Electro Industries GaugeTech

Nexus® 1500+

Power Quality Meter with Phasor Measurement Unit

www.electroind.com

User Manual

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Nexus® 1500+ High Performance Power Meter User Manual Version 1.22

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Westbury, NY 11590

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Westbury, NY 11590
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Our products are not to be used for primary over-current protection. Any protection feature in our products is to be used for alarm or secondary protection only.

Statement of Calibration

Our instruments are inspected and tested in accordance with specifications published by Electro Industries/GaugeTech. The accuracy and a calibration of our instruments are traceable to the National Institute of Standards and Technology through equipment that is calibrated at planned intervals by comparison to certified standards. For optimal performance, EIG recommends that any meter, including those manufactured by EIG, be verified for accuracy every five years using NIST traceable accuracy standards. In general, EIG metering devices should not require regular adjustments to maintain published accuracy. If the meter is to be used for revenue purposes, follow the verification and calibration guidelines adopted by your local utility.

Disclaimer

The information presented in this publication has been carefully checked for reliability; however, no responsibility is assumed for inaccuracies. The information contained in this document is subject to change without notice.

Safety Symbols

In this manual, this symbol indicates that the operator must refer to an important WARNING or CAUTION in the operating instructions. Please see Chapter 4 for important safety information regarding installation and hookup of the meter.

Dans ce manuel, ce symbole indique que l'opérateur doit se référer à un important AVERTISSEMENT ou une MISE EN GARDE dans les instructions opérationnelles. Veuillez consulter le chapitre 4 pour des informations importantes relatives à l'installation et branchement du compteur.

The following safety symbols may be used on the meter itself:

Les symboles de sécurité suivante peuvent être utilisés sur le compteur même:

This symbol alerts you to the presence of high voltage, which can cause dangerous electrical shock.

Ce symbole vous indique la présence d'une haute tension qui peut provoquer une décharge électrique dangereuse.

This symbol indicates the field wiring terminal that must be connected to earth ground before operating the meter, which protects against electrical shock in case of a fault condition.

Ce symbole indique que la borne de pose des canalisations in-situ qui doit être branchée dans la mise à terre avant de faire fonctionner le compteur qui est protégé contre une décharge électrique ou un état défectueux.

Our Focus at Electro Industries/GaugeTech (EIG)

EIG exclusively delivers integrated energy and power quality monitoring solutions utilizing AI and deep industry expertise to improve reliability, efficiency, and sustainability. With over 50 years' experience in the electrical industry, EIG has developed extensive energy management and power quality expertise to help customers find ideal solutions to complex challenges. Our corporate culture promotes being cutting edge and investing in R&D to continually improve our customer experience.

Our solutions are designed to deliver results in days, not years. Known for our reputation as being a dependable provider and for exemplary service and support, EIG is committed to customer satisfaction.

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1:Three-Phase Power Measurement

This introduction to three-phase power and power measurement is intended to provide only a brief overview of the subject. The professional meter engineer or meter technician should refer to more advanced documents such as the EEI Handbook for Electricity Metering and the application standards for more in-depth and technical coverage of the subject.

1.1: Three-Phase System Configurations

Three-phase power is most commonly used in situations where large amounts of power will be used because it is a more effective way to transmit the power and because it provides a smoother delivery of power to the end load. There are two commonly used connections for three-phase power, a wye connection or a delta connection. Each connection has several different manifestations in actual use.

When attempting to determine the type of connection in use, it is a good practice to follow the circuit back to the transformer that is serving the circuit. It is often not possible to conclusively determine the correct circuit connection simply by counting the wires in the service or checking voltages. Checking the transformer connection will provide conclusive evidence of the circuit connection and the relationships between the phase voltages and ground.

1.1.1: Wye Connection

The wye connection is so called because when you look at the phase relationships and the winding relationships between the phases it looks like a Y. Figure 1.1 depicts the winding relationships for a wye-connected service. In a wye service the neutral (or center point of the wye) is typically grounded. This leads to common voltages of 208/120 and 480/277 (where the first number represents the phase-to-phase voltage and the second number represents the phase-to-ground voltage).

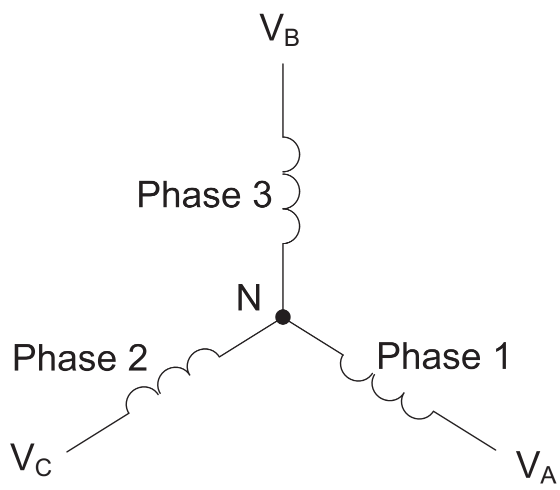


Figure 1.1: Three-phase Wye Winding

The three voltages are separated by 120^0 electrically. Under balanced load conditions the currents are also separated by 120^0. However, unbalanced loads and other conditions can cause the currents to depart from the ideal 120^0 separation. Three-phase voltages and currents are usually represented with a phasor diagram. A phasor diagram for the typical connected voltages and currents is shown in Figure 1.2.

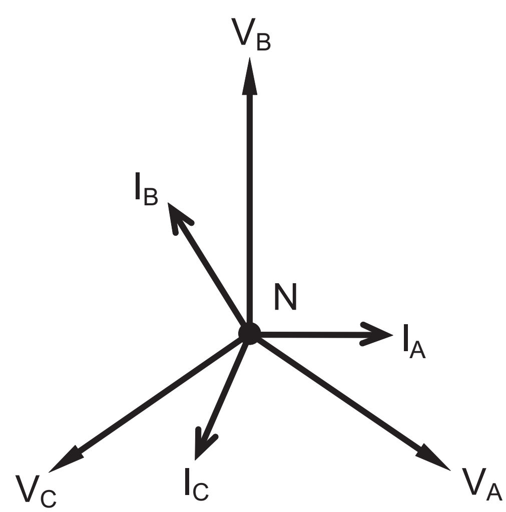


Figure 1.2: Phasor Diagram Showing Three-phase Voltages and Currents

The phasor diagram shows the 120^0 angular separation between the phase voltages. The phase-to-phase voltage in a balanced three-phase wye system is 1.732 times the phase-to-neutral voltage. The center point of the wye is tied together and is typically grounded. Table 1.1 shows the common voltages used in the United States for wye-connected systems.

Phase to Ground Voltage	**Phase to Phase Voltage**
120 volts	208 volts
277 volts	480 volts
2,400 volts	4,160 volts
7,200 volts	12,470 volts
7,620 volts	13,200 volts

Table 1: Common Phase Voltages on Wye Services

Usually a wye-connected service will have four wires: three wires for the phases and one for the neutral. The three-phase wires connect to the three phases (as shown in Figure 1.1). The neutral wire is typically tied to the ground or center point of the wye (refer to Figure 1.1).

In many industrial applications the facility will be fed with a four-wire wye service but only three wires will be run to individual loads. The load is then often referred to as a delta-connected load but the service to the facility is still a wye service; it contains four wires if you trace the circuit back to its source (usually a transformer). In this type of connection the phase to ground voltage will be the phase-to-ground voltage indicated in Table 1, even though a neutral or ground wire is not physically present at the load. The transformer is the best place to determine the circuit connection type because this is a location where the voltage reference to ground can be conclusively identified.

1.1.2: Delta Connection

Delta-connected services may be fed with either three wires or four wires. In a three-phase delta service the load windings are connected from phase-to-phase rather than from phase-to-ground. Figure 1.3 shows the physical load connections for a delta service.

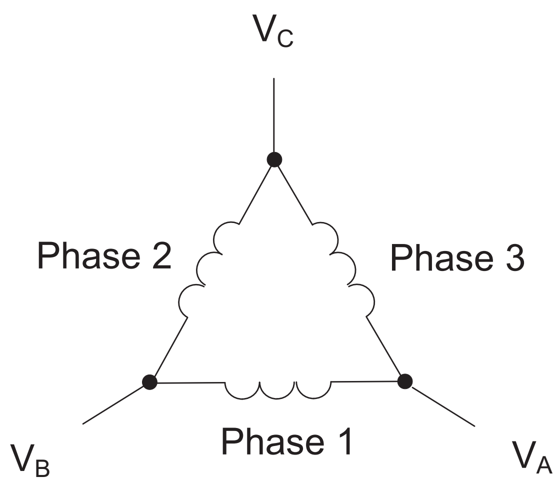


Figure 1.3: Three-phase Delta Winding Relationship

In this example of a delta service, three wires will transmit the power to the load. In a true delta service, the phase-to-ground voltage will usually not be balanced because the ground is not at the center of the delta.

Figure 1.4 shows the phasor relationships between voltage and current on a three-phase delta circuit.

In many delta services, one corner of the delta is grounded. This means the phase to ground voltage will be zero for one phase and will be full phase-to-phase voltage for the other two phases. This is done for protective purposes.

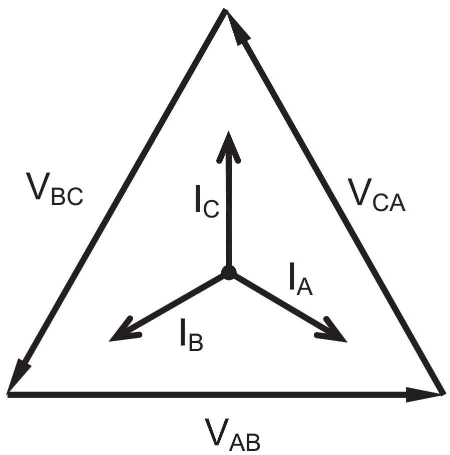


Figure 1.4: Phasor Diagram, Three-Phase Voltages and Currents, Delta-Connected

Another common delta connection is the four-wire, grounded delta used for lighting loads. In this connection the center point of one winding is grounded. On a 120/240 volt, four-wire, grounded delta service the phase-to-ground voltage would be 120 volts on two phases and 208 volts on the third phase. Figure 1.5 shows the phasor diagram for the voltages in a three-phase, four-wire delta system.

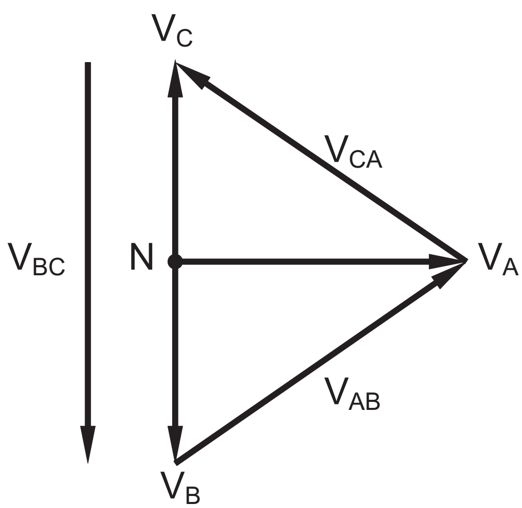


Figure 1.5: Phasor Diagram Showing Three-phase Four-Wire Delta-Connected System

1.1.3: Blondel's Theorem and Three Phase Measurement

In 1893 an engineer and mathematician named Andre E. Blondel set forth the first scientific basis for polyphase metering. His theorem states:

If energy is supplied to any system of conductors through N wires, the total power in the system is given by the algebraic sum of the readings of N wattmeters so arranged that each of the N wires contains one current coil, the corresponding potential coil being connected between that wire and some common point. If this common point is on one of the N wires, the measurement may be made by the use of N-1 Wattmeters.

The theorem may be stated more simply, in modern language:

In a system of N conductors, N-1 meter elements will measure the power or energy taken provided that all the potential coils have a common tie to the conductor in which there is no current coil.

Three-phase power measurement is accomplished by measuring the three individual phases and adding them together to obtain the total three phase value. In older analog meters, this measurement was accomplished using up to three separate elements. Each element combined the single-phase voltage and current to produce a torque on the meter disk. All three elements were arranged around the disk so that the disk was subjected to the combined torque of the three elements. As a result the disk would turn at a higher speed and register power supplied by each of the three wires.

According to Blondel's Theorem, it was possible to reduce the number of elements under certain conditions. For example, a three-phase, three-wire delta system could be correctly measured with two elements (two potential coils and two current coils) if the potential coils were connected between the three phases with one phase in common.

In a three-phase, four-wire wye system it is necessary to use three elements. Three voltage coils are connected between the three phases and the common neutral conductor. A current coil is required in each of the three phases.

In modern digital meters, Blondel's Theorem is still applied to obtain proper metering. The difference in modern meters is that the digital meter measures each phase voltage and current and calculates the single-phase power for each phase. The meter then sums the three phase powers to a single three-phase reading.

Some digital meters calculate the individual phase power values one phase at a time. This means the meter samples the voltage and current on one phase and calculates a power value. Then it samples the second phase and calculates the power for the second phase. Finally, it samples the third phase and calculates that phase power. After sampling all three phases, the meter combines the three readings to create the equivalent three-phase power value. Using mathematical averaging techniques, this method can derive a quite accurate measurement of three-phase power.

More advanced meters actually sample all three phases of voltage and current simultaneously and calculate the individual phase and three-phase power values. The advantage of simultaneous sampling is the reduction of error introduced due to the difference in time when the samples were taken.

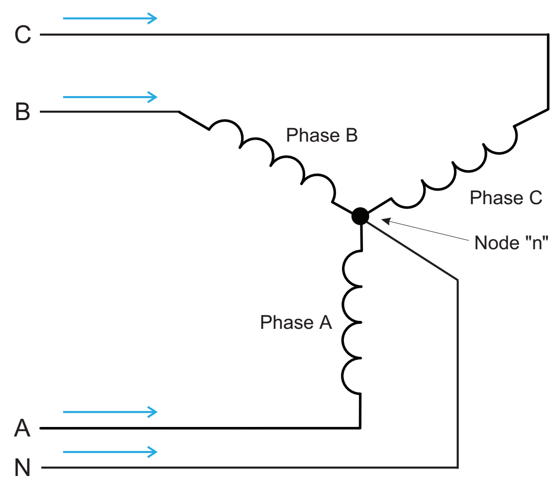


Figure 1.6: Three-Phase Wye Load Illustrating Kirchhoff’s Law and Blondel’s Theorem

Blondel's Theorem is a derivation that results from Kirchhoff's Law. Kirchhoff's Law states that the sum of the currents into a node is zero. Another way of stating the same thing is that the current into a node (connection point) must equal the current out of the node. The law can be applied to measuring three-phase loads. Figure 1.6 shows a typical connection of a three-phase load applied to a three-phase, four-wire service. Kirchhoff's Law holds that the sum of currents A, B, C and N must equal zero or that the sum of currents into Node "n" must equal zero.

If we measure the currents in wires A, B and C, we then know the current in wire N by Kirchhoff's Law and it is not necessary to measure it. This fact leads us to the conclusion of Blondel's Theorem- that we only need to measure the power in three of the four wires if they are connected by a common node. In the circuit of Figure 1.6 we must measure the power flow in three wires. This will require three voltage coils and three current coils (a three-element meter). Similar figures and conclusions could be reached for other circuit configurations involving Delta-connected loads.

1.2: Power, Energy and Demand

It is quite common to exchange power, energy and demand without differentiating between the three. Because this practice can lead to confusion, the differences between these three measurements will be discussed.

Power is an instantaneous reading. The power reading provided by a meter is the present flow of watts. Power is measured immediately just like current. In many digital meters, the power value is actually measured and calculated over a one second interval because it takes some amount of time to calculate the RMS values of voltage and current. But this time interval is kept small to preserve the instantaneous nature of power.

Energy is always based on some time increment; it is the integration of power over a defined time increment. Energy is an important value because almost all electric bills are based, in part, on the amount of energy used.

Typically, electrical energy is measured in units of kilowatt-hours (kWh). A kilowatt-hour represents a constant load of one thousand watts (one kilowatt) for one hour. Stated another way, if the power delivered (instantaneous watts) is measured as 1,000 watts and the load was served for a one hour time interval then the load would have absorbed one kilowatt-hour of energy. A different load may have a constant power requirement of 4,000 watts. If the load were served for one hour it would absorb four kWh. If the load were served for 15 minutes it would absorb ¼ of that total or one kWh.

Figure 1.7 shows a graph of power and the resulting energy that would be transmitted as a result of the illustrated power values. For this illustration, it is assumed that the power level is held constant for each minute when a measurement is taken. Each bar in the graph will represent the power load for the one-minute increment of time. In real life the power value moves almost constantly.

The data from Figure 1.7 is reproduced in Table 2 to illustrate the calculation of energy. Since the time increment of the measurement is one minute and since we specified that the load is constant over that minute, we can convert the power reading to an equivalent consumed energy reading by multiplying the power reading times 1/60 (converting the time base from minutes to hours).

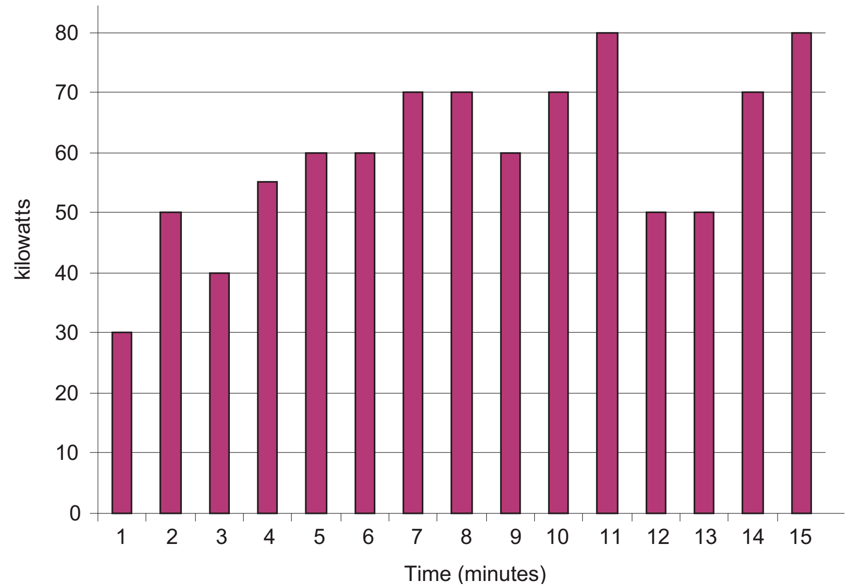


Figure 1.7: Power Use over Time

Time Interval (minute)	Power (kW)	Energy (kWh)	Accumulated Energy (kWh)
1	30	0.50	0.50
2	50	0.83	1.33
3	40	0.67	2.00
4	55	0.92	2.92
5	60	1.00	3.92
6	60	1.00	4.92
7	70	1.17	6.09
8	70	1.17	7.26
9	60	1.00	8.26
10	70	1.17	9.43
11	80	1.33	10.76
12	50	0.83	12.42
13	50	0.83	12.42
14	70	1.17	13.59
15	80	1.33	14.92

Table 1.2: Power and Energy Relationship over Time

As in Table 1.2, the accumulated energy for the power load profile of Figure 1.7 is 14.92 kWh.

Demand is also a time-based value. The demand is the average rate of energy use over time. The actual label for demand is kilowatt-hours/hour but this is normally reduced to kilowatts. This makes it easy to confuse demand with power, but demand is not an instantaneous value. To calculate demand it is necessary to accumulate the energy readings (as illustrated in Figure 1.7) and adjust the energy reading to an hourly value that constitutes the demand.

In the example, the accumulated energy is 14.92 kWh. But this measurement was made over a 15-minute interval. To convert the reading to a demand value, it must be normalized to a 60-minute interval. If the pattern were repeated for an additional three 15-minute intervals the total energy would be four times the measured value or

59.68 kWh. The same process is applied to calculate the 15-minute demand value. The demand value associated with the example load is 59.68 kWh/hr or 59.68 kWd. Note that the peak instantaneous value of power is 80 kW, significantly more than the demand value.

Figure 1.8 shows another example of energy and demand. In this case, each bar represents the energy consumed in a 15-minute interval. The energy use in each interval typically falls between 50 and 70 kWh. However, during two intervals the energy rises sharply and peaks at 100 kWh in interval number 7. This peak of usage will result in setting a high demand reading. For each interval shown the demand value would be four times the indicated energy reading. So interval 1 would have an associated demand of 240 kWh/hr. Interval 7 will have a demand value of 400 kWh/hr. In the data shown, this is the peak demand value and would be the number that would set the demand charge on the utility bill.

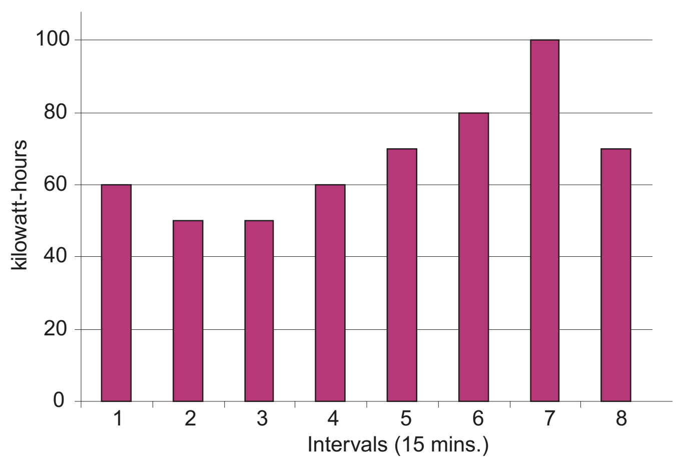


Figure 1.8: Energy Use and Demand

As can be seen from this example, it is important to recognize the relationships between power, energy and demand in order to control loads effectively or to monitor use correctly.

1.3: Reactive Energy and Power Factor

The real power and energy measurements discussed in the previous section relate to the quantities that are most used in electrical systems. But it is often not sufficient to only measure real power and energy. Reactive power is a critical component of the total power picture because almost all real-life applications have an impact on reactive power. Reactive power and power factor concepts relate to both load and generation applications. However, this discussion will be limited to analysis of reactive power and power factor as they relate to loads. To simplify the discussion, generation will not be considered.

Real power (and energy) is the component of power that is the combination of the voltage and the value of corresponding current that is directly in phase with the voltage. However, in actual practice the total current is almost never in phase with the voltage. Since the current is not in phase with the voltage, it is necessary to consider both the in-phase component and the component that is at quadrature (angularly rotated 90^0 or perpendicular) to the voltage. Figure 1.9 shows a single-phase voltage and current and breaks the current into its in-phase and quadrature components.

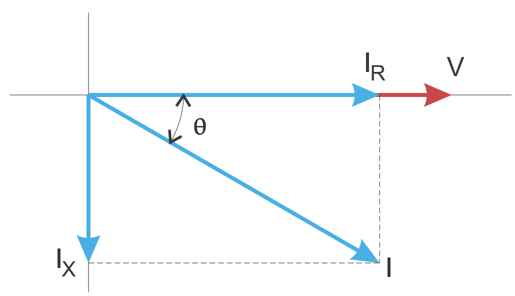


Figure 1.9: Voltage and Complex Current

The voltage (V) and the total current (I) can be combined to calculate the apparent power or VA. The voltage and the in-phase current (I_R) are combined to produce the real power or watts. The voltage and the quadrature current (I_X) are combined to calculate the reactive power.

The quadrature current may be lagging the voltage (as shown in Figure 1.9) or it may lead the voltage. When the quadrature current lags the voltage the load is requiring both real power (watts) and reactive power (VARs). When the quadrature current leads the voltage the load is requiring real power (watts) but is delivering reactive power (VARs) back into the system; that is VARs are flowing in the opposite direction of the real power flow.

Reactive power (VARs) is required in all power systems. Any equipment that uses magnetization to operate requires VARs. Usually the magnitude of VARs is relatively low compared to the real power quantities. Utilities have an interest in maintaining VAR requirements at the customer to a low value in order to maximize the return on plant invested to deliver energy. When lines are carrying VARs, they cannot carry as many watts. So keeping the VAR content low allows a line to carry its full capacity of watts. In order to encourage customers to keep VAR requirements low, some utilities impose a penalty if the VAR content of the load rises above a specified value.

A common method of measuring reactive power requirements is power factor. Power factor can be defined in two different ways. The more common method of calculating power factor is the ratio of the real power to the apparent power. This relationship is expressed in the following formula:

Total PF = real power / apparent power = watts/VA

This formula calculates a power factor quantity known as Total Power Factor. It is called Total PF because it is based on the ratios of the power delivered. The delivered power quantities will include the impacts of any existing harmonic content. If the voltage or current includes high levels of harmonic distortion the power values will be affected. By calculating power factor from the power values, the power factor will include the impact of harmonic distortion. In many cases this is the preferred method of calculation because the entire impact of the actual voltage and current are included.

A second type of power factor is Displacement Power Factor. Displacement PF is based on the angular relationship between the voltage and current. Displacement power factor does not consider the magnitudes of voltage, current or power. It is solely based on the phase angle differences. As a result, it does not include the impact of harmonic distortion. Displacement power factor is calculated using the following equation:

$$\text{Displacement PF} = \cos\theta$$

where θ is the angle between the voltage and the current (see Fig. 1.9).

In applications where the voltage and current are not distorted, the Total Power Factor will equal the Displacement Power Factor. But if harmonic distortion is present, the two power factors will not be equal.

1.4: Harmonic Distortion

Harmonic distortion is primarily the result of high concentrations of non-linear loads. Devices such as computer power supplies, variable speed drives and fluorescent light ballasts make current demands that do not match the sinusoidal waveform of AC electricity. As a result, the current waveform feeding these loads is periodic but not sinusoidal. Figure 1.10 shows a normal, sinusoidal current waveform. This example has no distortion.

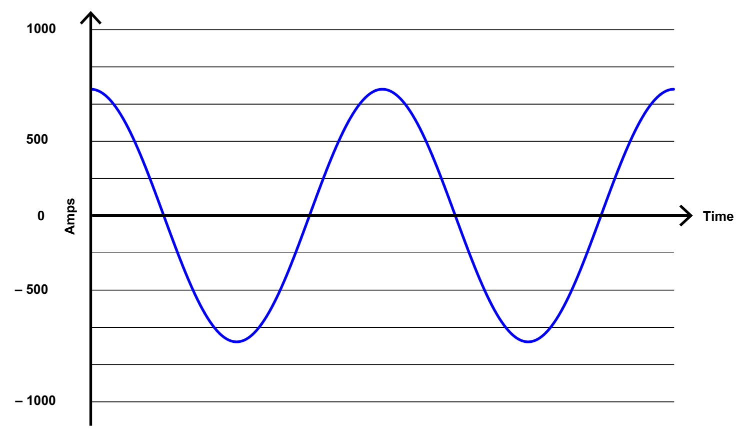


Figure 1.10: Nondistorted Current Waveform

Figure 1.11 shows a current waveform with a slight amount of harmonic distortion. The waveform is still periodic and is fluctuating at the normal 60 Hz frequency. However, the waveform is not a smooth sinusoidal form as seen in Figure 1.10.

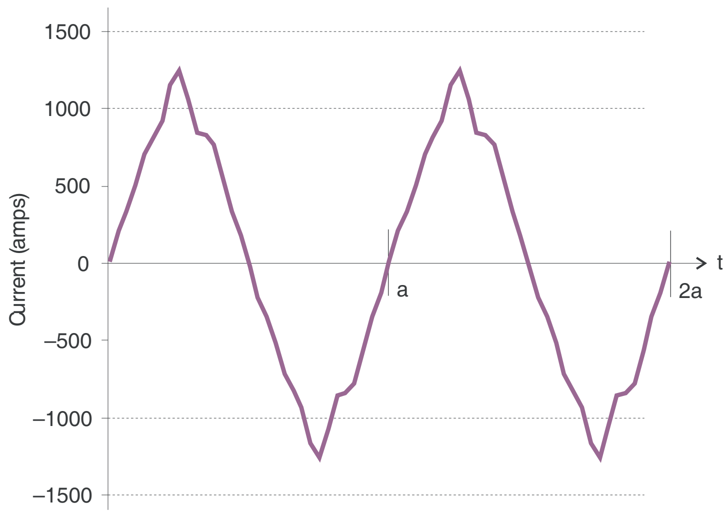


Figure 1.11: Distorted Current Waveform

The distortion observed in Figure 1.11 can be modeled as the sum of several sinusoidal waveforms of frequencies that are multiples of the fundamental 60 Hz frequency. This modeling is performed by mathematically disassembling the distorted waveform into a collection of higher frequency waveforms.

These higher frequency waveforms are referred to as harmonics. Figure 1.12 shows the content of the harmonic frequencies that make up the distortion portion of the waveform in Figure 1.11.

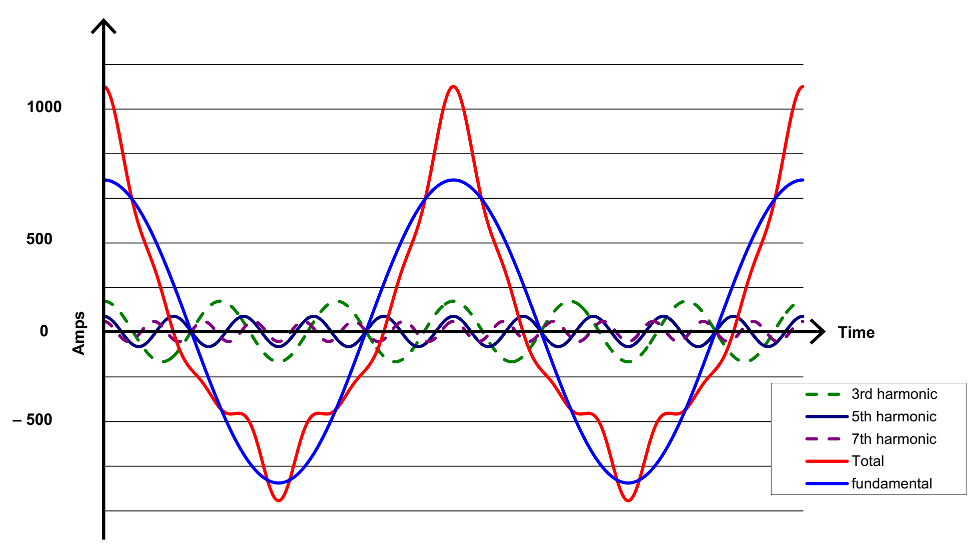


Figure 1.12: Waveforms of the Harmonics

The waveforms shown in Figure 1.12 are not smoothed but do provide an indication of the impact of combining multiple harmonic frequencies together.

When harmonics are present it is important to remember that these quantities are operating at higher frequencies. Therefore, they do not always respond in the same manner as 60 Hz values.

Inductive and capacitive impedance are present in all power systems. We are accustomed to thinking about these impedances as they perform at 60 Hz. However, these impedances are subject to frequency variation.

$X_L = j\omega L$ and

$X_C = 1/j\omega C$

At 60 Hz, $\omega = 377$; but at 300 Hz (5th harmonic) $\omega = 1,885$. As frequency changes impedance changes and system impedance characteristics that are normal at 60 Hz may behave entirely differently in the presence of higher order harmonic waveforms.

Traditionally, the most common harmonics have been the low order, odd frequencies, such as the 3rd, 5th, 7th, and 9th. However newer, non-linear loads are introducing significant quantities of higher order harmonics.

Since much voltage monitoring and almost all current monitoring is performed using instrument transformers, the higher order harmonics are often not visible. Instrument transformers are designed to pass 60 Hz quantities with high accuracy. These devices, when designed for accuracy at low frequency, do not pass high frequencies with high accuracy; at frequencies above about 1200 Hz they pass almost no information. So when instrument transformers are used, they effectively filter out higher frequency harmonic distortion making it impossible to see.

