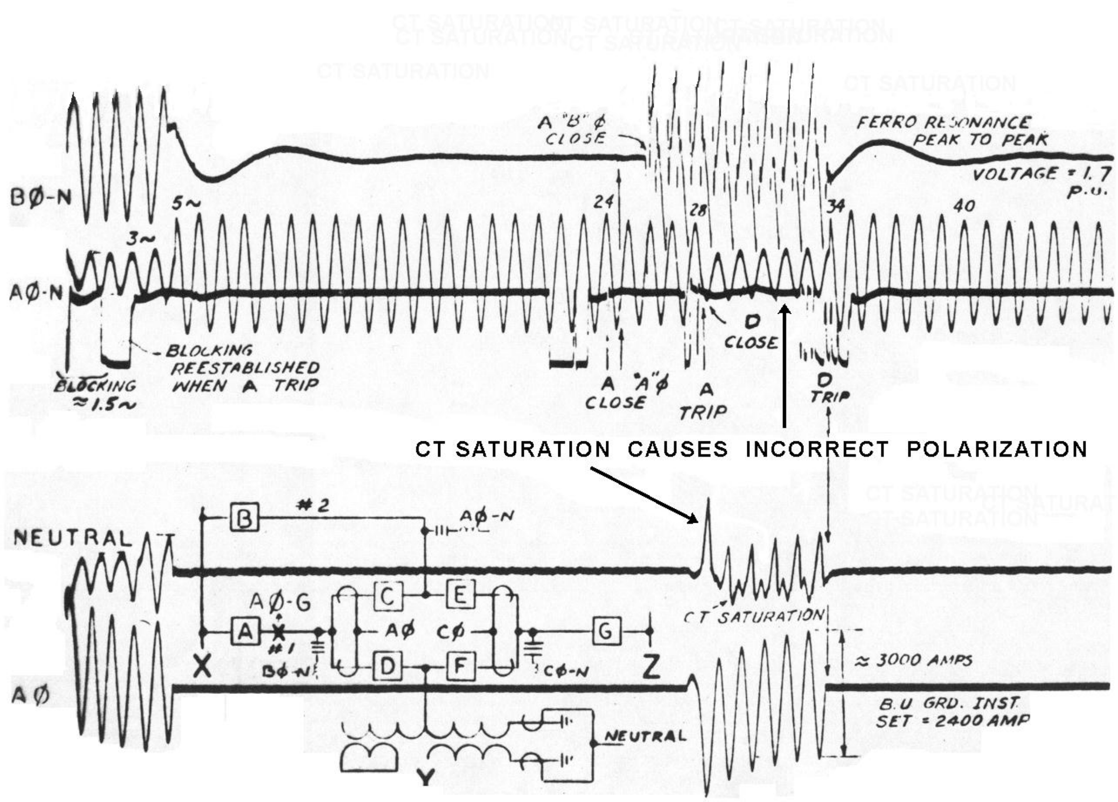


Figure 5.1 Oscillogram of harmonic conditions

Influence of Harmonic Distortion on Digital Protection Relays

The variations in power frequency and the harmonic distortion can make a relay work incorrectly. Following, the influence of harmonic distortion on digital relay is analysed.

Depending on the characteristics of the measured signal, in practice four types of harmonics can be found: quasi-stationary harmonics; fluctuating harmonics; rapidly changing harmonics, interharmonics as well as other spurious components. For protection relays rapidly changing harmonics have the worst effect. For this type of harmonics, it is recommended to make a continuous measure of the signal to detect any possible distortion.

High levels of harmonic in extreme cases can cause relay maloperation that is mainly a consequence of measurement error of the peak value and/or the angle of the waveform. For that reason, when measuring currents and voltages, the relays should measure the fundamental component of the signal alone. The standard IEC 1000-4-7 recommends using the Fourier Transform algorithm to filter out the harmonic distortion and to obtain the RMS value of the fundamental frequency signal only.

Another method utilised to obtain the RMS value is based on the calculations of the Mean Square value directly from the wave. This method does not eliminate the harmonics, and therefore, the calculated RMS value is different from that of the fundamental component alone. Higher RMS values are normally obtained with this method, which indicates that superfluous tripping activity can be produced by the relay in some cases.

Additionally, there are some other cases in which the presence of harmonic distortion can be interesting from the protection relay point of view. One such example is the case of differential protection of a transformer.

Example

In order to illustrate harmonic distortion, an incorrect operation of a distance digital relay is presented. The relay calculates the RMS value with the Mean Square method instead with the Fourier Transform, and as a result, the relay produces an incorrect trip. The analysis has been developed by simulation, using the software tool Mathcad.

This case study presents a single-phase to earth fault on a transmission line with high harmonic content. It is assumed that the only existing harmonics are the 5^{th} and the 7^{th}. The distance digital relay calculates the voltage and current RMS values from the distorted input waveforms (Figures 5.2 and 5.3).

