POWER QUALITY
a guide

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CONTENTS

1 Basic information

The measurement methodology is mostly imposed by the power quality standards, mainly IEC 61000-4-30. This standard, introducing precise measurement algorithms, ordered analyzers market, allowing customers to easily compare the devices and their results between the analyzers from different manufacturers. Previously, these devices used different algorithms, and often the results from measurements on the same object were completely different when tested with different devices.

The factors behind growing interest in these issues have included wide use of electronic power controllers, DC/DC converters and switched-mode power supplies, energy-saving fluorescent lamps, etc., that is widely understood electrical power conversion. All of these devices had a tendency to significantly deform the supply current waveform.
The design of switched-mode power supplies (widely used in household and industrial applications) is often based on the principle that the mains alternating voltage is first rec-tified and smoothed with the use of capacitors, meaning that it is converted to direct volt-age (DC), and then with a high frequency and efficiency is converted to required output voltage. Such a solution, however, has an undesirable side effect. Smoothing capacitors are recharged by short current pulses at moments when the mains voltage is close to peak value. From power balance rule it is known that if the current is taken only at short intervals, its crest value must be much higher than in case it is taken in a continuous manner. High ratio of current crest value to RMS value (a so-called Crest Factor) and reduction of Power Factor (PF) will result in a situation in which in order to obtain a given active power in a receiver (in watts), the power supplier must supply power greater than the re-ceiver active power (this is a so-called apparent power expressed in volt-amperes, VA). Low power factor causes higher load on the transmission cables and higher costs of electricity transfer. Harmonic current components accompanying such parameters cause additional problems. As a result, the electricity suppliers have started to impose financial penalties upon the customers who have not provided sufficiently high power factor.

Among entities that may be potentially interested in power quality analyzers are power utility companies on one hand, (they may use them to control their customers), and on the other hand the energy consumers who may use the analyzers to detect and possibly im-prove the low power factor and solve other problems related to widely understood power quality issues.

The power source quality parameters, as well as the properties of receivers, are described with many various parameters and indices. This paper can shed some light on this area.

As already mentioned, the lack of standardization of measurement methods has caused significant differences in values of individual mains parameters calculated with various devices. Efforts of many engineers resulted in IEC 61000-4-30 standard concerning power quality. For the first time, this standard (and related standards) provided very precise methods, mathematical relations and required measurement accuracy for power quality analyzers. Compliance with the standard (in particular, the class A) should be a guarantee of repeatable and almost identical measurement results of the same magnitudes measured with devices from different manufacturers

2 Current measurement

2.1 Current Transformer (CT) probes for measuring alternating currents (AC)

CT probes (CT - *Current Transformer*) are simply large current transformer processing high current of the primary winding into the lower current in the secondary winding. The jaws of typical current probe are made of a ferromagnetic material (e.g. iron) wound around the secondary winding. The primary winding is a conductor around which the probe jaws are closed - usually it is one single coil. If the 1000-ampere current flows through the tested conductor, in the secondary winding with 1000 coils the current will be only 1 A (if the circuit is closed). In probes with voltage output, a shunt resistor is located in the probes.

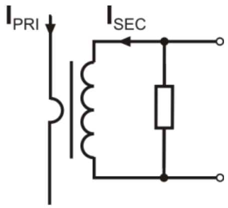

Fig. 1. CT probes with voltage output

This type of current transformer has several distinguishing features. It may be used to measure very high currents and its power consumption is low. Magnetizing current causes a phase shift (tenth of a degree), which may introduce an error in power measurement (especially at low power factor). The disadvantage of this type of probes is the core saturation when very high currents are measured (above the nominal range). Core saturation as a result of magnetizing hysteresis leads to significant measurement errors, which may be eliminated only by the core demagnetization. The core becomes saturated also when the measured current has a considerable DC component. Undeniable disadvantage of hard probes is their significant weight.

Despite these drawbacks, CT probes are currently the most widely used non-invasive method for measuring alternating currents (AC).

Together with the analyzer, you can use the following types of Sonel S.A. CT probes for measuring alternating currents:

- C-4(A), with a nominal range of 1000 A AC,
- C-6(A), with a nominal range of 10 A AC,
- C-7(A), with a nominal range of 100 A AC.

2.2 Probes for measuring alternating and direct currents (AC/DC)

In some situations it is necessary to measure the current DC component. For this purpose the user must apply probes with a principle of operation different than a traditional current transformer. Such probes operate basing on "Hall effect" and include a built-in Hall sensor (called also 'hallotron'). In brief: the effect is based on the occurrence of an electrical voltage on the walls of the conductor, through which an electric current flows and which is in magnetic field of direction transverse to the induction vector of this field.

Current probes based on this phenomenon may measure both DC and AC current components. The conductor with current located inside the probes generates a magnetic field which concentrates in its iron core. In the core slot, where the two parts of probes meet, a semiconductor Hall sensor is located, and its output voltage is amplified by battery-powered electronic circuit.

Probes of this type usually have a current-zero adjustment knob. To adjust the current zero, close the jaws (no conductor inside) and turn the knob until DC indication is zero.

Sonel S.A. offers this type of probes: C-5A with a nominal range of 1000 A AC / 1400 A DC. Probes of this type have a voltage output and for nominal current of 1000 A the provide voltage of 1 V (1 mV/A).

2.3 Flexible Rogowski probes

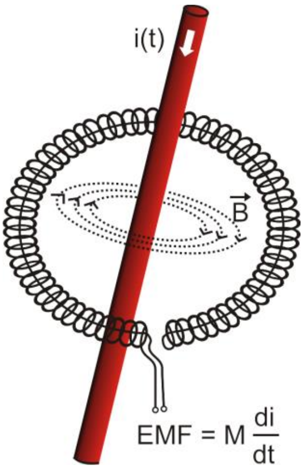

Fig. 2. Rogowski coil

Flexible probes (*Flexible Current Probes*) operate on a different physical principle than the current transformer. Their most important part is Rogowski coil, named after Walter Rogowski - a German physicist. It is an air-core coil wound around a conductor with current. Special design of the coil allows leading out its both ends on the same side, thus facilitating probe placement around the conductor (the return end is placed inside the coil at its entire length). The current flowing through the measured conductor causes centric magnetic field lines which due to the self-induction phenomenon induce the electromotive force at the end of the coil. This voltage, however, is proportional to the rate of current change in the conductor, and not to the current itself.

Rogowski coil has some undeniable advantages compared with current transformers. As it does not have a core, the core saturation effect is eliminated; thus being a perfect instrument to measure high currents. Such coil has also an excellent linearity and a wide pass band, much wider than a current transformer, and its weight is much smaller.

However, until recently the wider expansion of flexible probes in the current measurement area was difficult. There are some factors that hinder the practical implementation of the measurement system with a Rogowski coil. One of them is a very low voltage level which is induced on the probes (it depends on geometrical dimensions of the coil). For example, the output voltage for 50 Hz frequency of the F-series flexible probes (to be used with the analyzer) is approx. 40μV/A. Such low voltages require the use of precise and low-noise amplifiers which of course increase the costs.

As the output voltage is proportional to the current derivative, it is necessary to use an integrating circuit; generally, the flexible probes comprise a Rogowski coil and an analogue integrator circuit (characteristic battery-powered module). On the integrator output the voltage signal is available and proportional to the measured current and suitably scaled (for example 1mV/A).

Another problem concerning Rogowski coil, is its sensitivity to external magnetic fields. A perfect coil should be sensitive only to the fields closed within its area and should totally suppress external magnetic fields. But this is a very difficult task. The only way to obtain such properties is very precise manufacturing of the coil, with perfectly homogeneous windings and impedance as low as possible. It is the high precision which results in a relatively high price of such probes.

3 PLL synchronization

The need for the phase-locked loop (software, hardware or mixed hardware/software) results directly from the requirements of IEC 61000-4-7 standard, which describes the methodology and acceptable errors when measuring harmonics. This standard requires that the measuring window (which is the basis for a single measurement and evaluation of the harmonics) is equal to the duration of 10 mains cycles for 50 Hz systems and 12 cycles for 60 Hz systems. In both cases, it corresponds to approx. 200 ms. Since the frequency of the mains may be subject to periodic changes and fluctuations, the duration of the window may not be exactly 200 ms, and for example for frequency 51 Hz it will be approx. 196 ms.

The standard also prescribes that before applying the Fourier formula (in order to extract the spectral components) data should not be subject to windowing. No frequency synchronization and a situation where FFT is performed on the samples not covering integer number of cycles, may lead to spectral leakage. This would cause blurring of the harmonic line over a few adjacent interharmonic bands, which may lead to loss of information about the actual level and power of the tested line. It is allowed to apply Hann weighting window, which reduces the adverse effects of spectral leakage, but this is limited only to situations when PLL loses synchronization.

IEC 61000-4-7 specifies also the required accuracy of the synchronization block. This is expressed as follows: the time between the rising edge of the first sampling pulse and (M+1)-th pulse (where M is the number of samples within the measuring window) should be equal to the duration of specified number of periods in the measuring window (10 or 12) with a maximum allowable error of ± 0.03%. To explain it in a simpler way, consider the following example. Assuming network frequency of 50 Hz, the measuring window lasts exactly 200 ms. If the first sampling pulse occurs exactly at time t=0, then the first sampling pulse of the next measurement window should occur at t=200 ± 0.06 ms. This ±60 µs is the permissible deviation of the sampling edge. The standard also defines the recommended minimum frequency range at which the above-stated accuracy of the synchronization should be maintained and defines it as ± 5% of nominal frequency, i.e. 47.5...52.5 Hz for 50 Hz and 57...63 Hz for 60 Hz .

Another issue is the input voltage range for which PLL will work properly. For this issue, IEC 61000-4-7 standard does not provide any specific guidance or requirements. However, IEC 61000-4-30 standard defines the input voltage range in which the metrological parameters cannot be compromised and for class A the range is: 10%...150%U_{din}.

4 Flicker

In terms of power quality 'flicker' means a periodical changes of light intensity as a result of fluctuations of voltage supplied to light bulbs.

The flicker measurement function appeared in the power quality analyzers when it turned out that this phenomenon causes discomfort, irritation, sometimes headache, etc. The luminous intensity fluctuations must have a specified frequency, they cannot be too slow, as the human pupil is able to adapt to changes in illumination; they cannot be too fast because the filament inertia eliminates these fluctuations almost totally.

Studies have shown that the maximum discomfort occurs for frequencies around 9 changes per second. The most sensitive light sources are the traditional light bulbs with a tungsten filament. Halogen bulbs, which filaments have much higher temperature, have also much higher inertia, which reduces the perceived brightness changes. Fluorescent lamps have the best flicker "resistance", as due to their specific properties they stabilize the current flowing through the lamp during the voltage changes, and thus reduce the fluctuations.

Flicker is measured in perceptibility units, and there are two types of flicker: short-term P_{ST}, which is determined once every 10 minutes and long-term P_{LT}, which is calculated on the basis of 12 consecutive P_{ST} values, i.e. every 2 hours. Long time of measurement results directly from the slow-changing nature of this phenomenon - to collect sample data the measurement must be long. P_{ST} equal to 1 is considered to be a value on the border of annoyance – certainly sensitivity to flicker is different for different persons; this threshold has been assumed basing on tests carried out on a representative group of people.

What causes flicker? Most frequently, the reason is the voltage drop as a result of connecting and disconnecting large loads and some level of flicker is present in the majority of mains systems. In addition to the previously described adverse impact on human health, flicker does not need to be (and usually it isn't) a symptom of malfunctioning of our installation. However, if a rather abrupt and unexplainable flicker increase is observed in the mains (increased P_{ST} and P_{LT} parameters) it should not be ignored under any circumstances. It may turn out that the flicker is caused by poor connections in the installation – increased voltage drops on connections in the distribution panel (for example) will result in higher voltage fluctuations on the receivers, such as light bulbs. The voltage drops on connections also cause their heating, and finally sparking and possibly a fire. Periodical mains tests and described symptoms may turn our attention and help find the source of hazard.

5 Power and energy measurement

Power is one of the most important parameters determining the properties of electrical circuits. The basic unit used in financial settlements between the electricity supplier and consumer is electric energy calculated as the product of power and time.

In electrical engineering, several different power types are distinguished:

- *Active Power* - marked with P and measured in Watts,
- *Reactive Power* - marked with Q, unit: var,
- *Apparent Power*) S, unit: VA.

These three types of power are the most known, but there are also other types.

At school we are taught that these powers form the so-called 'power triangle' with properties expressed in the equation:

$$\mathrm{P}^2 + \mathrm{Q}^2 = \mathrm{S}^2$$

This equation, however, is valid only for systems with sinusoidal voltage and current waveforms.

Before moving to a more detailed discussion concerning power measurement, individual types of power should be defined.

5.1 Active power

Active power P is a magnitude with precise physical meaning and it expresses the ability of a system to perform a particular work. It is the power most desired by the energy consumers and it is for this supplied power that the consumer pays the supplier in a given settlement period (the problem of fees for additional reactive power is discussed separately – see below). It is the active power (and consequently, the active energy) which is measured by electric energy meters in each household.