However, when monitors can be connected directly to the measured circuit (such as direct connection to a 480 volt bus) the user may often see higher order harmonic distortion. An important rule in any harmonics study is to evaluate the type of equipment and connections before drawing a conclusion. Not being able to see harmonic distortion is not the same as not having harmonic distortion.

It is common in advanced meters to perform a function commonly referred to as waveform capture. Waveform capture is the ability of a meter to capture a present picture of the voltage or current waveform for viewing and harmonic analysis.

Typically a waveform capture will be one or two cycles in duration and can be viewed as the actual waveform, as a spectral view of the harmonic content, or a tabular view showing the magnitude and phase shift of each harmonic value. Data collected with waveform capture is typically not saved to memory. Waveform capture is a real-time data collection event.

Waveform capture should not be confused with waveform recording that is used to record multiple cycles of all voltage and current waveforms in response to a transient condition.

1.5: Power Quality

Power quality can mean several different things. The terms "power quality" and "power quality problem" have been applied to all types of conditions. A simple definition of "power quality problem" is any voltage, current or frequency deviation that results in mis-operation or failure of customer equipment or systems. The causes of power quality problems vary widely and may originate in the customer equipment, in an adjacent customer facility or with the utility.

In his book Power Quality Primer, Barry Kennedy provided information on different types of power quality problems. Some of that information is summarized in Table 1.3.

Cause	Disturbance Type	Source
Impulse transient	Transient voltage disturbance, sub-cycle duration	Lightning Electrostatic discharge Load switching Capacitor switching
Oscillatory transient with decay	Transient voltage, sub-cycle duration	Line/cable switching Capacitor switching Load switching
Sag/swell	RMS voltage, multiple cycle duration	Remote system faults
Interruptions	RMS voltage, multiple seconds or longer duration	System protection Circuit breakers Fuses Maintenance
Under voltage/over voltage	RMS voltage, steady state, multiple seconds or longer duration	Motor starting Load variations Load dropping
Voltage flicker	RMS voltage, steady state, repetitive condition	Intermittent loads Motor starting Arc furnaces
Harmonic distortion	Steady state current or voltage, long-term duration	Non-linear loads System resonance

Table 1.3: Typical Power Quality Problems and Sources

It is often assumed that power quality problems originate with the utility. While it is true that power quality problems can originate with the utility system, many problems originate with customer equipment. Customer-caused problems may manifest themselves inside the customer location or they may be transported by the utility system to another adjacent customer. Often, equipment that is sensitive to power quality problems may in fact also be the cause of the problem.

If a power quality problem is suspected, it is generally wise to consult a power quality professional for assistance in defining the cause and possible solutions to the problem.

2: Nexus® 1500+ Meter Overview

2.1: Meter Features

The Nexus® 1500+ meter has extensive features that make it the ideal choice for your power management needs.

- Certified Class A IEC 61000-4-30 Ed. 3 power quality measurement records every aspect of electrical power, including power quality and transients, and produces reports on the quality of the electrical circuit in compliance with the IEC 61000-4-30 Class A and EN 50160 international standards. The Nexus® 1500+ meter provides users with a comprehensive picture of a circuit's power usage and power reliability. The meter is also an auto-calibrating precision energy meter.

- Certified Class A IEC 61000-4-30 Ed, 3 power quality measurements provide full reporting of your system's power quality conditions.

- 50 MHz transient recording lets you capture events that lower speed recorders miss.

- Customizable EN 50160 reporting lets you meet any jurisdictional requirement.

- Auto-calibrating architecture ensures the meter maintains its high accuracy by self-calibrating every ten seconds, assuring you of precision measurements for your critical metering applications.

- The meter offers PMU functionality, supporting both P and M classes, for grid monitoring.

- Resilient Cyber Security™ protects your metering data on transmission lines.

Detailed Revenue Metering Features:

- Delivers highly accurate 0.06% watt-hour accuracy (at Unity PF) in a field-mounted device.

- Constant Calibration™ architecture, in which the meter auto-calibrates itself every ten seconds, means the meter stays accurate over time and temperature changes.

- Meets ANSI C12.20 (0.2 CL) Standard and IEC 62053-22 (0.2S Class) Standard accuracy specifications.
- Adjusts for transformer and line losses with user-defined compensation factors.
- Adjusts for CT and PT errors.
- Counts pulses and aggregates different loads.
- Offers a Test Mode that lets the user verify the accuracy of readings without affecting billing data, and preset energy accumulators for adjustments upon exiting Test Mode (see Chapter 12: Test Mode, on page 12-1, for detailed information).
- Offers a perpetual calendar and multiple tiered rates for TOU calculation (see Chapter 8: Time of Use Function, on page 8-1, for detailed information).
- New! Firmware version 20 and above offers advanced Resilient Cyber Security™, which is a role-based security that also supports firmware "signing," which is used to safeguard firmware integrity. See Appendix A for information on Resilient Cyber Security and Chapter 6 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for detailed security information and instructions.

Detailed Power Quality Features:

- Measures up to 800,000 samples per cycle on a transient voltage event (50 MHz).
- Records power quality and reliability captures on voltage or current waveform signals.
- Offers inputs for neutral-to-ground voltage measurements.
- Synchronizes with IRIG-B clock signal.
- Measures Harmonics per IEC 61000-4-30 Edition 3and Flicker per IEC 61000-4-15 Class A standards; Flicker analysis is available for Instantaneous, Short-Term, and Long-Term forms (see Chapter 10: EN 50160/IEC 61000-4-30 Class A Ed. 3 Reporting, on page 10-1, for detailed information).
- Provides programmable EN 50160 report generation to meet different jurisdictional requirements.

- New! Firmware version 20 and above offers Synchrophasor support, with the meter acting as a Phasor Measurement Unit (PMU) - see Appendix E: Synchrophasor Systems, on page E-1.

RTU Features:

- Advanced monitoring capabilities that provide detailed and precise pictures of any metered point within a distribution network.
- Extensive I/O capability is available in conjunction with all metering functions. I/O includes:
  - Optional Relay Output card with 6 relay contact outputs (up to 2 Relay Output cards can be installed in the meter).
  - Optional Digital Input card with 16 status inputs (up to 2 Digital Input cards can be installed in the meter, for a total of 32 status inputs).
  - Optional External I/O modules consisting of up to 4 Analog Output modules, 1 Digital Dry Contact Relay Output module, up to 4 Digital Solid State Pulse Output modules, and up to 4 Analog Input modules.

  NOTE: See Chapter 11: Using the I/O Options, on page 11-1 for detailed information on the I/O options.

- Logging of Modbus slave devices for RTU concentrator functions.

Extensive Memory and Communication:

- Onboard mass memory (up to 4000 Megabytes CompactFlash) that enables the Nexus® 1500+ meter to retrieve and store multiple logs for many years; the amount of memory used by the logs is assignable by the user.
- V-Switch™ key technology that allows you to upgrade the meter and memory in the field, without removing it from installation.
- Standard 10/100BaseT RJ45 Ethernet that allows you to connect to a PC via Modbus TCP/IP; a second, optional Ethernet connection that can be either RJ45 or Fiber Optic; each Ethernet card offers up to 32 Modbus TCP/IP connections, and, with V-Switch™ keys 2, 3, 5, and 6 either port offers an IEC 61850 Protocol server.

- Ethernet ports that are separately programmable for server and protocol port control.
- A USB Virtual Com Port, compatible with USB1.1/USB2.0, that provides serial communication.
- Optional RS485/Pulse Output card that provides two RS485 ports and 4 pulse outputs that are user programmable to reflect VAR-hours, Watt-hours, or VA-hours.
- Multiple Protocols that include Modbus, DNP3 (see 2.2: DNP3 Level 2, on page 2-5, for more details), IEC 61850 (see Appendix C: Using the IEC 61850 Protocol Network Server, on page C-1) and SNMP (see Chapter 9: Network Communications, on page 9-1 and Appendix D: Using SNMP, on page D-1).
- 1 cycle high-speed updates and programmable updates from 2 - 20 cycles RMS, that are available for Control applications.
- Multiple time synchronization options (see 5.11: Time Synchronization Alternatives, on page 5-14), including IEEE 1588 Precision Time Protocol (PTPv2).
- Synchrophasor PMU support - (see Appendix E: Synchrophasor Systems, on page E-1 and Appendix F: Setting up the PMU, on page F-1).

2.2: DNP3 Level 2

The Nexus® 1500+ meter supports DNP3 Level 2 over both its serial and dual Ethernet ports.

DNP Level 2 Features

- Up to 136 measurements (64 Binary Inputs, 8 Binary Counters, 64 Analog Inputs) can be mapped to DNP Static Points (over 3000) in the customizable DNP Point Map.
- Report-by-Exception Processing (DNP Events) - Deadbands can be set on a per-point basis.
- Freeze Commands - Available commands are Freeze, Freeze/No-Ack, Freeze with Time, and Freeze with Time/No-Ack.
- Freeze with Time Commands enable the Nexus® meter to have internal time-driven Frozen and Frozen Event data. When the Nexus® meter receives the time and interval, the data is created.

For complete details, download the Nexus® 1252/1262/1272/1500/1500+ DNP User manual from EIG’s website:
www.electroind.com/dl_page_nexus-meters.html.

2.3: V-Switch™ Key Technology

The Nexus® 1500+ meter is equipped with V-Switch™ key technology, a virtual firmware-based switch that allows you to enable meter features through software communication. V-Switch™ key technology allows the unit to be upgraded after installation without removing it from service.

Available V-Switch™ key upgrades:

V-Switch™ key 1 (V1) - Standard meter with 512 Megabytes memory and 512 samples per cycle.

V-Switch™ key 2 (V2) - V1 with 1 Gigabyte memory and 1024 samples per cycle.

V-Switch™ key 3 (V3) - V2 with 4 Gigabytes memory and 50 MHz transient recording.

V-Switch™ key 4 (V4) - V1 with Synchrophasor PMU and Advanced Cyber Security

V-Switch™ key 5 (V5) - V2 with Synchrophasor PMU and Advanced Cyber Security

V-Switch™ key 4 (V6) - V3 with Synchrophasor PMU and Advanced Cyber Security

NOTE: V-Switch™ keys 2, 3, 5, and 6 also enable the IEC 61850 Protocol server for either the standard or optional Ethernet card. See Appendix C: Using the IEC 61850 Protocol Network Server, on page C-1 for details.

2.3.1: Upgrading the Meter's V-Switch™ Key

To upgrade your meter to a higher V-Switch™ key (e.g., V-2), follow these steps:

1. Obtain a V-Switch™ upgrade key by contacting EIG's inside sales staff at sales@electroind.com or by calling 516-334-0870 (USA). You will be asked for the following information:

   a. Serial number(s) of the meter you are upgrading.

   b. Desired V-Switch™ upgrade.

   c. Credit card or Purchase Order number.

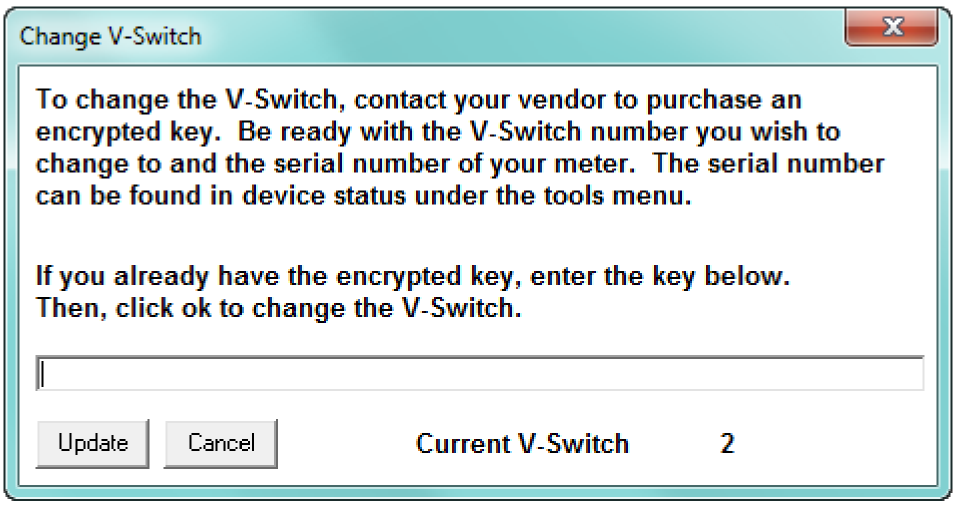
2. EIG will issue you the V-Switch™ upgrade key. To enable the key, follow these steps:

a. Open CommunicatorPQA® software.

b. Power up your Nexus® meter.

c. Connect to the meter via CommunicatorPQA® software. (See the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for detailed instructions: you can open the manual online by clicking **Help>Contents** from the CommunicatorPQA® software's Main screen).

d. Click **Tools>Change V-Switch**™ from the Title Bar of the Main screen. A screen opens, requesting the encrypted key.



e. Enter the upgrade key provided by EIG.

f. Click **Update**. The V-Switch™ key is enabled and the meter is reset.

2.4: Measurements and Calculations

The Nexus® 1500+ meter measures many different power parameters. Following is a list of the formulas used to perform calculations with samples for Wye and Delta services.

Samples for Wye/Delta: v_a, v_b, v_c, v_n, i_a, i_b, i_c, i_n

Root Mean Square (RMS) of Phase Voltages: N = number of samples

For Wye: x = a, b, c

$$V_{RMS_x} = \sqrt{\frac{\sum_{t=1}^{N} (V_{x(t)} - V_{n(t)})^2}{N}}$$

Root Mean Square (RMS) of Line Currents: N = number of samples

For Wye: x= a, b, c, n

For Delta: x = a, b, c

$$I_{RMS_x} = \sqrt{\frac{\sum_{t=1}^{N} i_{x(t)}^2}{N}}$$

Root Mean Square (RMS) of Line Voltages: N = number of samples

For Wye: x, y= a,b or b,c or c,a

$$V_{RMS_{xy}} = \sqrt{\frac{\sum_{t=1}^{N} (v_{x_{(t)}} - v_{y_{(t)}})^2}{N}}$$

For Delta: x, y= a,b or b,c or c,a

$$V_{RMS_{xy}} = \sqrt{\frac{\sum_{t=1}^{N} (V_{x(t)} - V_{y(t)})^2}{N}}$$

Root Mean Square (RMS) of Residual Current (Calculated Neutral Current): N = number of samples; *n* = sample number

$$I_{RMS_{res}} = \sqrt{\frac{\sum_n \left(\frac{i_{a_n} + i_{b_n} + i_{c_n}}{3}\right)^2}{n}}$$

Root Mean Square (RMS) of Residual Voltage: N = number of samples; *n* = sample number

$$V_{RMS_{res}} = \sqrt{\frac{\sum_n \left(\frac{v_{a_n} + v_{b_n} + v_{c_n}}{3}\right)^2}{n}}$$

Power (Watts) per phase: N = number of samples

For Wye: x = an, bn, cn

$$W_X = \frac{\sum_{t=1}^{N} (v_{x(t)} \bullet i_{x(t)})}{N}$$

Apparent Power (VA) per phase:

For Wye: x = an, bn, cn

$$VA_x = V_{RMS_X} \bullet I_{RMS_X}$$

Reactive Power (VAR) per phase:

For Wye: x = a, b, c

$$VAR_x = \sqrt{VA_x^2 - Watt_x^2}$$

Active Power (Watts) Total: N = number of samples

For Wye:

$$W_T = W_a + W_b + W_c$$

For Delta:

$$W_T = \frac{\sum_{t=1}^{N} (v_{ab(t)} \bullet i_{a(t)} - v_{bc(t)} \bullet i_{c(t)})}{N}$$

Reactive Power (VAR) Total: N = number of samples

For Wye:

$$VAR_T = \sqrt{VA_T^2 - W_T^2}$$

For Delta:

$$VAR_T = \sqrt{\left(V_{RMS_{ab}} \bullet I_{RMS_a}\right)^2 - \left[\frac{\sum_{t=1}^{N} v_{ab(t)} \bullet i_{a(t)}}{N}\right]^2} + \sqrt{\left(V_{RMS_{bc}} \bullet I_{RMS_c}\right)^2 - \left[\frac{\sum_{t=1}^{N} v_{bc(t)} \bullet i_{c(t)}}{N}\right]^2}$$

Apparent Power Total (VA/VAh) and Reactive Power Total (VAR/VARh):

For Wye: There are two computation methods for Total VA/VAh - either arithmetic sum or vector sum.

Arithmetic Sum Method for Total VA:

$$VA_T = VA_a + VA_b + VA_c$$

$$VAR_T = \sqrt{(VA_T \bullet VA_T) - (W_T \bullet W_T)}$$

Vector Sum Method for Total VA:

$$VAR_T = VAR_a + VAR_b + VAR_c$$

$$VA_T = \sqrt{W_T^2 + VAR_T^2}$$

For Delta:

$$VAR_T = \sqrt{\left(V_{RMS_{ab}} \bullet I_{RMS_a}\right)^2 - \left[\frac{\sum_{t=1}^{N} v_{ab(t)} \bullet i_{a(t)}}{N}\right]^2} + \sqrt{\left(V_{RMS_{bc}} \bullet I_{RMS_c}\right)^2 - \left[\frac{\sum_{t=1}^{N} v_{bc(t)} \bullet i_{c(t)}}{N}\right]^2}$$

Power Factor (PF):

For Wye: x = a,b,c,T

For Delta: x = T

$$PF_x = \frac{Watt_x}{VA_x}$$

Phase Angles:

$$\angle = \cos^{-1}\left(PF\right)$$

% Total Harmonic Distortion (%THD):

For Wye: x = V_{an}, V_{bn}, V_{cn}

For Delta: x = i_a, i_b, i_c, v_{ab}, v_{bc}, v_{ca}

$$THD = \frac{\sqrt{\sum_{h=2}^{127}\left(RMS_{xh}\right)^2}}{RMS_{x1}}$$

K Factor:

x = i_a, i_b, i_c

$$KFactor = \frac{\sum_{h=1}^{127}\left(h \bullet RMS_{x_h}\right)^2}{\sum_{h=1}^{127}\left(RMS_{x_h}\right)^2}$$

Watt hour (Wh): N = number of samples

$$Wh = \sum_{t=1}^{N} \frac{W_{(t)}}{3600_{sec/hr}}$$

VAR hour (VARh): N = number of samples

$$VARh = \sum_{t=1}^{N} \frac{VAR_{(t)}}{3600_{sec/hr}}$$

*Voltage Imbalance:

% voltage imbalance = maximum deviation from average voltage/average voltage x 100

*Current Imbalance:

% current imbalance = maximum deviation from average current/average current x 100

***NOTES:**

- For voltage and current imbalance, for cycle and high-speed reading updates in which the imbalance/unbalance computation does not follow the NEMA definition, use the formulas below:

For voltage imbalance:

$$\%Voltage_{unbalance} = \frac{V_{RMS_{res}}}{V_{RMS_a} + V_{RMS_b} + V_{RMS_c}} x100$$

For current imbalance:

$$\%Current_{unbalance} = \frac{I_{RMS_{res}}}{I_{RMS_a} + I_{RMS_b} + I_{RMS_c}} x100$$

- The meter also provides voltage/current imbalance based on the IEC 61000-4-30 standard, which uses the symmetrical component method:

For negative sequence unbalance:

$$0.2_{sec}\text{negative sequence unbalance} = u_2 = \frac{0.2_{sec}negative\ sequence}{0.2_{sec}positive\ sequence} x100$$

$$10_{min}\text{negative sequence unbalance} = \sqrt{\sum_{k=1}^{n}\left(\frac{0.2_{sec}negative\ sequence_k}{0.2_{sec}positive\ sequence_k}\right)^2}\ x100$$

For zero sequence unbalance:

$$0.2_{sec}zer\text{o sequence unbalance} = u_0 = \frac{0.2_{sec}zero\ sequence}{0.2_{sec}zero\ sequence} x100\text{symm}$$

$$10_{min}\text{zero sequence unbalance} = \sqrt{\sum_{k=1}^{n}\left(\frac{0.2_{sec}zero\ sequence_k}{0.2_{sec}positive\ sequence_k}\right)^2}\ x100$$

TDD: N = number of samples; *n* = sample number; *h* = harmonic order

For Wye: x = V_{an}, V_{bn}, V_{cn}, i_a, i_b, i_c

For Delta: x = v_{ab}, v_{bc}, v_{ca}

$$TDD = \frac{\sqrt{\sum_{h=2}^{127}(RMS_{xh})^2}}{RMS_{reference}}$$

2.5: Demand Integrators

Power utilities take into account both energy consumption and peak demand when billing customers. Peak demand, expressed in kilowatts (kW), is the highest level of demand recorded during a set period of time, called the interval. The Nexus® 1500+ meter supports the following most popular conventions for averaging demand and peak demand: Block Window Demand, Rolling Window Demand, and Thermal Demand. You can program and access all conventions concurrently with CommunicatorPQA® software (see Chapter 11 of the *CommunicatorPQA® and MeterManager-PQA® Software User Manual*). Note that you can also set TOU demand intervals for the Nexus® 1500+ meter.

Block (Fixed) Window Demand:

This convention records the average (arithmetic mean) demand for consecutive time intervals (usually 15 minutes).

Example: A typical setting of 15 minutes produces an average value every 15 minutes (at 12:00, 12:15. 12:30. etc.) for power reading over the previous fifteen minute interval (11:45-12:00, 12:00-12:15, 12:15-12:30, etc.).

Rolling (Sliding) Window Demand:

Rolling Window Demand functions like multiple overlapping Block Window Demands. The programmable settings provided are the number and length of demand subintervals. At every subinterval, an average (arithmetic mean) of power readings over the subinterval is internally calculated. This new subinterval average is then averaged (arithmetic mean), with as many previous subinterval averages as programmed, to produce the Rolling Window Demand.

Example: With settings of 3 five-minute subintervals, subinterval averages are computed every 5 minutes (12:00, 12:05, 12:10, 12:15, etc.) for power readings over the previous five-minute interval (11:55-12:00, 12:00-12:05, 12:05-12:10, 12:10-12:15, etc.). Further, every 5 minutes, the subinterval averages are averaged in groups of 3 (12:00. 12:05, 12:10, 12:15. etc.) to produce a fifteen (5x3) minute average every 5 minutes (rolling (sliding) every 5 minutes) (11:55-12:10, 12:00-12:15, etc.).

Thermal Demand:

Traditional analog Watt-hour (Wh) meters use heat-sensitive elements to measure temperature rises produced by an increase in current flowing through the meter. A pointer moves in proportion to the temperature change, providing a record of demand. The pointer remains at peak level until a subsequent increase in demand moves it again, or until it is manually reset. The Nexus® 1500+ meter mimics traditional meters to provide Thermal Demand readings.

Each second, as a new power level is computed, a recurrence relation formula is applied. This formula recomputes the thermal demand by averaging a small portion of the new power value with a large portion of the previous thermal demand value. The proportioning of new to previous is programmable, set by an averaging interval. The averaging interval represents a 90% change in thermal demand to a step change in power.

2.6: Meter Specifications

Power Supply

Range:	115 AC Option: UL Rated to (100-240) V AC @50/60 Hz D2: Universal, UL Rated to (100-240) V AC @50/60 Hz or (100-240) V DC (24-48 V DC systems) D: UL Rated to (18-60) V DC
Power Consumption:	(18 to 60) VA, (15 to 25) W - depending on the meter's hardware configuration; Max 60 VA, 25W
Connection:	3 Pin 0.300" Pluggable Terminal Block Torque: 3.5 Lb-In AWG#12-18, Solid or Stranded

NOTE: For the AC power supply, use 500 V, 3 A time delay fuse, for the 24 V DC power supply use 7 A time delay fuse.

Voltage Inputs

UL Measurement Category:	Category III
Range:	Universal, Auto-ranging: Line to neutral (Va, Vb, Vc, Vaux to neutral): (5 - 347) V AC Line to line (Va to Vb, Vb to Vc, Vc to Va): (10 - 600) V AC
Supported hookups:	3 Element Wye, 2.5 Element Wye, 2 Element Delta, 4 Wire Delta
Input Impedance:	5 MΩ/phase
Burden:	0.072 VA/phase max at 600 V; 0.003 VA/phase max at 120 V
Pickup Voltage:	5 V AC
Connection:	6 Pin 0.600" Pluggable Terminal Block Torque: 5 Lb-In AWG#12 -24, Solid or Stranded
Fault Withstand:	Meets IEEE C37.90.1
Reading:	Programmable Full Scale to any PT Ratio
Fuse:	0.5 A/600 V fast-acting fuse

Current Inputs

Class 2:	1 A Nominal CT Secondary, 2 A Maximum
Class 20:	5 A Nominal CT Secondary, 20 A Maximum
Burden:	0.008 VA per phase max at 20 A
Pickup Current:	0.1% of nominal

Connections:	O Lug or U Lug electrical connection (see Figure 4.1): Tighten with #2 Phillips screwdriver; Torque: 8 Lb-In Pass through wire, 0.177" / 4.5 mm Maximum Diameter (see Figure 4.2); Quick connect, 0.25" Male Tab (see Figure 4.3)
Current Surge Withstand (at 23° C):	100 A/10 s, 300 A/3 s, 500 A/1 s
Reading:	Programmable Full Scale to any CT Ratio
Continuous Current Withstand:	20 A; for sustained loads greater than 10 A use Pass-through wiring method (see Figure 4.2).

Frequency

Range:	(42.5-69.9) Hz; (45-65) Hz for IEEE C37.118.2

Isolation

All Inputs to Outputs are isolated to 2500 VAC.

Environmental Rating

Operating:	(-20 to +70) °C
Storage:	(-30 to +80) °C
Humidity:	up to 95% RH Non-condensing
Pollution Degree:	2
Altitude:	Maximum Rated - 2000 M
Protection Class:	IP30

Measurement Methods

Voltage, Current:	True RMS

Update Rate

High speed readings	1 cycle; and programmable for 2-20 cycles RMS
Revenue-accurate readings	1 second

Communication

Standard	10/100BaseT Ethernet ANSI Optical Port USB 1.1/2.0 Port, Full speed
Optional, through I/O card slot	Dual RS485 Serial Ports Second 10/100BaseT Ethernet or 100Base-FX Fiber Optic Ethernet
Protocols	Modbus RTU, Modbus ASCII, Modbus TCP, DNP3, IEC 61850 (V-switch™ keys 2, 3, 5, 6), SNMP, IEEE 1588 PTP v2 protocol, SMTP, IEEE C37.118-2 PMU, HTTP
Serial Port Baud Rate	9600 to 115200 bps
Serial Port Address	1-247 - Modbus protocol 1-65535 - DNP3 Level 2 protocol
Data Format	8 Bit, No Parity

Optional RS485 Port Specifications

RS485 Transceiver; meets or exceeds EIA/TIA-485 Standard:

Type:	Two-wire, half duplex
Min. Input Impedance:	96 kΩ
Max. Output Current:	±60 mA

Mechanical Parameters

Dimensions: see Chapter 3: Hardware Installation, on page 3-1.

Weight:	3.9 lbs

2.7: Accuracy

For 23 °C +/- 5 °C, 3 Phase balanced Wye or Delta load, at 50 Hz or 60 Hz (as per order), accuracy is as follows:

Parameters	Accuracy*	Range
Voltage	0.05% (1 s readings) 0.1% (2-20 cycle readings)	(45 to 347) V AC L-N (80 to 600) V AC L-L
Current	0.025% (1 s) 0.1% (2-20 cycle)	1% to 200% of Nominal Class 2: Nominal 1 A, maximum 2 A Class 20: Nominal 5 A, maximum 20 A
Energy	kWh 0.06% (1 s) kVAh 0.08% (1 s kVARh 0.08% (1 s)	I: 1% to 200% of Nominal V: (45 to 347) V PF: +/- (0.5 to 1) lag/lead
Power	kW (Unity PF) 0.1% (2-20 cycle) 0.06% (1 s) kW (0.5 PF) 0.1% (2-20 cycle) 0.1% (1 s) kVA 0.1% (2-20 cycle) 0.08% (1 s) kVAR (0.5 - 0.9 PF) 0.1% (2-20 cycle) 0.08% (1 s)	I: 1% to 200% of Nominal V: (45 to 347) V
Power Factor	0.08% (1 s) 0.1% (2-20 cycle)	
Frequency	0.001 Hz (10 s) 0.001 Hz (1 s) 0.03 - 0.003 Hz (2-20 cycles readings) 0.01 Hz (High resolution single cycle)	(42.5 to 69.9) Hz
	.005 Hz (PMU Frequency)	(45-65) Hz
Voltage/Current Unbalance[4]	±0.05	0.5% to 5% u2 0.5% to 5% u0
Harmonic/Interharmonic	0.2% (1 s)	
Voltage Sag/Swell Duration Depth[2]	 ½ cycle ±0.1% U_{din}	 4.97 hours maximum 10% to 150% U_{din}
Interruption duration	½ cycle	4.97 hour maximum
Rapid voltage Change (RVC) Duration Umax[2] Uss[2]	 ½ cycle ±0.1% U_{din} ±0.1% U_{din}	 4.97 hours maximum 10% to 150% U_{din} 10% to 150% U_{din}
Mains Signaling voltage[1,3]	±5% U_m $U_m \geq 1\%\ U_{nom}$ ±0.05% U_{nom} $U_m < 1\%\ U_{nom}$	10% to 200% of Class 3 electromagnetic environment in IEC 61000-2-4
Flicker	5% of reading	Pst: 0.2 to 10
Temperature		(-20 to +70) °C

Real time clock	3.5 ppm	
Timestamp (IRIG sync)	1 usec typical; 100 usec max	

1 – U_m (measured value), U_{nom} (nominal voltage range).
2 - U_{din} (declared input voltage): value obtained from the declared supply voltage by a transducer ratio.
3 - Because data is computed from interharmonics bins, error and range follow interharmonics.
4 - u2 (negative sequence), u0 (zero sequence).

*****1 s = 1 second; for 100 millisecond updates, set the High Speed readings update rate to 6 cycles @ 60 Hz or 5 cycles @ 50 Hz. See Chapter 11 in the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions.

2.8: Standards Compliance

- ANSI C12.20 - 0.2 Accuracy Class and C12.1 2008; 0.2 CL (MET Labs Certified)*
- ANSI C62.41 (Burst)
- FCC Part 15, Class A (Radiated and Conducted Emissions)*
- IEC 62053-22 - Accuracy, 0.2S (KEMA Labs Certified)
- IEC 62053-23 Ed.1
- CE (EN/IEC 61326-1 & EN/IEC 61000-3-2 & EN/IEC 61000-3-3) Certified*
    - IEC 61000-4-2 Ed. 2 2008 (Electrostatic Discharge)*
    - IEC 61000-4-3 Ed. 3.2 2010 (Radiated EM Immunity)*
    - IEC/EN 61000-4-4 Ed.3 2012, Class B (EFT)*
    - IEC/EN 61000-4-5, Class B (Surge Immunity)*
    - IEC 61000-4-6 Ed. 3 2008 (Conducted Immunity)*
    - IEC 61000-4-8 Ed. 2 2009 (Magnetic Immunity)*
    - IEC 61000-4-11 Ed. 2 2004 (Voltage Variations Immunity)*
- IEC 61000-4-30 Class A Ed.3 Certified*
    - IEC 61000-2-4 (Compatibility Levels)*
    - IEC 62586-2 Ed. 2 2013 (PQ Measurement in Power Supply Systems)*
    - IEC 61000-4-7 Ed. 2 2002 (Harmonics)*
    - IEC 61000-4-15 Ed. 2 2010 (Flicker Meter)*
- IEC 61000-6-2 2005 (Immunity for Industrial Environments)
- IEC 61000-6-4 2006 (Emissions Standards for Industrial Environments)
- IEC 61850 Level A, Ed. 2 Certified*

- CISPR11 Ed. 5.1 (Conducted Emissions)*
- CISPR22 Class A
  - IEC 62052-11 2003- General Requirements
- EU Directive 2011/65/EU (RoHS 3 Directive)
- Certified to UL/IEC 61010-1 and CSAC22.2 No. 61010-1, UL File: E250818

* Third party lab tested

3: Hardware Installation

This chapter explains how to install the Nexus® 1500+ meter and how to replace the meter's battery - see 3.4: Replacing the Meter's Battery, on page 3-8. For installation instructions on the optional I/O cards and external modules, see Chapter 11.