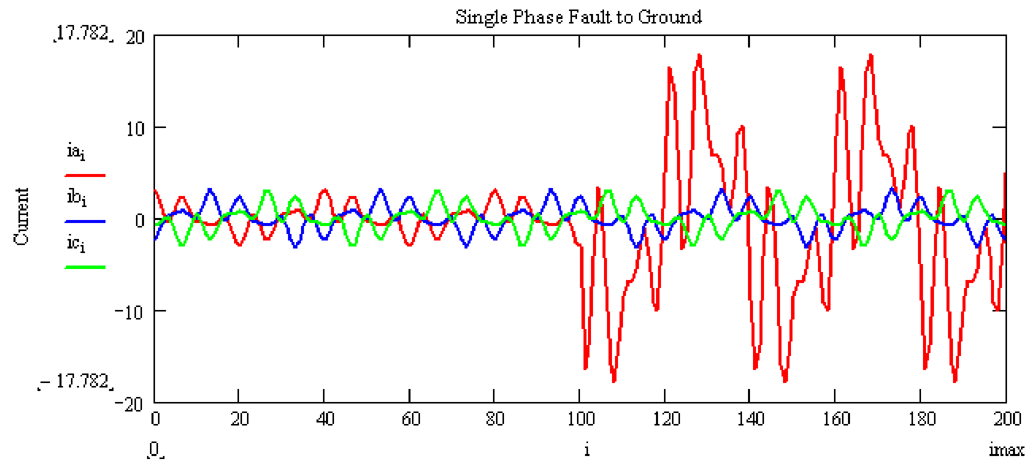


Figure 5.2. Current waveforms during single-phase fault

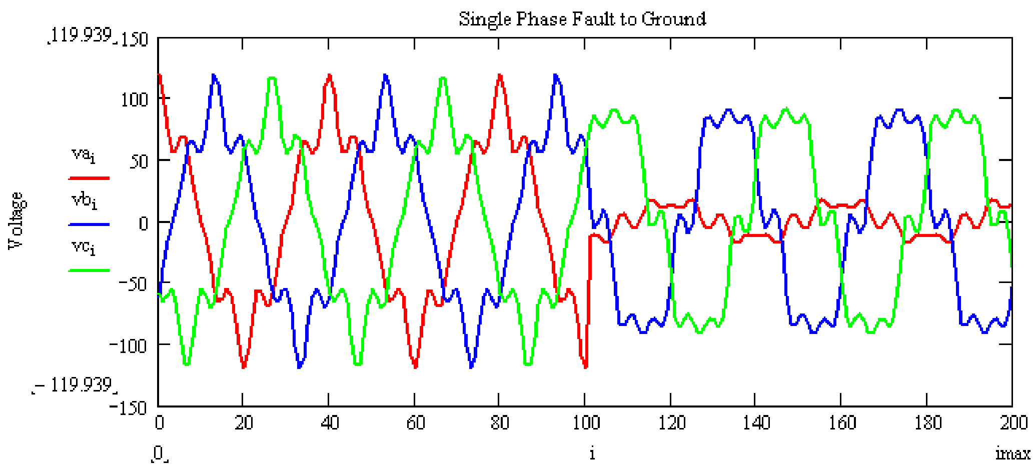


Figure 5.3. Voltage waveforms during single-phase fault

Figures 5.4 and 5.5 illustrate the difference between two RMS calculating methods, one based on the Mean Square value and the other on Fourier Transform. In this specific case, due to the presence of harmonics, the values obtained through the Mean Square value method is higher than the value obtained through the Fourier Transform. This is due to the fact that the Fourier Transform based method filters out higher harmonics and the final result contains fundamental frequency component only.

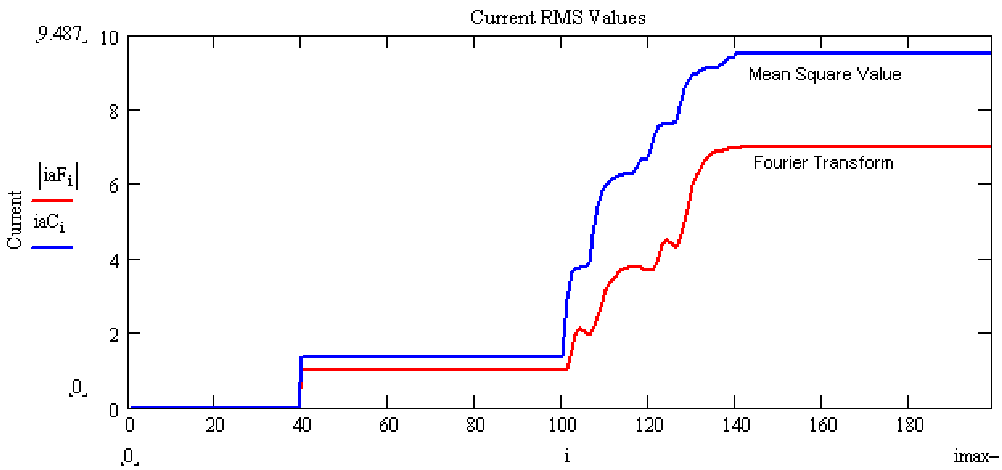


Figure 5.4. Current RMS value

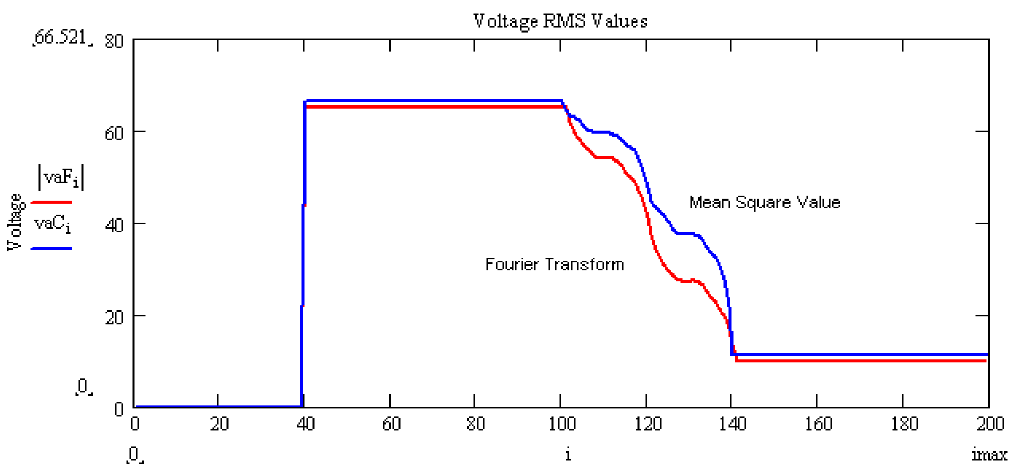


Figure 5.5. Voltage RMS value

Once this RMS value is obtained, impedance-evaluating algorithms of the digital relay are applied. The final response of the digital relay is presented in figures 5.6 and 5.7.

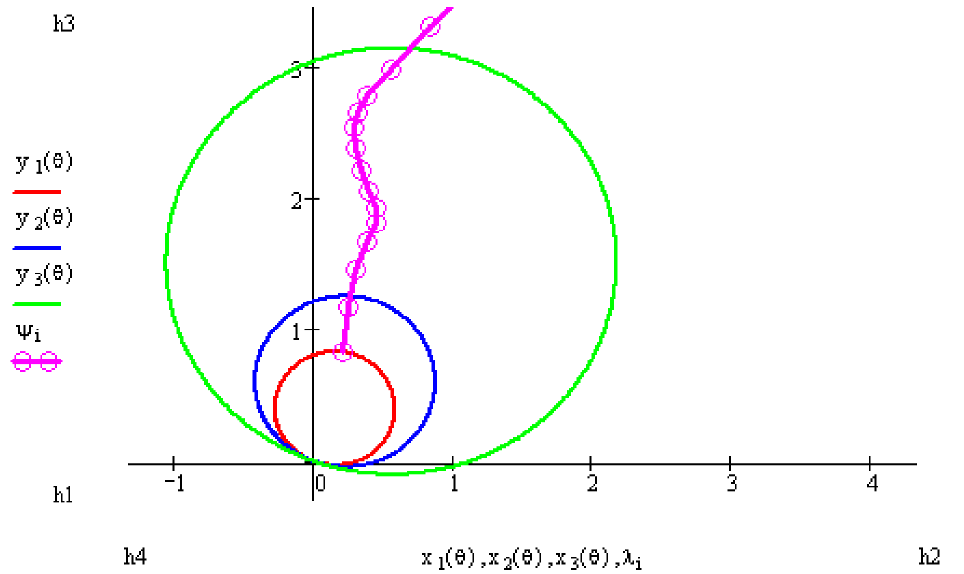


Figure 5.6. Digital Relay Impedance Evolution for Fourier Transform based algorithm.