The basic formula for calculating the active power is as follows:

$$P = \frac{1}{T}\int_{t}^{t+T} u(t)i(t)dt$$

where: u(t) – instantaneous voltage value, i(t) - instantaneous current value, T - period for which the power is calculated.

In sinusoidal systems, the active power may be calculated as:

$$P = UIcos\varphi$$

where: U is RMS voltage, I is RMS current and φ is the phase shift angle between voltage and current.

The active power is calculated by the analyzer directly from the integral formula, using sampled voltage and current waveforms:

$$P = \frac{1}{M}\sum_{i=1}^{M} U_i I_i$$

where M is a number of samples in 10/12-period measuring window (2048) and U_i and I_i are successive voltage and current samples.

5.2 Reactive power

The most known formula for *reactive power* is also correct only for one-phase circuits with sinusoidal voltage and current waveforms:

$$Q = UIsin\varphi$$

Interpretation of this power in such systems is as follows: it is the amplitude of AC component of the instantaneous power on source terminals. Existence of a non-zero value of this power indicates a bidirectional and oscillating energy flow between the source and the receiver.

Imagine a system with a single-phase sinusoidal voltage source, where the load is a RC circuit. As under such conditions, these components behave linearly, the source current waveform will be sinusoidal, but due to the properties of the capacitor it will be shifted in relation to the voltage source. In such a circuit, reactive power Q is non-zero and may be interpreted as an amplitude of the energy oscillation, which is alternately stored and returned by the capacitor. Active power of the capacitor is zero.

However, it turns out the energy oscillation seems only an effect, and that it appears in particular cases of circuits with sinusoidal current and voltage waveforms, and is not the cause of reactive power. Research in this area has shown that reactive power occurs also in circuits without any energy oscillation. This statement may surprise many engineers. In latest publications on power theory, the only physical phenomenon mentioned which always accompanies appearance of reactive power is phase shift between current and voltage.

The above mentioned formula for calculating the reactive power is valid only for single-phase sinusoidal circuits. How then we should calculate the reactive power in non-sinusoidal systems? For electrical engineers this question opens the 'Pandora’s box'. It turns out that the reactive power definition in real systems (and not only those idealized) has been subject to controversy and now (2018) we do not have one, generally accepted definition of reactive power in systems with non-sinusoidal voltage and current waveforms, not to mention even unbalanced three-phase systems. The IEEE (Institute of Electrical and Electronics Engineers) 1459-2010 standard (from 2010) does not give a formula for total reactive power for non-sinusoidal three-phase systems – as three basic types of power the standard mentions are active power, apparent power and – attention – non-active power designated as N. Reactive power has been limited only to the fundamental component and marked as Q_1.

This standard is the last document of this type issued by recognized organization which was to put the power definition issues in order. It was even more necessary as for many years specialists in scientific circles reported that the power definitions used so far may give erroneous results. Controversies concerned mainly the definition of reactive power and apparent power (and distortion power – see below) in single- and three-phase circuits with non-sinusoidal voltages and currents.

In 1987, professor L.S. Czarnecki proved the widely used definition of reactive power defined by Budeanu was wrong. This definition is still taught in some technical schools and it was presented by prof. Budeanu in 1927. The formula is as follows:

$$Q_B = \sum_{n=0}^{\infty} U_n I_n \sin\varphi_n$$

where U_n and I_n are voltage and current harmonics of order n, and φ_n are angles between these components.

When this parameter has been introduced, the known power triangle equation was not valid for circuits with non-sinusoidal waveforms - therefore Budeanu introduced a new parameter called the *distortion power*:

$$D_B = \sqrt{S^2 - \left(P^2 + {Q_B}^2\right)}$$

Distortion power strain was meant to represent powers occurring in the system due to distorted voltage and current waveforms.

For years, reactive power was associated with the energy oscillations between its source and the load. The formula indicates that according to Budeanu's definition, the reactive power is the sum of individual harmonics. Due to *sin*φ factor, such components may be positive or negative depending on the angle between the voltage and current harmonics. Thus, it is possible that the total reactive power Q_B is zero at non-zero harmonics. Observation that at non-zero components, total reactive power may be zero (according to this definition) is a key to a deeper analysis which finally allowed proving that in some situations Q_B may give quite surprising results. The research has questioned the general belief that there is a relation between energy oscillations and Budeanu reactive power Q_B. Examples of circuits may be presented, where despite the oscillating character of instantaneous power waveform, reactive power according to Budeanu is zero. Over the years, the scientists have not been able to connect any physical phenomenon to the reactive power according to this definition.

Such doubts about the correctness of this definition of course also cast shadow on the related *distortion power* D_B. The scientists have started to look for answers to the question whether the distortion power D_B really is the measure of distorted waveforms in non-sinusoidal circuits. The distortion is a situation in which the voltage waveform cannot be "put" on the current waveform with two operations: change of amplitude and shift in time. In other words, if the following condition is met:

$$u(t) = Ai(t - \tau)$$

then, voltage is not distorted in relation to the current. In case of sinusoidal voltage and load which is any combination of RLC elements, this condition is always met (for sinusoidal waveforms, these elements maintain linearity). However, when the voltage is distorted, the RLC load does not ensure absence of current distortion in relation to voltage any more, and the load is no longer linear – it is necessary to meet some additional conditions (module and phase of load impedance changing with frequency).

And then, is really D_B a measure of such distortion? Unfortunately, also in this case the Budeanu's power theory fails. It has been proven that the *distortion power* may be equal to zero in a situation when voltage is distorted in relation to current waveform, and vice versa, the *distortion power* may be non-zero at total absence of distortion.

Practical aspect of this power theory which relates to improvement of power factor in systems with reactive power was to be the feature to take the most advantage of correct definitions of reactive power. The compensation attempts based on the Budeanu reactive power and related distortion power failed. These parameters did not allow even a correct calculation of correction capacitance which gives the maximum power factor. Sometimes, such attempts resulted even in additional deterioration of power factor.

How come, then, that the Budeanu's power theory has become so popular? There may be several reasons for this. Firstly, engineers got accustomed to old definitions and the curricula in schools have not been changed for years. This factor is often underestimated, though as a form of justification it can be said that this theory had not been refuted for 60 years. Secondly, in the 1920s there were no measuring instruments which could give insight in individual voltage and current harmonic components and it was difficult to verify new theories. Thirdly, distorted voltage and current waveforms (i.e. with high harmonics contents) are a result of revolution in electrical power engineering which did not start before the second part of the last century. Thyristors, controlled rectifiers, converters, etc. began to be widely used. All these caused very large current distortion in the mains, and consequently increased harmonic distortion. Only then the deficiencies of Budeanu's theory became evident. Finally, the scientific circles related to power engineering were aware of the fact that industrial plants had invested a fortune in the measuring infrastructure (energy meters). Any change in this regard could have huge financial implications.

However, slow changes in the approach of electrical engineers began to be visible. With time, as non-linear loads were more and more frequent and the waveforms more and more distorted, the limitations of used formulas could no longer be tolerated.

A very significant event was publishing by IEEE (in 2000) 1459 standard "*Definitions for the Measurement of Electric Power Quantities Under Sinusoidal, Non-sinusoidal, Balanced, or Unbalanced Conditions*". For the first time, Budeanu's definition of reactive power has been listed as not recommended for new reactive power and energy meters. Many parameters have been also divided into the part related to the current and voltage fundamental component (first harmonics) and the part related to remaining higher harmonics. In most cases, it is recognized that the usable part of energy is transmitted by the 50/60Hz components, with much smaller (and often harmful) participation of higher harmonics.

The standard also introduced a new parameter – non-active power N which represents all non-active components of power:

$$N = \sqrt{S^2 - P^2}$$

Reactive power is the power of one of the components of the inactive power N. In single-phase systems with sinusoidal voltage and current waveforms, N equals Q; hence the non-active power does not have any other components. In three-phase systems, this is true only for symmetrical sinusoidal systems with a balanced purely resistive load.

Other non-active power components are related to specific physical phenomena. According to prof. Czarnecki's theory, which is one of the best in explaining the physical phenomena in three-phase systems, the power equation in such systems is as follows:

$$S^2 = P^2 + {D_s}^2 + Q^2 + {D_u}^2$$

D_s is the scattered power, which occurs in the system, as a result of changing conductance of the receiver with frequency. Thus, the presence of reactive elements may result in the scattered power.
In this equation, reactive power Q appears when there is a phase shift between the voltage and current harmonics.

D_u means the unbalanced power which is a measure of unbalance of a three-phase receiver. This component explains the situation in which an unbalanced three-phase load of a purely resistive character results in the power factor less than one. Such receiver has no reactive power Q, and still the results from the power triangle S, P, Q are totally different (the Budeanu's power theory with its distortion power could not explain this situation either – in a purely resistive receiver, the distortion power D_B equals zero).

An attempt to combine IEEE 1459-2000 standard with the Czarnecki's power theory leads to the conclusion that non-active power includes at least three separate physical phenomena, which influence the reduced effectiveness of energy transmission from the source to the receiver, i.e. reduction of the power factor:

$$PF = \frac{P}{S_e} = \frac{P}{\sqrt{P^2 + {D_s}^2 + Q^2 + {D_u}^2}}$$

In IEEE 1459-2000 standard, reactive power known as Q has been limited to the fundamental component and it applies both to single-phase and three-phase systems.
In single-phase systems:

$$Q_1 = U_1 I_1 \sin\varphi_1$$

In three-phase systems, only the positive sequence component is taken into account:

$$Q_1^+ = 3U_1^+ I_1^+ \sin\varphi_1^+$$

Correct measurement of this power requires the same phase rotation sequence (i.e. phase L2/B delayed by 120° in relation to L1/A, phase L3/C delayed by 240° in relation to L1/A).
The concept of positive sequence component will be discussed in more detail in the section devoted to unbalance.

The value of reactive power of the fundamental component is the main value which allows estimating the size of capacitor to improve the displacement power factor (DPF), that is the displacement of the voltage fundamental components in relation to the current fundamental component (i.e. compensator of the reactive power of the fundamental component).

5.3 Reactive power and three-wire systems

Correct reactive power measurement is impossible in unbalanced receivers connected in 3-wire systems (delta and wye systems without N conductor). This statement may be surprising.

The receiver can be treated as a "black box" with only 3 terminals available. We cannot determine its internal structure. In order to calculate the reactive power, we need to know the phase shift angle between the voltage and the current at each leg of such receiver. Unfortunately, we do not know this angle. In the delta-type receiver we know the voltages on individual impedances, but we do not know the current; in such systems, the phase-to-phase voltages and line currents are measured. Each line current is a sum of two phase currents. In the wye without N-type receivers, we know the currents flowing through impedance, but we do not know the voltages (each phase-to-phase voltage is a sum of two phase-to-neutral voltages.

We need to take account of the fact that at given voltage values at terminals and currents flowing into such "black box", there is an infinite number of variants of receiver internal structure which will give us identical measurement results of voltage and current values visible outside the black box.

Then, how is it possible that there are reactive power meters intended for measurements in three-wire systems and the mains analyzers which allow the reactive power measurement under such circumstances?

In both cases, the manufacturers use the trick which involves an artificial creation of a reference point (virtual neutral terminal N). Such point may be created very easily by connecting to the terminals of our black box a wye-connected system of three resistors of the same value. The potential of the central point in the resistor system is used to calculate the "phase voltages". Obviously quotation marks are justified here, as such virtual zero will provide quite correct results only when the unbalance of the receiver is minimal. In any other case, an indication of reactive power from such device should be treated very cautiously.

In no case should a measuring instrument mislead the user, and such approximation can be allowed only after a clear reservation that the indicated value is not a result of actual measurement, but only an approximated value.

5.4 Reactive power and reactive energy counters

Reactive energy counter are devices unknown to the household users who for settlements with energy suppliers use the meters of active energy expressed in Wh or kWh. Household users are in a comfortable situation – they pay only for usable energy and do not have to think what the power factor is in their installations.

In contrast to the first group, the industrial consumers are obliged in their contracts and sometimes under pain of financial penalties to keep the power factor at an appropriate level.

The EN 50160 standard gives some guidelines for the power quality requirements, and defines the quality parameters which should be met by energy supplier. Among these parameters are, among others, mains frequency, RMS voltage, total harmonic distortion (THD) and allowed levels of individual voltage harmonics. Besides EN 50160 requirements there is often an additional condition: the supplier does not need to comply with those requirements if an energy consumer does not ensure the $\tan\varphi$ factor below some threshold (agreed value which can be changed in the contract between the energy supplier and consumer, i.e. 0.4) and/or exceeds the agreed level of consumed active energy.

The $\tan\varphi$ is defined as a ratio of measured reactive energy to the active energy in a settlement period. Going back for a while to the power triangle in sinusoidal systems, we can see that the tangent of the phase shift angle between the voltage and the current is equal to the ratio of reactive power Q to active power P. Consequently, the requirement to maintain the $\tan\varphi$ below 0.4 means nothing else but only that maximum level of measured reactive energy may not exceed 0.4 of the measured active energy. Each consumption of reactive energy above this level is subject to additional fees.