3.1: Mounting the Nexus® 1500+ Meter

The Nexus® 1500+ meter is designed to mount in a panel. Refer to Section 3.2 for meter and panel cut-out dimensions, and Section 3.3 for mounting instructions.

NOTE: The meter can be installed either horizontally or vertically. If you mount the meter vertically, you can then rotate the display screens to support the vertical installation (see Chapter 6 for instructions).

To clean the unit, wipe it with a clean, dry cloth.

3.2: Meter and Panel Cut-out Dimensions

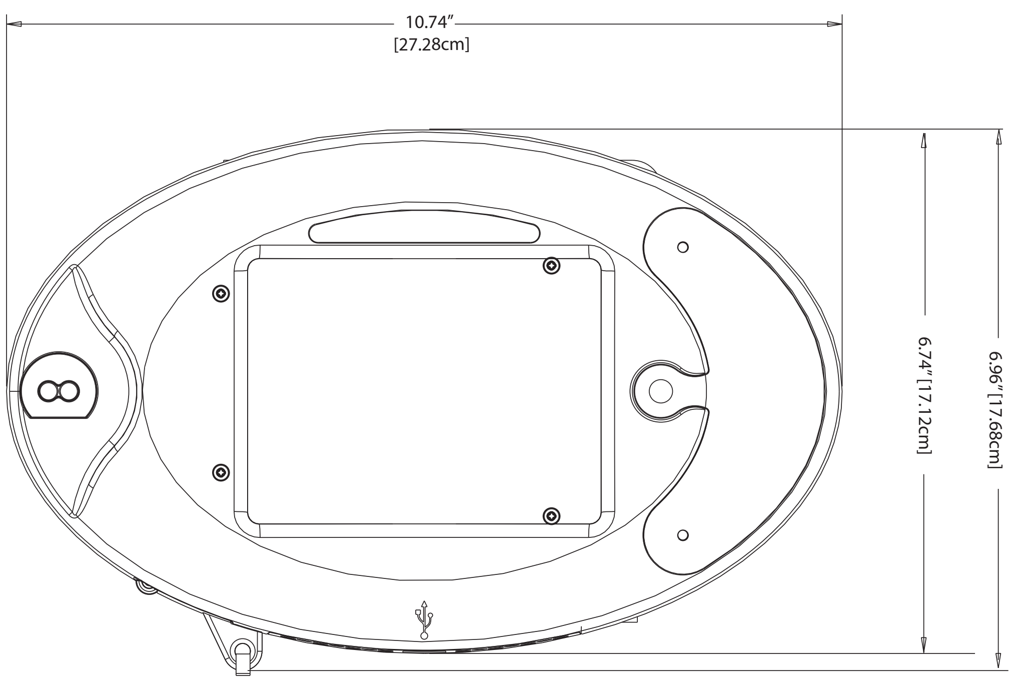
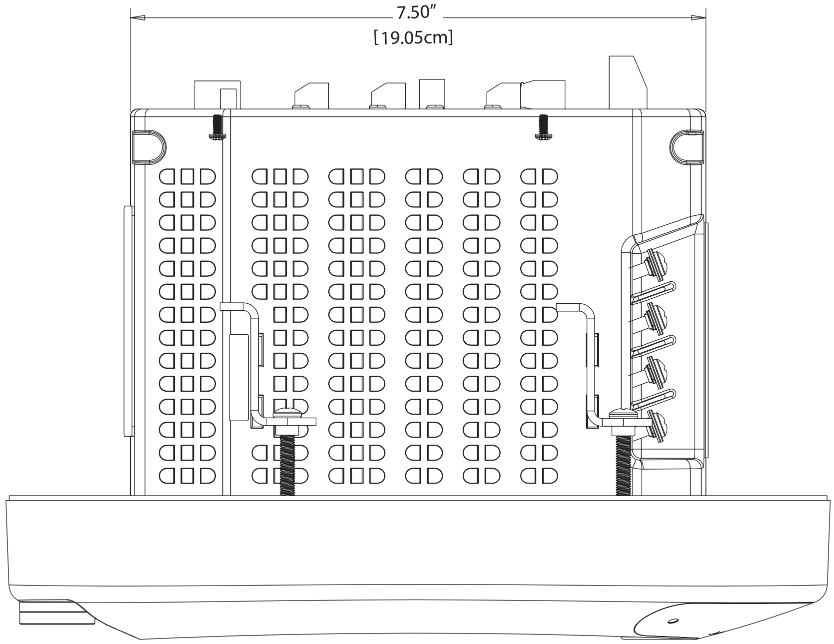


Figure 3.1: Meter Dimensions (Front)

Meter Top View



Meter Side View

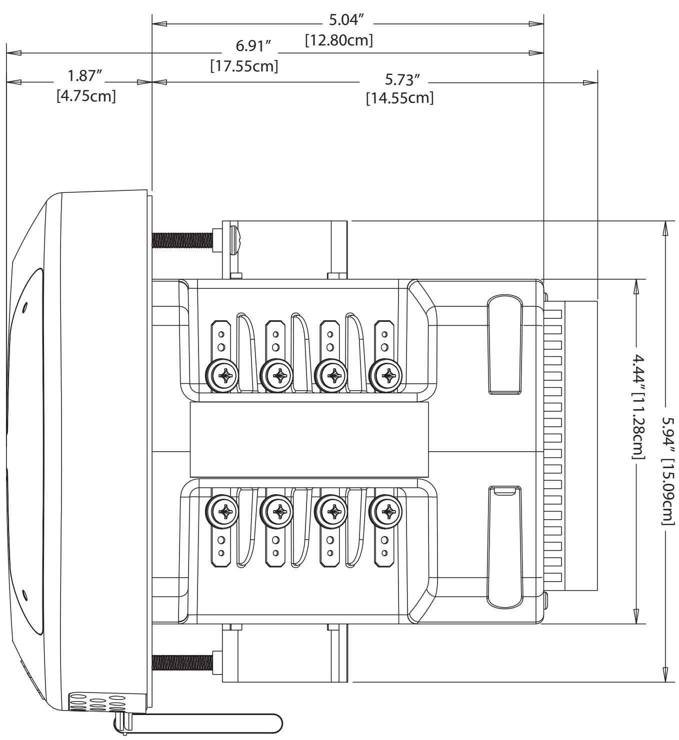


Figure 3.2: Meter Dimensions (Top and Side)

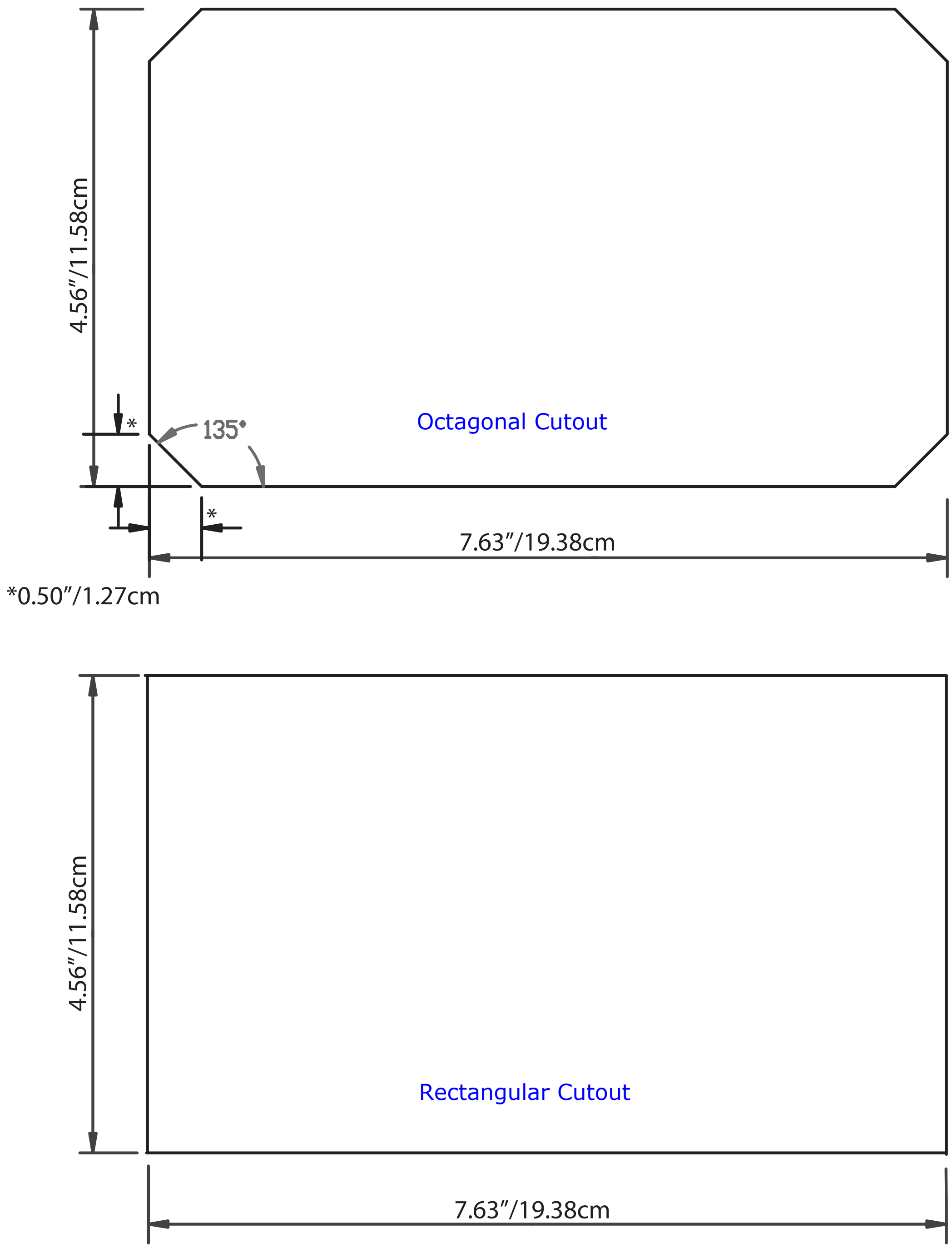
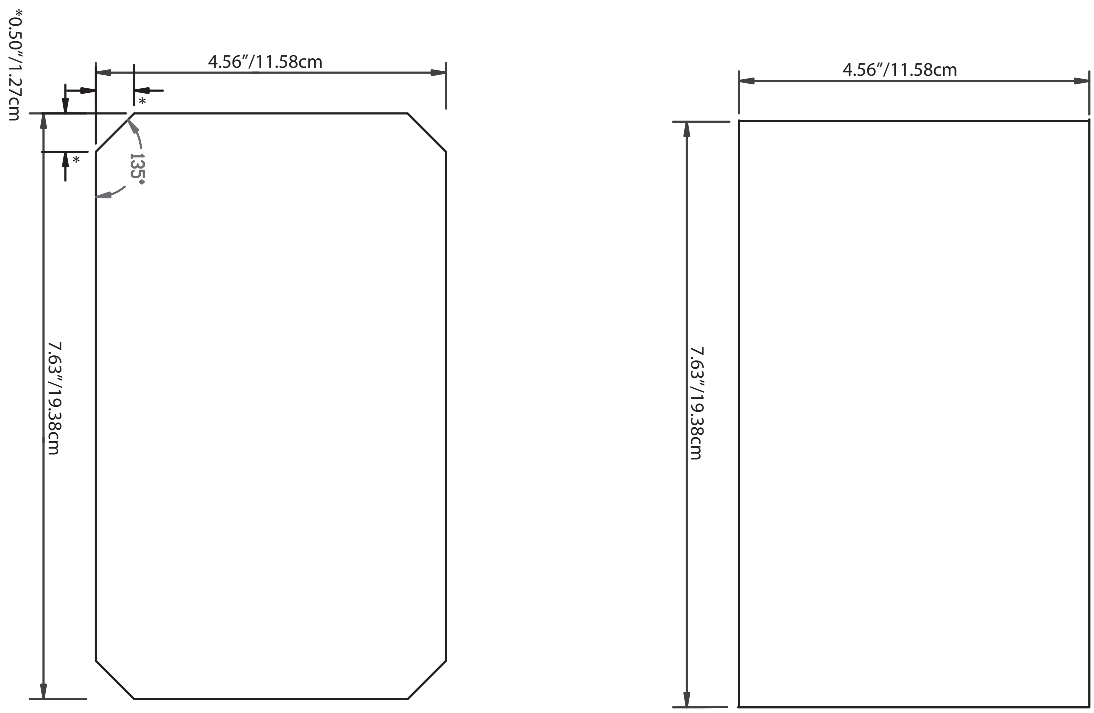


Figure 3.3: Optional Panel Cutout Dimensions - Horizontal

Note that these cut-outs can also be made in a vertical orientation, with the longer dimensions on the side, for vertical mounting of the meter. See the figures, below.



Octagonal Cutout

Rectangular Cutout

Figure 3.4: Optional Panel Cutout Dimensions - Vertical

3.3: Mounting Instructions

1. Slide the meter into the panel. Note that you can mount the meter either horizontally or vertically (see figures 3.5 and 3.6).

2. From the back of the panel, slide 4 mounting brackets into the grooves on the top and bottom of the meter housing (2 fit on the top and 2 fit on the bottom), if you are mounting horizontally, or on either side, if you are mounting vertically (2 on each side).

3. Snap the mounting brackets into place.

4. Secure the meter to the panel with lock washer and a #8 screw in each of the 4 mounting brackets (see figures 3.5 and 3.6).

5. Tighten the panel mounting screws with a #2 Phillips screwdriver. Do not over-tighten. Maximum installation torque is 3.5 Lb-In.
   NOTE: If necessary, replacement mounting brackets (Part number E145316) may be purchased from EIG.

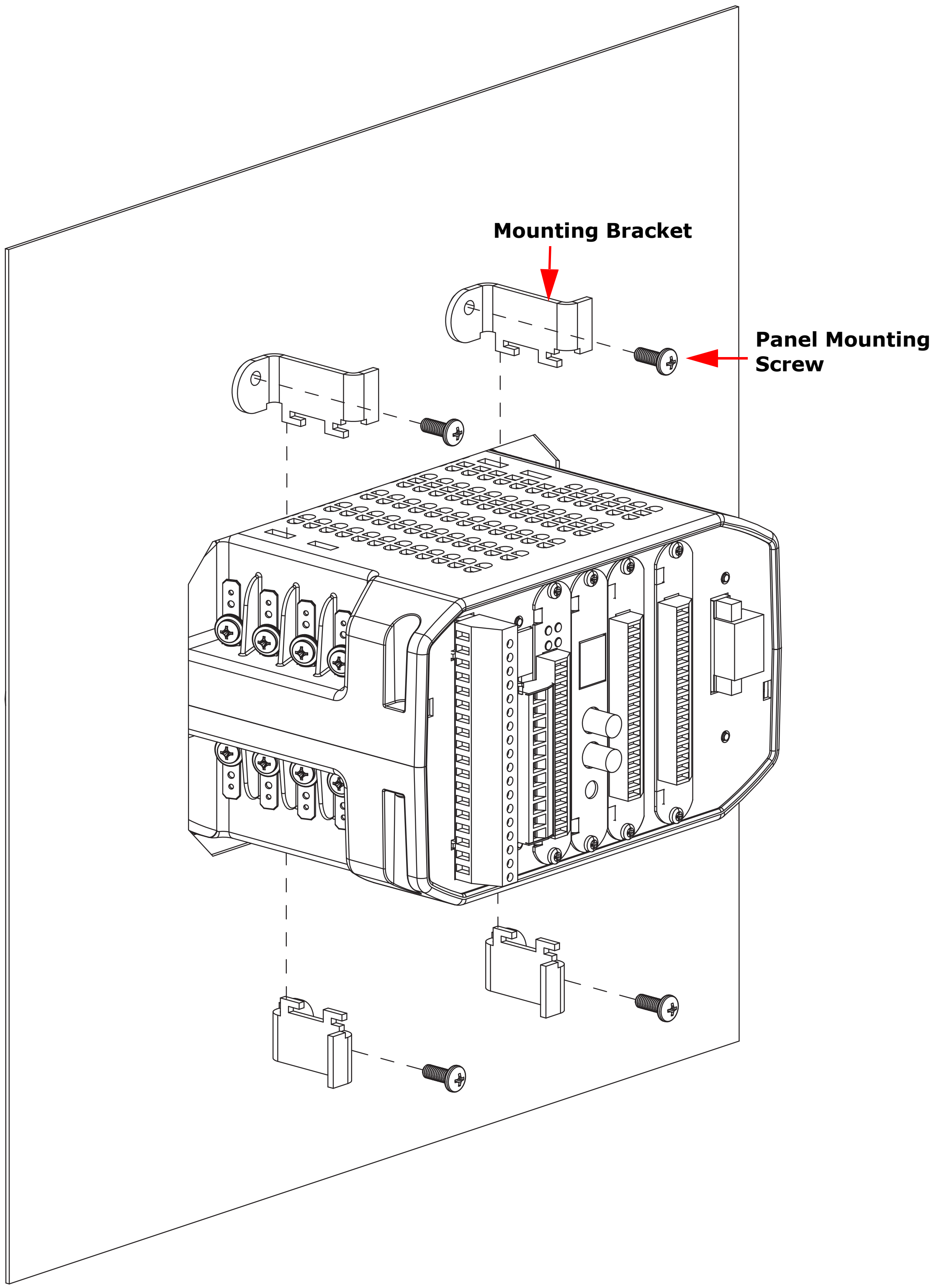


Figure 3.4: Mounting the Meter Horizontally

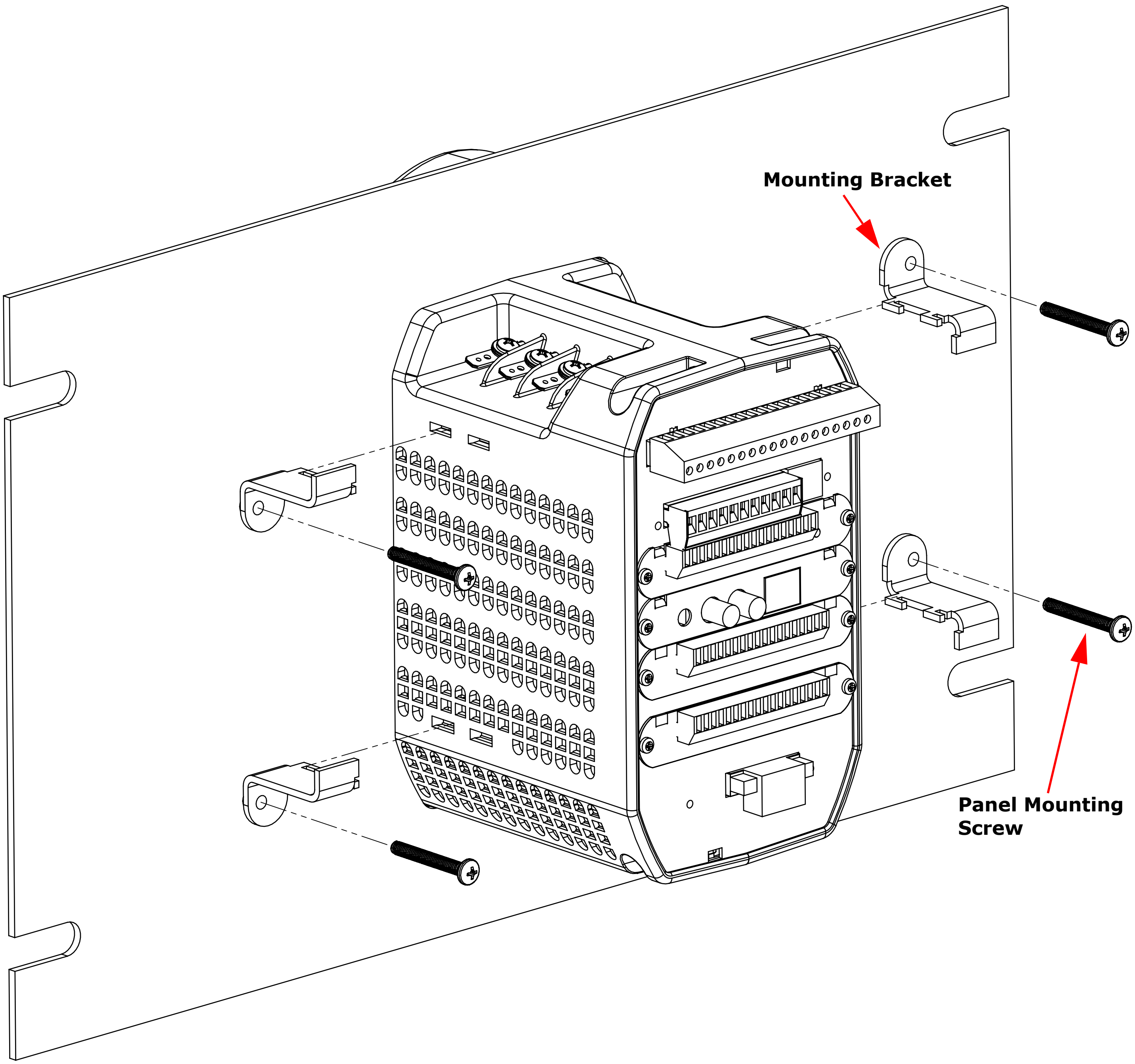


Figure 3.5: Mounting the Meter Vertically

3.4: Replacing the Meter's Battery

This section gives instructions for replacing the meter's Lithium battery.

CAUTION! All personnel opening the Nexus® 1500+ meters are required to be aware of the ESD threat to the electronic components and are required to maintain ESD prevention measures.

You will need the following tools for the job:

- Ultra-grip static-dissipative screwdriver Phillips round blade, #1 tip, 3-1/8" blade length
- Phillips power bit 1/4" hex shank, tip #1, 2" length
- Torque set screw driver: torque settings on drill 10in-lbs.
- ESD rigid plastic tweezers, 4 1/2".
- Battery insertion tool: 3 1/4" width x 3" length, non-conductive plastic.
- Non-metallic latex gloves.

NOTE: Save all hardware (screws, washer, etc.) during disassembly, as it will be needed during the reassembly of the unit.

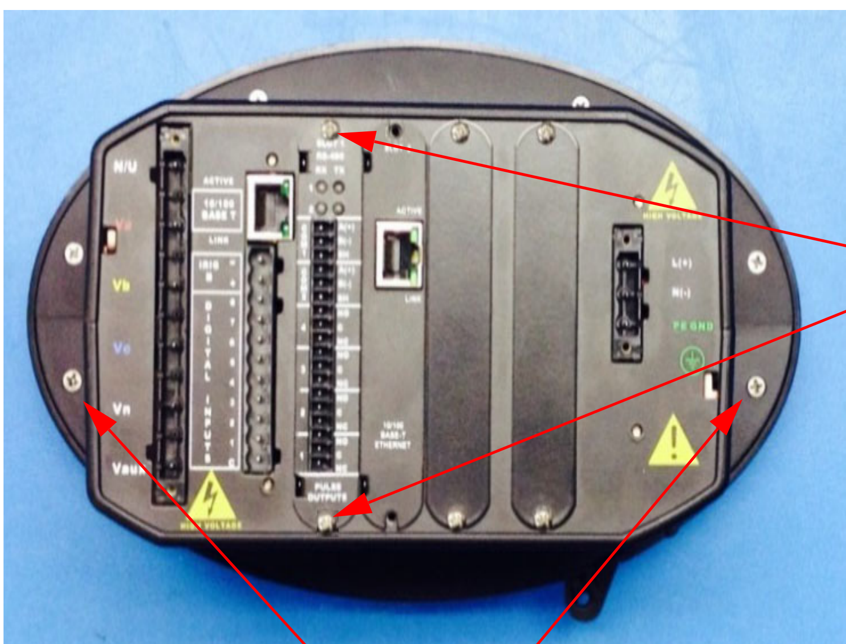


Figure 3.6: Location of Meter Screws

Follow this procedure:

1. Turn the meter over and remove all of the option cards. Each option card is secured with two ¼ Phillips pan head screws (see 11: Using the I/O Options, on page 11-1). Refer to Figure 3.6

   NOTE: Take note of the slot where each option card is installed. When reassembling the unit the option cards must be placed in the same slot from which they were removed.

2. Remove the eight flat head screws connected to the front panel.

3. With the eight flat head screws removed, carefully separate the front panel from the body of the unit.

4. Remove the digital board insulator - see Figure 3.7.

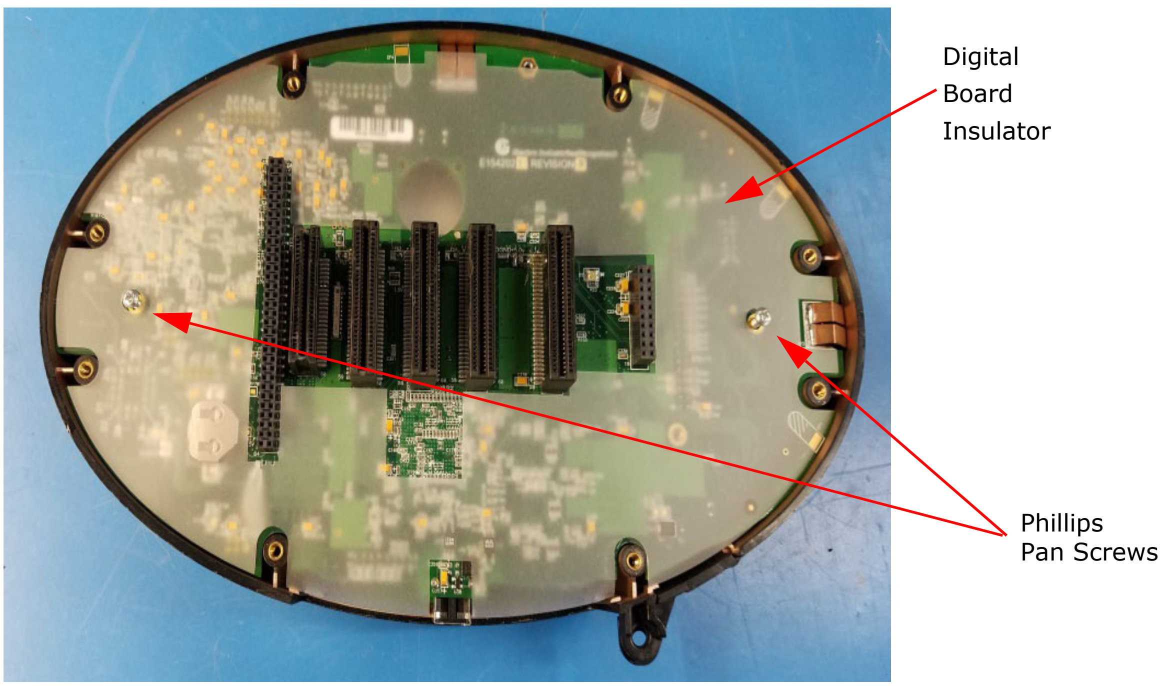


Figure 3.7: Inside of Meter Showing the Digital Board Insulator

5. Remove the two Phillips pan screws used to mount the digital board on the front panel. See Figure 3.7

6. With one hand on the front panel and the other on the digital board, carefully separate the front panel from the digital board. See Figures 3.8 and 3.9.

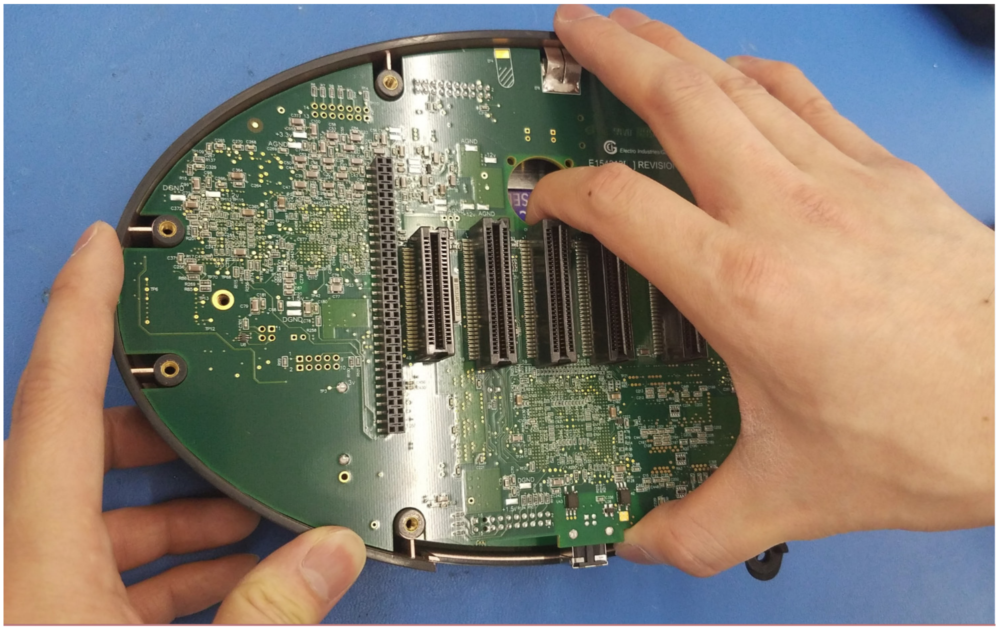


Figure 3.8: Holding the Front Panel and Digital Board

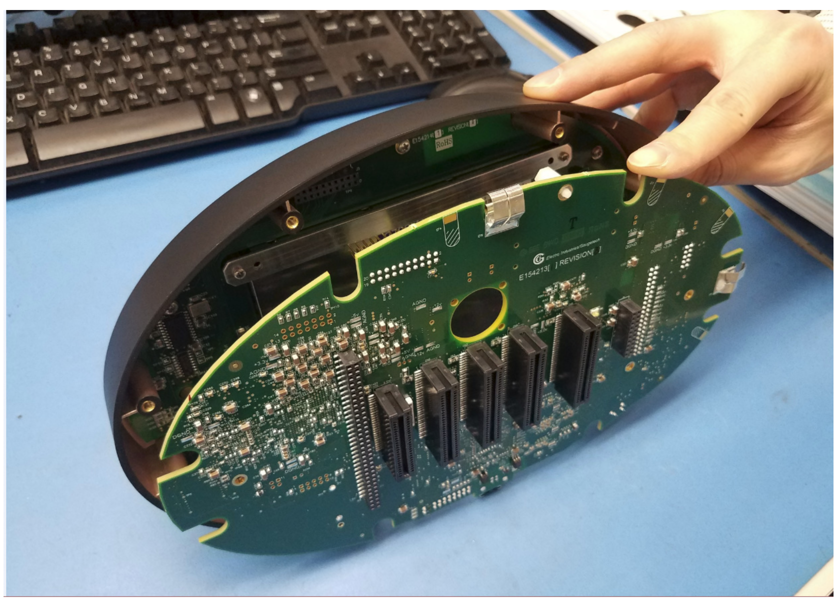
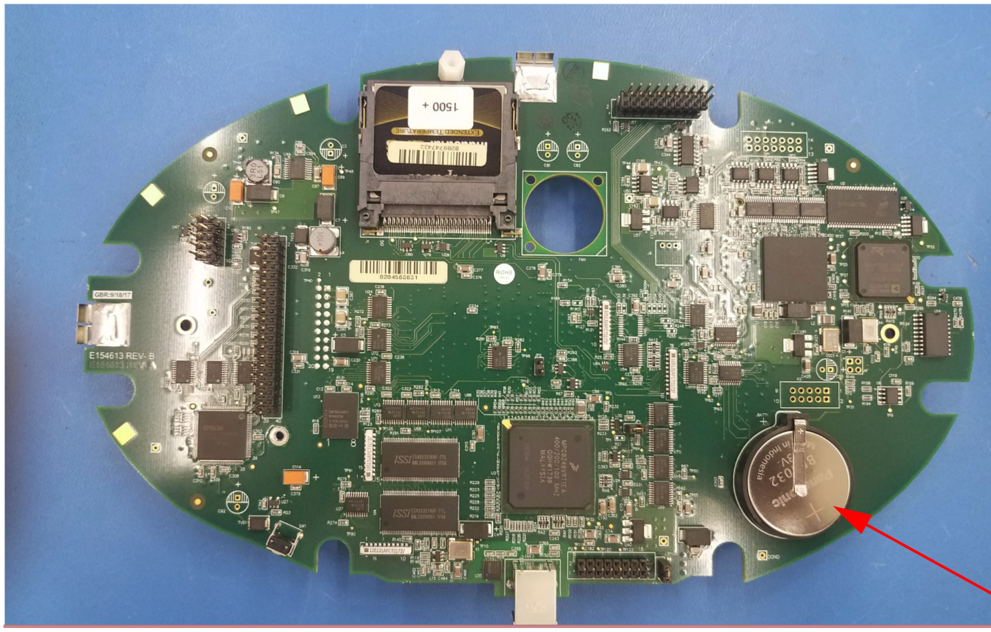


Figure 3.9: Separating the Front Panel from the Digital Board

7.Turn the digital board so that the battery is facing you - see Figure 3.10



Battery

Figure 3.10: Location of Battery

8. To remove the battery, (Manufacturer Part #: Panasonic Battery BR 3032 3V Lithium Coin Size Battery), first slide the battery insertion tool under the battery between the negative pole of the battery and the battery holder. See Figure 3.11.