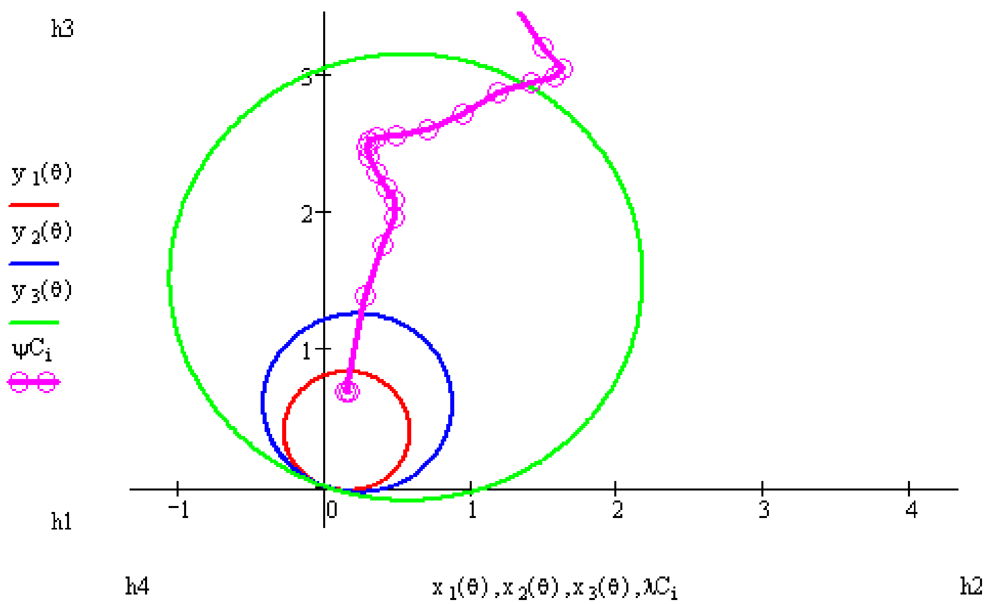


Figure 5.7. Digital Relay Impedance Evolution for Mean Square Value based algorithm

It can be observed how a fault located in zone 2 of protection (figure 5.6), is seen in zone 1 by a digital relay which uses Mean Square method to obtain the RMS value. This digital relay will give an incorrect trip (figure 5.7).

6. POWER QUALITY MONITORING IN PROTECTIVE RELAYS

This section provides a summary of the power quality monitoring functionality in protective relays or other IEDs.

6.1 Using Relay Functions For Power Quality Monitoring

Modern microprocessor based protection and control devices have numerous functions that allow them to become power quality monitoring devices. They can be divided in the following categories:

Protection functions:

- Undervoltage
- Overvoltage
- Underfrequency
- Overfrequency
- Broken conductor detection
- User defined threshold
- Metering functions:
- Power factor
- Harmonics
- Programmable Scheme Logic
- Event reports
- Disturbance recording

Protection functions

Undervoltage Protection

Undervoltage conditions may occur on a power system for a variety of reasons, some of which are outlined below:

- Increased system loading.
- Faults occurring on the power system result in a reduction in voltage of the phases involved in the fault.
- Complete loss of bus voltage. This may occur due to fault conditions present on the incoming feeder or the bus itself, resulting in total isolation of the incoming power supply.
- Where outgoing feeders from a bus are supplying induction motor loads, excessive dips in the supply may cause the connected motors to stall, and

should be tripped for voltage reductions which last longer than a pre-determined time.

The undervoltage condition is detected by appropriately set instantaneous or time delayed elements. They can be used in combination with other timers in order to build a logic scheme in order to distinguish between voltage sags and power interruptions.

Overvoltage protection

As previously discussed, undervoltage conditions are relatively common, as they are related to fault conditions etc. However, overvoltage conditions are also a possibility and are generally related to loss of load conditions as described below:

- Under conditions of load rejection, the supply voltage will increase in magnitude.
- During ground fault conditions on a power system there may be an increase in the healthy phase voltages.

The overvoltage condition is detected by appropriately set instantaneous or time delayed elements. They can be used in combination with other timers in order to build a logic scheme in order to detect voltage swells or transients.

Underfrequency protection

Underfrequency conditions in the power system will occur when the load exceeds the generation. Power system overloading can arise when a power system becomes split, with load left connected to a set of 'islanded' generators that is in excess of their capacity.

The underfrequency condition is detected by appropriately set instantaneous or time delayed elements. In some specialized abnormal frequency load-shedding and restoration relays rate-of-change of frequency or the trend of the rate-of-change can be used for more advanced detection of such abnormal system conditions.

Overfrequency protection

Overfrequency conditions arise when the generation exceeds the load. The most common occurrence of overfrequency is after substantial loss of load in an isolated system.

The overfrequency condition is detected by appropriately set instantaneous or time delayed elements.

Broken conductor detection

Broken conductors, maloperation of single-phase switchgear, or the operation of fuses can cause unbalanced conditions or power interruptions. Such series faults will not cause an increase in phase current on the system and are not affecting the voltage in the substation, hence are not readily detectable by standard protection functions described earlier. However, they will produce an unbalance and a resultant level of negative phase sequence current, which can be detected.

It is possible to apply a negative phase sequence overcurrent relay to detect the above condition. However, on a lightly loaded line, the negative sequence current resulting from a series fault condition may be very close to, or less than, the full load steady state unbalance arising from CT errors, load unbalance etc.

A negative sequence element therefore would not operate at low load levels. An element that measures the ratio of negative to positive sequence current (I_2/I_1) provides a better solution. This will be affected to a lesser extent than the measurement of negative sequence current alone, since the ratio is approximately constant with variations in load current. Hence, a more sensitive setting may be achieved and used for the detection of unbalanced load conditions or power interruption to customers located further down a distribution feeder.

Metering functions

Metering functions can be used for power quality monitoring in cases when there are no protection functions associated with the power quality parameter. Another requirement is that the parameter is changing with a relatively low speed. An example is given below.

Power factor

Power factor is one of numerous quantities that are calculated based on the measured by the protective IED currents and voltages. Different relays provide options for single phase power factor monitoring or the total power factor calculation.

In order to get an indication and trigger recording, a user defined threshold setting of the monitored parameter is required. It can be instantaneous or time delayed depending on the specifics of the application and user power quality monitoring requirements.