Does the knowledge of $tan\varphi$ calculated in this manner gives both interested parties an actual view of energy transmission effectiveness? Have we not mentioned before that the reactive power is only one of the non-active power components which influence the power factor reduction?
Indeed, it seems that instead of $tan\varphi$ we should use the power factor PF which takes into account also other issues.

Unfortunately, the present regulations leave no choice, therefore the correct reactive power measurement seems a key matter. Now, a question should be asked whether the reactive energy meters ensure correct readings in the light of the controversies described above? And what we actually measure using this popular reactive power meters?

The answers to these questions may be searched in the standard concerning such devices: IEC 62053-23. Unfortunately, to our disappointment, we will not find there any reference to measurements in non-sinusoidal conditions – the calculation formulas relate to sinusoidal conditions (we can read in the standard that due to “practical” reasons, non-sinusoidal waveforms have been excluded). The standard does not give any measurement criteria which would allow checking the meter properties at distorted voltage and current waveforms. As a surprise comes also the fact that the older standard (IEC 61268: already withdrawn) defined the test which involved checking the measurement accuracy at 10% of the third current harmonic.

The present situation leaves the choice of measuring method to the energy counters designers, which unfortunately leads to significant differences in reactive energy indications in the presence of high harmonic distortion level.

Older, electromechanical meters have characteristics similar to that of a low-pass filter – the higher harmonics are attenuated in such meters and the reactive power measurement in the presence of harmonics is very close to the value of reactive power of the fundamental component.

Electronic meters which are more and more popular may carry out measurements using various methods. For example, they may measure active and apparent power, and then calculate the reactive power from the power triangle (square root from the sum of both such powers squared). In reality, taking into account IEEE 1459-2000 standard, they measure the non-active power, not the reactive power. Another manufacturer may use the method with voltage waveform shift by 90°, which gives a result close to the reactive power of the fundamental component.

The higher the harmonics content, the higher difference in readings, and of course, as a consequence, other fees for measured energy.

As it has been indicated before, the reactive power measurement in unbalanced three-wire systems with traditional meters is subject to an additional error caused by creation of a virtual zero inside the meter which has little to do with actual zero of the receiver.

On top of that, the manufacturers usually do not give any information about the applied measuring method.

We may only wait for the next version of the standard, which will define (hopefully) the measuring and testing methods much more precisely, also for non-sinusoidal conditions.

5.5 4-quadrant reactive energy measurement

In the power sector, in many situations the reactive energy is divided into four separate components, each of which is counted separately. This division into so-called quadrants is based on the signs of active and reactive power as shown in Fig. 3.

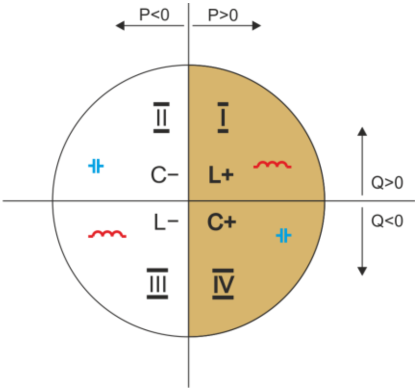

Fig. 3. Four-quadrant division of power and energy flow.

- quadrant I (marked as "L+"): active power is positive (receiving of active energy), reactive power is positive (receiving of reactive power). In such conditions, the nature of the load is inductive.
- quadrant I (marked as "C-"): active power is negative (delivering of active energy), reactive power is positive (receiving of reactive power). The nature of the load is capacitive.
- quadrant III (marked as "L-"): active power is negative (delivering of active energy), reactive power is also negative (delivering of reactive energy). In such conditions, the nature of the load is inductive.
- quadrant IV (marked as "C+"): active power is positive (receiving of active energy), reactive power is negative (delivering of reactive power). The nature of the load is capacitive.

Plus and minus signs in marking quadrants indicate the sign of active power.

Presented division allows the construction of reactive energy meters, which increase their state only when the energy flow takes place in a given quadrant. This also means that at a given moment, only one of the counters can increase its status.

In typical case of supplying the energy to a receiver, the operation takes place in two quadrants: I (L+) and IV (C+). Moreover, in these two quadrants the tangents φ ratio is monitored for customers connected to MV and LV networks in some countries. The four-quadrant tanφ coefficients are determined on the basis of recorded appropriate energy intakes:

$$tan\varphi_{(L+)} = \frac{\Delta E_{Q(L+)}}{\Delta E_{P+}}$$

$$tan\varphi_{(C+)} = \frac{\Delta E_{Q(C+)}}{\Delta E_{P+}}$$

If the convention is used, assuming all energy meters have a positive sign, the calculated values of tangents are complemented with a character resulting from the character of active and reactive power in a given quadrant. Thus, the sign of $\tan\varphi_{(L+)}$ is always positive, while in case of $\tan\varphi_{(C+)}$ it is always negative.

The calculated values of tangents may be the basis to calculate any penalties for reactive power consumption above the contracted level. In case of quadrant I (L+), a typical limit value above which fees are charged is 0.4. Often, for quadrant IV (C+) any reactive power consumption is the basis for calculating fines. This also results in practical conclusion that the most profitable (for consumer) is operation in the first quadrant (L+) in the range of $\tan\varphi_{(L+)}$ between 0 and 0.4.

5.6 Apparent power

Apparent power *S* is expressed as the product of RMS voltage and current:

$$S = UI$$

As such, the apparent power does not have a physical interpretation; it is used during designing of transmission equipment. In terms of value, it is equal to maximum active power which can be supplied to a load at given RMS voltage and current. Thus, the apparent power defines the maximum capacity of the source to supply usable energy to the receiver.

The measure of effective use of supplied power by the receiver is the power factor, which is the ratio of apparent power to active power.
In sinusoidal systems:

$$PF = \frac{P}{S} = \frac{UIcos\varphi}{UI} = cos\varphi$$

In non-sinusoidal systems such simplification is not acceptable and the power factor is calculated based on the actual ratio of active power and apparent power:

$$PF = \frac{P}{S}$$

In single-phase systems, the apparent power is calculated as shown in the formula above and there are no surprises here. However, it turns out that in three-phase systems calculation of this power is equally difficult as calculation of reactive power. Of course, this is related to actual systems with non-sinusoidal waveforms which additionally can be unbalanced.

The tests have shown that the formulas used so far can give erroneous results if the system is unbalanced. Since the apparent power is a conventional parameter and does not have a physical interpretation, determination which of proposed apparent power definitions is correct could be difficult. Yet, the attempts have been made, based on the observation that the apparent power is closely related to the transmission losses and the power factor. Knowing the transmission losses and the power factor, one can indirectly specify a correct definition of apparent power.

The definitions used so far include arithmetic apparent power and vector apparent power. The test have shown however that neither the arithmetic definition nor the vector definition give correct value of the power factor. The only definition which did not fail in such a situation, was the definition proposed as early as in 1922 by F. Buchholz - a German physicist:

$$S_e = 3U_eI_e$$

It is based on the effective values of voltage and current, and the power is called the effective apparent power (for this reason, index "e" is used in marking three-phase systems). Those effective voltage and current values are such theoretical values which represent voltage and current in an energetically equivalent three-phase balanced system. Consequently, the key issue is to determine U_e and I_e.

IEEE Standard 1459 specifies the following formula. In three-wire systems:

$$I_e = \sqrt{\frac{{I_a}^2 + {I_b}^2 + {I_c}^2}{3}}$$

$$U_e = \sqrt{\frac{{U_{ab}}^2 + {U_{bc}}^2 + {U_{ca}}^2}{9}}$$

In four-wire systems:

$$I_e = \sqrt{\frac{{I_a}^2 + {I_b}^2 + {I_c}^2 + {I_n}^2}{3}}$$

$$U_e = \sqrt{\frac{3\left({U_a}^2 + {U_b}^2 + {U_c}^2\right) + {U_{ab}}^2 + {U_{bc}}^2 + {U_{ca}}^2}{18}}$$

where I_a, I_b, I_c are RMS currents for individual phases (line or phase), I_n is the RMS current in neutral conductor, U_a, U_b, U_c are RMS phase-to-neutral voltages, and U_{ab}, U_{bc}, U_{ca} are RMS phase-to-phase voltages.

S_e calculated in this manner includes both the power losses in the neutral conductor (in four-wire networks) and the effect of unbalance.

5.7 Distortion power D_B and effective apparent power S_{eN}

During the discussion on reactive power, it was mentioned that the distortion power according to Budeanu cannot be used for large distortions of voltage and current and for the unbalance of three-phase systems (a paradox of distortion power which is not a measure of actual distortion). However, this power is often used by energy quality specialists and manufacturers of systems for reactive power compensation.

It must be clearly said that this parameter has given relatively good results only in conditions of slight distortion of voltage and current waveforms.

IEEE 1459-2000 standard lists this definition of power, however just like in case of Budeanu reactive power, it has a non-removable defect and it is recommended to discard it entirely. Instead of D_B, another value was proposed to reflect total distortion power in a system in a better way – it is called non-fundamental apparent power S_{eN}. S_{eN} power allows a quick estimation whether a load works in conditions of small or large harmonic distortion; it is also a basis for estimating the static values and active filters or compensators.

According to the definition (for 3-phase systems):

$$S_{eN} = \sqrt{S_e^2 - S_{e1}^2}$$

where:

$$S_{e1} = 3I_{e1}U_{e1}$$

Effective current and RMS voltage of the fundamental component (I_{e1} and U_{e1} respectively) are calculated similarly to I_e and U_e but instead of RMS phase-to-neutral or phase-to-phase voltages, the effective voltages of fundamental components are substituted.

In single-phase systems to calculate the distortion apparent power, a simpler formula may be used:

$$S_N = \sqrt{S^2 - (U_1 I_1)^2}$$

where U_1 and I_1 are effective values of the fundamental components of phase-to-neutral voltage and current.

5.8 Power Factor

True Power Factor or Power Factor (TPF or PF) is the value which takes into account also the presence of higher harmonics. For sinusoidal circuits, it is equal to Displacement Power Factor (DPF) i.e. popular cosφ.

DPF is therefore a measure of the phase shift between the fundamental voltage and current components. Power Factor is the ratio between active and apparent powers:

$$DPF = \frac{P_1}{S_1} = \frac{U_1 I_1 cos\varphi_{U1I1}}{U_1 I_1} = cos\varphi_{U1I1}$$

$$PF = \frac{P}{S}$$

In case of a purely resistive load (in a one-phase system), the apparent power is equal to active power (in terms of value), and reactive power equals zero, so such load fully uses the energy potential of the source and the power factor is 1. Appearance of reactive component inevitably leads to reduction of energy transmission effectiveness – the active power is then less than apparent power, and the reactive power is increasing.

In three-phase systems, the power factor reduction is also influenced by receiver unbalance (see discussion on reactive power). In such systems, correct power factor value is obtained using the effective apparent power S_e, that is the value defined, among others, in IEEE 1459-2000 standard.

6 Harmonics

Dividing periodic signal into harmonic components is a very popular mathematical operation based on Fourier's theorem which says that any periodic signal can be represented as a sum of sinusoidal components with frequencies equal to multiples of fundamental frequency of such signal. Time-domain signal can be subjected to Fast Fourier Transform (FFT) to receive amplitudes and phases of harmonic components in the frequency domain.

In a perfect situation, voltage is generated in a generator which at output gives a pure sinusoidal 50/60 Hz waveform (absence of any higher harmonics). If the receiver is a linear system, then also current in such situation is a pure sinusoidal waveform. In real systems, voltage and current waveforms can be distorted, hence in addition to the fundamental component there must be harmonics of higher orders.

Why is the presence of higher harmonics in the network undesirable?
One of the reasons is the skin effect which involves pushing out the electrons from the centre of conductor towards the surface as the current frequency is increasing. As a result, the higher the frequency, the smaller the effective conductor cross section which is available for the electrons, which means that the conductor resistance is increasing. Consequently, the higher the current harmonics, the higher effective cabling resistance for this harmonics, and this inevitably leads to more power losses and heating of conductors.

A classic example connected with this effect is related to neutral conductor in three-phase systems. In a system with little distortion, little unbalance and a balanced (or slightly unbalanced) receiver, the current in neutral conductor has the tendency of zeroing (it is much smaller that RMS phase currents). Such observation has tempted many designers to obtains savings by installing the cabling in such systems with neutral conductor of a smaller cross section than in phase conductors. And everything went well until the appearance of odd harmonic orders which are multiples of 3 (third, ninth, etc.). Suddenly, the neutral conductor began overheating and the measurement showed very high RMS current. Explanation of this phenomenon is quite simple. In this example, the designer did not take into consideration two circumstances: in systems with distorted waveforms, the higher harmonics might not zero in the neutral conductor, and quite to the contrary, they may sum up, and secondly, the skin effect and high harmonic currents additionally contributed to the neutral conductor heating.