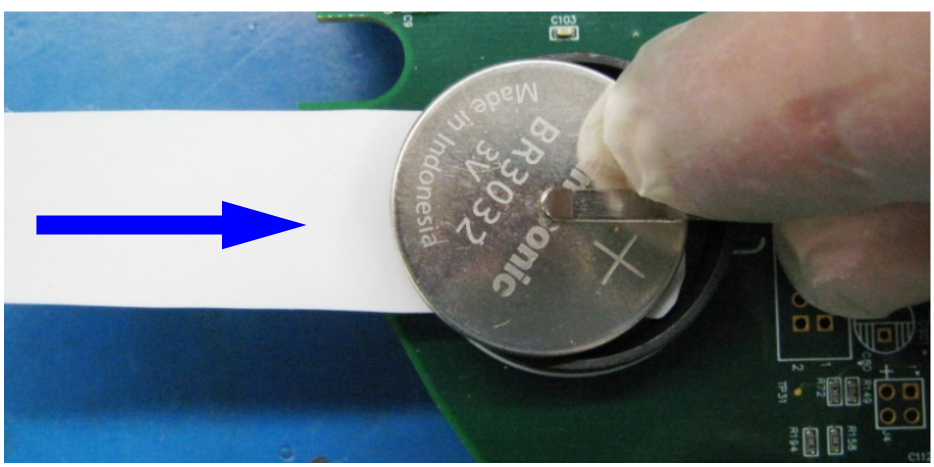


Figure 3.11: Positioning the Battery Insertion Tool

9..Using a gloved hand/finger, gently slide the battery out of the holder and along the battery insertion tool. See Figure 3.12.

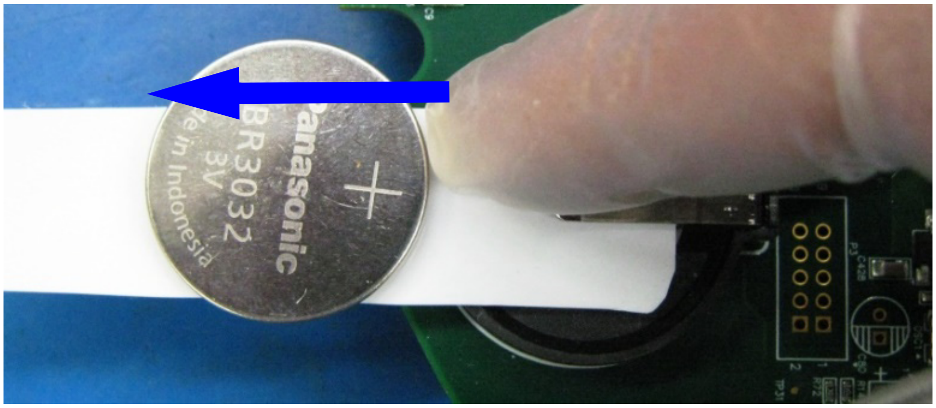


Figure 3.12: Sliding the Battery Out

10. Dispose of the battery properly.

11. Slide the battery insertion tool between the positive (+) tab and the negative tab (NEG) of the battery holder. See Figure 3.13.

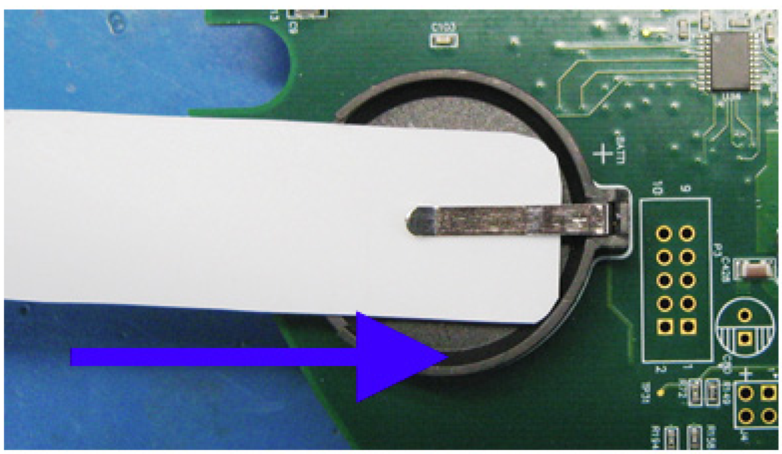


Figure 3.13: Placement of Battery Insertion Tool

12. Use a non-conductive tweezer to gently lift the Positive (+) tab up. See Figure 3.14.

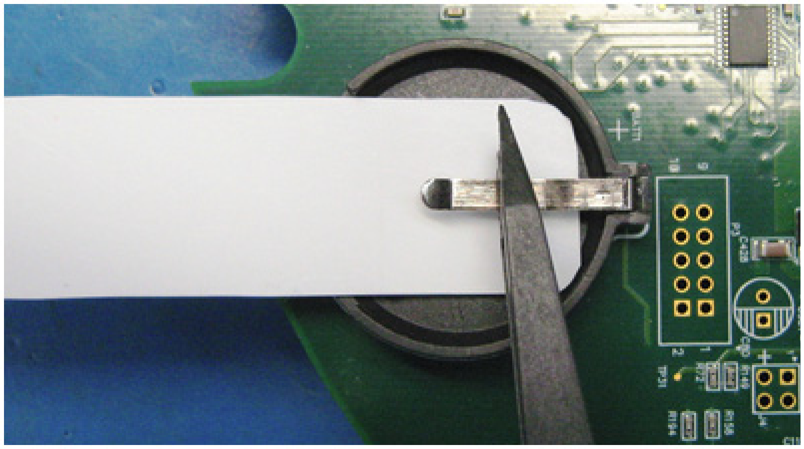


Figure 3.14: Lifting the Positive Tab

NOTE: Always keep the plus (+) side of the battery up.

13. Using a gloved hand and observing the correct battery polarity (plus (+) side up), gently slide the battery under the Positive (+) tab. Push the battery all the way into the battery holder. See Figure 3.15.

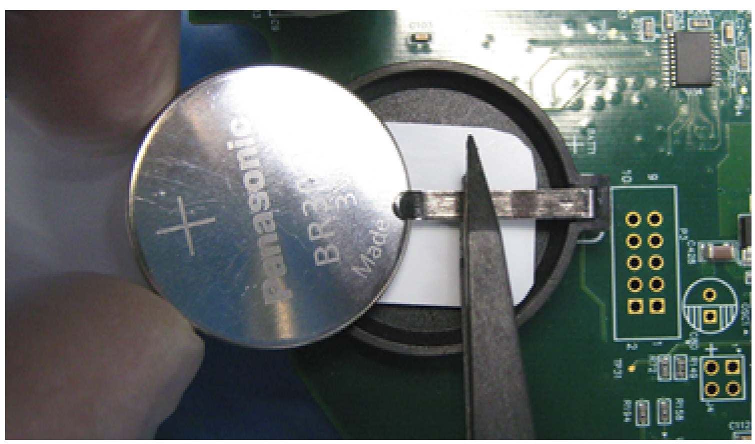


Figure 3.15: Inserting the Battery

14. Gently pull the battery insertion tool out from under the installed battery and make sure the battery is fully installed into the holder. See Figure 3.16.

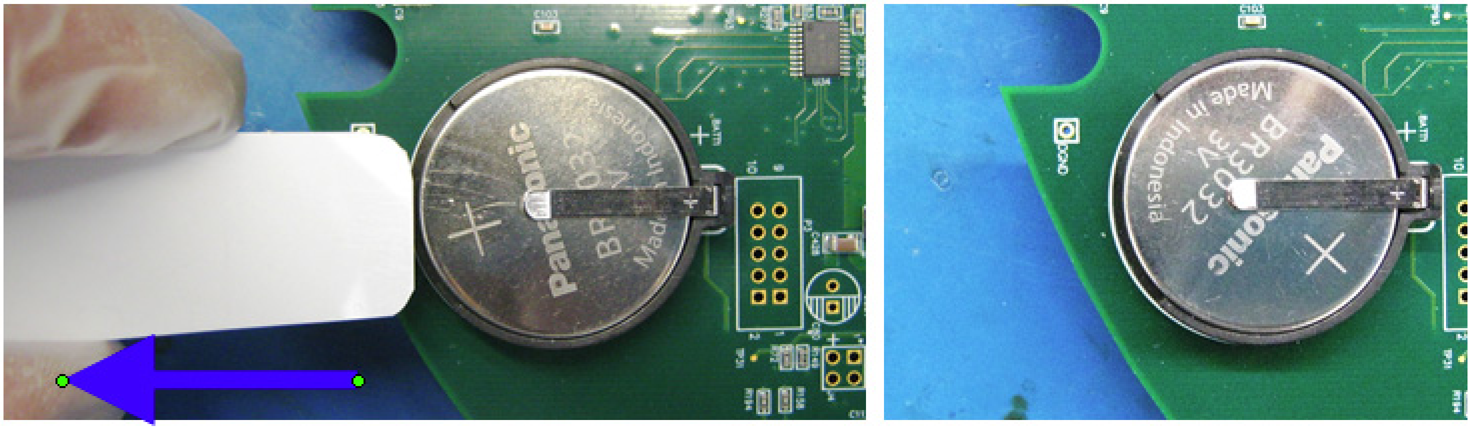


Figure 3.16: Removing the Battery Insertion tool and Battery Installed Correctly

15. Check that the digital board headers have no bent pins, and then align the headers and connectors of the digital board and the front panel board. Carefully push the main digital board on to the front panel display making sure the connectors are aligned. Once fully seated, secure the main digital board to the front panel using two pan head screws. See Figure 3.17.

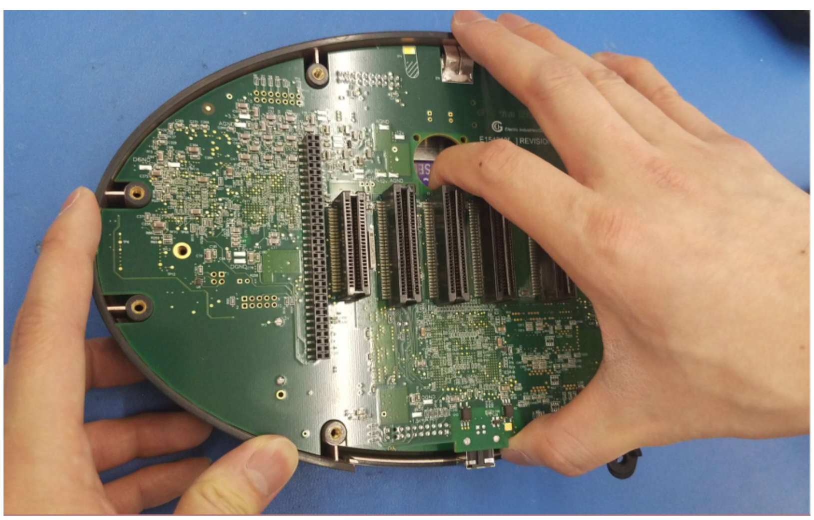


Figure 3.17: Aligning the Digital Board and the Front Panel Board

16. Place the digital board insulator on the digital board as shown in Figure 3.18. The EMI shielding tabs of the digital board should be placed within the boundaries of the front panel shell, not on the outer surface of the front panel shell.

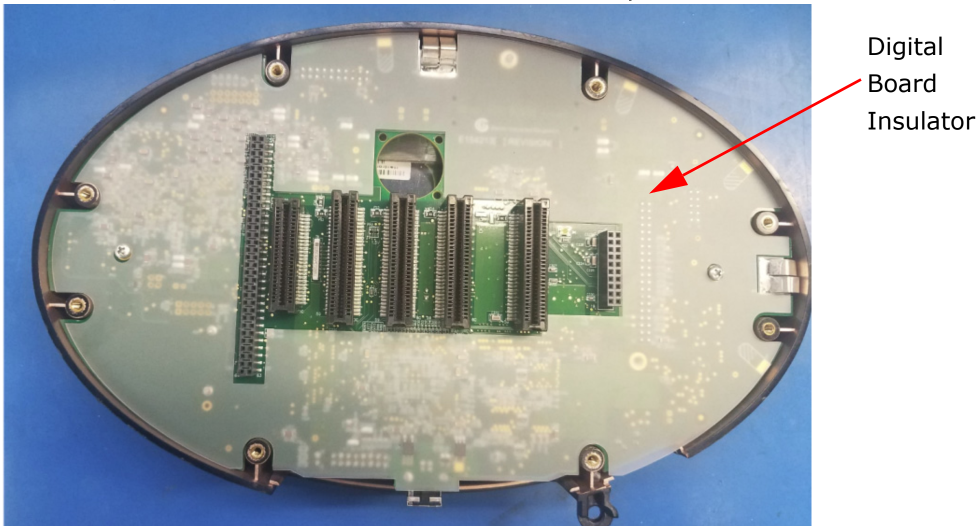


Figure 3.18: Replacing the Digital Board Insulator

17. Align the base of the meter with the front panel assembly. Be sure that the connectors from the power supply and the analog board are aligned and inserted correctly into the main digital board. Carefully push the two assemblies together until fully seated. Secure the base unit to the front panel assembly with the eight flat head screws that were removed in step 2.

18.Reinstall each option card back into the same slot from which it was removed. Be sure the option card(s) is fully seated in the connector, then secure with the two pan head screws that were removed in Step 1.

19. Check that all screws are tight and that no extra hardware is left over.

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4: Electrical Installation

4.1: Considerations When Installing Meters

Installation of the Nexus® 1500+ meter must be performed only by qualified personnel who follow standard safety precautions during all procedures. Those personnel should have appropriate training and experience with high voltage devices. Appropriate safety gloves, safety glasses and protective clothing are recommended.

During normal operation of the Nexus® 1500+ meter, dangerous voltages flow through many parts of the meter, including: Terminals and any connected CTs (Current Transformers) and PTs (Potential Transformers), all I/O (Inputs and Outputs) and their circuits. All Primary and Secondary circuits can, at times, produce lethal voltages and currents. Avoid contact with any current-carrying surfaces.

Do not use the meter for primary protection or in an energy-limiting capacity. The meter can only be used as secondary protection.

Do not use the meter for applications where failure of the meter may cause harm or death.

Do not use the meter for any application where there may be a risk of fire.

All meter terminals should be inaccessible after installation.

Do not apply more than the maximum voltage the meter or any attached device can withstand. Refer to meter and/or device labels and to the Specifications for all devices before applying voltages.

Do not HIPOT/Dielectric test any Outputs, Inputs or Communications terminals.

EIG requires the use of fuses for voltage leads and power supply, and shorting blocks to prevent hazardous voltage conditions or damage to CTs, if the meter needs to be removed from service. One side of the CT must be grounded.

NOTE: The current inputs are only to be connected to external current transformers provided by the installer. The CTs shall be Approved or Certified and rated for the current of the meter used.

Branch circuit protection size should be 15 amps.

For sustained loads greater than 10 amps, the CT wires should be wired directly through the CT opening (pass through wiring method - see Section 4.3), using 10 AWG wire.

L'installation des compteurs de Nexus 1500+ doit être effectuée seulement par un personnel qualifié qui suit les normes relatives aux précautions de sécurité pendant toute la procédure. Le personnel doit avoir la formation appropriée et l'expérience avec les appareils de haute tension. Des gants de sécurité, des verres et des vêtements de protection appropriés sont recommandés.

Pendant le fonctionnement normal du compteur Nexus 1500+ des tensions dangereuses suivant de nombreuses pièces, notamment, les bornes et tous les transformateurs de courant branchés, les transformateurs de tension, toutes les sorties, les entrées et leurs circuits. Tous les circuits secondaires et primaires peuvent parfois produire des tensions de létal et des courants. Évitez le contact avec les surfaces sous tensions. Avant de faire un travail dans le compteur, assurez-vous d'éteindre l'alimentation et de mettre tous les circuits branchés hors tension.

Ne pas utiliser les compteurs ou sorties d'appareil pour une protection primaire ou capacité de limite d'énergie. Le compteur peut seulement être utilisé comme une protection secondaire.

Ne pas utiliser le compteur pour application dans laquelle une panne de compteur peut causer la mort ou des blessures graves.

Ne pas utiliser le compteur ou pour toute application dans laquelle un risque d'incendie est susceptible.

Toutes les bornes de compteur doivent être inaccessibles après l'installation.

Ne pas appliquer plus que la tension maximale que le compteur ou appareil relatif peut résister. Référez-vous au compteur ou aux étiquettes de l'appareil et les spécifications de tous les appareils avant d'appliquer les tensions. Ne pas faire de test HIPOT/diélectrique, une sortie, une entrée ou un terminal de réseau.

EIG nécessite l'utilisation de les fusibles pour les fils de tension et alimentations électriques, ainsi que des coupe-circuits pour prévenir les tensions dangereuses ou endommagements de transformateur de courant si l'unité Nexus 1500+ doit être enlevée du service. Un côté du transformateur de courant doit être mis à terre.

NOTE: Les entrées actuelles doivent seulement être branchées dans le transformateur externe actuel par l'installateur. Le transformateur de courant doit être approuvé ou certifié et déterminé pour le compteur actuel utilisé.

La taille de la protection de la dérivation doit être de 15 ampères.

Pour les charges continues de plus de 10 ampères, les fils des transformateurs de courant doivent être câblés directement à travers l'ouverture pour les transformateurs de courant (la méthode de câblage de passage - voir Section 4.3), à l'aide de fils de calibre américain des fils de 10.

IF THE EQUIPMENT IS USED IN A MANNER NOT SPECIFIED BY THE MANUFACTURER, THE PROTECTION PROVIDED BY THE EQUIPMENT MAY BE IMPAIRED.

THERE IS NO REQUIRED PREVENTIVE MAINTENANCE OR INSPECTION NECESSARY FOR SAFETY. HOWEVER, ANY REPAIR OR MAINTENANCE SHOULD BE PERFORMED BY THE FACTORY.

DISCONNECT DEVICE: The following part is considered the equipment disconnect device. A SWITCH OR CIRCUIT-BREAKER SHALL BE INCLUDED IN THE END-USE EQUIPMENT OR BUILDING INSTALLATION. THE SWITCH SHALL BE IN CLOSE PROXIMITY TO THE EQUIPMENT AND WITHIN EASY REACH OF THE OPERATOR. THE SWITCH SHALL BE MARKED AS THE DISCONNECTING DEVICE FOR THE EQUIPMENT.

IMPORTANT! SI L'ÉQUIPEMENT EST UTILISÉ D'UNE FAÇON NON SPÉCIFIÉE PAR LE FABRICANT, LA PROTECTION FOURNIE PAR L'ÉQUIPEMENT PEUT ÊTRE ENDOMMAGÉE.

Il N'Y A AUCUNE MAINTENANCE REQUISE POUR LA PRÉVENTION OU INSPECTION NÉCESSAIRE POUR LA SÉCURITÉ. CEPENDANT, TOUTE RÉPARATION OU MAINTENANCE DEVRAIT ÊTRE RÉALISÉE PAR LE FABRICANT.

DÉBRANCHEMENT DE L'APPAREIL : la partie suivante est considérée l'appareil de débranchement de l'équipement. UN INTERRUPTEUR OU UN DISJONCTEUR DEVRAIT ÊTRE INCLUS DANS L'UTILISATION FINALE DE L'ÉQUIPEMENT OU L'INSTALLATION. L'INTERRUPTEUR DOIT ÊTRE DANS UNE PROXIMITÉ PROCHE DE L'ÉQUIPEMENT ET A LA PORTÉE DE L'OPÉRATEUR. L'INTERRUPTEUR DOIT AVOIR LA MENTION DÉBRANCHEMENT DE L'APPAREIL POUR L'ÉQUIPEMENT.

4.2: Installing Current Transformer Sensors Terminated to Meter

The Nexus® 1500+ meter measures current using traditional 5 A secondary or 1 A secondary current transformers. These transformers step down the primary current to a range that they meter and sense.

The Nexus® 1500+ meter is designed to have current inputs wired in one of three ways. Diagram 4.1 shows the most typical connection where CT Leads are terminated to the meter at the current gills. This connection uses nickel-plated brass rods with screws at each end. This connection allows the CT wires to be terminated using either an "O" or a "U" lug. Tighten the screws with a #2 Phillips screwdriver.

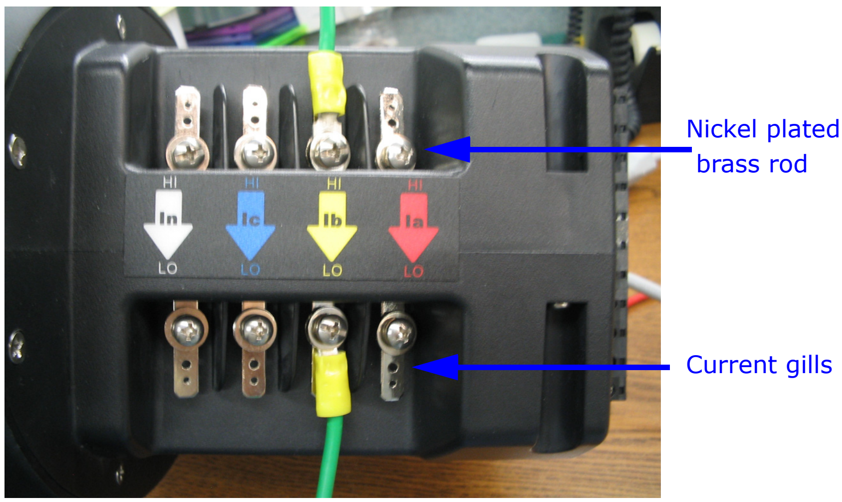


Figure 4.1: CT Leads terminated to Meter, #8 Screw for Lug Connection

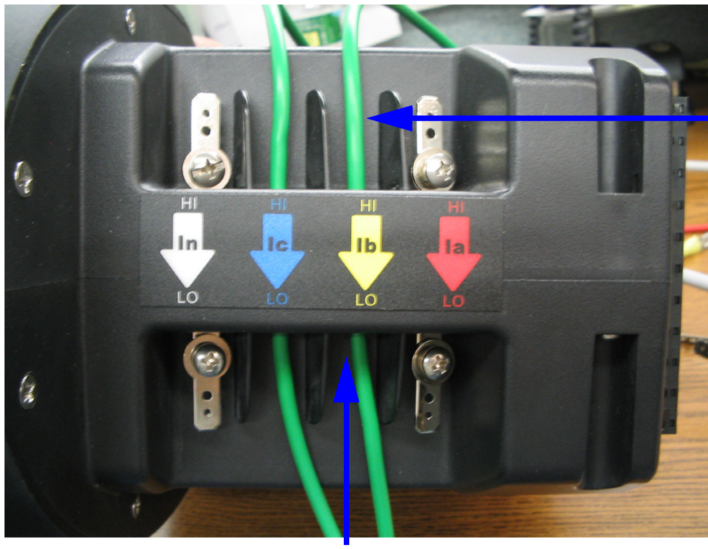
Other current connections are shown in sections 4.2 and 4.3. Voltage and RS485/KYZ connections can be seen in Figure 4.4.

Wiring diagrams are shown in Section 4.12 of this chapter; Communications connections are detailed in Chapter 5.

NOTE: For sustained loads greater than 10 A, use pass through wiring method (Section 4.3), using 10 AWG wire.

4.3: Installing Current Transformer Sensors with No Meter Termination (Pass Through)

The second method allows the CT wires to pass through the CT inputs without terminating at the meter. In this case, remove the current gills and place the CT wire directly through the CT opening. The opening accommodates up to 0.177"/4.5mm maximum diameter CT wire.



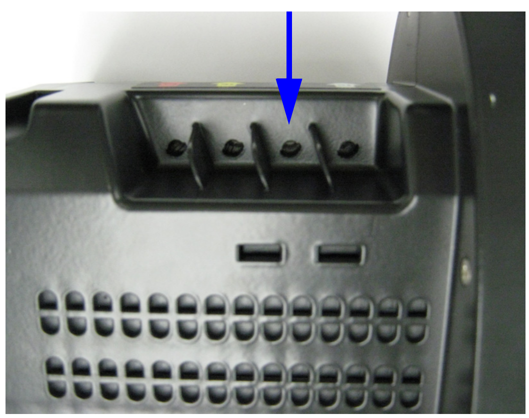


Figure 4.2: Pass Through Wire Electrical Connection

NOTE: For sustained loads greater than 10 A, use 10 AWG wire.

4.4: Quick Connect Crimp-on Terminations

You can use 0.25" Quick Connect Crimp-on connectors for quick termination or for portable applications.

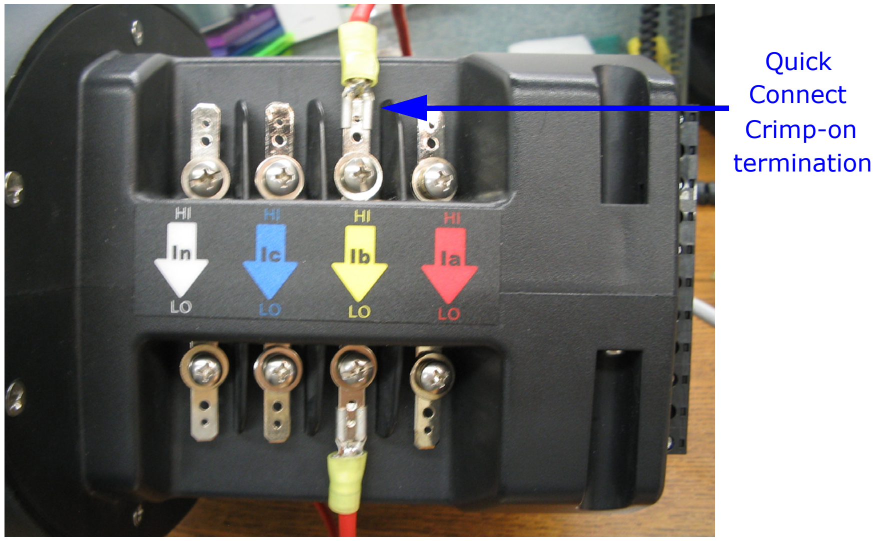


Figure 4.3: Quick Connect Electrical Connection

NOTE: For sustained loads greater that 10 amps, use pass through wiring method (Section 4.3), using 10 AWG wire.

4.5: Nexus® 1500+ Meter's Monitored Inputs

The diagram below shows the Nexus® 1500+ meter's inputs, and the following sections give details on them. Note that I/O is also displayed, for clarity.

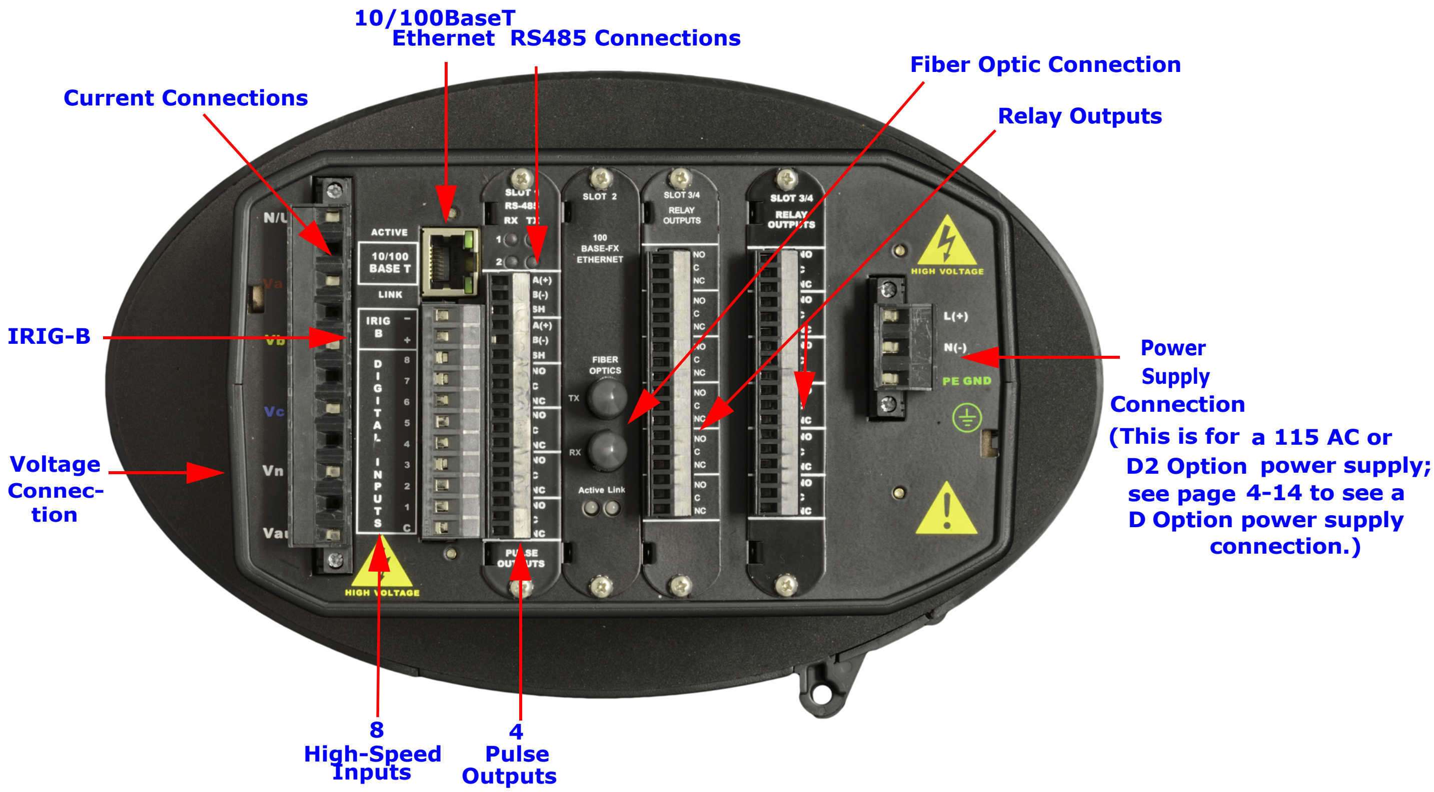


Figure 4.4: Voltage and Power Supply Connections, Current Connections, RS485, Pulse Outputs, IRIG-B, 10/100BaseT Ethernet, High-Speed Inputs, Fiber Optic Connection, and Relay Outputs

4.5.1: Voltage Inputs

Select a wiring diagram from Section 4.6 that best suits your application and wire the meter exactly as shown. For proper operation, the voltage connection must be maintained and must correspond to the correct terminal. Program the PT ratios in the Device Profile section of the CommunicatorPQA® software; see the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for details.