Harmonics

Harmonics are calculated based on the sampled current and voltage signals. The number of calculated harmonics is a function of the sampling rate of the protection and control IED.

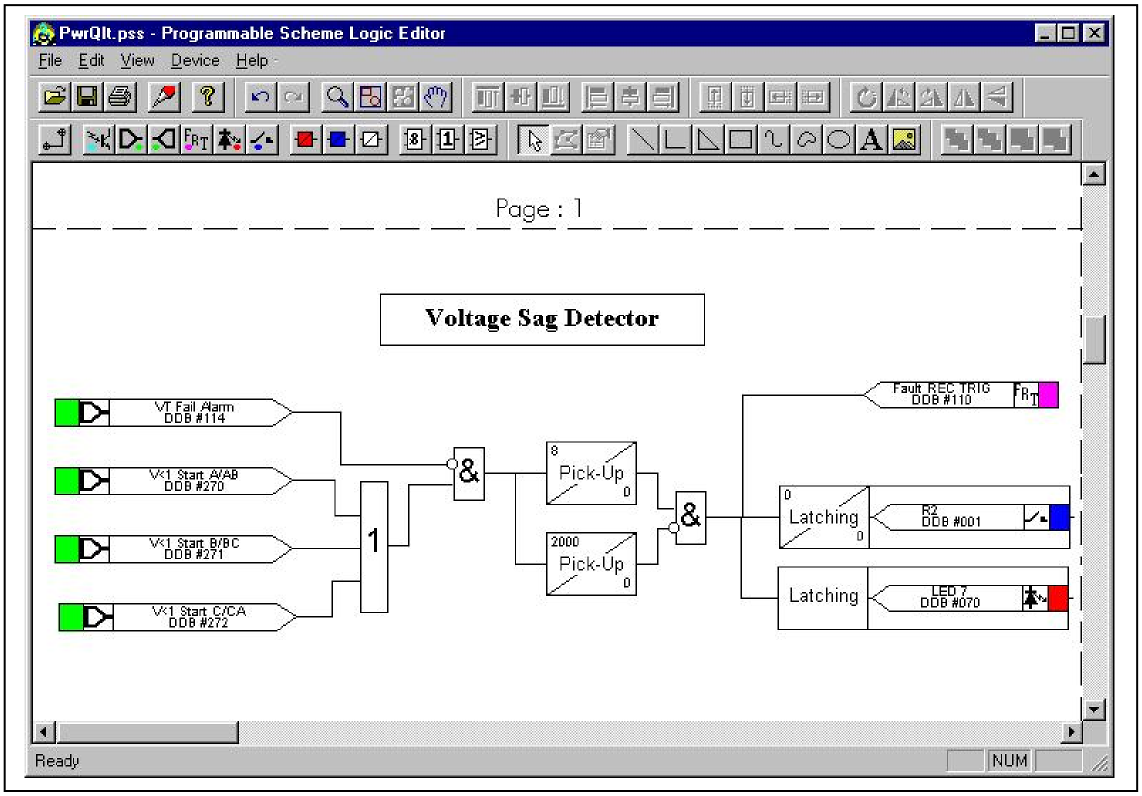
This also requires the use of appropriate thresholds in order to alarm or record the deviation from normal power supply parameters.

Programmable Scheme Logic

The purpose of the programmable scheme logic (PSL) is to allow the relay user to configure an individual protection, control or alarm scheme in order to suit a particular application. This is achieved through the use of programmable logic gates and delay timers.

The input to the PSL is any combination of the status of the digital input signals from the opto-isolators on the input board, the outputs of the protection elements, e.g. protection starts and trips, and the outputs of the fixed protection scheme logic. The fixed scheme logic provides the relay's standard protection schemes. The PSL itself consists of software logic gates and timers. The logic gates can be programmed to perform a range of different logic functions and can accept any number of inputs. The timers are used either to create a programmable delay, and/or to condition the logic outputs, e.g. to create a pulse of fixed duration on the output regardless of the length of the pulse on the input. The outputs of the PSL are the LEDs on the front panel of the relay and the output contacts at the rear.

Figure 6.1 Programmable Scheme Logic based Voltage Sag Detector



The execution of the PSL logic is event driven; the logic is processed whenever any of its inputs change, for example as a result of a change in one of the digital input signals or a trip output from a protection element. Also, only the part of the PSL logic that is affected by the particular input change that has occurred is processed. This reduces the amount of processing time that is used by the PSL. The protection and control software updates the logic delay timers and checks for a change in the PSL input signals every time it runs.

This system provides flexibility for the user to create individualized scheme logic designs. It can be used in combination with the described above protection functions in order to detect and alarm for power quality events. An example of a voltage sag detection scheme is given in Fig. 6.1.

The voltage sag is detected by phase A, B or C undervoltage element, while at the same time there is no Voltage Transformer Supervision alarm. The output of the AND gate starts two timers in order to define a voltage sag window of 8ms to 2 sec. These time settings can be different and are determined by the user's definition for a voltage sag. The output of the second AND gate will operate a relay output, an LED on the front panel of the relay and will trigger the Disturbance Recorder in order to capture the voltage sag waveforms.

The relay output and the LED are latched to ensure that the indication of the event is not lost. However, the relay output can be unlatched if the signal is going to SCADA in order to remove the alarm signal as soon as the undervoltage condition ends. It will still be time-stamped and logged and the latched LED will have to be reset from the front panel of the relay after reviewing the event information.

Similar schemes shall be used for the detection of the other power quality monitoring functions in the protective relay.

Event and Fault Records

The relays record and time tag multiple events. This enables the system operator to establish the sequence of events that occurred within the relay following a particular power system condition, switching sequence etc. When the available space is exhausted, the new one automatically overwrites the oldest event.

The real time clock within the relay provides the time tag to each event, to a resolution of 1ms. IRIG-B input to the relays should be used for time synchronization in order to ensure accurate time stamping for further analysis of the records from multiple IEDs in distributed analysis architecture.