Let's try to answer two basic questions:
What is the cause of harmonic components in voltage?
What is the cause of harmonic components in current?

Seemingly, these two questions are almost identical, but separation of current and voltage is extremely important to understand the essence of this issue.

The answer to the first question is as follows: harmonics in voltage are a result on a non-zero impedance of the distribution system, between the generator (assuming that it generates a pure sinusoid) and the receiver.

Harmonics in current, on the other hand, are a result of non-linear impedance of the receiver. Of course, it must be noted that a linear receiver to which distorted voltage is supplied will also have identically distorted current waveform.

The literature often uses the statement that "receiver generates harmonics". It should be remembered that in such case, the receiver is not a physical source of energy (as suggested by the word "generates"). The only source of energy is the distribution system. If the receiver is a passive device, the energy sent from the receiver to the distribution system comes from the same distribution system. We are dealing here with a disadvantageous and useless bidirectional energy flow. As mentioned earlier in the section on power factor, such phenomenon leads to unnecessary energy losses, and the current "generated" in the receiver causes an additional load on the distribution system.

Consider the following example. A typical non-linear receiver, such as widely used switched-mode power supplies (i.e. for computers) receives power from a perfect generator of sinusoidal voltage. For now, let's assume that the impedance of connections between the generator and the receiver is zero. The voltage measured on the receiver terminals will have sinusoidal waveform (absence of higher harmonics) – this is imply the generator voltage. The receiver current waveform will already include harmonic components – a non-linear receiver often takes current only in specified moments of the total sinusoid period (for example, maximum current can take place at the voltage sinusoid peaks).

However, the receiver does not generate these current harmonics, it simply takes current in alternating or discontinuous way. All the energy is supplied solely by the generator.
In the next step, we may modify the circuit by introducing some impedance between the generator and the receiver. Such impedance represents the resistance of cabling, transformer winding, etc.

Measurements of voltage and current harmonics will give slightly different results. What will change? Small voltage harmonics will appear, and in addition current frequency spectrum will slightly change.

When analysing the voltage waveform on the receiver, one could notice that original sinusoidal waveform was slightly distorted. If the receiver took current mainly at voltage peaks, it would have visibly flattened tops. Large current taken at such moments results in larger voltage drops on the system impedance. A part of the ideal sinusoidal voltage is now dropped on this impedance. A change in the current spectrum is a result of slightly different waveform of voltage supplied to the receiver.

The example described above and "flat tops" of the sinusoid are very frequent in typical systems to which switched-mode power supplies are connected.

6.1 The method for measuring harmonics

Harmonics measurement is carried out according to IEC 61000-4-7.
It defines the method for calculating individual harmonics.

The whole process consists of several steps:

- synchronous sampling (10/12 periods),
- FFT (Fast Fourier Transform),
- grouping.

FFT analysis for the test window of 10/12 period (approx. 200 ms). As a result of FFT, we receive a set of spectral lines from 0 Hz (DC) to the 50-th harmonics (approx. 2.5 kHz for 50 Hz or 3 kHz for 60 Hz). The distance between successive lines directly results from the duration of the measurement window and is approximately 5 Hz.

It is essential to maintain a constant synchronization of the sampling frequency with the mains. FFT may be performed only on the data containing an integer multiple of the network period. This condition must be met in order to minimize the so-called spectral leakage, which leads to falsifying information about the actual levels of spectral lines. The analyzer meets these requirements, as the sampling frequency is stabilized by the phase locked loop (PLL).

Because the sampling frequency may fluctuate over time, the standard provides for grouping the main spectral lines of harmonics with the spectral lines located in their direct vicinity. The reason is that the energy of components may partially pass into adjacent interharmonics components.

Two methods of grouping are provided:

- harmonic group (includes the main line and five or six adjacent interharmonic components),
- harmonic subgroup (includes the main line and one of each adjacent lines).

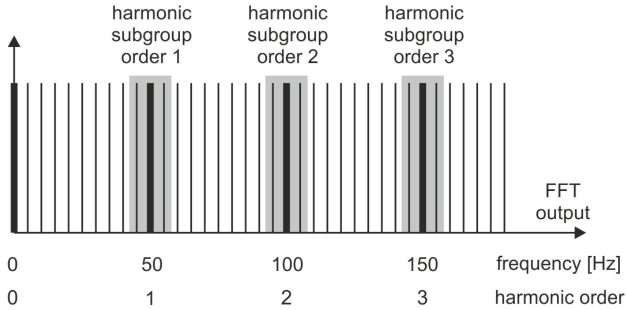

Fig. 4. Determining harmonics subgroups (50 Hz system).

Example *In order to calculate the 3rd harmonic component in 50 Hz system, use 150 Hz main spectral line and adjacent lines 145 Hz and 155 Hz. The resulting amplitude is calculated using RMS method.*

6.2 Harmonics active power

Decomposing receiver voltage and current to harmonic components enables using more detailed analysis of energy flow between the supplier and the consumer.

We assume that the power quality analyzer is connect between the voltage source and the receiver. Both, supply voltage and current are subjected to FFT, as a result of which we receive the harmonics amplitudes with phase shifts.

It turns out that the knowledge of voltage and current harmonics and of phase shift between these harmonics allows calculating the active power of each harmonic individually:

$$P_h = U_h I_h \cos\varphi_h$$

where:

P_h – active power of the h-th order harmonic,
U_h – RMS voltage of the h-th order harmonic,
I_h – RMS current of the h-th order harmonic,
φ_h – phase shift angle between the voltage and current harmonics of the h-th order.

When P_h power has positive sign (+), then the dominating source of energy of this harmonics is on the energy supplier's side. When it is negative, the receiver is the dominating source. It must be noted that on the basis of harmonics active powers measured in this way one cannot determine that only one party is the sole source of the harmonics, as the measured value is a resultant of the supplier and the consumer.

Example *When the supplier generates active power of harmonic P_{hD} = 1 kW, and the consumer "generates" the power of this harmonics equal to P_{hO} = 100 W, then the resultant power measured at the terminals between the supplier and the consumer is $P_h = P_{hD} – P_{hO}$ = 0.9 kW.*

In a situation presented above, we are dealing with two separate sources of energy flow. Unfortunately, basing on such measurement, we cannot directly indicate the actual distribution.

In real systems, determination of the dominant source is often sufficient. By grouping the harmonic components with plus signs, we receive a set of power values which are responsible for the energy flow from the source to the receiver, which is the useful energy.

On the other hand, the set of harmonics active power values with negative sings makes up this part of energy which does not play any useful role and is "returned" back to the distribution system.

By adding all active harmonics power values we receive the receiver active power. Hence, we can notice that there are at least two alternative active power measurement methods.

The first method involves calculation of average active power instantaneous value, which is calculated on the basis of successive voltage and current:

$$P = \frac{1}{M}\sum_{i=1}^{M} U_i I_i$$

where U_i is a successive voltage sample, I_i is a successive current sample and M is the number of samples in the measuring window.

The second method involves adding individual harmonics active power values which are obtained by the FFT decomposition:

$$P = \sum_{h} U_h I_h \cos\varphi_h$$

6.3 Harmonics reactive power

The harmonics reactive power values may be calculated in a similar manner as the active power values:

$$Q_h = U_h I_h \sin\varphi_h$$

Knowledge of reactive power harmonics is valuable information used in the development of reactive parallel compensators of reactive power. Such compensators consist of LC branches tuned to a specific frequency harmonics.

The sign of the individual power components indicates the character of load for this component. When the sign is positive (+), then the character is inductive, and when it is negative (-), it is capacitive.

Passive source current may be reduced to zero when the following condition is met for each harmonic:

$$B_h + B_{kh} = 0$$

where:

B_h – receiver susceptance for the *h*-th harmonic,

B_{kh} – parallel compensator susceptance for the *h*-th harmonic.

As the compensator complexity grows proportionally to the number of harmonics subjected to compensation, usually only the fundamental component is compensated and maximum a few higher harmonics with the largest values. However, the compensation of the fundamental component may considerably improve the power factor and may be sufficient.

6.4 Harmonics in three-phase systems

In three-phase systems, harmonics of given orders have a particular feature which is shown in the table below:

Order	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
Frequency [Hz]	50	100	150	200	250	300	350	400	450
Sequence (+ positive, – negative, 0 zero)	+	–	0	+	–	0	+	–	0

"Sequence" line refers to the symmetrical components method which allows to decompose any of the three vectors into three sets of vectors: positive, negative and zero sequence (more in section related to unbalance).

For example: Let's assume that a three-phase motor is supplied from a balanced, 4-wire mains (RMS phase-to-neutral voltage values are equal, and angles between the individual fundamental components are 120° each).

"+" sign in the line specifying the sequence for the 1st harmonics means the normal direction of the motor shaft rotation. The voltage harmonics, for which the sign is also "+" cause the torque corresponding with the direction of the fundamental component. The harmonics of the 2nd, 5th, 8th and 11th order are the opposite sequence harmonics, meaning that they generate the torque which counteracts normal motor direction of rotation, which can cause heating, unnecessary energy losses, and reduced efficiency. The last group are the zero sequence components, such as the 3rd, 6th and 9th, which do not generate torque but flowing through the motor winding cause additional heating.

Basing on the data from the table, it is easy to note that the series +, –, 0 is repeated for all successive harmonic orders. The formula which links the sequence with order is very simple, and for 'k' being any integer:

Sequence	Harmonic order
positive "+"	3k +1
negative "–"	3k – 1
zero "0"	3k

The even order harmonics do not appear when a given waveform is symmetrical in relation to its average value, and this is the case in majority of power supply systems. In a typical situation, the measured even order harmonics are of minimal value. If we consider this property, it turns out that the group of harmonics with the most undesirable properties is the 3rd, 9th, 15th (zero sequence), and the 5th, 11th, and 17th (negative sequence).

The current harmonics which are multiples of 3 cause additional problems in some systems. In 4-wire systems, they have a very undesirable property of summing up in the neutral conductor. It turns out that, contrary to other order harmonics, in which the sum of instantaneous current values is zeroed, the waveforms of these harmonics are in phase with each other which causes adding of the phase currents in the neutral conductor. This may lead to overheating of this conductor (particularly in the distribution systems where the conductor has a smaller cross-section than the phase conductors, as it was widely practiced until recently). Therefore, in systems with non-linear loads and large current distortions, it is now recommended that the cross section of neutral conductor is larger than that of the phased conductors.

In the delta systems, the harmonics of these orders are not present in the line currents (provided these are balanced systems), but they circulate in the load branches, also causing unnecessary power losses.

The nature of individual harmonics as shown in the table is fully accurate only in three-phase balanced systems. Only in such systems, the fundamental component has the exclusively positive sequence character. In actual systems, with some degree of supply voltage unbalance and the load unbalance, there are non-zero positive and negative sequence components. The measure of such unbalance is so-called unbalance factors. And this is due to this unbalance of the fundamental component and additionally the differences in amplitudes and phases of the higher harmonics, that also these harmonics will have the positive, negative and zero sequence components. The larger the unbalance, the higher the content of remaining components.

IEC 61000-4-30 standard recommends that the harmonic subgroup method is used in power quality analyzers for calculating harmonic components.

6.5 Total Harmonic Distortion

Total Harmonic Distortion (THD) is the most widely used measure of waveform distortion. Two versions of this factor are applied in practical use:

- THD_F (THD-F or simply THD) – total harmonic distortion referred to the fundamental component,
- THD_R (THD-R) – total harmonic distortion referred to the RMS value.

In both cases, THD is expressed in percent. Definitions are presented below:

$$THD_F = \frac{\sqrt{\sum_{h=2}^{n} A_h^2}}{A_1} \times 100\%$$

$$THD_R = \frac{\sqrt{\sum_{h=2}^{n} A_h^2}}{A_{RMS}} \times 100\%$$

where: A_h – RMS of the h-th order harmonic,
A_1 – RMS of the fundamental component,
A_{RMS} – RMS of the waveform.

Limitation of the number of harmonics used to calculate THD is conventional and results mainly from measuring limitations of the device. As the analyzer is capable of measuring the harmonic components up to the 50th order, the harmonics of the 50th or 40th order are used to calculate THD (the user can select either 40th or 50th order as the limit).

Please note that when the waveforms are very distorted, the two definitions presented above will give significantly different results. THD_R cannot exceed 100%, while THD_F has no such limit and may be 200% or more. Such a case may be observed when measuring very distorted current. The voltage harmonic distortion usually does not exceed a few percent (both THD_F and THD_R); e.g. EN 50160 standard defines the limit of 8% (THD_F).

6.6 TDD - Total Demand Distortion

Total Demand Distortion is an indicator representing the level of the RMS value of the harmonics in current referenced to the maximum demand current. It is derived from THD, and the value is expressed by the formula:

$$TDD = \frac{\sqrt{\sum_{h=2}^{n} I_h^2}}{I_L} \times 100\%$$

where: I_h – RMS of the h-th order harmonic,
I_L – demand current.