4.5.1.1: Wiring the Voltage Inputs

- The cable required to terminate the voltage sense circuit should have an insulation rating greater than 600VAC and a current rating greater than 0.1A.
- Wire type: Solid or stranded
- Wire gauge: 12-24 AWG for either solid or stranded wire
- Strip length: 7-8mm
- Torque: 5 Lb-In

4.5.1.2: Fusing the Voltage Connections

- For accuracy of the readings and for protection, EIG requires using 0.5 A/600 V fast acting fuses on all voltage inputs.
- The Nexus® 1500+ meter allows measurement up to a nominal 347 V AC phase to neutral and up to 600 V AC phase to phase. Potential Transformers (PTs) are required for higher voltages to insure proper safety.

4.5.2: Wiring the Vaux Input

The voltage auxiliary (Vaux) connection is an auxiliary voltage input that can be used for any desired purpose, such as monitoring two different lines on a switch. The Vaux voltage rating is the same as the metering voltage input connections.

4.5.3: Ground Connections

The meter's PE GND terminal should be connected directly to the installation's protective earth ground. Use AWG#12/2.5mm^2 wire for this connection.

4.5.4: Current Inputs

Program the CT ratios in the Device Profile section of the CommunicatorPQA® software; see the CommunicatorPQA® *and MeterManagerPQA® Software User Manual* for details.

4.5.4.1: Wiring the Current Inputs

Mount the current transformers (CTs) as close as possible to the meter. The following table illustrates the maximum recommended distances for various CT sizes, assuming the connection is via 14 AWG cable.

EIG Recommendations

CT Size (VA)	Maximum distance from CT to Nexus® 1500+ Meter (Feet)
2.5	10
5	15
7.5	30
10	40
15	60
30	120

WARNING! DO NOT leave the secondary of the CT open when primary current is flowing. This may cause high voltage, which will overheat the CT. If the CT is not connected, provide a shorting block on the secondary of the CT.

AVERTISSEMENT! NE PAS laisser le transformateur de courant secondaire ouvert lorsque le courant primaire est fluent. Cela peut provoquer une haute tension qui surchauffera le transformateur de courant. Si ce dernier n'est pas branché, fournir un court-circuit sur le transformateur de courant secondaire.

It is important to maintain the polarity of the CT circuit when connecting to the Nexus® 1500+ meter. If the polarity is reversed, the meter will not provide accurate readings. CT polarities are dependent upon correct connection of CT leads and the direction CTs are facing when clamped around the conductors. Although shorting blocks are not required for proper meter operation, EIG recommends using shorting blocks to allow removal of the Nexus® 1500+ meter from an energized circuit, if necessary.

4.5.4.2: Isolating a CT Connection Reversal

For a Wye System, you may either:

- Check the current phase angle reading on the Nexus® 1500+ meter's display (see Chapter 6). If it is negative, reverse the CTs.
- Go to the Phasors screen of the CommunicatorPQA® software application.* Note the phase relationship between the current and voltage: they should be in phase with each other.

For a Delta System:

Go to the Phasors screen of the CommunicatorPQA® software application.* The current should be 30 degrees off the phase-to-phase voltage.

*See the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions.

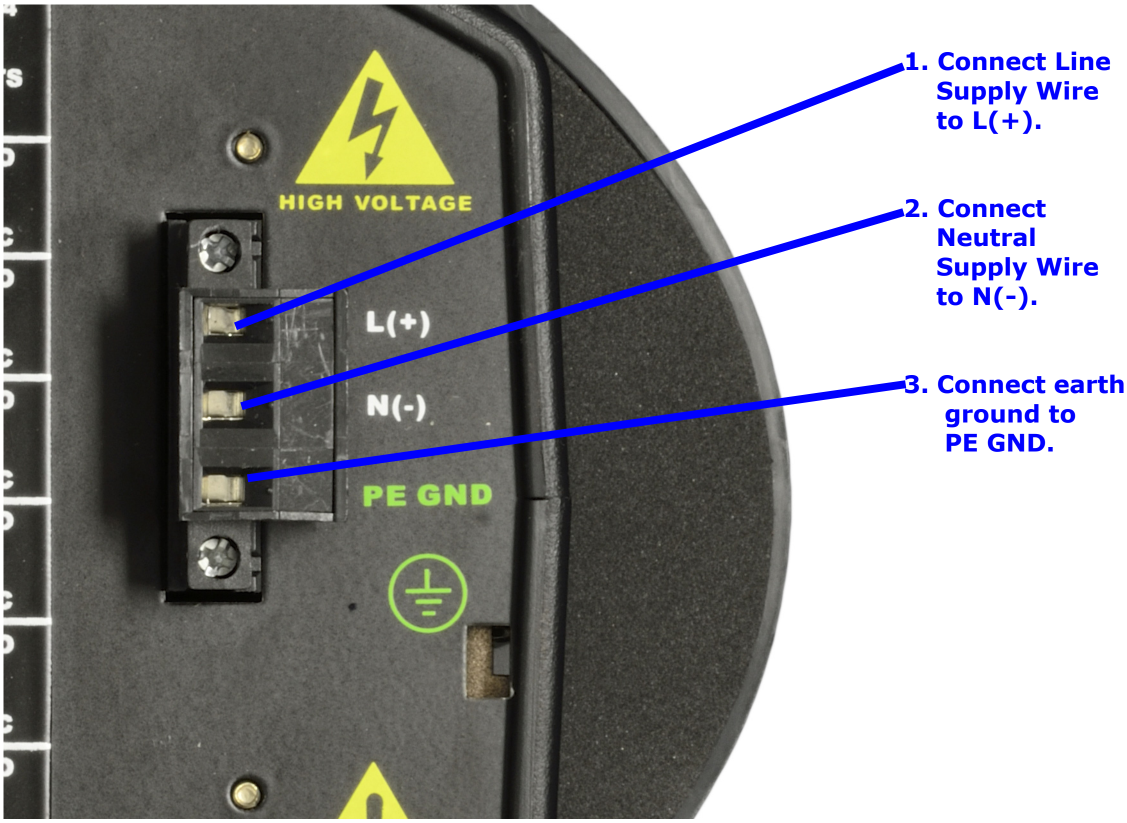
4.5.5: Instrument Power Supply Connections

- Wire gauge: 12-18 AWG for either solid or stranded wire
- Torque: 3.5 Lb-In
- Branch circuit protection size should be 15 A.

The Nexus® 1500+ meter requires a separate power source. There are three control power options: 115AC, D2 high-voltage, and D low-voltage.

CAUTION: The power supply connections vary depending on the power supply Option being used. **CAREFULLY** follow the instructions and drawings in Sections 4.5.5.1-4.5.5.3 for proper wiring.

4.5.5.1: 115AC Power Supply



For the 115AC Option power supply:

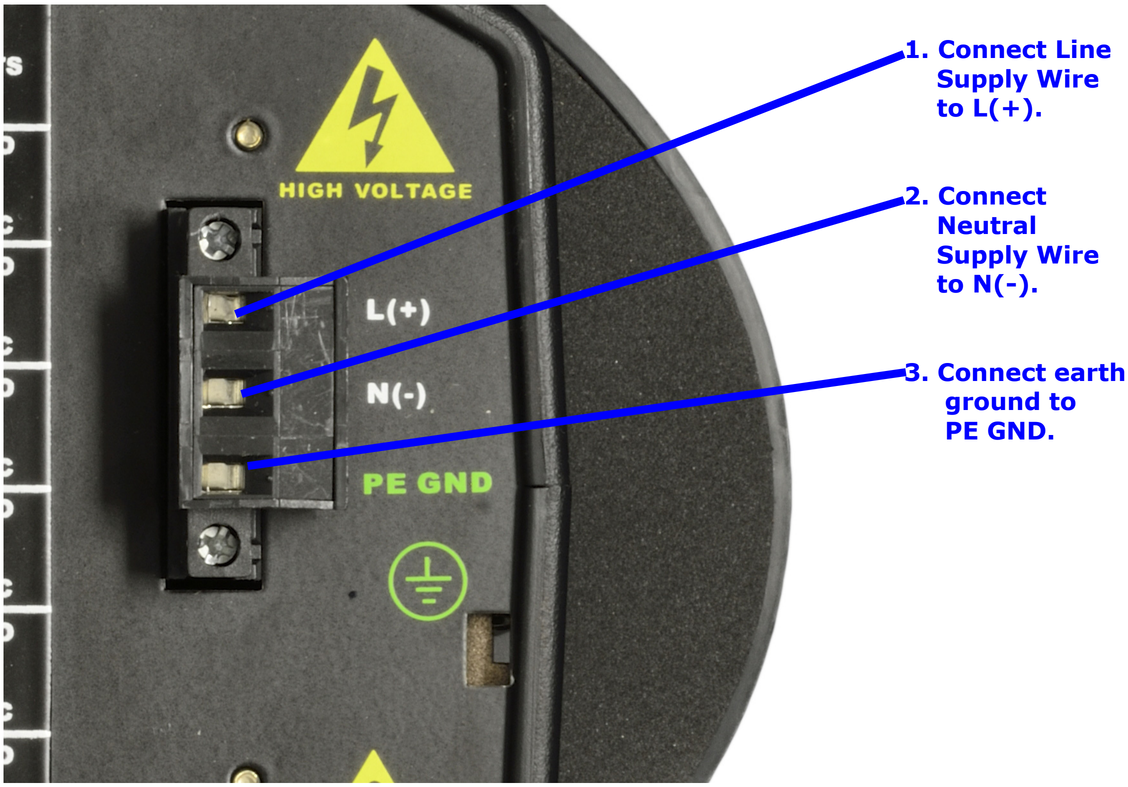
1. Connect the line supply wire to the L+ terminal.

2. Connect the neutral supply wire to the N(-) terminal.

3. Connect earth ground to the PE GND terminal.

Add a properly voltage-rated, 3 A/500 V, time-delayed (slow blow) fuse in the power supply feed.

4.5.5.2: D2 High-Voltage Power Supply



For the D2 Option power supply:

1. Connect the line supply wire to the L+ terminal.

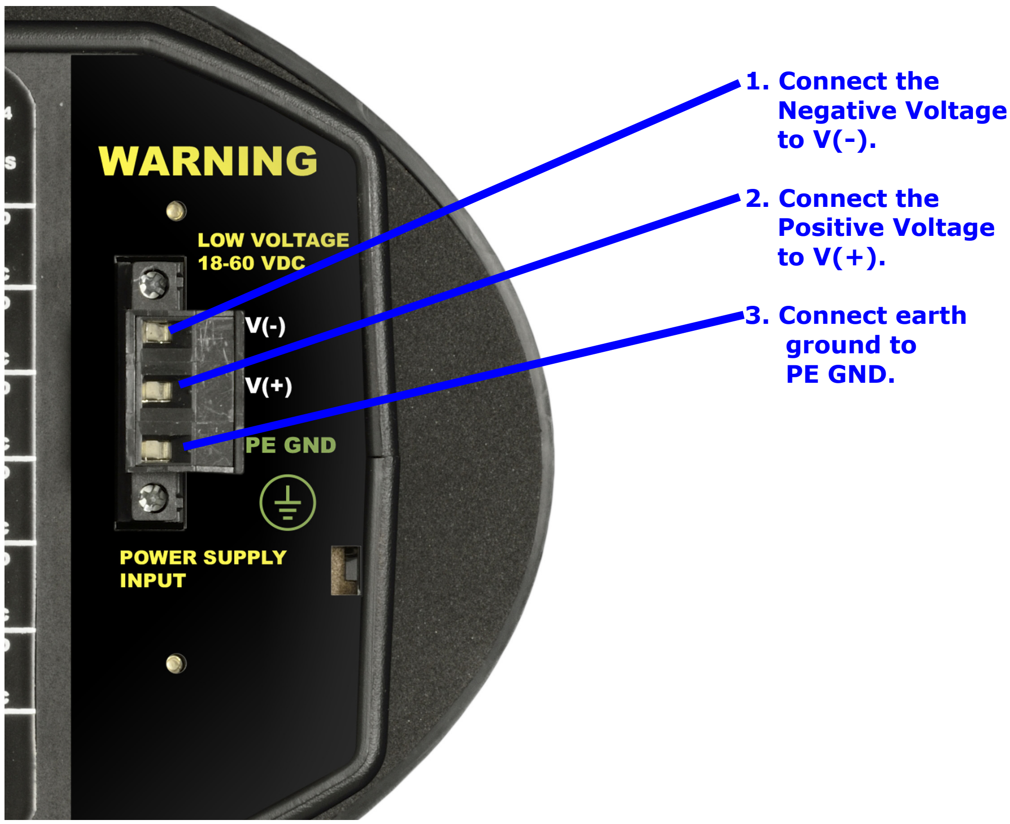
2. Connect the neutral supply wire to the N- terminal.

3. Connect earth ground to the PE GND terminal.

Add a properly voltage-rated, 3 A/500 V, time-delayed (slow blow) fuse in the power supply feed.

4.5.5.3: D Low-Voltage Power Supply

CAUTION: Note that the wiring for the D Option power supply has the Positive and Negative terminals **REVERSED** from the 115AC and D2 models - **BE CAREFUL** to follow the diagram and instructions below.



For the D Option power supply:

1. Connect the negative voltage to the V(-) terminal.

2. Connect the positive voltage to the V(+) terminal.

3. Connect earth ground to the PE GND terminal.

Add a properly voltage-rated, 7 A, time-delayed (slow blow) fuse in the power supply feed.

4.6: Wiring Diagrams

The meter must be wired specifically for the power system circuit it is measuring. Power system circuit diagrams are shown on the following pages. Choose the diagram that best suits your application. If the connection diagram you need is not shown, contact EIG for a custom connection diagram.

IMPORTANT! Any unused sense voltage inputs must be shorted to Neutral input.

Service	PTs	CTs	Measurement Method	Figure No.
4W Wye/ Delta	0, Direct Connect	3(4*)	3 Element	4.5
4W Wye/ Delta	3	3(4*)	3 Element	4.6
4W Wye	2	3	2.5 Element	4.7
4W Wye	0, Direct Connect	3	2.5 Element	4.8
3W Open Delta	2	2	2 Element	4.9
3W Open Delta	0, Direct Connect	2	2 Element	4.10

*With optional CT for current measurement only.

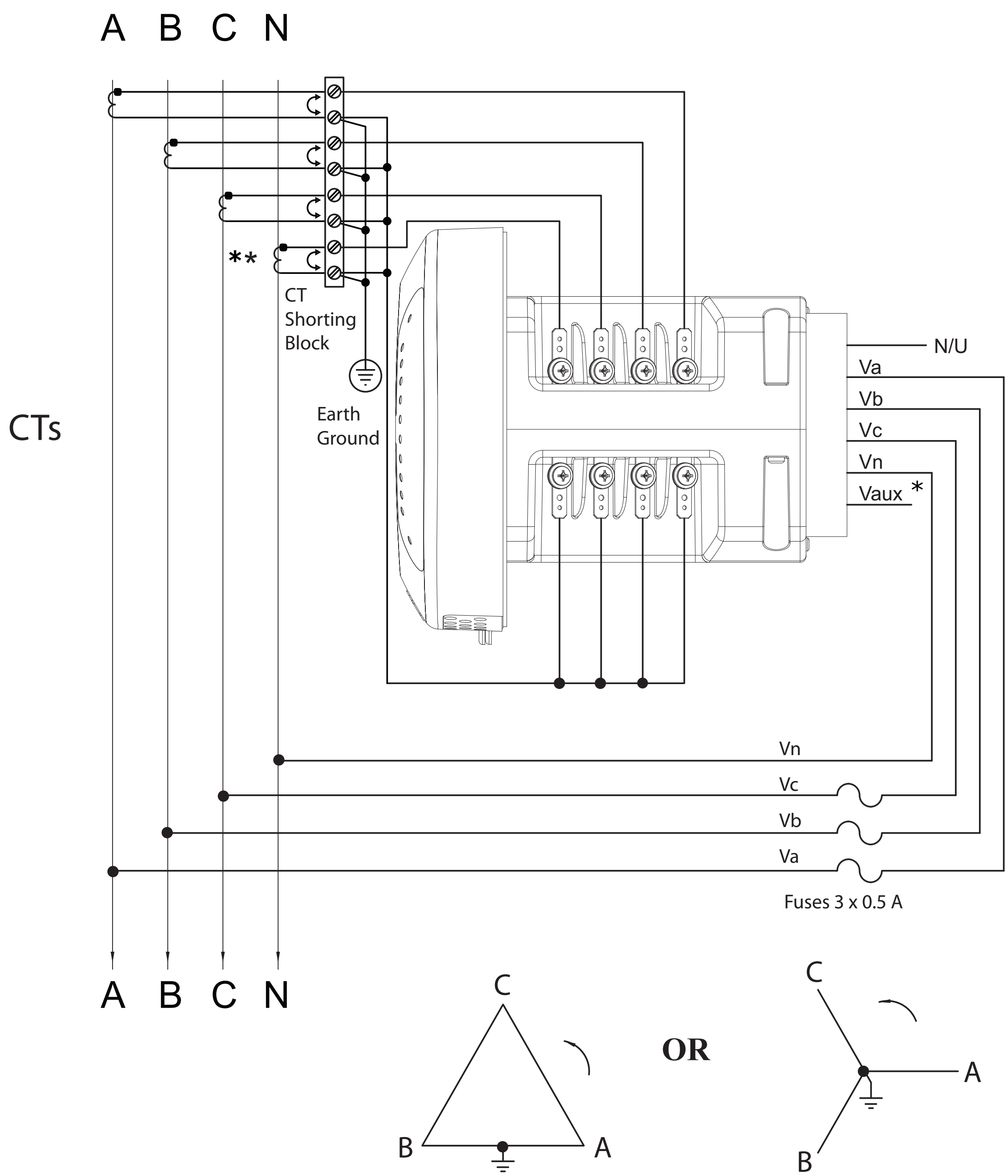


Figure 4.5: 4-Wire Wye or Delta***, 3 Element Direct Connect with 4 CTs

* See Section 4.5.2.

** Optional CT for current measurement only.

*** Typically used with Wye system (see 2 Element Delta wiring diagrams).

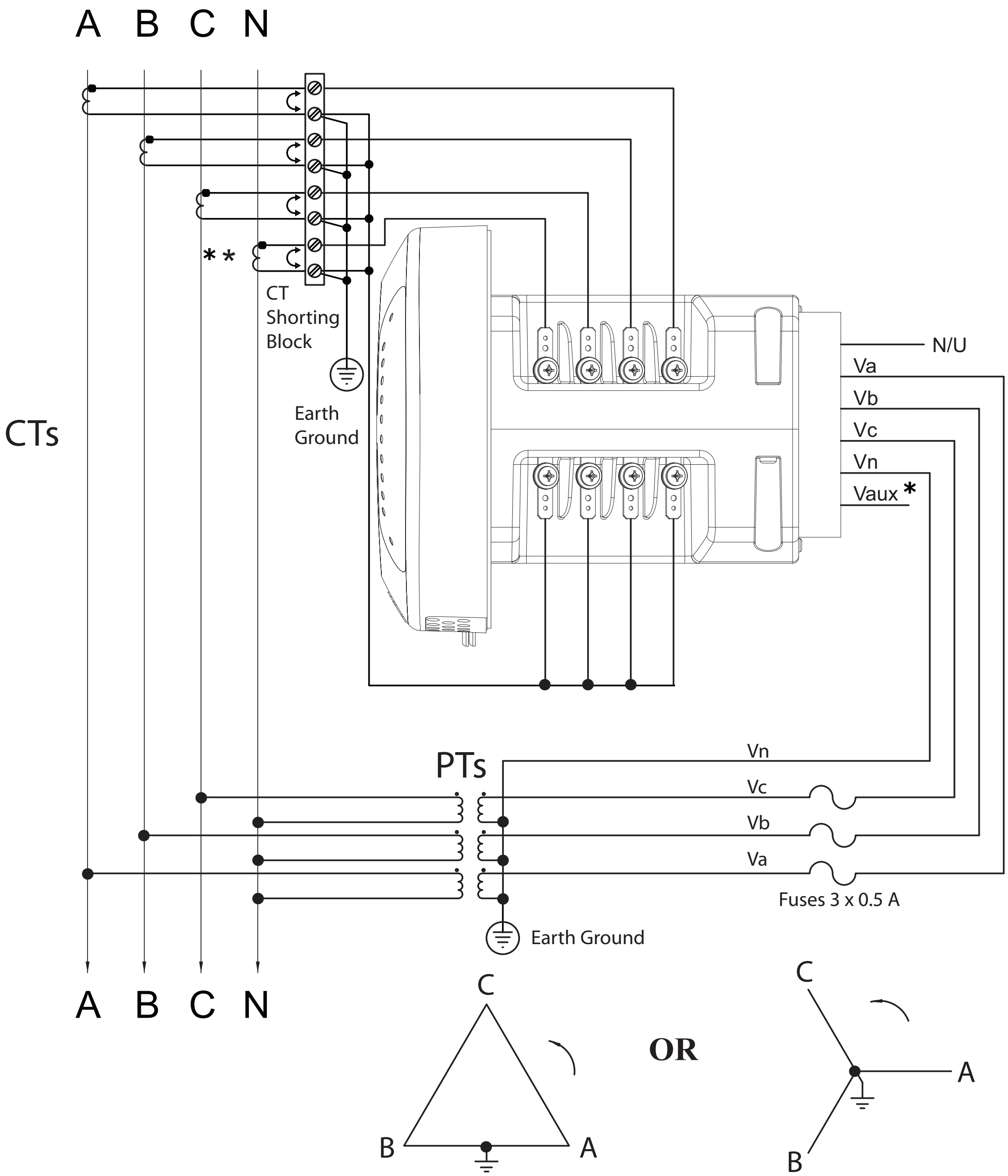


Figure 4.6: 4-Wire Wye or Delta***, 3-Element with 3 PTs and 4 CTs

* See Section 4.5.2.

** Optional CT for current measurement only.

*** Typically used with Wye system (see 2 Element Delta wiring diagrams).

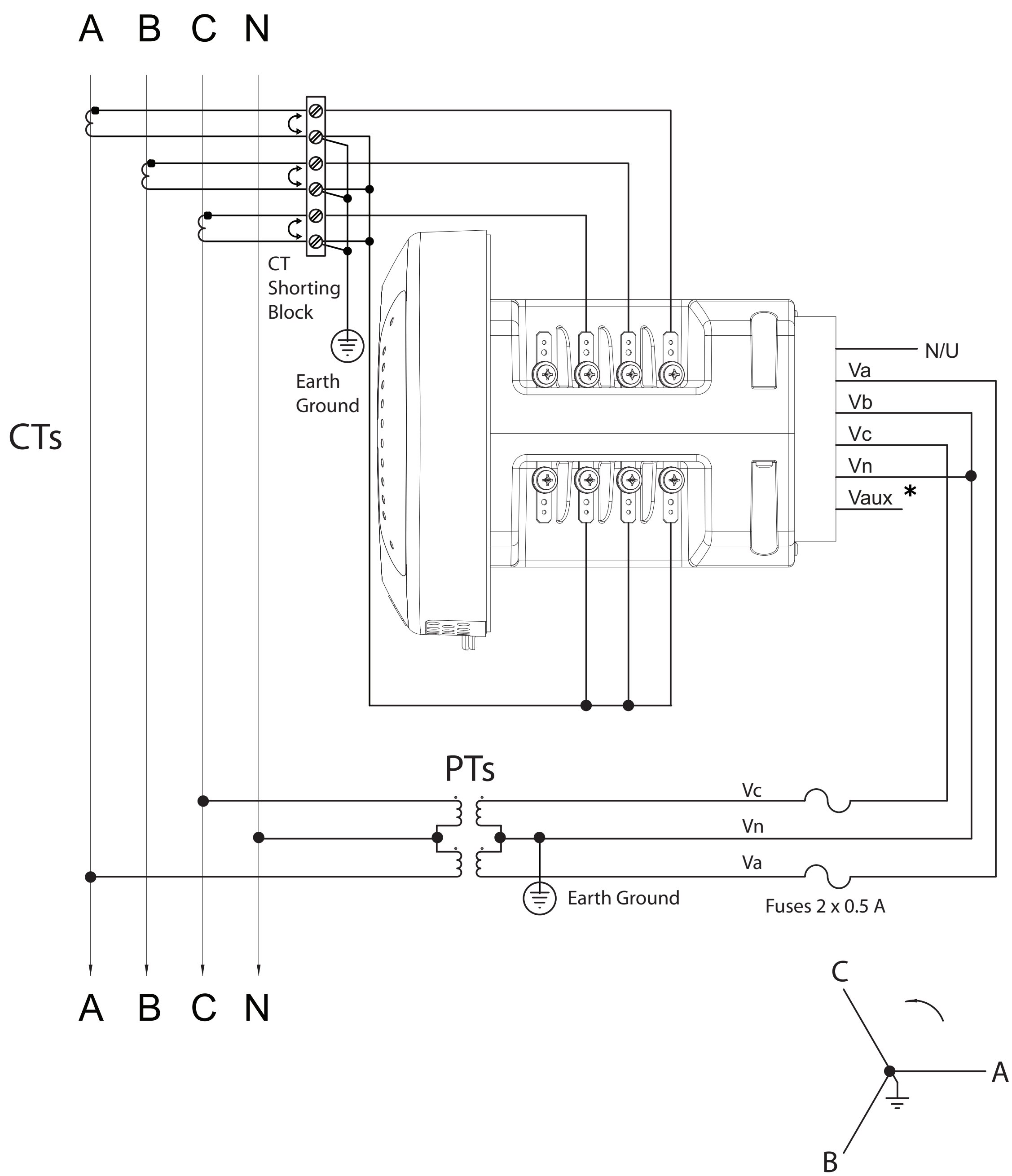


Figure 4.7: 4-Wire Wye, 2.5-Element with 2 PTs and 3 CTs

* See Section 4.5.2.

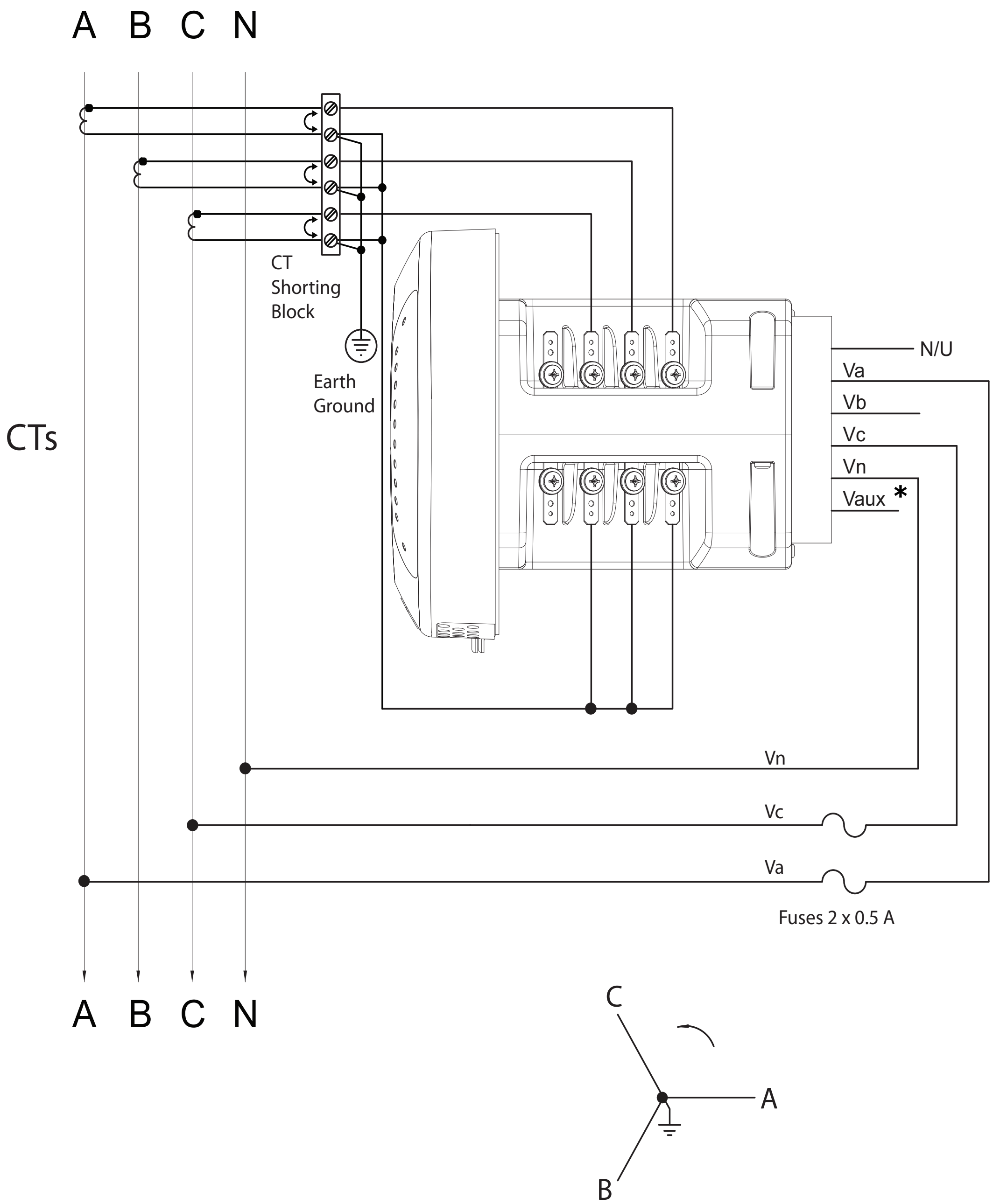


Figure 4.8: 4-Wire Wye, 2.5-Element Direct Connect with 3 CTs

* See Section 4.5.2.

