# The Importance of Substation Metering in the Presence of Harmonics

***By Dennis Stewart, P.E.***

Customer load characteristics are changing. Solid-state devices that create significant harmonics increasingly replace the clean sinusoidal loads of the past. At the same time some utilities are reducing metering devices in an attempt to save construction dollars. These two trends, when combined, pose a serious threat to stable operation and good engineering.

Historically, the composite load seen at the substation was fairly clean. Steady-state voltage and current were sinusoidal and predictable. The worst problems were usually related to such things as load balance, capacity, steady-state voltage conditions or an occasional flicker problem.

The features available in most microprocessor devices used in stations has led to the incorrect conclusion that all voltage and current readings are created equal. In an effort to cut costs, some utilities have decided to use relays or other non-metering devices to gather voltage, current, and power values.
Unfortunately, while station designs were being evaluated historically, utility customers have been changing their equipment and their future use. Much of the new equipment installed today both creates and is sensitive to harmonic content. Many substations now have measurable harmonic content in voltage and current. This change in load characteristic is causing some utility engineers to ask, "How much is too much" when it comes to harmonics. The answer may surprise you.

A utility had just installed new meters in their substation. They had selected the Electro Industries/GaugeTech model Nexus 1250 because of its high accuracy, high-speed measurement of transient conditions, and extensive harmonics measurement capability. After the installation was complete, the distribution engineer observed that the neutral current calculated by the meter was significantly higher that expected; it read higher than any of the other indicating devices in the station.

Because the new meter was the only instrument indicating a problem, the engineer suspected the meter must have been malfunctioning. In order to verify the meter performance he collected the indicated readings from the meter and from relays to perform analysis.
The meter showed a calculated neutral current about 30% higher than other station devices. When the individual phase currents were combined using phasor analysis the calculated results matched the other devices and not the meter's indicated reading. The meter showed a THD on current of slightly over 3%. The THD consisted of about 3% for both the 3rd and 5th harmonic and about 1% for the 7th and 9th harmonic. Other harmonics were present at much lower levels and were deemed insignificant.

When phasor representations of each harmonic were added to the fundamental and the three phases were combined, there was a sizable discrepancy between the meter?s neutral current and the calculated quantity. The engineer concluded that there may be a problem in the meter and requested the manufacturer's assistance.
The manufacturer's applications engineer downloaded a complete set of real-time readings from the meter. The harmonics levels were consistent with those observed by the utility engineer. The manufacturer's engineer performed two different types of analysis on the downloaded data. To simplify the manual calculations, only the 3rd through the 9th harmonics were used. Table 1 provides the measured phase currents and the corresponding harmonic content for each phase.

In the first analysis the harmonics data was combined to create a single phasor representation of each RMS phase current. The phase currents were added together; the resulting calculated neutral current was quite close to the values provided by relays in the station. This was just what the manufacturer's engineer expected.
The second analysis did not combine the harmonics with the fundamental to create a single RMS current phasor. Rather, the harmonics were included with the fundamental to create a new phasor value for each time increment over a five-cycle interval. This analysis allowed an elapsed time of about 500 microseconds between each phasor; 32 phasor representations for each cycle. Each phasor value was combined to create a net neutral current phasor at each 500-microsecond interval. The one-cycle RMS value of the combined phasors was calculated over each cycle.

The neutral current calculated by the second method was almost exactly the same as the current value provided by the meter. It was also 30% higher than the value provided by other station indicating devices. Figure 1 shows the fundamental neutral current and the neutral current with the effects of harmonics included. The fundamental neutral current has an RMS value of about 66 amps. When harmonics are included the RMS value increases to 87 amps. The first analysis was incorrect because it was based on improper assumptions. The second analysis showed the true impact of the harmonic content.

Phasor analysis is of necessity a representation of a single point in time. When phasors are used in RMS calculations they must still portray a single point in time. Unfortunately when harmonics are present the multiple phasors that create the RMS value are not rotating at the same rate. The fundamental phasor is rotating at 60 Hz. The 3rd harmonic is rotating at 180 Hz. Other harmonics are rotating at correspondingly higher speeds. The RMS value of the fundamental does not change because the value of the fundamental does not change appreciably over time.

However, as the fundamental makes one rotation, the 3rd harmonic phasor makes three rotations. The magnitude of the phasor that represents the sum of the fundamental and the 3rd harmonic changes continuously over time. The harmonic phasors affect the net RMS value because they change the magnitude of the net current over each cycle. So calculating a single RMS value phasor and using it as a composite representation of the current is incorrect. At just 3% THD in the current, the difference between the fundamental phasor and the combined total value is significant. In the experience cited, the resulting neutral current was not a clean 60 Hz sine wave as might be expected. Although the neutral was periodic the frequency and magnitude varied significantly from the expected 60 Hz value. The actual RMS value of the resulting waveform was, in fact about 30% higher than the value indicated by most of the measuring equipment installed.

This experience demonstrates the importance of discreet good metering equipment. Only advanced metering equipment with high-speed sampling and precision resolution was able to capture the true conditions on the substation neutral. The higher, actual neutral current forced the engineer to evaluate the neutral current impacts on installed equipment. The elevated neutral current could affect the transformer and the feeder neutral conductors to a greater degree than previous thought.

If the engineer had only had access to relays or lower quality monitoring devices for measurement, he would not have known of a serious potential problem. With only a 3% THD in the current quantity, the engineer did not expect to see an RMS value of neutral current at such an elevated level. The experience suggests that it may be prudent to install high quality meters on any circuit that may have THD at above 2%. This threshold is much lower than the level that might be expected prior to this experience.

Even though there appears to be a small cost advantage to relying on lower grade monitoring devices, there is a serious threat to long-term system operation. Slower, lower accuracy metering often found in relaying devices and older meters simply cannot provide enough information on the waveform to enable successful operation in the presence of harmonics and other transient events.

Devices such as the Nexus 1250 meter from Electro Industries/GaugeTech provide precise measurement of all aspects of the voltage and current waveform and the associated power values. Only with such advanced metering products can the integrity of the electrical system be maintained in the face of massive load characteristic changes being experienced today. Moreover, a cost savings occurs in using discreet meters with high-end functionality because it eliminates the need for exotic relaying. Low cost relays can be used in addition to the high performance metering.

***About the Author:***
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## Table 1: Phase Current Magnitudes and Harmonics Content

| Phase | A | | B | | C | |
|---|---|---|---|---|---|---|
| Magnitude | 801.99 | | 777.25 | | 726.52 | |
| Phase Angle | 17.33 | | 138.77 | | -101.10 | |
| Harmonic | Percent | Phase Shift | Percent | Phase Shift | Percent | Phase Shift |
| 3 | 3.08% | 105.11 | 2.97% | 124.17 | 3.00% | 110.87 |
| 5 | 2.97% | 45.62 | 2.38% | 47.52 | 2.42% | 54.56 |
| 7 | 2.97% | 171.02 | 1.16% | -163.74 | 0.68% | 153.12 |
| 9 | 2.97% | 113.96 | 0.70% | 135.99 | 0.64% | 147.10 |