Comparing the above formula with the formula for THD currents it is apparent that they differ only by the value of the denominator. The nominator remains unchanged and represents the RMS value of harmonics.
Demand current I_L is the maximum average value of the fundamental component, recorded during the observation period. Usually, the observation period in one week or one month.

To understand the difference between THD and TDD, see the following example. Assume that the fundamental component of the current in the circuit changes between 1000 A and 10 A. The deformation of the current waveform is more or less at the same level over the entire range of variation of the fundamental component and has a level resulting in THD-F of approx. 50%. When a graph of the THD variation in time is generated, it presents more or less constant value of 50% of the entire time interval. Note that despite the fact that in the analyzed period of time, the funda-mental component changed 100-fold, the graph of THD provides no basis for conclusions on en-ergy losses in the circuit resulting from the flow of harmonics. A similar graph of the TDD would be similar to the waveform of fundamental current component - maximum TDD values would reach 50%, while the minimum values approx. 0.5%. Thus, TDD reflects the changes in RMS value of harmonics better: if the current reaches the maximum value, TDD value is close to THD, how-ever, if the value of current in the circuit decreases, the TDD also decreases.

To calculate TDD, it is required to determine or calculate I_L current. PQM analyzers offer two methods:

- automatic– I_L current is determined by the application as the maximum recorded mean value of the fundamental current component (in the whole recording range of all the measured current channels). When TDD recording is enabled, the analyzer automatically records the parameters required to calculate its value,
- manual – I_L current is applied by the user (in the application, during the data analysis). TDD values are calculated based on the entered value.

6.7 K-Factor – transformer loss factor

K-Factor, also called the transformer loss factor is a measure used in determining the requirements for power transformers. Higher harmonics in current cause increased heat losses in windings and metal parts of the transformer. The main reasons is the presence of eddy currents generated by current components of higher frequencies and by the skin effect.

The transformer temperature increase is directly proportional to current components squared, the value called K-Factor takes this into account, and the factor is calculated according to the following formula:

$$KFactor = \sum_{h=1}^{n} I_{hr}^2 h^2 = \frac{\sum_{h=1}^{n} I_h^2 h^2}{I_1^2}$$

where: I_{hr} - relative value of the *h*-th order harmonic component (in relation to the fundamental component),
I_h - amplitude of the *h*-th order of current harmonic component,
I_1 - amplitude of current fundamental component,
h – harmonic order,
n – the maximum order of harmonics taken into account.

In case of this parameter, the higher harmonics are much more important than the lower – each harmonic component is multiplied by its order squared.

K-Factor is useful when defining the requirements for transformers which must work in conditions of significant current distortion. It t is assumed that the transformer, which works in conditions, where K =*x*, will generate *x* times more heat than at purely sinusoidal current (K=1).

6.8 Transformer load reduction factor – Factor K

The transformer load reduction factor (Factor K) is a parameter developed in Europe to determine the requirements for power supply transformers. This factor is determined according to the formula given in the HD 538.3.S1 standard:

$$Factor\ K = \sqrt{1 + \frac{e}{1+e}\left(\frac{I_1}{I}\right)^2 \sum_{h=2}^{n}\left(h^q\left(\frac{I_h}{I_1}\right)^2\right)}$$

where: e – ratio of eddy current losses at the fundamental frequency to active losses, at the same temperature,
I_h – amplitude of the h-th order harmonic of the current,
I_1 – amplitude of the fundamental component of the current,
I – effective value of the current,
h – order of the harmonic,
n – maximum order of harmonics taken into account,
q – exponent – a constant depending on the type of winding and the frequency. Typical values are 1.7 for transformers in which both windings are wound with a wire of circular or rectangular cross-section, and 1.5 for transformers with a low voltage winding wound with a foil wire.

The value of the coefficient calculated in this way determines the extent to which the rated power of the transformer should be reduced so that the losses with the current distorted by harmonics do not exceed the losses for the fundamental component of the current.

7 Interharmonics

Interharmonics are components of the frequency spectrum for voltage or current with a frequency that is not a multiple of the fundamental frequency network (50 or 60 Hz). The cause of interharmonics may be e.g. asynchronous processes and transient states related to connection processes, frequency converters that generate the output frequency different from the frequency of the power supplying mains and introduce into the system spectral interharmonics, arc furnaces, induction motors and drives with variable load. Ripple control signals, i.e. signals with defined frequencies generated in control systems and introduced into mains should also be considered as interharmonics components. Interharmonics at frequencies lower than the mains fundamental frequency are called subharmonic components.

The effects of interharmonics may include:

- increased losses in mechanical motors, temperature rise; subharmonics are particularly harmful elements, as the power loss increases with decreasing frequency,
- flicker; also in this case subharmonics have particularly adverse effects. For example subharmonic with 8.8Hz frequency causes the modulation of mains voltage within the range, where human eye is most sensitive to this phenomenon (see also sec. 4),
- low-frequency oscillations in mechanical systems,
- interferences in the operation of control and protection systems,
- telecommunications and acoustic interferences,
- saturation of magnetic cores by subharmonic components (e.g. transformers, motors, etc.).

The interaction of higher harmonics and interharmonics may also lead to unexpected phenomena such as beating-in at low frequencies. For example, ninth harmonic (450 Hz) with interharmonic of 460 Hz frequency generates the effect of beating-in at the frequency of 10 Hz, despite the fact that in this frequency spectrum a component of this frequency is not present. Human eye is very sensitive in this frequency range, and the interaction may lead to a significant flicker effect. 230 V/50 Hz voltage waveform for this case is presented in Fig. 5 (significantly higher level of the interharmonic was assumed in this case to illustrate the effect better).

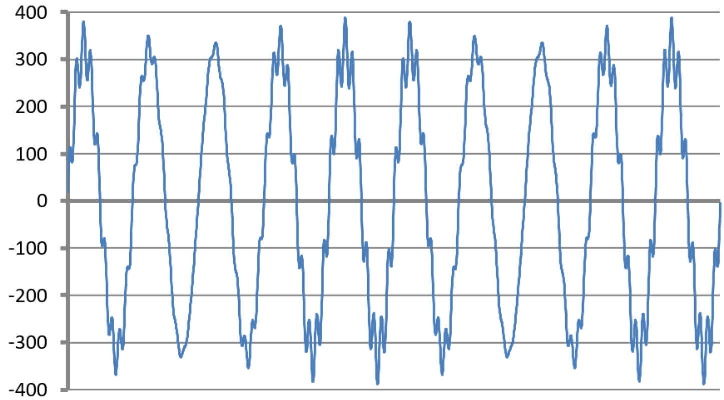

Fig. 5. The effect of 9th harmonic interaction (450 Hz, 10% Unom) and interharmonic 460 Hz (10% Unom). The apparent change in the voltage envelope with frequency of 10Hz that may cause flicker (Unom = 230 V RMS, 50 Hz).

7.1 The method for measuring interharmonics

Interharmonics measurement is carried out according to IEC 61000-4-7 and IEC 61000-4-30.

They provide a method of calculating the individual components of interharmonics in power quality analyzers.

The whole process, similarly as in case of harmonics, consists of several steps:

- synchronous sampling (10/12 periods),
- FFT (Fast Fourier Transform),
- grouping.

FFT analysis for the test window of 10/12 period (approx. 200 ms). As a result, we obtain a set of spectral lines from 0 Hz (DC). The distance between successive lines results from the duration of the measurement window and is approximately 5 Hz.

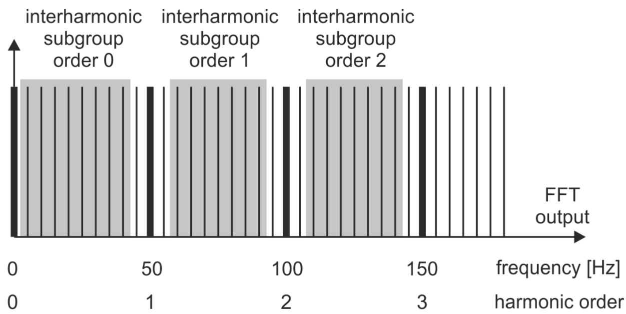

Fig. 6. Determining interharmonics subgroups (50 Hz system)

Each interharmonic subgroup is the sum of RMS for seven (for 50 Hz mains) or nine (for 60 Hz mains) spectral lines obtained by Fourier transform. The exception is zero subgroup, i.e. sub-harmonic subgroup that contains one line more - 5Hz. It is presented in Fig. 6. Determining interharmonics subgroups (50 Hz system) with an example of 50 Hz network. Interharmonic subgroup of 0 order, i.e. subharmonic, consists of eight lines with frequencies from 5 Hz to 40 Hz. Each following interharmonic subgroup consists of seven lines located between harmonic subgroups, e.g. subgroup of 1st order includes spectral lines of frequencies from 60 Hz to 90 Hz. In case of subharmonic subgroup, the range of spectral lines was extended by 5 Hz line, otherwise the energy in this lowest frequency band would not be included and would be lost. All subsequent spectral lines are included either in the harmonic subgroup or interharmonic subgroup.

Similarly as in case of the harmonics, interharmonics are calculated at least to 50th order; for mains frequency of 50 Hz it gives a range of slightly above 2.5 kHz, and for 60 Hz, a range of slightly above 3 kHz.

7.2 Total Interharmonic Distortion

A measure of the total presence of interharmonics is the TID, which is defined as:

$$TID_F = \frac{\sqrt{\sum_{ih=0}^{n} A_{ih}^2}}{A_1} \times 100\%$$

$$TID_R = \frac{\sqrt{\sum_{ih=0}^{n} A_{ih}^2}}{A_{RMS}} \times 100\%$$

where: TID_F - Total Interharmonic Distortion related to fundamental component,
TID_R - Total Interharmonic Distortion related to RMS value,
A_{ih} – RMS of *ih*-th interharmonic (interharmonic sub-group),
A_1 – RMS of the fundamental component,
A_{RMS} – RMS of the waveform,
n - in case of analyzers described in this manual it is equal to 50.

TID is the ratio of the RMS value of all interharmonics to the fundamental component (for TID_F) or RMS value (for TID_R).

Acceptable level of interharmonic interferences in voltage is a matter discussed among professionals involved power quality matters. Some sources state that the overall rate of voltage interharmonics distortion should not exceed 0.2%.

8 Mains signalling

Ripple control signals are signals entered into the electricity network in order to control and check of remote control devices connected to the same network. In addition to the transmission of electricity, a distribution network is in this case used as a transmission medium for communication between devices. EN 50160 standard distinguishes three types of signals:

- *Ripple control signals* from 110 to 3000 Hz,
- *Power Line Carrier Communication*, *PLCC*, frequency range from 3 to 148.5 kHz,
- *Marking signals*, short transients imposed at a specific point on the voltage waveform.

Since the introduction of such signals to the power supply may have negative consequences for some devices, similarly to the effect of harmonics or interharmonics, EN 50160 standard defined limits for the 3-second mean values of such signals, as shown in Fig. 8. During the measurement, 99% of average 3-second control signals values must be below the specified limit.

Low frequency signals (up to 3 kHz) are used for switching on/off the loads, filters and protection devices. One application is to control the street lighting or (in some countries) remote controlling of HVAC devices. Often, this kind of signals are used for customers using two types of energy tariff (e.g. when using a cheaper night tariff, the energy supplier automatically disables selected loads). This type of communication is usually unidirectional. Due to the low attenuation features of the distribution network at this frequency range (attenuation increases with increasing frequency), communication using this method allows users to achieve the greatest range of transmission (even hundreds of kilometres). During the transmission control signal is transmitted in several packages and repeated at specified intervals. The period during which the signal is active may be quite long, e.g. for 2 seconds signal is on and for 2 seconds it is off - this sequence is repeated several times. There are cases when this type of transmission results in flicker. An example of this type of transmission is shown in Fig. 7.

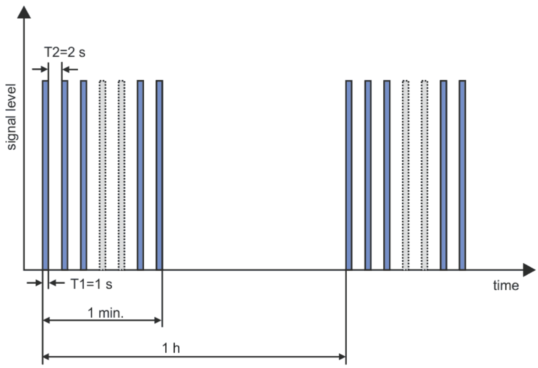

Fig. 7. An example of low-frequency signal transmission.

Higher transmission frequencies (and hence, higher bit rates) are typical for PLCC communication. This type of communication uses modulation of amplitude or carrier frequency (or other modulation method). Modern methods use complex algorithms to process signals in order to achieve the highest resistance to interference and highest bit rate (transmission speed). PLCC transmission continuously gains popularity and its application range increases. The communication between network points may be bidirectional. The concept of so-called *smart grid* is based on PLCC, which is one of the main methods of communication between energy meters and central points. The main application areas include: telemetry, optimization of power consumption, remote control of loads. Attenuation of the distribution network limits the maximum transmission range. Maximum range may reach a few km, while there is a strong correlation between the type of modulation, bit rate and achieved distances.