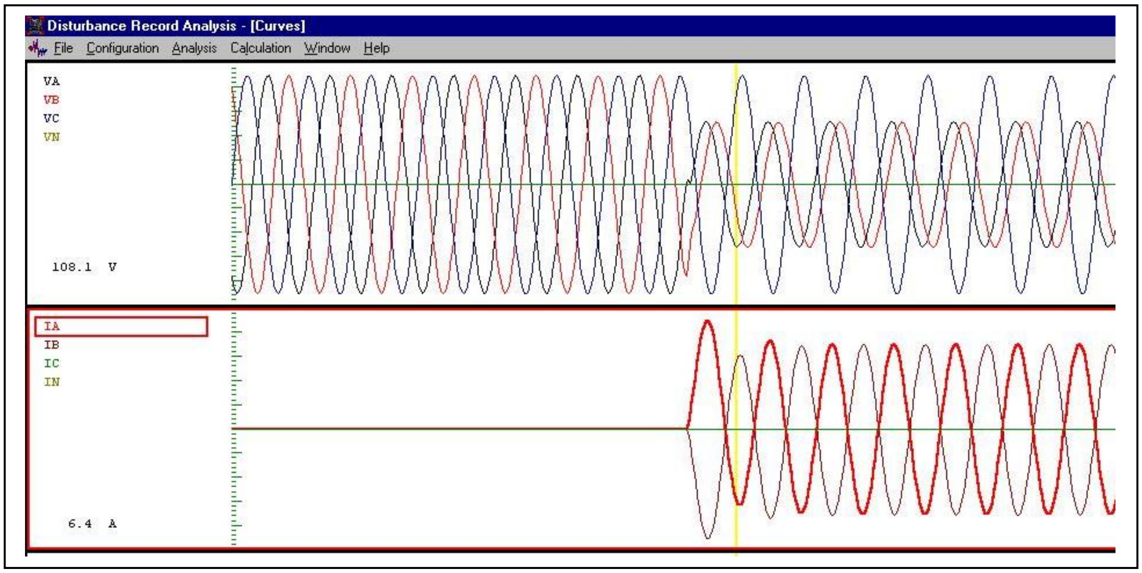
An event may be a change of state of a control input or output relay, an alarm condition, setting change etc. They can be protection element starts and trips or as shown in the example above, the operation of the power quality monitoring scheme.

Any operation of protection elements, (either a start or a trip condition), will be logged as an event record, consisting of a text string indicating the operated element and an event value. This value is intended for use by the event extraction software.

Disturbance recorder

The integral disturbance recorder in the relays has an area of memory specifically set aside for record storage. The number of records that may be stored is dependent upon the selected recording duration but the relays typically have the capability of storing a minimum of 20 records, each of 10.5-second duration.

Figure 6.2 Disturbance record showing a voltage sag during a phase to phase fault



This is very important in the case of power quality monitoring functions, since it allows a longer pre-and post-trigger record that will provide a better understanding of the system behavior during the event. Disturbance records continue to be recorded until the available memory is exhausted, at which time the oldest record(s) are overwritten to make space for the newest one.

The recorder stores actual pre-filtered samples that are taken at a different rate as a function of the hardware and software of the IED. Some typical sampling rates are 4, 8, 12, 16, 20, 24, 32 or higher samples per cycle.

If a further trigger occurs whilst a recording is taking place, the recorder will ignore the trigger if the "Trigger Mode" has been set to "Single". However, if this has been set to "Extended", the post trigger timer will be reset to zero, thereby extending the recording time.

Power Quality Monitoring Architecture

Modern microprocessor based relays are typically being integrated in hierarchical substation protection and control systems. This allows the distribution of protection, control and monitoring functions between multiple devices and with different level of complexity at the different levels of the hierarchy.

The system has two or three levels depending on the type and size of the substation, as well as the user requirements.

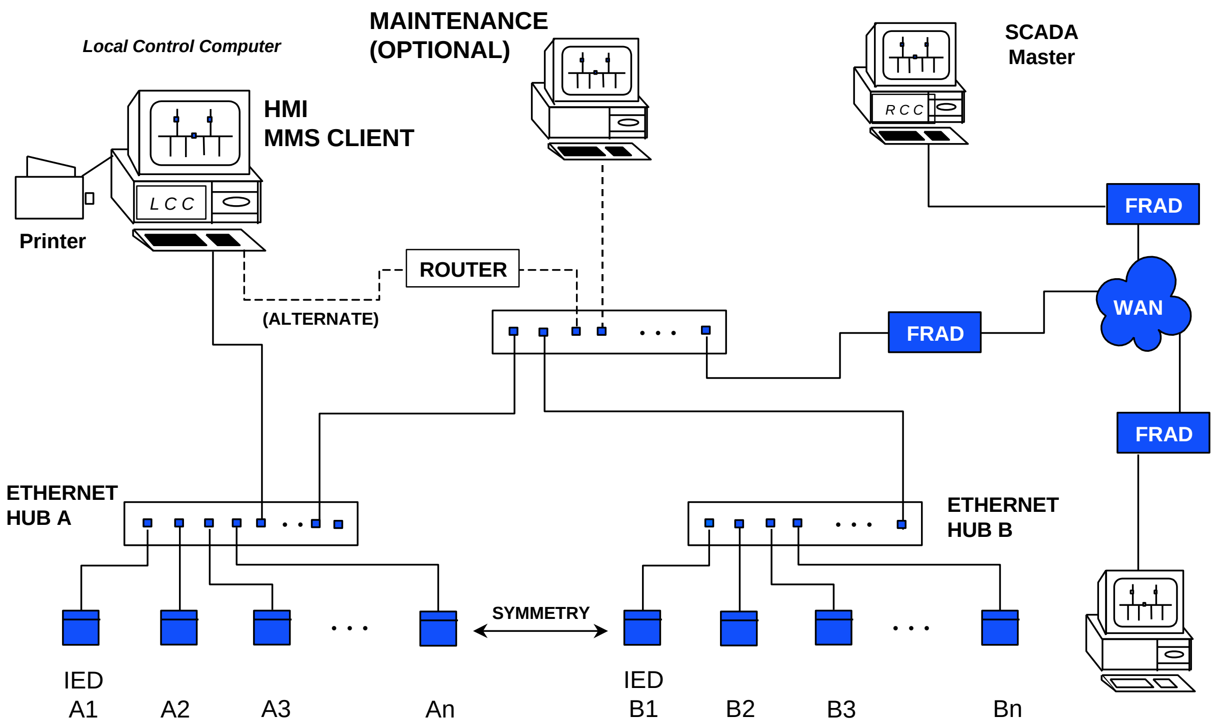


Figure 6.3 Hierarchical power quality monitoring and analysis system architecture

The system shown in Fig. 6.3 has a two level architecture with protective IEDs performing power quality problems detection, alarm, logging and recording. All IEDs are connected to a substation local area network (SLAN). They represent the lower level, directly related to the individual power equipment in the substation - transformers, distribution feeders, transmission lines, buses, etc.