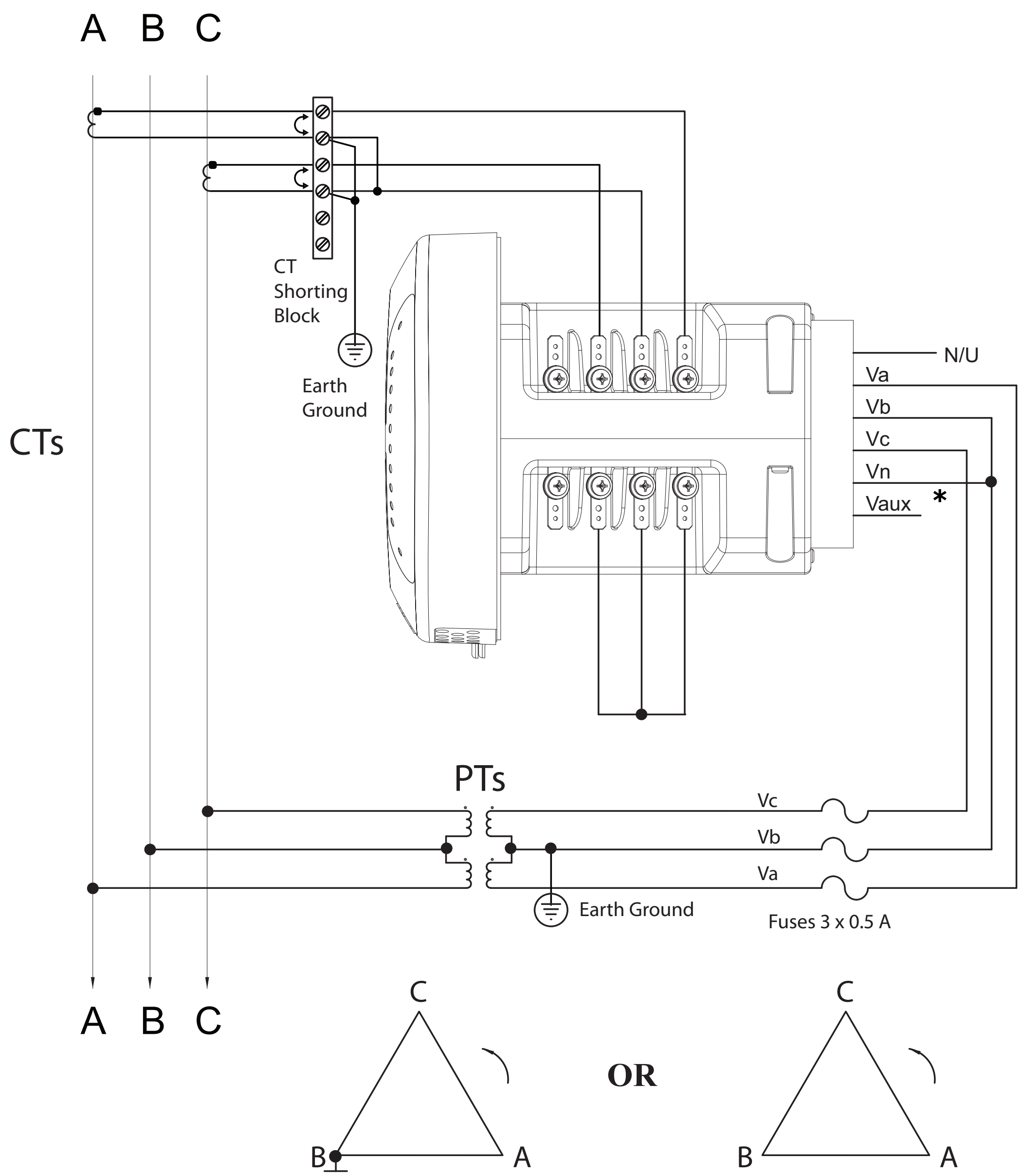


Figure 4.9: 3-Wire, 2-Element Open Delta** with 2 PTs and 2 CTs

* See Section 4.5.2.

** Typically used for Delta systems.

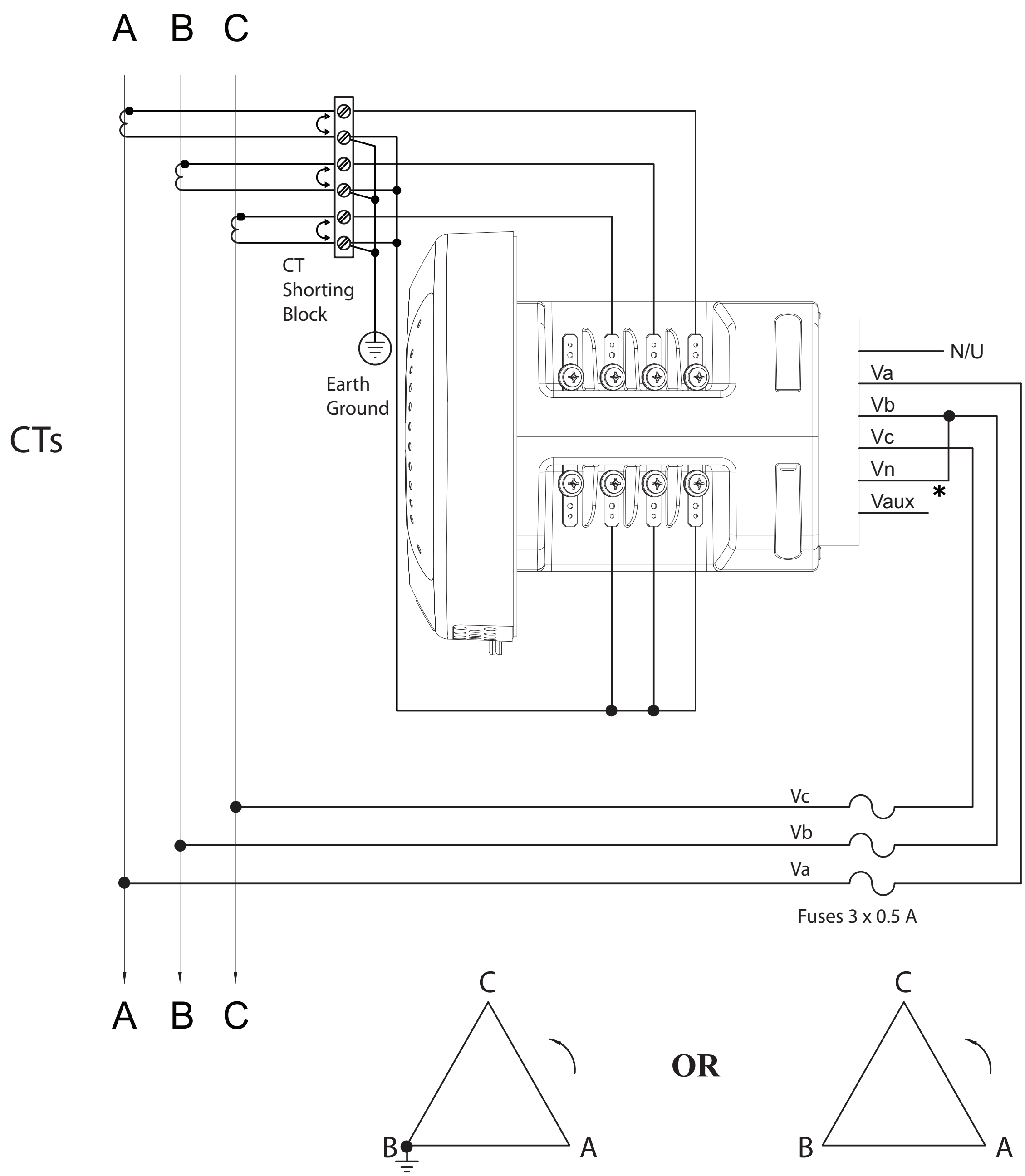


Figure 4.10: 3-Wire, 2-Element Open Delta** Direct Voltage with 2 CTs

* See Section 4.5.2.

** Typically used for Delta systems.

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5: Communication Wiring

5.1: Communication Overview

The Nexus® 1500+ meter has many simultaneous paths for sending data to software systems or other electronic instruments. This chapter contains instructions for using the Nexus® 1500+ meter's standard and optional communication port capabilities. The Nexus® 1500+ meter offers the following communication modes:

- RJ45 10/100BaseT Ethernet connection (standard)
- ANSI Optical port (standard)
- USB 2.0 connection (standard)
- Two RS485 communication ports (optional)
- Second Ethernet connection - either RJ45 or Fiber Optic (optional)

5.2: RJ45 and Fiber Ethernet Connections

The standard RJ45 connection allows a Nexus® 1500+ meter to communicate with multiple PCs simultaneously. The RJ45 jack is located on the back of the meter. The Nexus® 1500+ meter's Ethernet port conforms to the IEEE 802.3, 10BaseT and 100BaseT specifications using unshielded twisted pair (UTP) wiring. EIG recommends CAT5 for cabling. For details on this connection, see Chapter 9.

The optional second Ethernet connection for the Nexus® 1500+ meter consists of either an RJ45 (NTRJ) or a Fiber Optic (NTFO) Communication card. See Chapter 11 for details.

5.3: ANSI Optical Port

The Optical port lets the Nexus® 1500+ meter communicate with one other device, e.g., a PC. Located on the left side of the meter's face, it provides communication with the meter through an ANSI C12.18 Type II Magnetic Optical Communications Coupler, such as the B10U Optical Probe, which connects to the USB port of the PC.
NOTE: You can order this device from EIG's webstore:
https://www.electroind.com/products/b10u-zero-power-ansi-optical-probe/.

You can then program the meter through the Optical port using CommunicatorPQA® software.

Figure 5.1: B10U Optical Probe

B10U Instructions:

Depending on your OS, you may need to download and install the driver for the B10U. From its webpage (above address), click Downloads>Tech Documents>USB Driver. When you download the driver file you will see a file that has installation instructions.

Note that the Nexus® 1500+ meter's optical port offers the standard inverted mode for communication, but can also be programmed in non-inverted mode using the CommunicatorPQA® software. Refer to Chapter 11 in the *CommunicatorPQA®* and *MeterManagerPQA® Software User Manual* for instructions (you can download the manual from https://www.electroind.com/products/communicatorpqa-software-application-5/ - click Downloads>Tech Documents>User Manual).

5.4: USB Connection

The USB connection allows the Nexus® 1500+ meter to communicate with a computer that has a USB 1.1 or USB 2.0 Host port. The meter's USB port is configured to operate as a virtual serial communication channel that the PC sees as a simple COM port with a baud rate of up to 115200. The USB virtual serial communication channel:

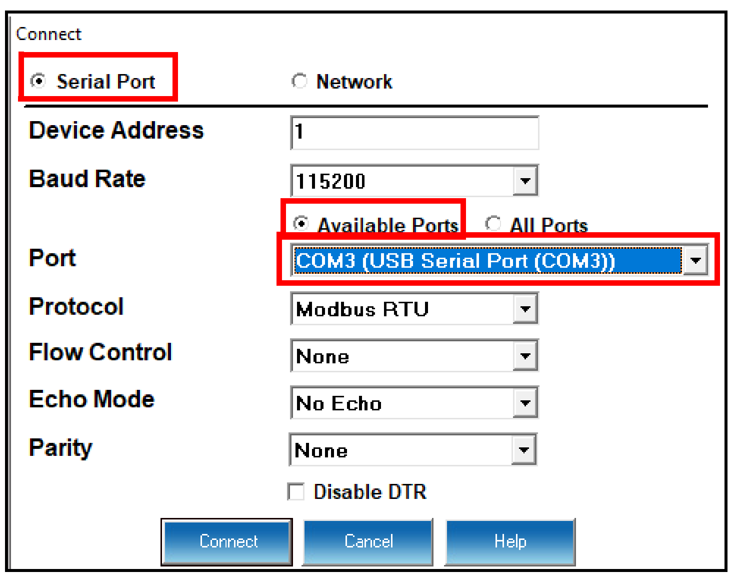
- Supports legacy applications that were designed to only work with a serial communication channel
- Is compatible with standard USB cables that terminate with a USB Type B plug (see Figure 5.2)
- The maximum length of the USB cable is 5 meters. Greater lengths require hubs or active extension cables (active repeaters).

Figure 5.2: USB Type B Plug

If you are using a PC with Windows® 7 OS or higher, connect the USB cable from your PC to the meter’s USB port on the front panel. The system will install a driver for you. (For earlier operating systems, EIG provides a driver for PC compatible computers. See 5.4.1: Procedure for OS Earlier than Windows 7 on page 5-4.)

To connect to the meter using the USB port:

1. Open CommunicatorPQA® software.
2. Click the Connect icon. You will see the Connect screen, shown on the right. Click the Serial Port and Available Ports radio buttons and select the virtual COM Port (USB Serial Port) from the Port field’s pull-down menu.
3. Click Connect.



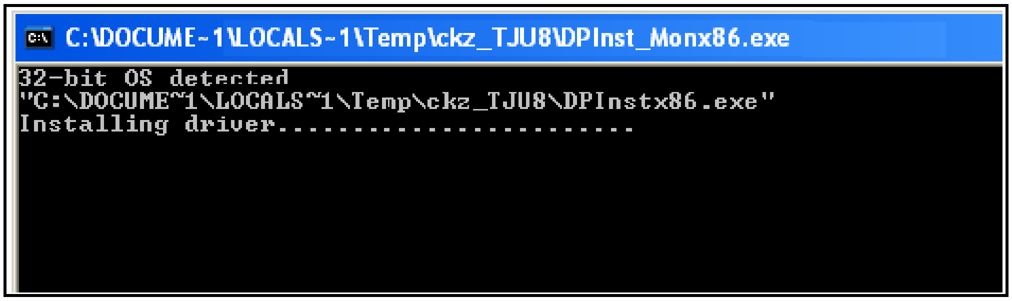
5.4.1: Procedure for OS Earlier than Windows 7

1. Use this link to access the meter’s webpage:
   https://www.electroind.com/products/nexus-1500-power-quality-meter-with-phasor-measurement-unit/

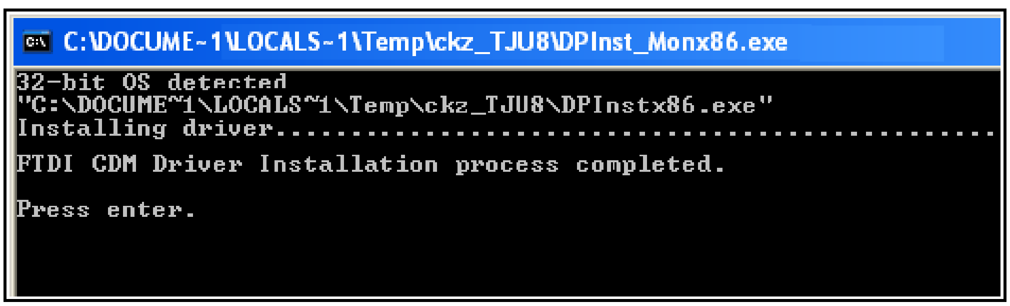
2. From the right side of the webpage click Downloads>Tech Documents>USB port driver.

3.Extract the setup file from the zip folder.

4. Open the setup file. The setup program opens a DOS command screen on your PC, as shown below. You will see a message indicating that the driver is being installed.



Once the driver installation is complete, you will see the following message on the DOS command screen.



5. Press **Enter**. The DOS screen closes.

6. Plug a USB cable into your PC and the Nexus® 1500+ meter's USB port. You will see pop-up message windows telling you that new hardware has been found and that it is installed and ready to use. See the connection instructions on the previous page.

5.5: RS485 Connections

The optional RS485 connections allow multiple Nexus® 1500+ meters to communicate with another device at a local or remote site. All RS485 links are viable for a distance of up to 4000 feet (1219 meters). RS485 ports 1 and 2 on the Nexus® 1500+ meter are optional two-wire, RS485 connections with a baud rate of up to 115200.

If you are planning to use an RS232 connection on your PC, you need an RS485 to RS232 converter, such as EIG's Unicom 2500. See Section 5.5.1 for information on using the Unicom 2500 with the Nexus® 1500+ meter.

NOTE: You can buy the Unicom 2500 from EIG's webstore: www.electroind.com/store. Select the Communications Products category from the left side of the webpage.

Figure 5.3 shows the detail of a 2-wire RS485 connection.

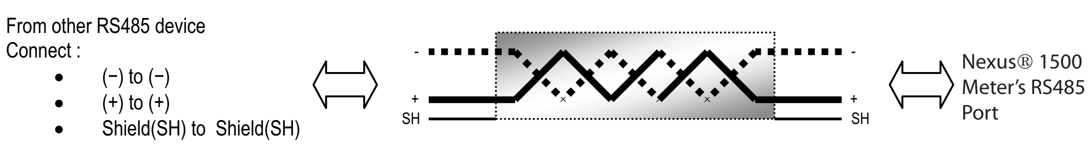


Figure 5.3: 2-wire RS485 Connection

NOTES on RS485 Communication:

- Use a shielded twisted pair cable 22 AWG (0.33 mm2) or thicker, and ground the shield, preferably at one location only.
- Establish point-to-point configurations for each device on a RS485 bus: connect (+) terminals to (+) terminals; connect (-) terminals to (-) terminals.

- Connect up to 31 meters on a single bus using RS485. Before assembling the bus, each meter must have a unique address: refer to Chapter 3 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions.

- Protect cables from sources of electrical noise.

- Avoid both "Star" and "Tee" connections (see Figure 5.5).

- Connect no more than two cables at any one point on an RS485 network, whether the connections are for devices, converters, or terminal strips.

- Include all segments when calculating the total cable length of a network. If you are not using an RS485 repeater, the maximum length for cable connecting all devices is 4000 feet (1219 meters).

- Connect shield to RS485 Master and individual devices as shown in Figure 5.4. You may also connect the shield to earth-ground at one point.

NOTE: Termination Resistors (R_T) may be needed on both ends for longer length transmission lines. However, since the meter has some level of termination internally, Termination Resistors may not be needed. When they are used, the value of the Termination Resistors is determined by the electrical parameters of the cable.

Figure 5.4 shows a representation of an RS485 Daisy Chain connection. Refer to Section 5.5.1 for details on RS485 connection for the Unicom 2500.

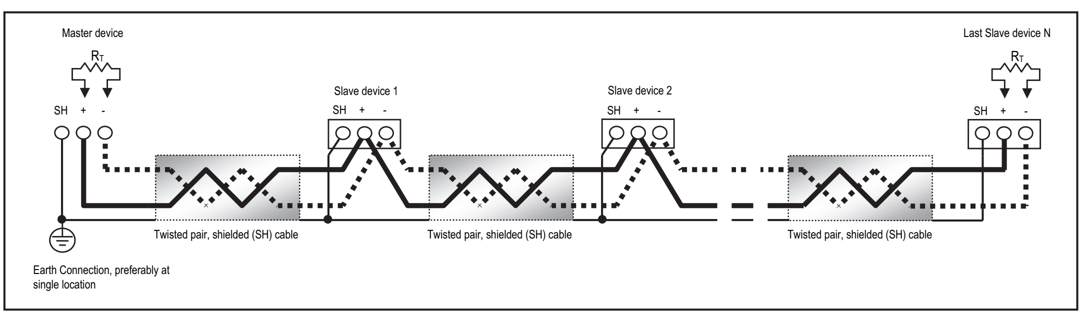


Figure 5.4: RS485 Daisy Chain Connection

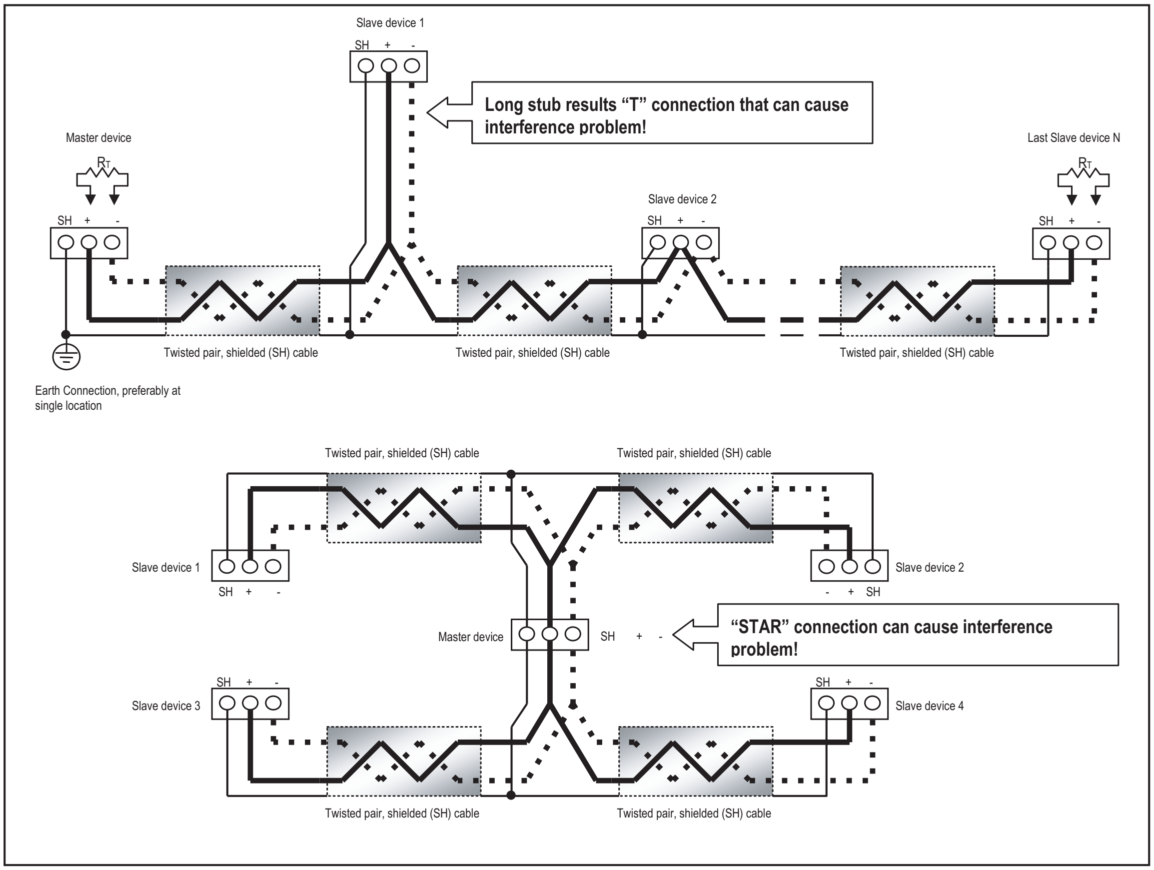


Figure 5.5: Incorrect "T" and "Star" Topologies

5.5.1: Using the Unicom 2500

The Unicom 2500 provides RS485/RS232 connection, allowing a Nexus® 1500+ meter with the optional RS485 port to communicate with a PC or other RS232 serial device. See the *Unicom 2500 Installation and Operation Manual* for additional information. **You can order the Unicom 2500 and the recommended communication cable for it from EIG's webstore: www.electroind.com/store.** From the left side of the webpage, select Communication Products for the Unicom 2500 and Cables and Accessories for the RS485 4-wire to 2-wire cable. Figure 5.6 illustrates the Unicom 2500 connections for RS485.

NOTE: We recommend you use EIG's 4-wire to 2-wire communication cable so you do not have to use jumper wires. The part number is E145350 and it can be ordered from the EIG web store: www.electroind.com/product/e145350-rs485-4-wire-to-2-wire-cable/

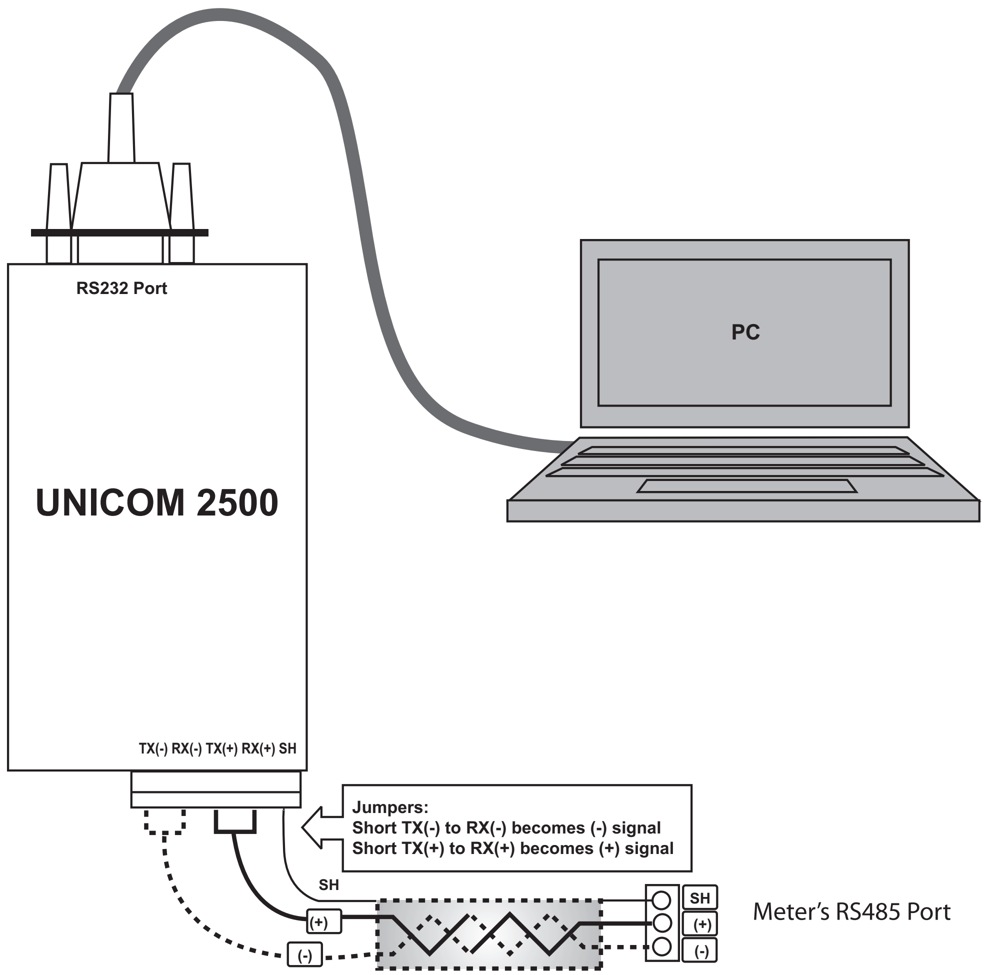
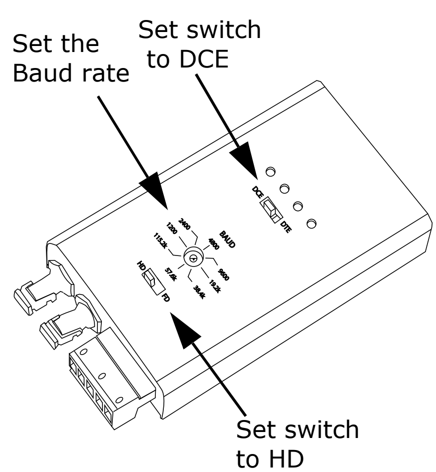


Figure 5.6: Unicom 2500 with Connections



The Unicom 2500 can be configured for either 4-wire or 2-wire RS485 connections. Since the Nexus® meter uses a 2-wire connection, **unless you are using the RS485 4-wire to 2-wire communication cable available from EIG's online store**, you need to add jumper wires to convert the Unicom 2500 to the 2-wire configuration. As shown in Figure 5.7, you connect the "RX-" and "TX-" terminals with a jumper wire to make the "-" terminal, and connect the "RX+" and "TX+" terminals with a jumper wire to make the "+" terminal. See the figure on the right for the Unicom 2500's settings. The

Unicom’s Baud rate must match the Baud rate of the meter’s RS485 port: you set the Baud rate by turning the screw to point at the rate you want.

5.6: Remote Communication with RS485

Use either optional RS485 port on the Nexus® 1500+ meter. The link using RS485 is viable for up to 4000 feet (1219 meters).

Use CommunicatorPQA® software to set the port's baud rate to 9600 and enable Modbus ASCII protocol. See Chapter 3 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions. Remember, Modbus RTU **will not** function properly with Modem communication. You must change the protocol to Modbus ASCII.

You must use an RS485 to RS232 converter and a Null modem. EIG recommends using its Modem Manager, a sophisticated RS232/RS485 converter that enables devices with different baud rates to communicate. It also eliminates the need for a Null modem and automatically programs the modem to the proper configuration. Also, if the telephone lines are poor, Modem Manager acts as a line buffer, making the communication more reliable.

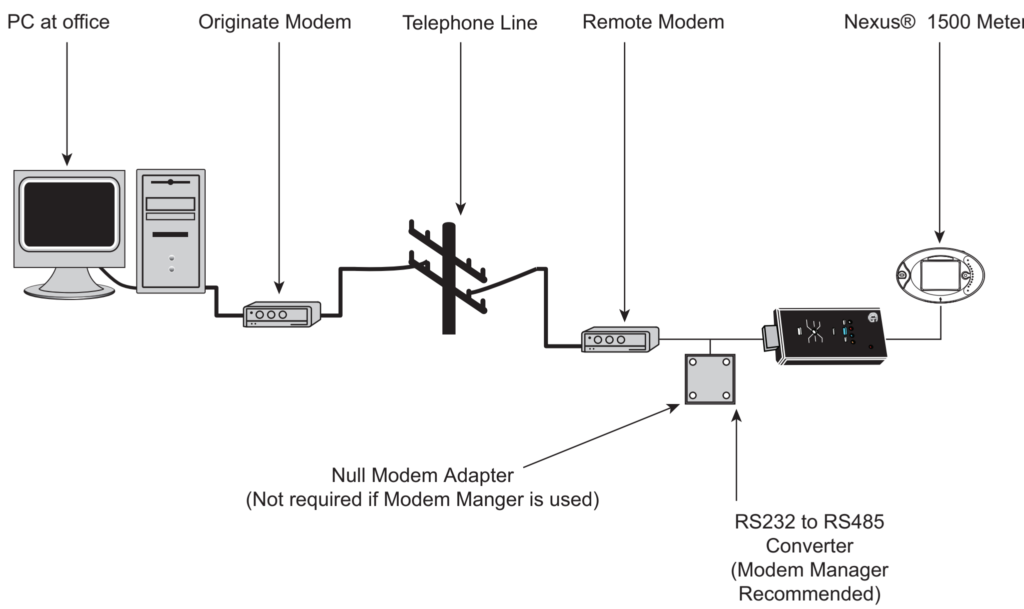


Figure 5.7: Remote Communication

5.7: Programming Modems for Remote Communication

You must program a modem before it can communicate properly with most RS485 or RS232-based devices. This task is often quite complicated because modems can be unpredictable when communicating with remote devices.

If you are not using the EIG Modem Manager device, you must set the following strings to communicate with the remote Nexus® meter(s). Consult your modem's User manual for the proper string settings or see Section 5.8 for a list of selected modem strings.

Modem Connected to a Computer (the Originate Modem)

- Restore modem to factory settings. This erases all previously programmed settings.
- Set modem to display Result Codes. The computer will use the result codes.
- Set modem to Verbal Result Codes. The computer will use the verbal result codes.
- Set modem to use DTR Signal. This is necessary for the computer to insure connection with the originate modem.
- Set modem to enable Flow Control. This is necessary to communicate with remote modem connected to the Nexus® meter.
- Instruct modem to write the new settings to activate profile. This places these settings into nonvolatile memory; the setting will take effect after the modem powers up.

Modem Connected to the Nexus® Meter (the Remote Modem)

- Restore modem to factory settings. This erases all previously programmed settings.
- Set modem to auto answer on n rings. This sets the remote modem to answer the call after *n* rings.
- Set modem to ignore DTR Signal. This is necessary for the Nexus® meter, to insure connection with originate modem.
- Set modem to disable Flow Control. The Nexus® meter's RS232 communication does not support this feature.

- Instruct modem to write the new settings to activate profile. This places these settings into nonvolatile memory; the setting will take effect after the modem powers up.

- When programming the remote modem with a terminal program, make sure the baud rate of the terminal program matches the Nexus® meter's baud rate.