At the same time, standardization works are in progress to use of higher frequencies (above 148.5 kHz to tens of MHz) for the purpose of short-distance data transmission.

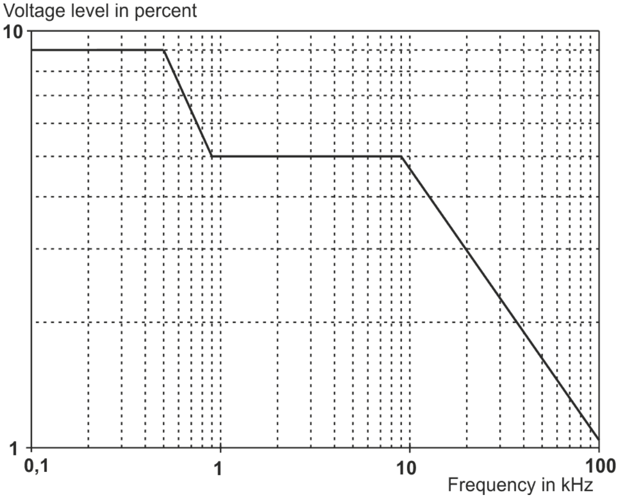

Fig. 8. Allowable levels of mains signalling according to EN 50160 standard.

In networks with substantial contents of harmonics, where additional filters are used for reducing interferences, the consequences of their use may also include additional attenuation of the frequency range used for the signalling. Both the presence of filters and a high level of harmonics and interharmonics may significantly reduce the possibility of efficient use of the distribution network for communication with low-frequency or PLCC methods.

IEC 61000-4-30 standard provides the following measurement method of ripple control signals:

- if the frequency of a control signal is a multiple of 5 Hz (i.e. it covers exactly the output line of FFT frequency analysis), then only this single line is taken into account along with its RMS,
- if the frequency is not a multiple of 5 Hz, then RMS value is calculated from four adjacent frequency lines of FFT.

9 Unbalance

Unbalance is a concept associated with the three-phase systems and may refer to:

- supply voltage unbalance,
- load current unbalance,
- receiver unbalance.

In three-phase systems, the unbalance of voltage (current) occurs when values of three component voltages (currents) are different and/or the angles between individual phases are not equal to 120°.

The receiver unbalance occurs when impedance values of individual receiver branches are not equal.

These phenomena are particularly dangerous for three-phase motors, in which even a slight voltage unbalance can cause current unbalance that is many times larger. In such situation, the motor torque is reduced, heat losses in windings increase, and mechanical wear is faster. The unbalance also has an unfavorable effect on power supply transformers.

The most frequent reason of unbalance is uneven load on individual phases. A good example is connecting to three-phase systems of large one-phase loads, such as railway traction motors.

The analyzer is capable of measuring the voltage and current unbalance with a symmetrical components method. This method is based on the assumption that each set of three unbalanced vectors can be resolved to three groups of vectors: positive sequence, negative sequence and zero sequence.

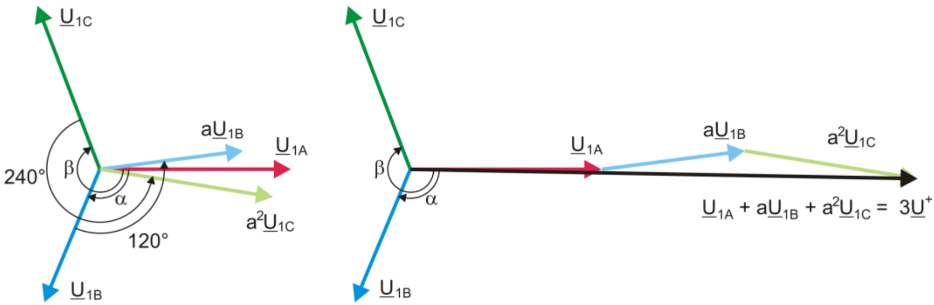

Fig. 9. Example of determining positive sequence component.

Presented example shows the method for calculating voltage positive sequence component. By definition:

$$\underline{U}^{+} = \frac{1}{3}\left(\underline{U}_{1A} + a\underline{U}_{1B} + and^{2}\underline{U}_{1C}\right)$$

where: $\underline{U}^{+}$ is a vector of positive sequence,

where $\underline{U}_{1A}$, $\underline{U}_{1B}$, $\underline{U}_{1C}$ are vectors of fundamental components of phase voltages U_A, U_B, U_C

$$a = 1e^{j120^\circ} = -\frac{1}{2} + \frac{\sqrt{3}}{2}j$$

$$a^2 = 1e^{j240^\circ} = -\frac{1}{2} - \frac{\sqrt{3}}{2}j$$

Fig. 9 shows graphical method of determining this component. As we can see from the definition, the vector of positive-sequence component equals one third of the sum of the components: $\underline{U}_{1A}$, $a\underline{U}_{1B}$, $a^2\,\underline{U}_{1C}$. Operator a and a^2 are unit vectors with angles of 120° and 240°. The procedure is as follow: turn voltage vector $\underline{U}_{1B}$ by 120° counter-clockwise (multiply by a) and add to vector $\underline{U}_{1A}$. Then, turn the vector $\underline{U}_{1C}$ by 240° and add to the previous sum of vectors. The result is vector $3\underline{U}^{+}$. Vector $\underline{U}^{+}$ is the desired symmetrical positive sequence component. Note that in case of perfect symmetry (equal voltages and angles) the positive sequence component is equal to the value of the phase-to-neutral voltages.

The positive sequence component is a measure of similarity of the tested set of three-phase vectors to the symmetrical set of positive sequence vectors.

Similarly, the negative sequence component is a measure of similarity to the symmetrical set of negative sequence vectors.

The zero sequence component exists in the systems in which the sum of three voltages (or currents) is not equal to zero.

A measure of the system unbalance which is widely used in the power generation is the negative sequence and zero sequence unbalance (formulas are for voltage):

$$u_0 = \frac{U_0}{U_1} \cdot 100\%$$

$$u_2 = \frac{U_2}{U_1} \cdot 100\%$$

where: u_0 – unbalance factor for zero sequence,
u_2 – negative sequence unbalance,
U_0 – zero symmetric component,
U_1 – positive sequence symmetrical component,
U_2 – negative sequence symmetrical component.

The most convenient method to calculate the symmetrical components and unbalance is using the complex number calculus. The vectors parameters are amplitude of the voltage (current) fundamental component and its absolute phase shift angle. Both of these values are obtained from FFT.

10 Voltage dips, swells and interruptions

Voltage dips, swells and interruptions are network disturbances when the effective voltage (RMS) is significantly different from the nominal value. Each of the three states may be detected by the analyzer when the event detection is activated and when the user defines the threshold values.

Voltage dip is a state during which the RMS voltage is lower than the user-defined voltage dip threshold. The basis for the dip measurement is $U_{RMS(1/2)}$, which is the one period RMS value refreshed every half period.

Definition of dip (acc. to IEC 61000-4-30 standard):

The voltage dip starts at the moment when $U_{RMS(1/2)}$ voltage decreases below the dip threshold value, and ends at the moment when $U_{RMS(1/2)}$ voltage is equal to or greater than the dip threshold value plus the voltage hysteresis.

The dip threshold may be specified at 90% of U_{nom}. During the voltage dip, the analyzer remembers the minimum recorded voltage (this is called the residual voltage U_{res} and is one of the parameters characterizing the dip) and the average voltage value.

Interruption is a state during which $U_{RMS(1/2)}$ voltage is lower than the specified interruption threshold. The interruption threshold is usually set much below the voltage dip level, at approx. 1..10% U_{nom}.

The voltage interruption starts at the moment when $U_{RMS(1/2)}$ voltage decreases below the interruption threshold value, and ends at the moment when $U_{RMS(1/2)}$ voltage is equal to or greater than the interruption threshold value plus the voltage hysteresis.

During the interruption, the analyzer remembers the minimum recorded voltage and the average voltage value.

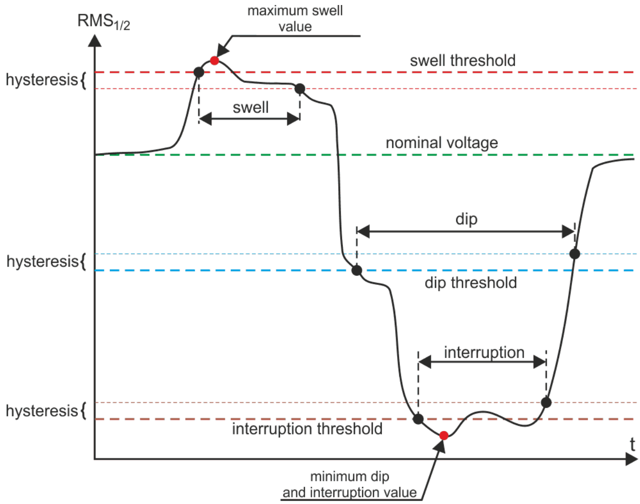

Fig. 10. Voltage swells, dips and interruptions

Voltage swell is a state of increased voltage. The swell threshold is usually set at a level close to 110% of U_{nom}.

Swell starts at the moment when $U_{RMS(1/2)}$ voltage increases above the swell threshold value, and ends at the moment when $U_{RMS(1/2)}$ voltage is equal or below the swell threshold value minus the voltage hysteresis. During the swell, the analyzer remembers the maximum recorded voltage and the average voltage value.

The hysteresis for all three states is the same and it is a user-defined percent of nominal voltage.

The analyzer remembers the event start and end time (with a half a period accuracy).

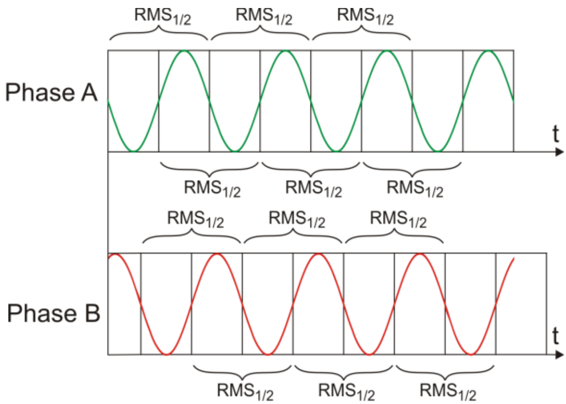

Fig. 11. Determining values of $U_{RMS(1/2)}$

The minimum voltage dip, interruption and swell duration is a half of the period.

$U_{RMS(1/2)}$ values are determined in 1 period during crossing through zero of the fundamental voltage component - they are refreshed every half-period, independently for each voltage channel. It means that these values will be obtained at different times for different channels. Fig. 11 shows the method for determining $RMS_{1/2}$ values at two voltage phases. Information on crossing zero of the fundamental component is obtained by FFT.

11 Waveshape variation

A very useful diagnostic function is the ability to detect disturbances in the shape of the voltage waveform: so-called waveshape variation events.

This method compares two adjacent periods of the voltage waveform and the difference between them is calculated and their maximum amplitude is checked - these values are then compared with the threshold set by the user. The percentage value of the threshold refers to the nominal voltage. If the calculated change in the amplitude exceeds the threshold, the waveshape event is triggered. This event is considered completed when for at least three consecutive waveform periods no detected exceedance of the tolerance threshold is detected.

The principle of the algorithm may be explained using Fig. 12. Each period of the voltage waveform has assigned range of permissible changes (shown as bright red area), having a width (in volts) of $2U_{TH}$, which is formed on the basis of the voltage waveform in the previous period. U_{TH} is the detection threshold for events, which is set by user in the measurement configuration. If the instantaneous voltage exceeds the limits set for this area, then the event is detected. ΔU represents the difference in the values of voltage samples of the two adjacent periods.

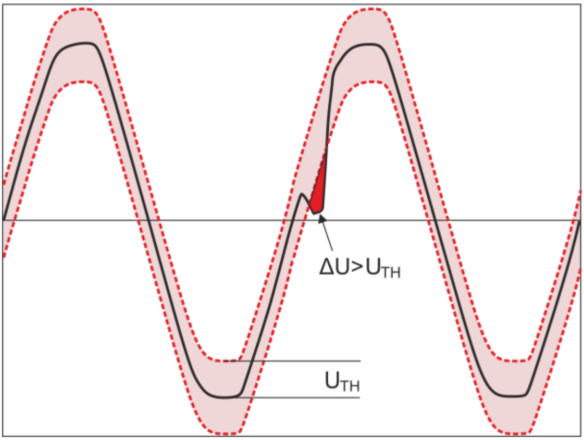

Fig. 12. Detecting waveshape variation events.

This functionality is very helpful in detecting any non-stationary disturbances in the supply network, especially when the analyzer is not equipped with fast transients module.