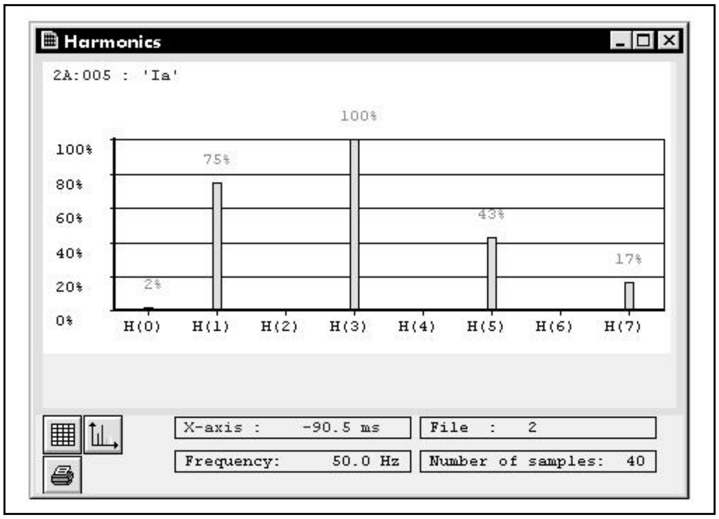


Figure 6.4 Harmonic analysis results at the substation level based on a disturbance record from the relay

A substation computer is also connected to the SLAN and performs multiple functions based on the data and information available from the IEDs at the power equipment level. It represents the substation level in the hierarchy. Typical functions include the human machine interface (HMI), alarm and event logging at the substation level, settings, control, load profiles and analysis, etc. It also includes the centralized power quality analysis functions. An example is the harmonic analysis based on the disturbance records extracted from the relay memory shown in Fig. 6.4.

The event logs from multiple devices during voltage sags, swells and other power quality deviations can be analyzed at the substation level in order to determine the cause of the event and its effect on different customers supplied with power from the substation.

The analysis is based not only on the detection of power quality deviation, but also on the available information for protection and control functions operation in the IED.

If the substation integration system is based on UCA, all IEDs will support the power quality related measurements object models. An object browser will be configured to poll for the different power quality data objects or data sets grouped into power quality bricks. Table 1 shows the measurement (MX) data objects from the Power Quality RMS Variations (MPQV) brick defined in GOMSFE 0.91. This brick contains other data objects such as configuration, control, description, etc [1].

Table 6.1 MPQV Brick

FC	Object Name	Class	rwec	m/o	Description
MX	TotVar	INT16U			RMS variation events (phs. agg.)
	AggVar	INT16U			RMS variation events (time and phs. agg.)
	TotVVar	INT16U			RMS V variation events (phs. agg.)
	AggVVar	INT16U			RMS V variation events (time and phs. agg.)
	TotAVar	INT16U			RMS A variation events (phs. agg.)
	AggAVar	INT16U			RMS A variation events (time and phs. agg.)
	TotVSag	INT16U			Voltage sag events (phs. agg.)
	AggVSag	INT16U			Voltage sag events (time and phs. agg.)
	TotVSwl	INT16U			Voltage swell events (phs. agg.)
	AggVSwl	INT16U			Voltage swell events (time and phs. agg.)
	TotVInt	INT16U			Voltage interruption events (phs. agg.)
	AggVInt	INT16U			Voltage interruption events (time and phs. agg.)
	TotASag	INT16U			Current sag events (phs. agg.) since last reset
	AggASag	INT16U			Current sag events (time and phs. agg.)
	TotASwl	INT16U			Current swell events (phs. agg.)
	AggASwl	INT16U			Current swell events (time and phs. agg.)
	TotAInt	INT16U			Current interruption events (phs. agg.)
	AggAInt	INT16U			Current interruption events (time and phs. agg.)
	RMSRsTim	BTIME6			Time of last counter reset
	RMSEvtTim	BTIME6			Time of last RMS event
	RMSVArr	INT16[64]			RMS voltage variation counting bins array
	RMSAArr	INT16[64]			RMS current variation counting bins array
	RMSEvtBuf	INT8U			Size of circular recent event buffer
	LasEvtIdx	INT8U			Index in event array of latest event
	RcnRMSArr	RRE[N]			Recent event circular buffer array
	FilCtlBlk	FCB			File Control Block (max files before delete, naming rules, etc.)

6.2 Factors to Consider

This section outlines factors that should be considered when implementing power quality monitoring in protective relays.

Sampling Rates and Anti-Aliasing Filters

By design, relays and other IEDs typically utilize a fixed sampling rate and employ anti-aliasing analog or digital filters. The sampling rate is proportional to the cutoff frequency of the anti-aliasing filter and prevents harmonics above the cutoff frequency from being processed. While preventing computational error, this has the effect of blocking the detection of higher frequency events. While many power quality events outlined in previous sections involve high frequency components, several of interest do not. In particular, outage, sags, swells, and harmonics below the cutoff frequency may be detected.

Independent Phase Detection

Since large parts of an electrical network are three phase unbalanced, particularly in MV distribution, it is desirable to capture power quality events on a per phase basis. Thus, three-phase phenomenon will register as three separate events. For instance, the voltage sag calculation unit may monitor all three-voltage phases independently and records events where the voltage drops below a threshold for a specified period of time.

Interruption and Sag Events

According to the IEEE definitions, voltage sags may or may not ultimately be classified as an interruption. However, voltage interruptions will always initially appear as a voltage sag. If necessary, this data can be filtered using off-line analysis tools.

Need to Filter Event Data On-Line

A major difficulty on on-line classification of PQ events is that a single voltage disturbance may result in several on-line events according to the IEEE definition. For example, consider the case below shown in Figure 6.5.

According to the definition of the instantaneous and momentary sag, this single phenomenon may result in two PQ events: instantaneous sag from time 0 until time Tx, and a momentary sag from time 0 until time Ty. While technically correct, this is confusing to the end user and, results in redundant data. To clarify this, the real time IED should categorize this as a momentary sag from time 0 until time Ty.