5.8: Selected Modem Strings

Modem	String/Setting
Cardinal modem	AT&FE0F8&K0N0S37=9
Zoom/Faxmodem VFX V.32BIS(14.4K)	AT&F0&K0S0=1&W0&Y0
Zoom/Faxmodem 56Kx Dual Mode	AT&F0&K0&C0S0=1&W0&Y0
USRobotics Sportster 33.6 Faxmodem: DIP switch setting	AT&F0&N6&W0Y0 (for 9600 baud) Up Up Down Down Up Up Up Down
USRobotics Sportster 56K Faxmodem: DIP switch setting	AT&F0&W0Y0 Up Up Down Down Up Up Up Down

5.9: High-speed Inputs Connection

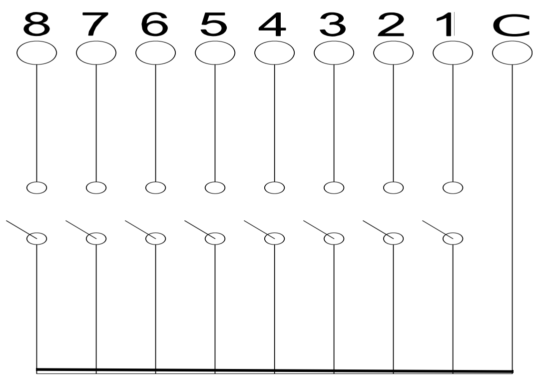
The Nexus® 1500+ meter's built-in high-speed inputs can be used in two ways:

- Attaching status contacts from relays, breakers or other devices for status or wave-form initiation

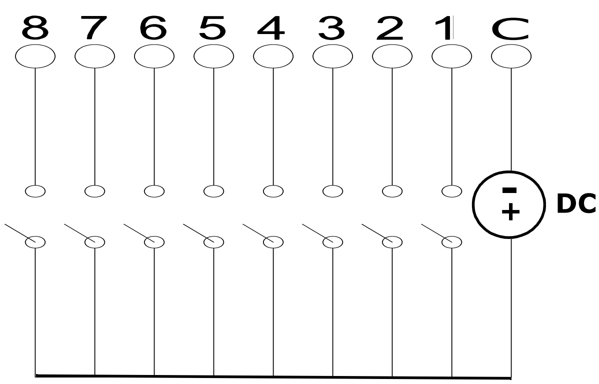
- Attaching the KYZ pulse outputs from other meters for pulse counting and totalizing

Even though these inputs are capable of being used as high-speed digital fault recording inputs, they serve a dual purpose as KYZ counters and totalizers. The function in use is programmable in the meter and is configured via the CommunicatorPQA® application. Refer to Chapter 11 in the *CommunicatorPQA®and MeterManagerPQA® Software User Manual* for instructions on programming these features.

The high-speed inputs can be used with either dry or wet field contacts. No user programming is necessary - the inputs automatically sense whether the circuit is externally wetted. If externally wetted, the common rides on a unit-generated Nominal 15 V DC and input up to 150 V DC is accepted. If internally wetted, the meter supplies the necessary voltage for the control application.



Connection for Dry Contacts



Connection for Wet Contacts

Figure 5.8: High-Speed Inputs Connection

5.10: IRIG-B Connections

IRIG-B is a standard time code format that synchronizes event time-stamping to within 1 millisecond. An IRIG-B signal-generating device connected to the GPS satellite system synchronizes Nexus® 1500+ meters located at different geographic locations. Nexus® meters use an unmodulated signal from a satellite-controlled clock (such as Arbiter 1093B). For details on installation, refer to the User's manual for the satellite-controlled clock in use. Below are installation steps and tips to help you.

Connection:

Connect the (+) terminal of the Nexus® meter to the (+) terminal of the signal generating device; connect the (-) terminal of the Nexus® meter to the (-) terminal of the signal generating device.

Installation:

Set Time Settings for the meter being installed.

1. From the CommunicatorPQA® Device Profile menu:

    a. Click **General Settings>Time Settings>one of the Time Settings lines** to open the Time Settings screen.

    b. Set the Time Zone and Daylight Savings (Select **AutoDST** or **Enable** and set dates).

    c. Click **Update Device Profile** to save the new settings.

    (See Chapter 11 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for details.)

2. Before connection, check that the date on the meter clock is correct (or, within 2 Months of the actual date). This provides the right year for the clock (GPS does not supply the year).

3. Connect the (+) terminal of the Nexus® meter to the (+) terminal of the signal generating device; connect the (-) terminal of the Nexus® meter to the (-) terminal of the signal generating device.

Troubleshooting Tip: The most common source of problems is a reversal of the two wires. If you have a problem, try reversing the wires.

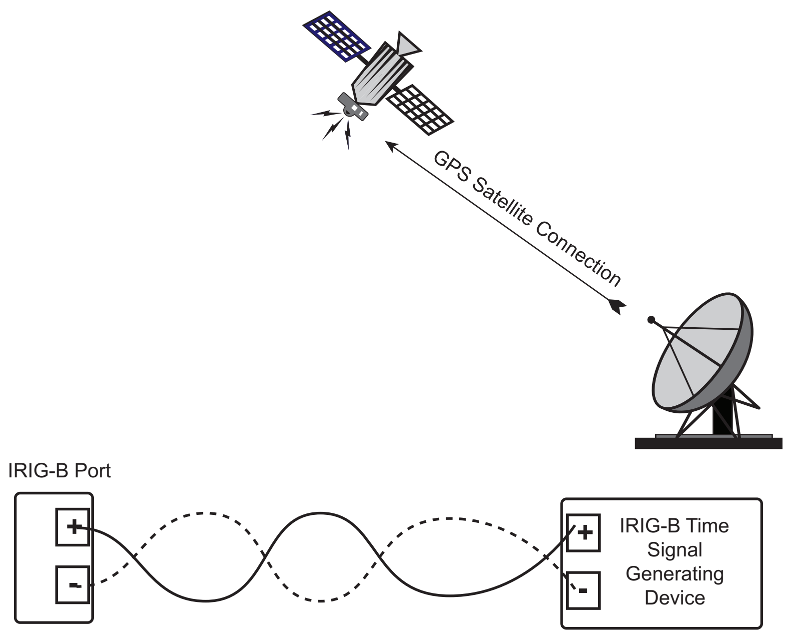


Figure 5.9: IRIG-B Communication

NOTE: Please make sure that the selected clock can drive the amount of wired loads.

5.11: Time Synchronization Alternatives

(See the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for details.)

IRIG-B (see Section 5.10 for more details)

- IRIG-B, or inter-range instrumentation group, time codes are clock signals received from a precision timing GPS receiver.
- All Nexus® 1500+ meters are equipped to use IRIG-B for time synchronization.
- If IRIG-B is connected, this form of time synchronization takes precedence over the internal clock. If the GPS Signal is lost, the internal clock takes over time keeping at the precise moment the signal is lost.
- IRIG-B is one of the two time synchronization methods you can use with synchrophasors (see Appendix E: Synchrophasor Systems on page E-1).

Line Frequency Clock Synchronization

- Line Frequency Sync (synchronization) allows the meter to use the AC line frequency as a time base to keep its internal clock accurate. It should be used as the default when better time synchronization is not available.
- All Nexus® meters are equipped with Line Frequency Clock Synchronization, which may be enabled or disabled for use instead of IRIG-B. If Line Frequency Clock Synchronization is enabled and power is lost, the internal clock takes over at the precise moment power is lost.

  NOTE: The valid frequency range for line synchronization is:
  - 50 Hz: 49.5 Hz <frequency< 50.5 Hz
  - 60 Hz: 59.5 Hz <frequency< 60.5 Hz

Internal Clock Crystal

- The Nexus® 1500+ meter is equipped with an internal clock crystal that is accurate to 3.5 ppm, or less than 10 seconds per month drift, and which can be used if IRIG-B is not connected and/or Line Frequency Clock Synchronization is not enabled.
- The meter has a battery backup that is used for the real time clock, only, in case of a power outage. The battery is a Panasonic BR3032, which is rated at 500 mAh and which has a battery life of at least ten years. A Low Batt message is displayed on the status bar of the CommunicatorPQA® software's Main screen (see Section 2.2.2 software manual for details) when the battery is equal to or less than 2.55 volts, which is still well within the operating range of the clock component. It is recommended that you change the battery within three months after the Low Batt message appears. Contact EIG’s customer service and support department at phone number 516-334-0870 (or fax number 516-338-4741) for battery replacement instructions.

SNTP (Simple Network Time Protocol)

- With SNTP you access a Network Time Protocol (NTP) Server for time synchronization. The NTP server can be either a device with a real-time clock that is networked with your meter, or an NTP server on the Internet. You can configure SNTP time synchronization for either the standard or the optional Ethernet card. SNTP configuration is done in the Device Profile. Refer to Chapter 11 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions.

DNP Time Synchronization

- Using CommunicatorPQA® software, you can set the meter to request time synchronization from the DNP Master. Requests can be made from once per minute to once per day. See the *Nexus® 1252/1262/1272/1500/1500+ DNP User Manual* for instructions. You can download the manual from EIG's website: www.electroind.com/dl_page.html.

IEEE 1588 PTPv2 (Precision Time Protocol)

- The time synchronization provided by optional IEEE 1588 PTPv2 architecture lets you synchronize time for a network without needing a GPS receiver for each node. The IEEE 1588 standard uses a "Best Master Clock" algorithm, which identifies the clock with the most accurate time and then synchronizes all the other devices on the network with it, to maintain accurate time throughout the network of devices. This time synchronization method achieves accuracy within the sub-microsecond range. When set up as the meter's time synchronization source, the meter's Network card 2 operates as a slave device which gets its time synchronization from a PTP Master. You use CommunicatorPQA® software to program IEEE 1588 PTPv2 as the meter's time synchronization source- see Chapter 11 in the *software manual,* for instructions.
- IEEE 1588 PTPv2 is one of the two time synchronization methods you can use with synchrophasors (see E: Synchrophasor Systems on page E-1).

Other Time Setting Tools

- **Tools>Set Device Time**: for manual or PC Time Setting
- **Script & Scheduler**: time Stamps Retrieved Logs and Data
- **MV90**: can synchronize time on retrievals in the form of a time stamp; refer to the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* (HHF Converter) for more MV90 details.

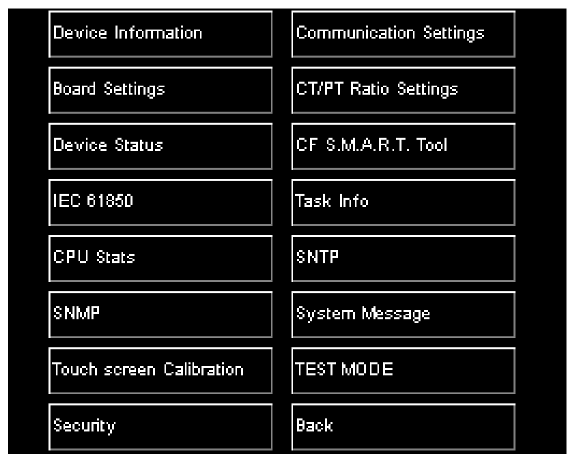
6: Using the Touch Screen Display

6.1: Introduction

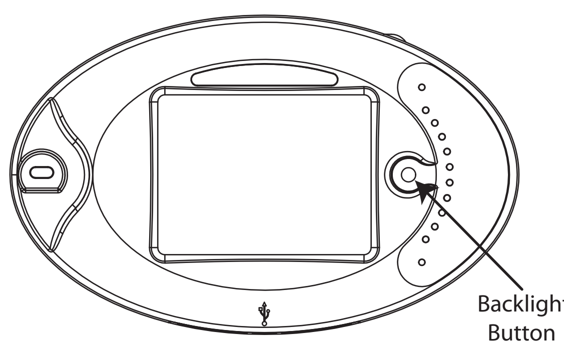
The Nexus® 1500+ meter's display is a QVGA (5.7 in., 320 x 240 pixel) LCD color display with a resistive touchscreen overlay. The display screens are divided into two groups:

- Fixed System screens - used for system data and diagnostics
- Dynamic screens - used for viewing electrical information

6.2: Fixed System Screens



There are 15 Fixed System screen options: Device Information, Communication Settings, Board Settings, CT/PT Ratio Settings, Device Status, CF S.M.A.R.T. Tool, IEC-61850, Task Info, CPU Stats, SNTP, SNMP, System Message, Touch Screen Calibration, Test Mode (the Test Mode button is hidden until it is activated. See Chapter 12 for instructions), and Security (for firmware version 20 and later; the Security button is hidden, but can be displayed when password protection and the sealing switch are enabled). In addition, there is a Back option, which brings you to the first Dynamic screen. To view a screen, touch the screen name on the display.



NOTES:

- You will only see the System Message option if there are messages for you to view. See page 6-5 for additional information on the System Message screen.
- If you want to calibrate the touch screen, perform the following actions:
    1. Press and hold the **Backlight** button on the right front panel of the meter for about 2 seconds.

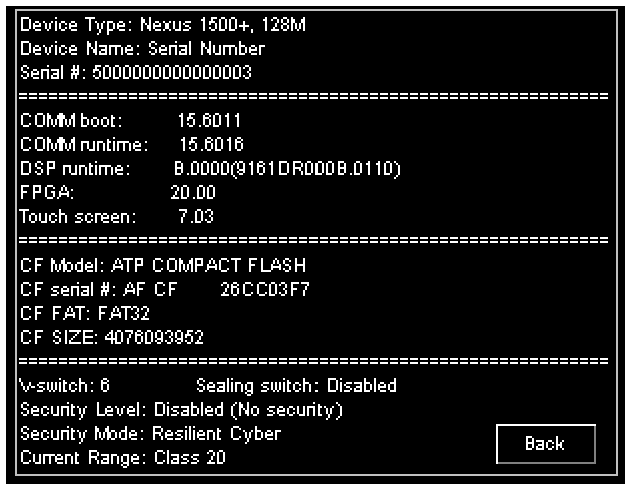
2. Press the "**i**" button at the top of the Dynamic screen within ten seconds of pressing the **Backlight** button.

3. You will see the Fixed System screens menu shown above. Touch "Touch Screen Calibration." See the instructions for using the Touch Screen Calibration screen on page 6-5.

- To make the Security button visible (for Firmware version 20 and later) when the password and/or sealing switch are enabled,

Device Information:

This screen displays the following information about the Nexus® 1500+ meter:



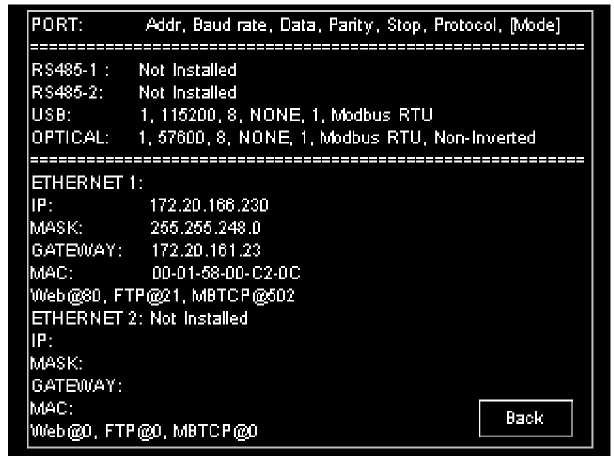
- Device type
- Device name
- Serial number
- COMM boot version
- COMM runtime version
- DSP runtime version
- FPGA version
- Touch screen version
- CF (Compact Flash) model
- CF (Compact Flash) serial number
- CF (Compact Flash) FAT type
- CF (Compact Flash) size
- V-switch™ key level enabled currently
- Sealing switch status
- Security (Password) status
- Current range (The current range class of the meter)

See the example screen on the right. The **Back** button returns you to the initial Fixed System screen.

Communication Settings:

This screen displays the following Communication port information:

- RS485 Port 1 settings
- RS485 Port 2 settings
- USB port settings
- Optical port settings
- Ethernet Port 1 settings
- Ethernet Port 2 settings



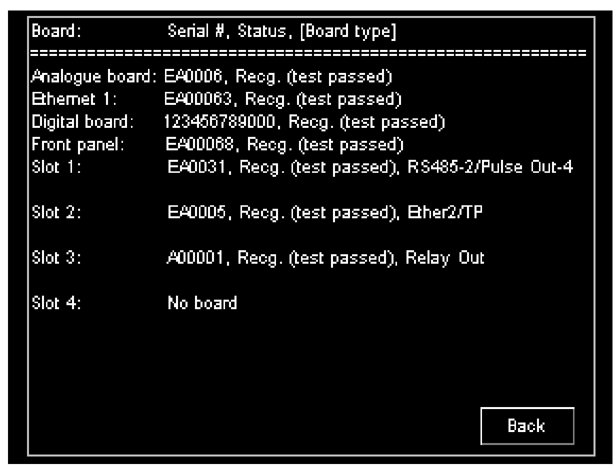
See the example screen on the right.

The **Back** button returns you to the initial Fixed System screen.

Board Settings:

This screen displays the following information:

- Analogue board settings
- Ethernet 1 board settings
- Digital board settings
- Front panel settings
- Option card Slot 1 settings
- Option card Slot 2 settings
- Option card Slot 3 settings
- Option card Slot 4 settings

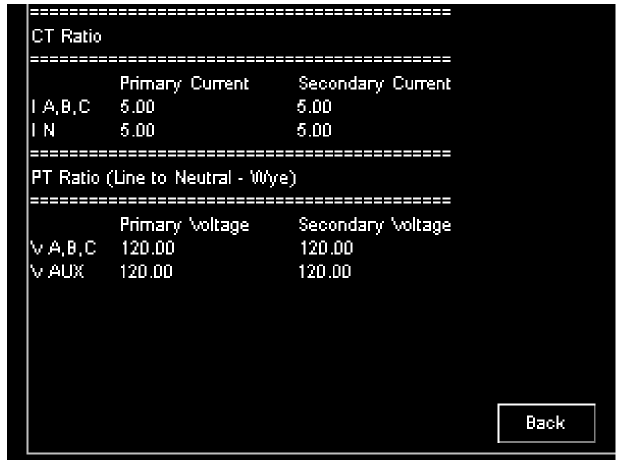


See the example screen on the right. The **Back** button returns you to the initial Fixed System screen.

CT and PT Ratio Settings:

This screen displays the following information:

- CT Ratio Primary Current I A,B,C; IN
- CT Secondary Current I A,B,C; I N
- PT Ratio Primary Voltage V A,B,C; VAUX
- PT Ratio Secondary Voltage V A,B,C; VAUX

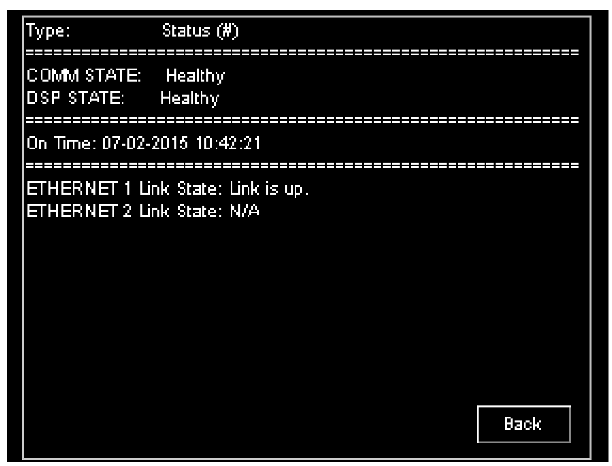


The screen will indicate if the meter is configured as Wye or Delta: the text next to PT Ratio will be either “Line to Neutral - Wye” for 3 element and 2.5 element Wye, or “Line to Line - Delta” for Delta with 2 or 3 CTs or 4 wire Delta. See the example screen on the right. The **Back** button returns you to the initial Fixed System screen.

Device Status:

This screen displays the following information:

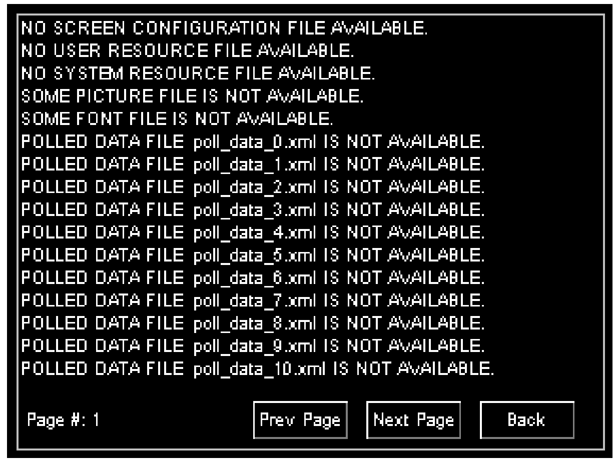
- COMM state
- DSP state
- Meter "On Time"
- Ethernet port link state



See the example screen on the right. The **Back** button returns you to the initial Fixed System screen.

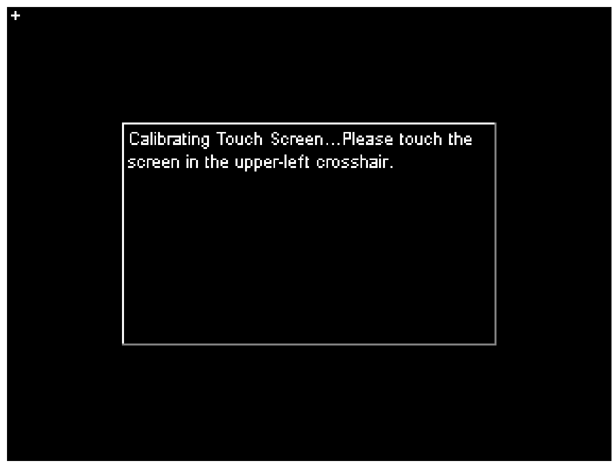
System Message:

This screen displays any system messages. The bottom of the screen will show **Prev Page** and **Next Page** buttons only if there is more than one page of messages. See the example screen on the right. The **Back** button returns you to the initial Fixed System screen. Note that this option only appears in the Fixed System screens menu if there are messages to display.

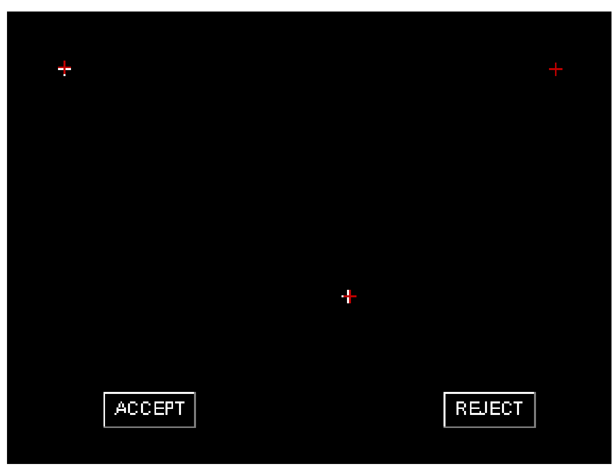


Touch Screen Calibration:

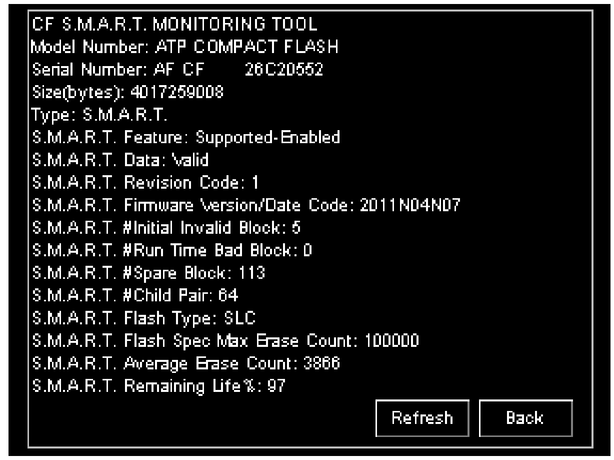
This screen is used to calibrate the touch screen display. When you select this option, a series of four messages directs you in performing screen calibration. Each message tells you to touch a corner of the screen where a small crosshair is located. Touching the crosshair calibrates the display. Use a pointed tool to touch the calibration crosshairs. See the example screen on the right, showing the first of the four messages.



When all four calibrations have been performed, a Calibrating Test screen is shown. Three crosshairs indicate places to touch. After each touch a red crosshair is shown to verify the calibration. If the calibration is correct, press the **Accept** button; otherwise press the **Reject** button, which causes the calibration process to start again. See the example screen on the right. See page 6-1 for instructions on accessing Touch Screen Calibration.



CF S.M.A.R.T. Tool



The Nexus® 1500+ meter uses an Industrial grade, specialized compact flash disk drive. This drive has many features not found in commercial flash. One of these features is the S.M.A.R.T. tool. This tool provides user accessed diagnostics on the health of the drive.

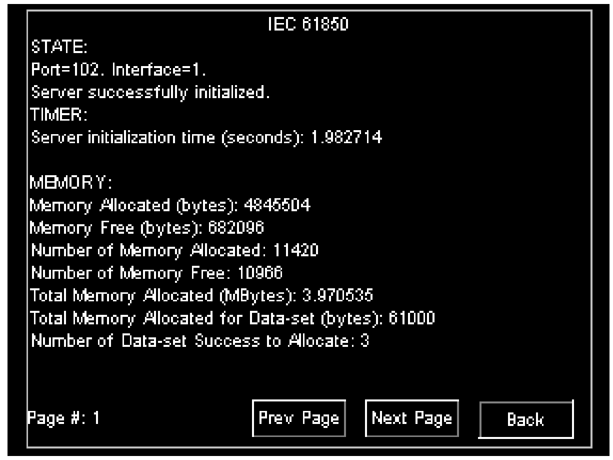
This screen displays compact flash S.M.A.R.T. (Self-Monitoring, Analysis, and Reporting Technology) tool information. The S.M.A.R.T. tool must be supported and enabled to contain valid data. The screen displays the following information:

- Compact flash model number
- Compact flash serial number
- Compact flash size in bytes
- Type of compact flash (Regular/S.M.A.R.T.)
- Status of S.M.A.R.T. feature (Supported/Not Supported, Enabled/Disabled)
- Status of S.M.A.R.T. data (Valid/Invalid)
- S.M.A.R.T. Revision code
- S.M.A.R.T. Firmware version and date code
- S.M.A.R.T. number of Initial Invalid blocks, number of bad Run Time blocks, number of Spare blocks (decimal)
- S.M.A.R.T. number of child pairs (decimal)
- Compact flash type (SLC)
- Compact flash specification’s maximum erase count (100000 if flash is SLC; 5000 if flash is MLC)
- Compact flash’s average erase count
- Compact flash remaining % of life (100 - "Average erase count"*100/"Flash spec max erase count")

This diagnostic information lets the user know when the drive may wear out and need to be replaced or the meter be de-commissioned.

IEC 61850

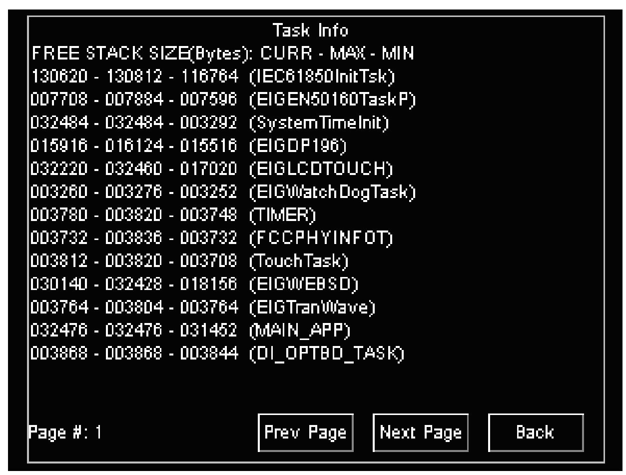
The IEC 61850 screen contains information about the IEC 61850 Protocol Ethernet Network server, including any system or error messages. It displays:



- Server state: server port, interface
- Server Initialization time in seconds
- Memory statistics
- SCL parsing messages
- Stack indications
- Stack messages

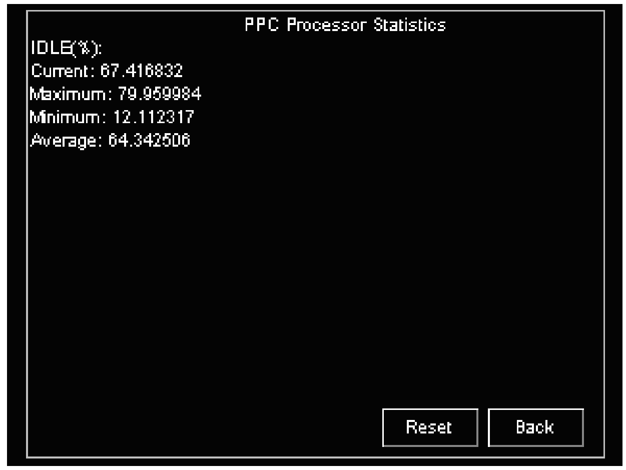
Task Info

The Task Info screen contains information about free stack size based on the tasks in the processing stack. This information is only useful for trouble-shooting or de-bugging purposes.



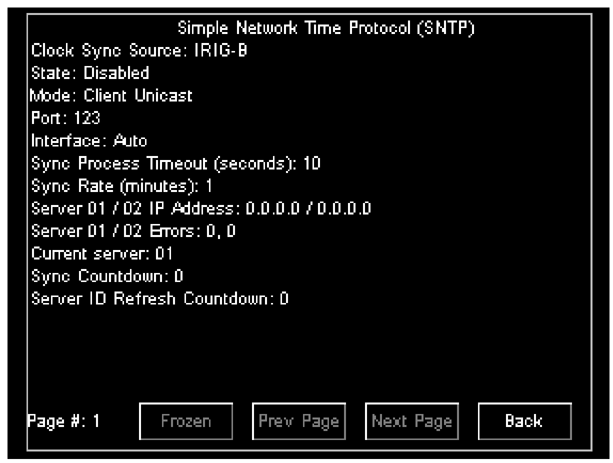
CPU Stats

The CPU Stats screen contains information about the processor's state and how close it is to executing the Idle task.



SNTP

The SNTP screen contains information about the meter's SNTP (Simple Network Time Protocol) settings:



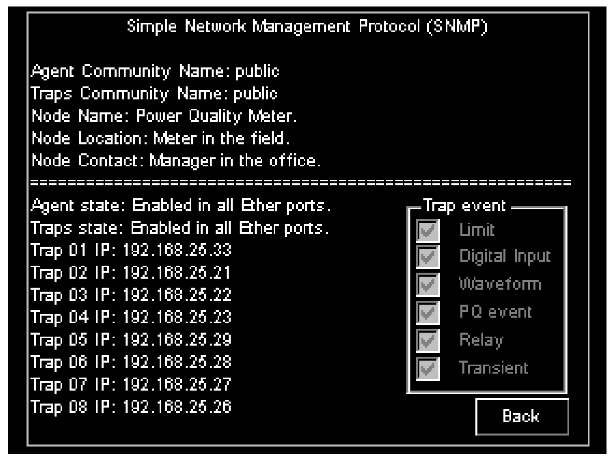
- Clock Sync Source
- State (enabled or disabled)
- Mode
- UDP port number
- Interface
- Sync process timeout in seconds
- Sync rate in minutes
- SNTP server(s) IP address
- Server errors
- Current server

- Sync Countdown
- Server ID Refresh Countdown

See Chapter 11 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for details on setting SNTP through the meter's Device Profile.