12 Phase jumps

Some analyzers allows for detecting changes in the fundamental voltage phase angle. The detection algorithm compares the angles of the fundamental voltage component of two or three adjacent periods. If the angle difference is greater than the threshold set by the user (expressed in angle degrees), then the information is recorded on detecting the event, along with the measured value of the phase jump.

Phase jumps are usually accompany voltage dips - change in the load impedance in relation to the impedance of the power supply network causes the change of observed angle of fundamental voltage.

Example of phase jump is shown in Fig. 13. Information about the detected event includes the time of its occurrence and designated phase jump value, expressed in angle degrees (angle φ shown in the figure).

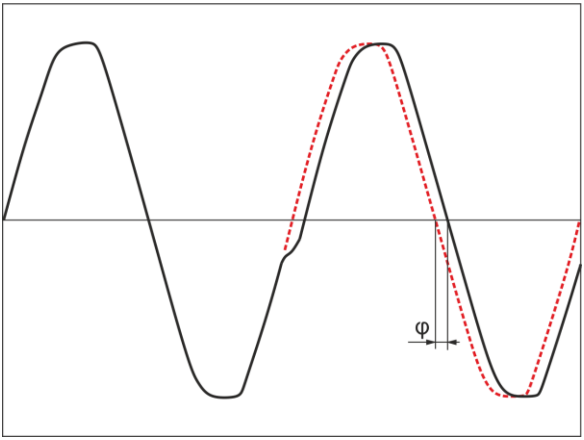

Fig. 13. Phase jump.

13 Rapid Voltage Changes (RVC)

Definition of Rapid Voltage Changes (*RVC*): a sudden change in RMS voltage between two stable states in which the RMS voltage does not exceed the dip and swell thresholds.
In simple terms, it may be stated that RVC have some similarities in nature to dips and swells, but of smaller amplitude. Events of this type usually results from changes in loads of power grid, switching effects or failures.

In both of these types of events, the same source data is used - the RMS values of 1-period, refreshed every half-period and indicated by symbol $U_{RMS(1/2)}$.

The algorithm of RVC is as follows (see Fig. 14):

- The arithmetic mean value is calculated from the preceding 100/120 values of $U_{RMS(1/2)}$ (approx. 1 s). The mean value is then updated with each new value $U_{RMS(1/2)}$. The figure shows it as the continuous curve in red.
- If all of 100/120 previous values $U_{RMS(1/2)}$ are within the area defined by the mean value, extended from both sides with the hysteresis (two red dotted lines in the figure), then it is considered that the voltage is in the "stable" condition.
- When the "stable" condition is not met, i.e. when one or more $U_{RMS(1/2)}$ values exceeds the permitted range, then RVC event starts (blue areas in the figure). At the same, the hysteresis is applied to the threshold (permissible range of changes is reduced by the hysteresis) and signal changes specifying the voltage "stability" are blocked for the duration of 100/120 network half-periods. For this reason, the RVC events will not be detected more than once per approx. 1 second.

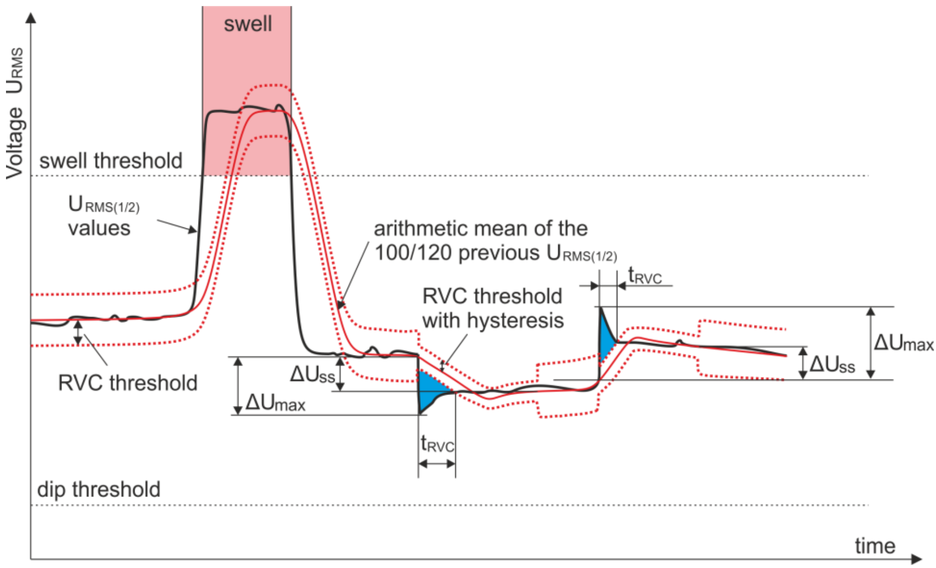

Fig. 14. Rapid Voltage Changes (RVC) - example.

- Once again the voltage "stability" condition is met, RVC event is completed. The end time of the event is retracted by 100/120 half-periods in relation to the change of stability signal "unstable" to "stable" state.

- If during the RVC event, a voltage dip or swell occurs, then such RVC event is dropped. The figure shows voltage increase - this event cancels the potential RVC events, if they are detected at that period.

Specific parameters for Rapid Voltage Changes include:

- ΔU_{SS} (steady-state) – it is the difference between the mean ("stable") voltages before and after RVC event.
- ΔU_{MAX} – is the maximum deviation of $U_{RMS(1/2)}$ value from the mean value during the event. ΔU_{MAX} is usually greater than ΔU_{SS}.
- Duration of RVC (in Fig. 14 marked as "t_{RVC}"). The shortest possible RVC event has a length of one half-cycle of the network.

At the time of publication of this manual, there are no international standards on permissible values of rapid voltage changes in electricity grids. European standard EN 50160 (edition of 2010) does not provide prescriptive requirements for this type of events. Some countries have their own criteria for RVC, e.g. an event is detected above the threshold of 5% of U_{NOM} (detected events have ΔU_{MAX} > 5% of U_{NOM}). Sometimes the number of RVC events per day is established.

14 Transients and overvoltages

Transients are unwanted, rapid and short-term disturbances in the mains. They are accompanied by a sudden change in voltage and current. The duration of a disturbance is typically from a few nanoseconds to a few milliseconds. Often, terms used to describe them include: overvoltages, voltage peaks, surges, impulse waves, oscillations. But these terms narrow their meaning. Transient is a disturbance in signal over the time, and as such, its meaning includes all of the above terms. It may be classified in terms of duration and rise, amplitude, frequency spectrum, transmitted energy, source, etc. The most dangerous for electrical devices are transients that cause a significant voltage increase in the supply line (surges). Due to the source, the transients are often divided into the following groups:

- lightning surges - caused by atmospheric discharges,
- oscillating transients caused most often by switching capacitor banks,
- other switching transients (including ferroresonance).

Surges caused by atmospheric discharges may have destructive effects due to the very high energy triggered during the discharge. Most of surges of this type observed in networks, result from voltage induced by close but not direct lightning stroke. In the area of lightning stroke, a very strong electromagnetic field is generated and long overhead/underground lines induce high voltage that penetrate into the distribution network. These surges have pulse nature with rise time on the order of microseconds. An example of the lightning impulse recorded by PQM-703 analyzer, with amplitude of approx. 6.6 kV is shown in Fig. 15.

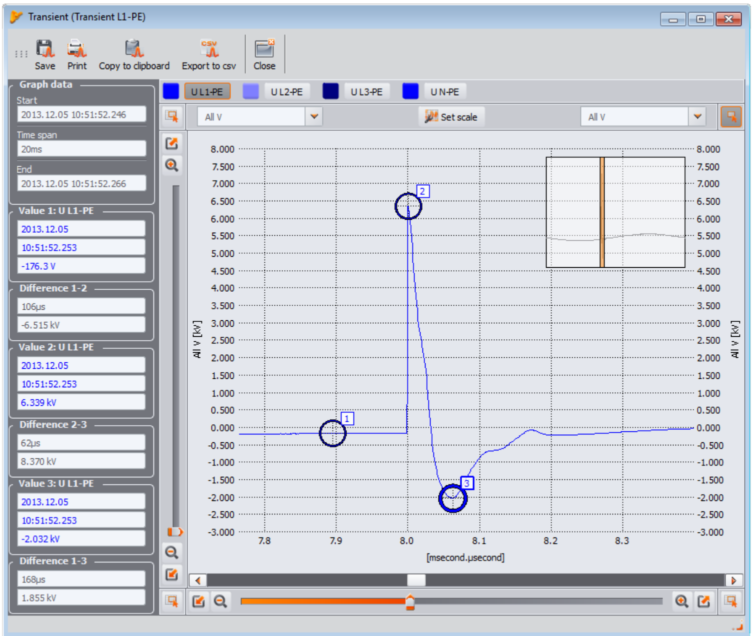

Fig. 15. Example of lightning surge.

Tests of ICT devices carried out before introducing them into markets, include immunity tests for simulated lightning surges. AC power connections are tested with ±2 kV pulses applied between power lines and grounding lines, and ±1 kV pulses applied directly between power supply lines. Standardized pulse has voltage rise time of 1.2 µs and voltage fall time of 50 µs. For the measuring devices that may be connected directly to distribution networks at the distribution boards or at LV transformers, authorities defined a measurement category (overvoltage category), which informs about the device protection level against surges. For example, to be included into measurement category IV 600 V, the devices must be immune to impulses of 1.2 μs/50 μs with 8 kV amplitude, applied directly between test terminals at source impedance of 2 Ω. Peak current during surge may be therefore equal to 4 kA.

The main protection measures against such surges include the circuits limiting the maximum voltage such as gas discharge tubes (GDTs) and varistors. Their construction must ensure receiving impact energy and limiting voltage penetrating the device circuits to a safe level.

Transients caused by switching compensation capacitance, as opposed to lightning strokes, have their source within the distribution network. The compensation is used to improve the power factor and efficiency of energy transfer to the load. At the moment of switching on, a capacitor is a short circuit for the network, thus initially there is a sudden voltage drop almost to zero, followed by fast recovery and an overshoot when voltage much higher than the nominal is reached (usually it does not exceed the double value of peak voltage in standard conditions), and then the disturbance is suppressed in oscillatory way. The oscillating nature of the disturbance is caused by the interaction of the capacitor capacitance with network inductance and resulting resonance. The oscillation frequency is usually around a few hundred Hz. The resistance in the circuit results in gradual suppression of these oscillations. The whole transient usually lasts no longer than a few - few dozen milliseconds. An example of such a transient is shown in Fig. 16.

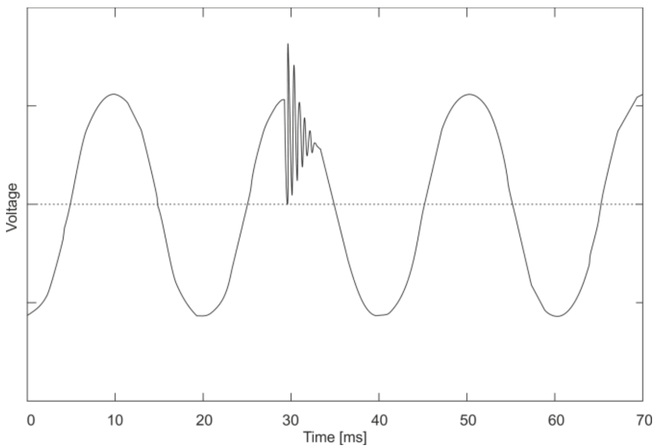

Fig. 16. An example of a transient after switching capacitor banks.

Apart from the causes listed above, transients in networks are generated by switching on and off capacitive loads, inductive loads, by tripping protection devices (fuses) and by short-circuits. Switching on loads (circuits) connected to the transformer windings, often leads to ferroresonance, which is an oscillating transient caused by resonance between the capacitances in the circuit and by the non-linear inductance of transformer ferromagnetic core. Disconnection of inductive loads is often accompanied by the sparking on contacts. The voltage generated at the switch contacts exceeds boundary voltage of the dielectric and spark-over occurs, which may be repeated, until the gap is too big for breakdown.

Transients may also be propagated in different ways between network segments, e.g. lightning stroke in a MV network can partially penetrate through the transformer to a LV sub-network. Attenuation properties of the transformer usually significantly reduce the amplitude of the surge, as well as change its timing parameters.

15 CBEMA and ANSI curves

CBEMA curve was first proposed in the 70's of the last century by the organization that gave the curve its name - *Computer and Business Equipment Manufacturers Association* (now *Information Technology Industry*), which associated manufacturers of computer and office equipment. The curve was developed as a guide in the construction of power supply adapters and at the beginning it was a graph showing the tolerance of equipment to the size and duration of the disturbances in the power grid. Later, the curve was used to design equipment sensitive to voltage fluctuations as the reference range in which the equipment must operate properly. Finally the curve began to be widely used in the analyses of power-supply quality in terms of disturbances such as swells, dips, interruptions.