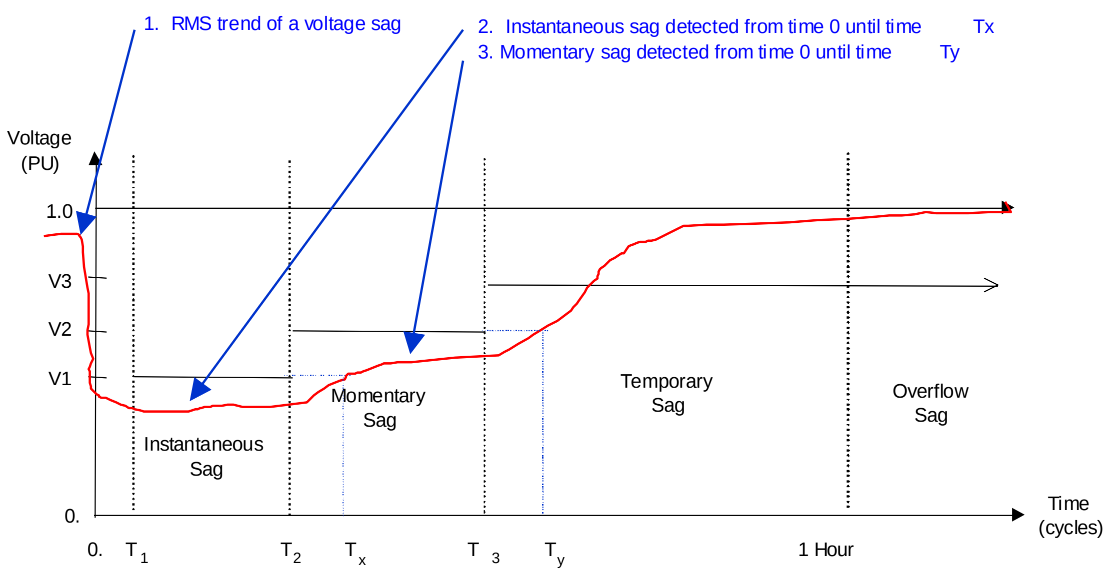


Figure 6.5: Event Classification

Waveform Capture and an Event Record

One of the major objectives of capturing data in the real time IED is to provide concise information on the PQ events. This can be accomplished in three ways:

- Event Record to Summarize the Event
- Oscillographic Samples of the Event
- RMS Trending of the Event

Providing an event record gives the end user an accurate summary of what has occurred on the system. This also enables the user to sort events by phase, type, duration, and deviation with ease. Thus, a typical event record will include:

Date | Time | Duration | Phase | Min/Max Deviation | Pre-Event Load

Using this format, up to 128 or 256 PQ events can easily be recorded in an IED and quickly downloaded for off-line analysis. Oscillographic data provides the most detailed information for engineering troubleshooting analysis. This data is most often three-phase to provide a complete snapshot of the system activity. However, oscillographic data occupies the most memory for storage. For example, eight cycles of oscillographic data at 32 samples per cycle would require approximately 3.5 kbytes of memory (8cycles*32 samples/cycle *7 channels *2 bytes). Thus, 128 events would require just under ½ megabytes of memory. Such memory capability is not present in a great number of IEDs, so oscillographic data may only be stored for the last several events. This provides data for recent events, while earlier events are still logged in event records for off-line analysis.

The last option, RMS trending offers a practical compromise for oscillographic data. RMS data for events can be stored periodically, not at every sample, and reduce the memory requirements. For example, an IED sampling at 32 times/cycle can store the rms data four times per cycle, reducing the memory requirements by a factor of eight. For archival analysis, if only the affected phase is stored, the memory requirements are reduced again by a factor of three. Thus, most of the critical information can be stored for the affected phase with a potential saving of 1/24th the memory if all samples were stored. Thus, rms trending may be a more practical option if a large number of events are to be stored.

Harmonic Computations

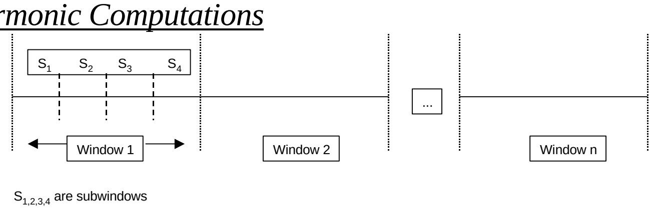


Figure 6.6: Profile window calculation of THD and TDD.

A profile window calculation scheme is shown in Figure 6.6 and a sliding window calculation scheme is shown in Figure 6.7.

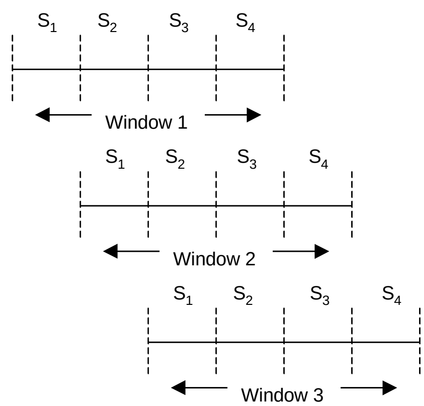


Figure 6.7: Sliding window calculation of THD and TDD.

In either case, the THD and TDD are computed as the average of the respective sub-window quantities. The equation for the sub-window average is shown below for THD. In the case of a sliding window, the window advances one sub-period and the sub-window computations are used in multiple windows.

$$THD_{window} = \frac{1}{NSW}\sum_{i=1}^{NSW}\left(THD_{subwindow}\right)_i$$

Where: NSW is the number of sub-windows in a window.

The THD and TDD are computed in each sub-window as the average of the respective quantities computed on a cycle basis for every cycle within the window. The equation for the THD sub-window calculation is given below.

$$THD_{subwindow} = \frac{1}{NCSW}\sum_{i=1}^{NCSW}\left(THD_{cycle}\right)_i$$

Where: NCSW is the number of cycles in a sub-window.

6.5 PQDIF Power Quality Data Interchange Format

PQDIF is similar to COMTRADE in that it is a data format for exchanging data. However, PQDIF is designed to handle a broader range of data than COMTRADE. It is not a vendor-specific data format and it is not a database. It is a means of transferring data from vendor-specific databases and file structures that are used by monitoring equipment vendors and simulation programs into a form that can be used by other applications and database systems.

Simulation programs typically save the simulation results in output files with specific formats. For instance, the Electro-Magnetic Transients Program saves simulation results in a binary file with a specified structure (PL4 file). Data converters can be developed to export selected results of the simulations to a PQDIF file format for use by other applications.

PQDIF has a hierarchical structure. The basic levels are illustrated in Figure 6.8.

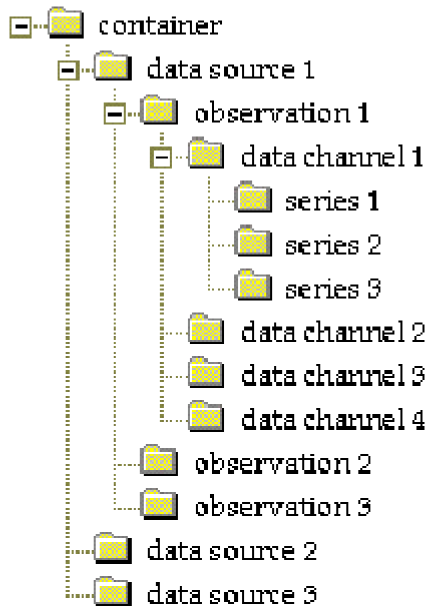


Figure 6.8 Hierarchical levels in the PQDIF Schema

The following is a description of these different levels, starting from the top and working down to the lowest levels.

Containers

The PQDIF concept can be implemented in a variety of different forms. The method of implementing the data transfer is referred to as a container. The following are important types of containers for the PQDIF schema:

- Disk based file - ASCII or BINARY, Conventional or Structured
- Memory object
- Serial communication stream

A container is a convenient place for the data to be transferred to reside between source and destination. A container can have a number of attributes, which should include the creation time, author, owner, access control information, size, and type.

Data Sources

A container can hold data from one or more data sources. These data sources represent the output of a monitoring device, simulation program, or some manually entered data. The data sources are characterized with a name, a type (measurement, manual recording, simulation), a vendor, location description, information about the installation and setup, system configuration information, and additional private data that may be appropriate.

The data source description must also include specification of the physical and derived data channels that are being used to provide data for the PQDIF transfer. These are discussed in more detail below. All of the individual observations that are included in the PQDIF data will be based on this consistent set of data channels. Not all of the data channels must be included in each observation record but the data channels defined represent the full set of data channels available. For measurements, a data source will typically be a single monitoring instrument at a fixed location. Description of the instrument, setup information, and information about the monitoring location will be included in the data source description along with information describing all the data channels being used by the instrument.

Observations

A data source object contains a list of one or more observations made using one or more data channels. Each observation is characterized by important information describing the observation, followed by the actual data for each data channel used. Important information includes an identifier for the observation, date/time stamps (when the record was created, time for the start of the record, time for the trigger), and any private data that may be appropriate.

Data Channels

Each data source can have one or more data channels. These data channels may be physical as in the case of an instrument or logical as in the case of a simulation program. In either case, there are a number of important attributes that should be defined for each channel. These attributes are defined as part of the information associated with a data source.

- Channel Number
- Name
- Location Identifier (used in combination with the phase to uniquely identify the channel)
- Phase or Other Name (a, b, c, ab, bc, neutral, residual, pos. seq.)
- Channel Type (Time Domain, Freq. Domain, XY Data, Probability)
- Channel Sub Type (Scan, Spectrum, Correlation, General, CPF, Histogram)
- Quantity Type (Voltage, Current, Power, Energy, Temperature, Frequency)
- Quantity Units (Volts, Amps, Watts, HP, Joules, Ergs, C, F, Cycles, Hertz)
- Preferred Greek Prefix (automatic, milli, micro, etc.)
- Base Quantity (for per-unitization)
- Preferred units mode - Per Cent, PU, Eng. Units
- Variant Style (described below) - value, min./max., min./max./avg., etc.
- Trigger Type - not triggered, high level, low level, float
- High Trigger Level
- Low Trigger Level
- Vendor specific setup information
- Private Data

Channel definitions are a very important part of the PQDIF data transfer schema. Accurate definitions of the channels allow the third party database and analysis tools to take full advantage of the data recorded or simulated for a power quality event or characteristic. Underneath the observation definition, each data channel used for the specific observation will be identified with a Channel ID followed by one or more series of actual data.

Data Series

Everything up to this point has been defining where the data came from and what the data is. Depending on the channel type, sub-type, and variant, one or more actual series of data points are saved. Each series object can have the following properties:

- Quantity Type (Voltage, Current, Power, Energy, Temperature, Frequency)
- Quantity Units (Volts, Amps, Watts, HP, Joules, Ergs, C, F, Cycles, Hertz)
- Base Quantity (for per-unitization)
- Private Data

The quantity type and units associated with a series may override the same information that is provided as part of the data channel information. The data channel information is intended to indicate the type and units of the principal series. For some applications that generate XY type data (primarily simulation programs), the series types and units information are more significant to the end use application. The most common type of series will involve a magnitude series vs. time. The magnitudes could be absolute magnitude values (waveforms), rms magnitudes (trends), or they could be complex values (magnitude and phase vs. time for phasor quantities). Other types of series are also supported. Spectrums or frequency scans are defined by a magnitude or phasor series that is a function of frequency. Statistical characteristics of quantities are represented by a magnitude series that corresponds to probability levels. These can be used to define histograms or cumulative probability distributions for a quantity, such as the rms voltage magnitude, the voltage unbalance, or the total harmonic distortion. For any quantity, there are often a number of variants of that quantity recorded (or simulated) at each sampling interval. Each variant requires a series in addition to the series for the independent variable (e.g. time series). For instance, some series will include min, max, and average values for each time value (each time value represents a time period). In other cases, each time value might have a corresponding value for a whole group of statistical values representing the quantity variations within the time period (e.g. minimum, 5% value, 10 % value, average, 90% value, 95% value, maximum). These statistical methods of quantifying variations are inherent in IEC power quality standards. Descriptions of the specific formats for the series and options for representing the values in the series are beyond the scope of this article but can be found in the documentation at the IEEE web site. Examples of applying the PQDIF architecture for representing measurement data are also included. References: http://www.electrotek.com/pqdif/ http://grouper.ieee.org/groups/1159/3/docs.html

7. SUMMARY

The impact of power quality on protective relaying is such that "good" power quality has no impact, i.e. protective relays will properly perform their functions when the power quality is "good". However, when power quality is "poor" the reliability of protective relays to perform their intended function is degraded and the full impact of "poor" power quality is unknown. When power quality is "poor", the parameters that protective relays rely on for detecting faults (voltage and current) can become distorted to the point that making reliable decisions become problematic. The relay engineer can no longer rely on the performance of the relay under these system conditions. Testing of protective relays under conditions of "poor" power quality is needed to provide sufficient information about the performance and to allow the relay engineer to adequately apply particular protective relays. Proper testing under these scenarios of "poor" power quality will enable the engineer to design protective relaying systems that are more secure and dependable.

The impact of protective relaying on power quality is such that properly implemented protective relaying applications and settings are capable of helping maintain "good" power quality by reducing the duration of sags, improving supply reliability and protecting loads against unacceptable voltage, frequency, and phase unbalance. Protection systems at the transmission level limit fault duration to a few cycles. Protection systems at the distribution level allow faults to persist for a longer period of time but still not an excessive amount of time. There are still some areas that could be implemented to further improve power quality such as protection against excessive harmonic. Protective relays designed to protect against excessive harmonics are not yet widely available. Protective relays with digital fault recorders can also be a data source in determining the origin and level of power quality problems.

More information is required to provide relay engineers with limits as to acceptable power quality events. While modern numerical protective relays are capable of functioning under many of the "poor" power quality conditions, older electromechanical protective relays may not perform as intended under degraded condition. Harmonic limits are well defined and protective relays that can protect against these conditions exist but their deployment is not wide spread. The ITIC curve is well known but limited in application to distribution level loads. Some of the parameters such as frequency, reliability, or phase balance need better definition of limits. Standards work in these areas need to be addressed by the power quality groups.

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