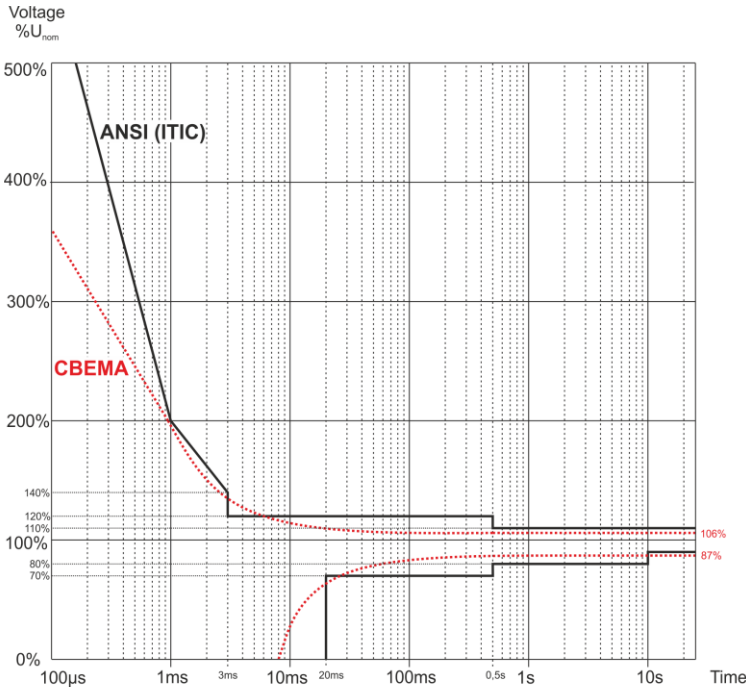

Fig. 17. Voltage tolerance curves: ANSI (ITIC) and CBEMA.

The vertical axis of the graph presents voltage in percent of the nominal value, whereas the horizontal axis presents time (in logarithmic scale). The middle part of the graph (between curves) represents the area of the correct operation of the device. The area above represents high voltage conditions that may damage the device or trigger over-voltage protection, while the area under the curves represents a situation of low voltage in mains, which may disconnect the power supply or temporary power shortage resulting in incorrect operation of the equipment.

As shown in the graph, there is a relationship between the voltage value and the duration of the disturbance. For example, voltage swell of 200% U_{NOM} and with duration of 1 ms, in typical cases, does not result in failure or malfunctioning (point between curves), but an interference of such amplitude, which lasts for half-period of the mains may be have very adverse effects (the point above two curves). Generally it is accepted that in a typical situation, events occurring in the power grid when it comes to the value of the mains voltage, should fit in the middle area of the graph (between curves) and then they should not lead to malfunction or damage to the connected equipment. Equipment manufacturers (especially power adapters) often use this pattern while designing their products, in order to ensure their reliable operation and maintaining proper output voltage. Note, however, that the curve represents typical cases and cannot be a guarantee of correct operation for each device, as tolerance for interferences is very different.

ITIC curve is the successor of the CBEMA curve developed by ITI in 1994, and later modified to its present form in 2000. This curve has the form of two broken lines and is also known as ANSI curve, as it was adapted by ANSI (*American National Standards Institute*). Both curves are presented in Fig. 17.

16 Averaging the measurement results

Mains monitoring over a longer period means that a significant amount of data needs to be collected. To ensure that such data analysis is possible at all, it is necessary to introduce the mechanisms for reducing data size to the values acceptable by both, people and machines.

Let us take the example of EN 50160 compliant power quality measurements The basic mains test period is one week. If all 200-millisecond RMS values were to be remembered, we would get 3.024 million measurements. Processing this amount of data may be time-consuming and difficult.

Therefore, the averaging concept has been introduced which involves recording one value per a specified time interval for the analysis purposes. For the EN 50160 standard, such time interval is 10 minutes. In such case, the analyzer calculates an average 10-minute value basing on about 3000 of 200-millisecond values (approximately, as in reality the conventional 200-millisecond value is 10/12-period value synchronized with the mains frequency). Each average voltage value is recorded every 10 minutes which gives "only" 1008 measurement results.

Averaging of measurement results leads to the loss of extreme values (smoothing of results). In cases when the information about limit values of the measured parameter is important, the user may use the option of measuring the minimum, maximum values in the averaging period. If a given parameter is measured in the 10/12-cycle time, the minimum and maximum value is respectively the smallest and the largest 10/12-cycle value measured in a given averaging interval. On the other hand, the instantaneous value is the last 10/12-cycle value in this averaging interval.

In the case of rms values of currents and voltages, you can search for minimum and maximum values with greater sensitivity - with an accuracy of 1-period $U_{RMS(1/2)}$, refreshed every half period.

Selecting the right averaging time is not easy. To a large extent it depends on the type of disturbance in the system and the user's expectations for the final data analysis. A frequent situation is that we know only that there is a problem in the mains, and the measurements with the analyzer will only help us identify the cause. In this situation it is better to use shorter averaging times (e.g. 10 seconds), and activate the recording of minimum and maximum values (for the voltages and currents it is advisable in such situation to set the shortest possible time for determining the maximum and minimum value, i.e. half-period). Short time averaging will give more precise diagrams of changes of parameters over time, and minimums and maximums will be detected and recorded. Recording with short averaging times is performed mostly during a limited time, primarily due to rapid growth of data; the aim of such recording is identifying the possible cause of a problem, and not a long-term analysis.

Recording with a short averaging time may be sufficient to evaluate the performance of the mains and disturbances in it. However, equally detailed information can probably also be obtained with longer times (in minutes) but with activated recording of minimum and maximum values and event detection. An important advantage in this situation that the volume of recorded data is much smaller which means faster data retrieval and analysis.

On the other hand, the power quality tests are usually made according to the EN 50160. In this case, the analysis is carried out over a longer period of time (e.g. 7 days), and therefore the chosen averaging time is also long - 10 minutes.

Please note that there is no single best setting for both, the averaging time and other parameters or event thresholds. Each mains system is different and so are the goals of the mains tests. Therefore, the optimal configuration of the analyzer may require several approaches and will also depend on the experience of the operator.

16.1 Class A

Fig. 18 shows how a Class A analyzer resynchronizes 10/12-cycle measurement blocks in the case of 10-minute averaging.

Average values are synchronized with a real time clock as follows. When the clock counts another integer multiple of the averaging period, two processes occur:

- current 10/12-cycle interval (*k*-th measurement in Fig. 18) is assigned as the last in the aggregation interval (x),
- simultaneously the first 10/12-cycle interval is started for the next averaging period (x +1).

Such a resynchronization method generates *Overlap 1* (see Fig. 18). The data from this area are processed twice, as each of the 10/12-cycle interval is analyzed independently. The aim of this kind of resynchronization is to ensure that the two analyzers of Class A, connected to the same system, and synchronized with UTC, will give the same results.

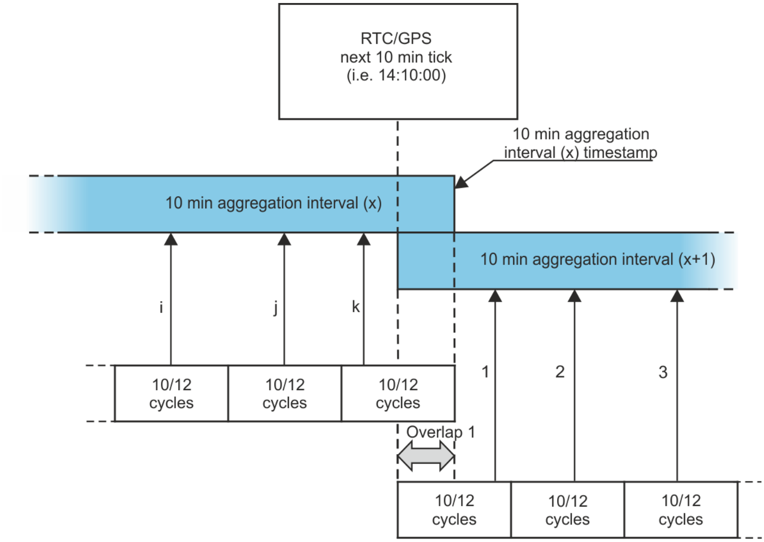

Fig. 18. Resynchronization of 10/12-cycle intervals at 10-minute aggregation intervals.

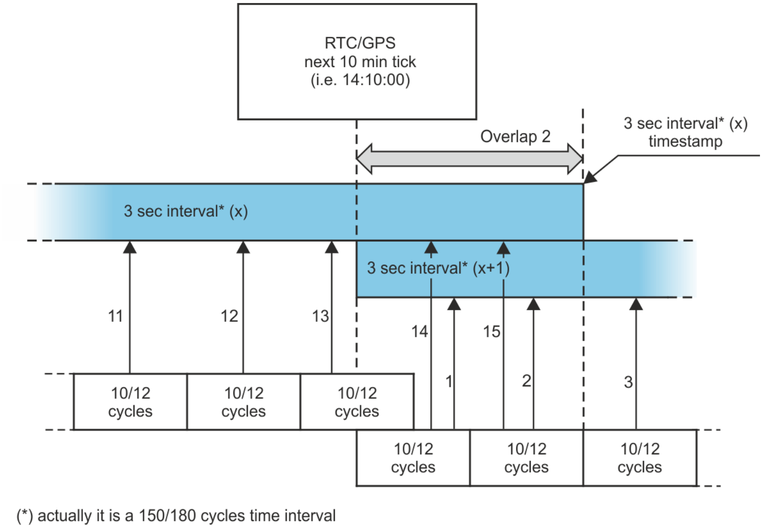

Fig. 19. Resynchronization of 10/12-cycle intervals at 150/180-cycle aggregation intervals.

The method of determining 150/180-cycle average values for such periods is shown in Fig. 19. Also in this case the resynchronization of 10/12-cycle intervals takes place, but it is always done using clock time of 10 minutes. When the clock counts another integer multiple of the 10-min. period, another aggregation interval is resynchronized and the next interval is started; the aggregation interval (x) is terminated normally, until the specified number of 10/12-cycle windows are gathered (e.g. for 3-second averaging, always 15 intervals are gathered). The re-synchronization results in generating *Overlap 2* (see Fig. 19), where data from two aggregation intervals are simultaneously processed ((x)-interval ends, (x+1)-interval starts). The size of the overlap depends on fluctuations in the mains frequency.

The time stamp corresponds to the end of the aggregation interval.

16.2 Class S

Fig. 20 presents the method according to which a Class S analyzer determines the average values at averaging intervals equal to 10-minute.

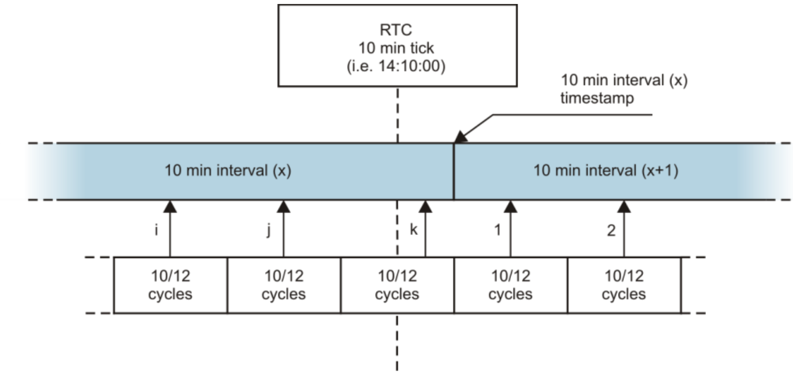

Fig. 20. Determining the 10-minute averaging intervals.

The average values are synchronized with real time clock in the following manner. When the clock measures a successive full multiple of the averaging period, the instantaneous 10/12-cycle measurement is added as the last to the average value (*k*-th measurement in Fig. 20). Simultaneously, the ending of averaging period is given a time stamp which relates to its end. The next 10/12-cycle measurement is the first in a consecutive averaging period.

Averaging for 150/180-cycle intervals is somewhat different. The method of average values determination for such periods is shown in Fig. 21. Here, we do not have synchronization with the real time clock. Instead, when a defined number of 10/12-cycle blocks is collected, the averaging period is closed and a new one starts. The time stamp corresponds to the end of the interval.

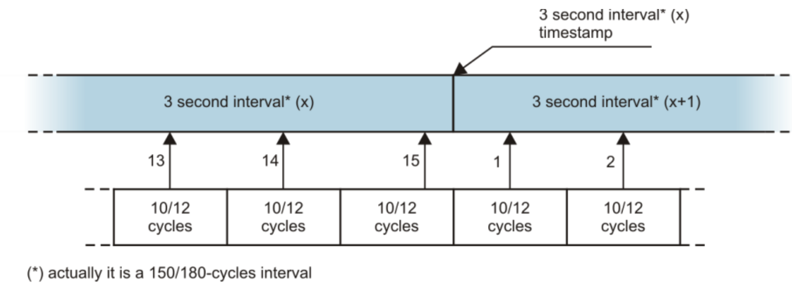

Fig. 21. Determining the 150/180-cycle averaging intervals.

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