SNMP

The SNMP screen shows the state and settings for the meter's Simple Network Management Protocol (SNMP) implementation. It displays:



- Agent Community Name
- Traps Community Name
- Node Name
- Node Location
- Node Contact
- Agent State
- Traps State
- Traps 01 - 08 IP addresses
- Trap events

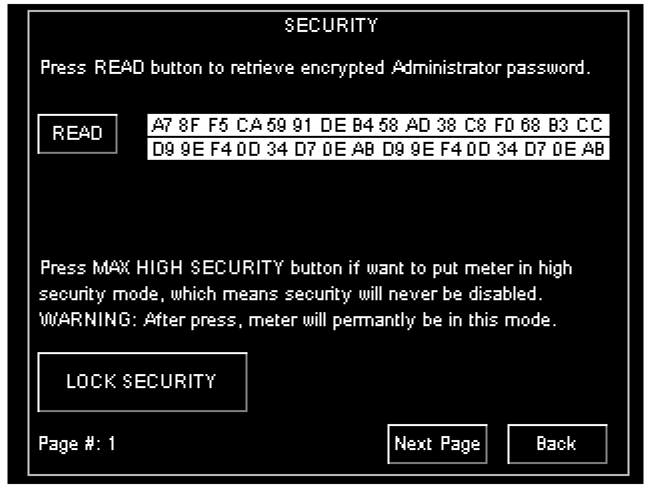
See Appendix D for details on the meter's SNMP implementation.

Test Mode

See Chapter 12 for instructions on using Test Mode.

Security:

When password protection and the sealing switch are enabled, you can display the Security screens in this way: while on one of the Dynamic screens, press and hold the Back-light button for two seconds and then press the i button while still pressing the Backlight button. You will see the main Fixed System screen and the Security button will be shown. Press the Security button to open the Security screen.



- The Read button can only be pressed if the sealing switch has been activated, and it will remain active until the sealing switch times out. This button can be used if the Admin password is lost. When pressed, this button retrieves the Admin password, encrypted using the TEA algorithm. After retrieval, contact EIG support (Telephone number 516-334-0870) and let them know the encrypted password, so that they can recover your Admin password.

- The Lock Security button can only be pressed if the sealing switch is enabled. After pressing this button, a new screen with a keyboard is displayed, asking for the Admin username (Admin) and password. As soon as these are entered correctly, **the security is locked and cannot be disabled**.

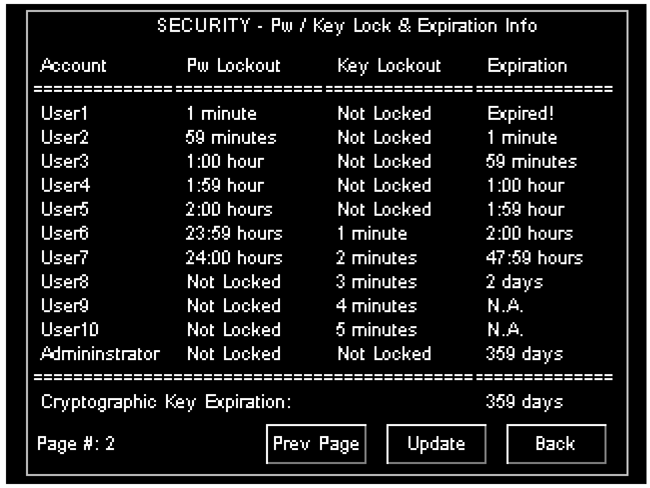
IMPORTANT! Make sure you want to lock security before entering the Admin password. There is **no way** to disable security once it is locked. See Chapter 6 in the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for detailed information on the meter's security and sealing switch features (you can download the manual from https://www.electroind.com/products/communicatorpqa-software-application-5/ - click Downloads>Tech Documents>User Manual).

- The Back button returns you to the main Fixed System screen.

- The Next Page button will be shown only when the meter is in Resilient Cyber Security mode. When pressed, the Security - Pw/Key Lockout & Expiration Info screen is displayed (see description on the next page).

Security - PW/Key Lockout & Expiration Info

This screen displays Resilient Cyber Security's expiration and lockout information.



- Under account, the ten user IDs and the Admin are listed.
- PW lockout shows the amount of time, in hours and/or minutes, that a user's password is locked out - i.e., the user can't sign on. Password lockout occurs when there are failed attempts at logging on. After three failed attempts, the user is locked out for one minute. After each subsequent set of three failed attempts, the lockout time is doubled; the maximum lockout time is 24 hours. The lockout time is reset after a successful entry.
- Expiration shows the amount of time a user is locked out due to repeated signon attempts when the cryptographic key (i.e., the encryption key) has expired. The cryptographic/encryption key is used to transmit sensitive data between the meter and the computer over the network.
  NOTES:
  - The Admin can set an expiration time for the cryptographic/encryption key. When the cryptographic/encryption key has expired, any user login is rejected. If a user tries to log in more than five times after the cryptographic/encryption key is expired, that user is locked out for 24 hours, even if the cryptographic/encryption key gets updated. The user will be unblocked if either cryptographic/encryption key expiration is disabled or the lockout time is over.
  - If the Admin is logged in when the encryption key expires, the Admin still has full rights and then can enable/disable the encryption key expiration. If the encryption key has already expired, the Admin user will be able to sign on, but will only

have rights to update the encryption key or passwords. The Admin must sign out and then sign in again to disable encryption key expiration.

- The amount of time before the cryptographic/encryption key expires, is shown toward the bottom of the screen.
- The Prev Page button returns you to the first Security screen.
- The Update button refreshes the screen with new lockout/expiration times.
- The Back button returns you to the main Fixed System screen.

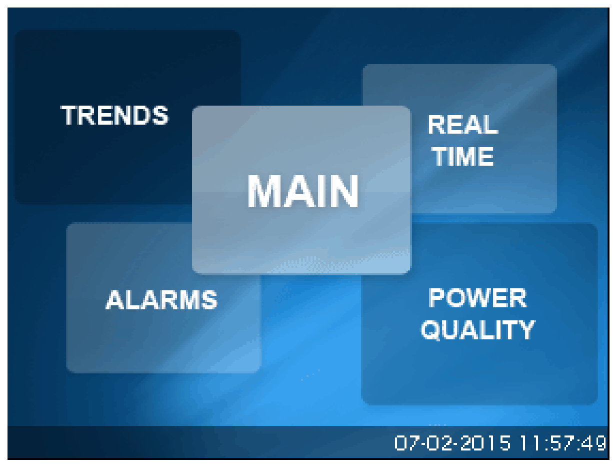
6.3: Dynamic Screens

All of the Dynamic screens show the time and date at the bottom of the screen. With the exception of the Home screen, all of the Dynamic screens have buttons on the top that allow you to navigate to the Fixed Main screen, the next screen in sequence, the previous screen, and the Dynamic Home screen. There is also a **Play/Pause** button that stops and starts the scrolling between Dynamic screens. You can adjust the screen rotation, which lets you mount the meter vertically as well as horizontally, and you can select the display language (see **Display Settings** on page 6-27).

Home Screen:

This is the first Dynamic screen shown after the system boots up. Touch the buttons to access the following screens:

- Trends: the Dynamic Trends screen
- Alarms: the Dynamic Alarms screen
- Real Time: the Real Time Readings screen
- Power Quality: the Harmonics screen
- Main: the Dynamic Main screen



(Dynamic) Main Screen:

This is a navigation screen for the Dynamic screens that are in scroll mode. Touch the button of the screen you want to access. Each of the screens is described in the following sections.

Real Time:

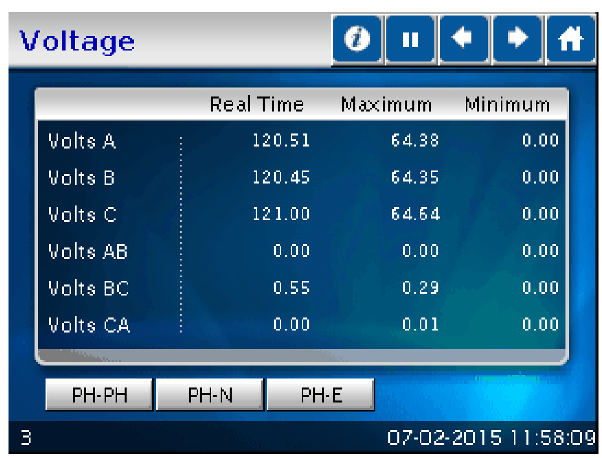
Brings you to an overview of Real Time Readings, consisting of the following:

- Volts AN/BN/CN/AB/BC/CA
- Amps A/B/C
- Watts
- VARs
- VA
- FREQ

NOTE: If a value is not available due to the hookup settings, e.g., the meter has Delta wiring, the field is displayed with N/A. See the example on the right.

Voltage:

Brings you to voltage reading details, consisting of the following:



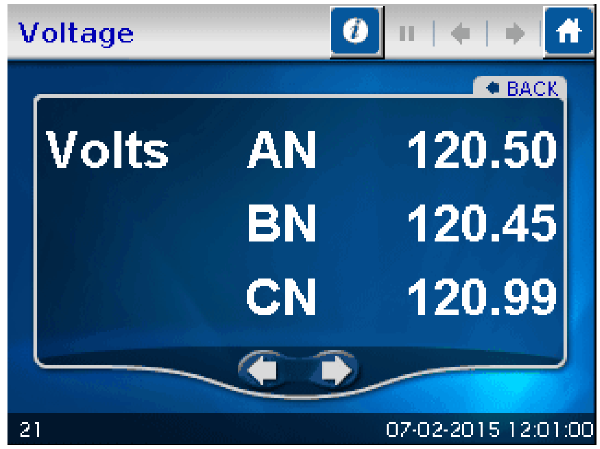
- Real time volts AN/BN/CN/AB/BC/CA
- Maximum volts AN/BN/CN/AB/BC/CA
- Minimum volts AN/BN/CN/AB/BC/CA

Touch **PH-N**, **PH-PH** or **PH-E** to view details of Phase-to-Neutral, Phase-to-Phase or Phase-to-Earth readings.

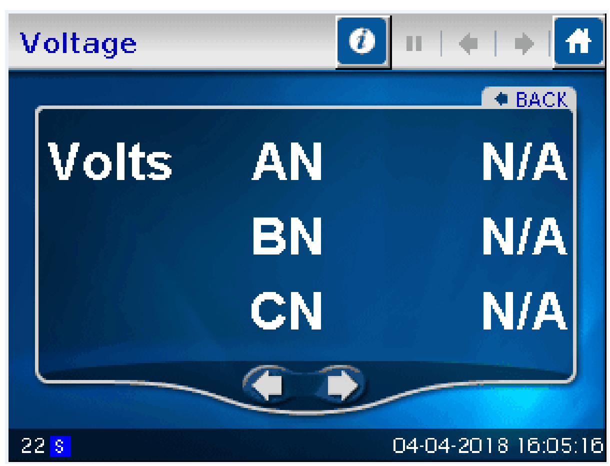
- <u>Volts: Voltage Readings PH-N</u>

  Volts AN/BN/CN

  - Touch the **Back** button to return to the Volts screen.
  - Touch the **Next/Previous** arrows to go to Voltage Reading PH-PH and Current Reading A-B-C.
  - Touch the **Home** button to go to the Dynamic Home screen.

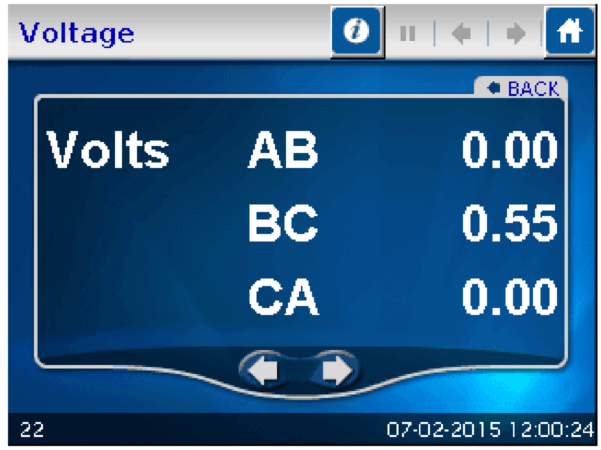


NOTE: For the Real Time and PH-N Voltage screens, if a value is not available due to the hookup settings, e.g., if the meter has Delta wiring, the field is displayed with N/A. See the example screens on the right.



- Volts: Voltage Readings PH-PH

  Volts AB/BC/CA

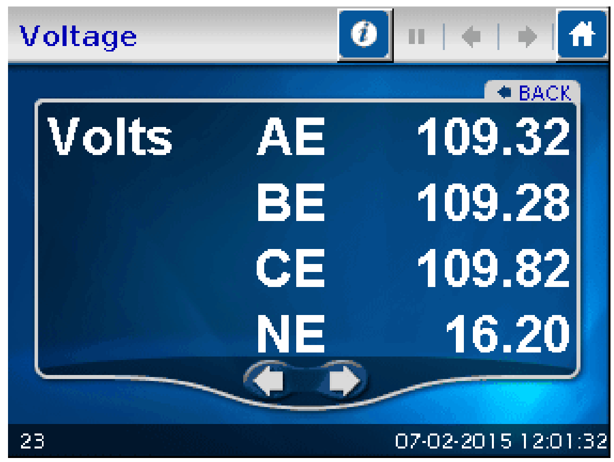
  •Touch **Back** to return to the Volts screen.

  •Touch **Next/Previous** arrows to go to Voltage Reading PH-E and PH-N Readings.

  •Touch the **Home** button to go to the Dynamic Home screen.

- Volts: Voltage Readings PH-E

  Volts AE/BE/CE/NE

  •Touch **Back** to return to the Volts screen.

  •Touch **Next/Previous** arrows to go to Current Reading A-B-C and Voltage Reading PH-PH.

  •Touch the **Home** button to go to the Dynamic Home screen.

Current:

Brings you to current readings details, consisting of the following:

- Real time current A/B/C
- Maximum current A/B/C
- Minimum current A/B/C
- Current calculated Nc/measured Nm
- Maximum Current calculated Nc/ measured Nm

- Minimum Current Calculated Nc/Measured Nm

Touch **A-B-C** to view Currents Detail.

- Amps: Current Readings A-B-C

  Real Time Current A/B/C

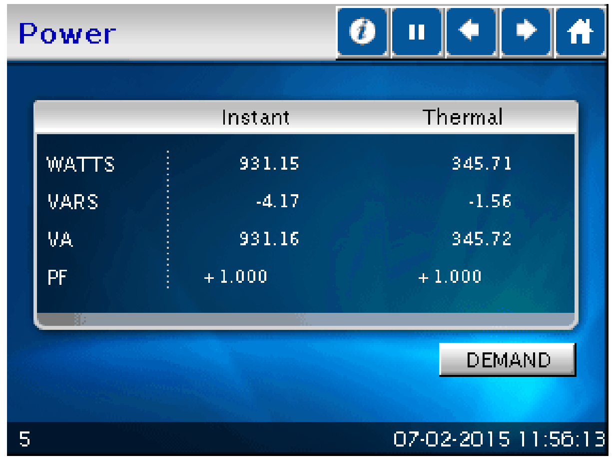
  - Touch **Back** to return to the Amps screen.
  - Touch **Next/Previous** arrows to go to Voltage Reading PH-N and Voltage Reading PH-PH.
  - Touch the **Home** button to go to the Dynamic Home screen.

Power:

Power Readings Details

- Instant Watt/VAR/VA/PF Thermal Watt/VAR/VA/PF
- Predicted Watt/VAR/VA

Touch **Demand** to go to the Demand screen (shown below).

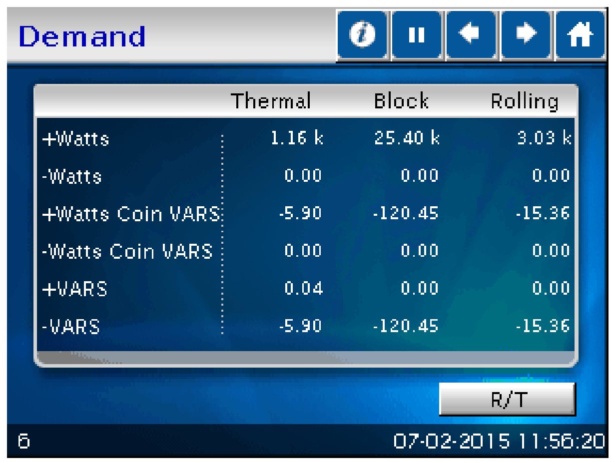


Demand:

Demand Readings Details

- Thermal Window Average Maximum +Watt/+VAR/CoIn VAR Block (Fixed) Window Average Maximum +Watt/+VAR/CoIn VAR
- Predictive Rolling (Sliding) Window Maximum +Watt/+VAR/CoIn VAR

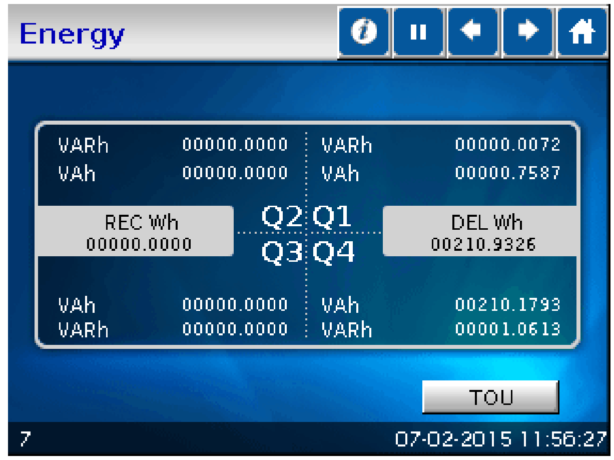
Touch **R/T** to view the Real Time Power screen.



Energy:

Brings you to Accumulated Energy Information, consisting of the following:

- -Watthr Quadrant 2+Quadrant 3 (Primary)
- +VAhr Quadrant 2 (Primary)
- +VARhr Quadrant 2 (Primary)
- +VAhr Quadrant 3 (Primary)
- -VARhr Quadrant 3 (Primary)
- +Watthr Quadrant 1+Quadrant 4 (Primary)
- +VAhr for all quadrants (Primary)

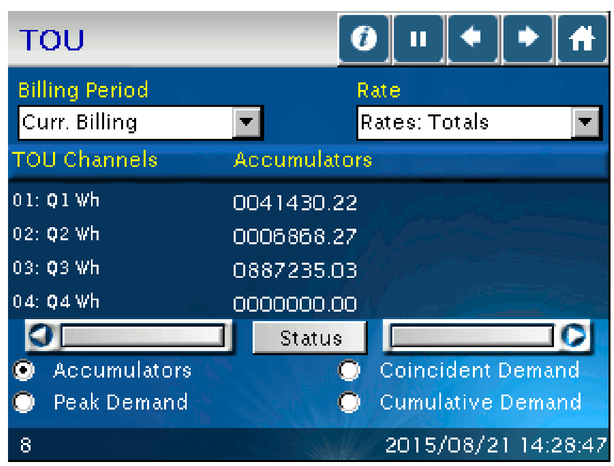


Touch **TOU** to view the TOU Register Accumulations screen.

TOU:

Brings you to TOU information, consisting of the following:

- Billing Period
- Rates
- TOU Channels
- Accumulators - click the button at the bottom of the screen to view.



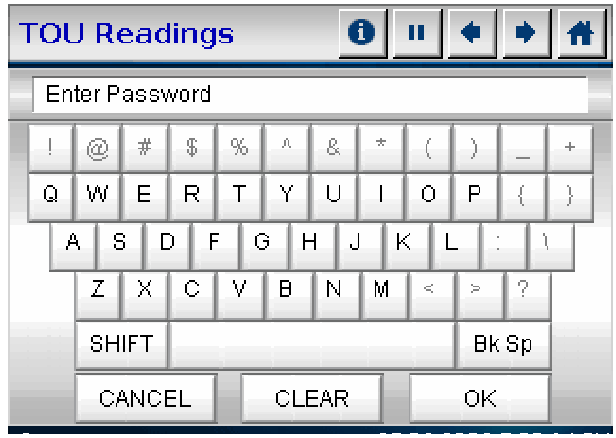
- Peak Demand - click the button at the bottom of the screen to view.
- Coincident Demand - click the button at the bottom of the screen to view.
- Cumulative Demand - click the button at the bottom of the screen to view.

Touch **Peak Demand** to view the Register Peak Demand screen.

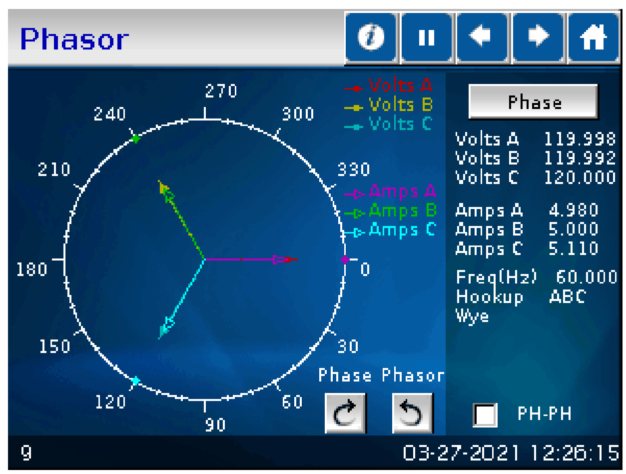
Touch **Next/Previous** arrows to scroll Registers 1 - 8 and Totals.

Touch **Next/Previous** arrows to scroll Frozen, Prior Month, Active, and Current Month.

NOTE: If password protection is enabled for the meter, a keyboard screen displays, allowing you to enter the password. If a valid password is entered, the TOU data readings are displayed; otherwise a message displays, indicating that the password is invalid.



Phasors:
Brings you to Phasor Analysis Information.



- **Phase/Phasor** arrow buttons change the rotation of the diagram. Note that you can click on the arrows to change the display directions from clockwise to counter-clockwise.

- **Phase/Mag** button shows the phase/magnitude of:

  - Phase angle or magnitude Van/bn/cn

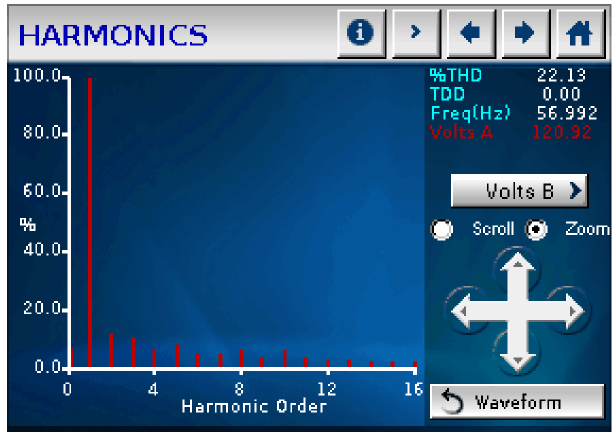
  - Phase angle or magnitude Ia/b/c

  - Phase angle or magnitude Vab/bc/ca

- The **PH-PH** check box shows/hides the phase to phase voltage.

Harmonics-Spectrum:
Brings you to Harmonic Spectrum Analysis information, consisting of the following:

- %THD
- TDD (current only)
- KFactor
- Frequency
- Phase A - N voltage



Touch **Waveform** to see the channel's waveform.

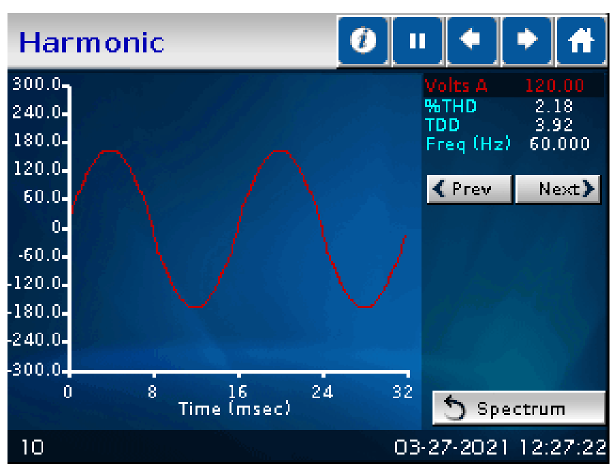
Touch **Volts BN** to view the Harmonics screen for Phase B - N voltage; Touch **Volts CN** (from the Volts B screen) to view the Harmonics screen for Phase C - N voltage.

Use the **Scroll/Zoom** radio buttons to select the mode of the directional arrows:

- If Scroll is selected, the directional arrows move the axes horizontally/vertically.
- If Zoom is selected, the directional arrows cause the display to zoom in/out.

Harmonics:
Brings you to the Waveform: Real Time Graph, showing the following information:

- %THD:% total harmonic distortion
- TDD (current only): total demand distortion
- KFactor
- Frequency



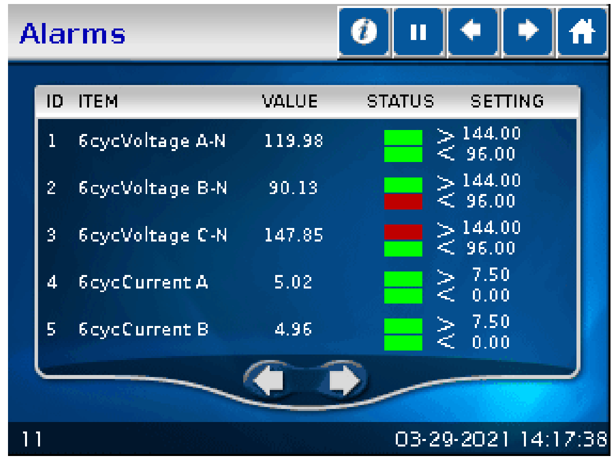
Touch **Spectrum** to see the Harmonic Spectrum Analysis screen for the channel.

Touch **Volts B** to view the Harmonics screen for Phase B - N voltage; Touch **Volts C** (from the Volts B screen) to view the Harmonics screen for Phase C - N voltage.

Alarms:

Brings you to Alarm (Limits) Status information, consisting of the following:

- Current Limits settings for the meters, ID 1 - 32.
- For each ID number, the type of reading, value, status and setting is shown.
  - The green rectangle indicates a Within Limits condition and the red rectangle indicates an Out of Limits condition.
  - The first screen displays the settings for Meters ID 1 to 4.

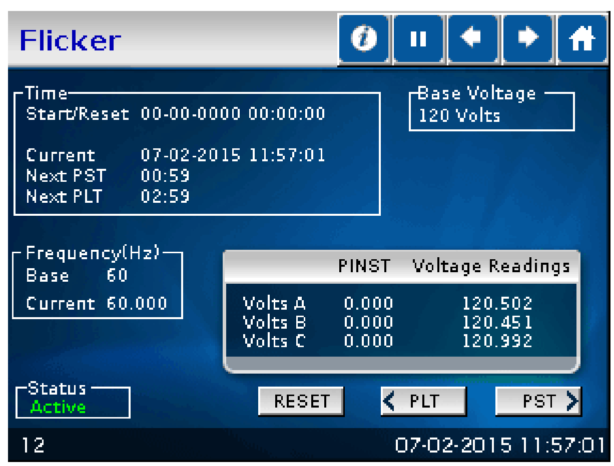


Touch **Next/Previous** arrows to view all of the Limits.

Flicker:

Brings you to Flicker Instantaneous information, consisting of the following:

- Time: Start/Reset, Current, Next PST, Next PLT
- Frequency
- Base voltage
- Voltage readings



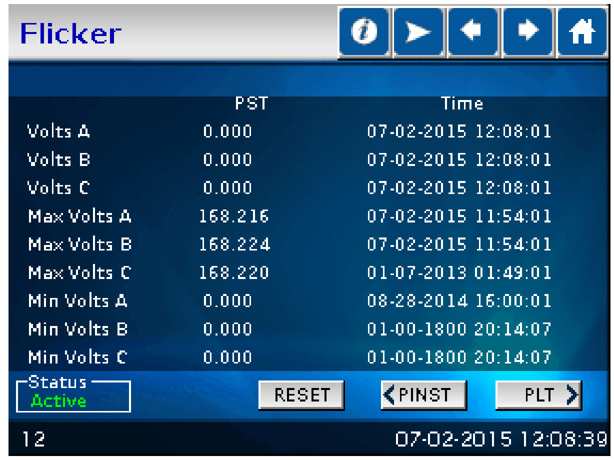
Touch **PST** (Short Term) or **PLT** (Long Term) to view other flicker screens.

Flicker - Short Term:

Displays the following information:

- Volts A/B/C Max volts A/B/C
- Min volts A/B/C

Touch **PINST** (Instantaneous) or **PLT** (Long Term) to view other flicker screens.

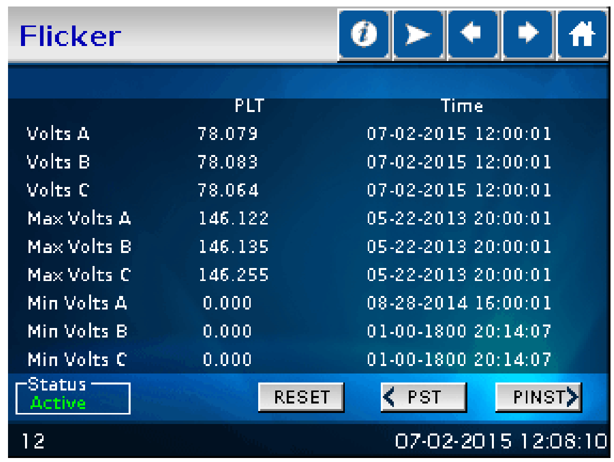


Flicker - Long Term:

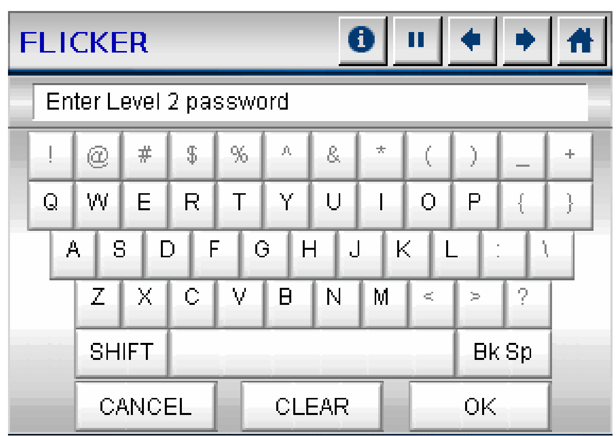
Displays the following information:

- Volts A/B/C Max volts A/B/C
- Min volts A/B/C

Touch **PINST** (Instantaneous) or **PST** (Short Term) to view other flicker screens.

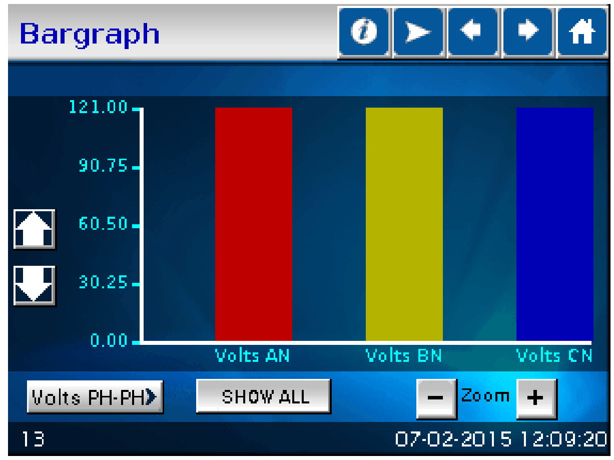


NOTE: If password protection is enabled for the meter, a keyboard screen displays when you press any action button (e.g., **Reset**). Use the keyboard to enter the password. If a valid password is entered, the requested Flicker action takes place; otherwise a message displays, indicating that the password is invalid.



Bargraph:

Brings you to a Bargraph display, consisting of the following:



- Phase AN voltage
- Phase BN voltage
- Phase CN voltage

Touch the **Up/Down** arrows to move the vertical axis up/down.

Touch the **+/-** buttons to zoom in/out.

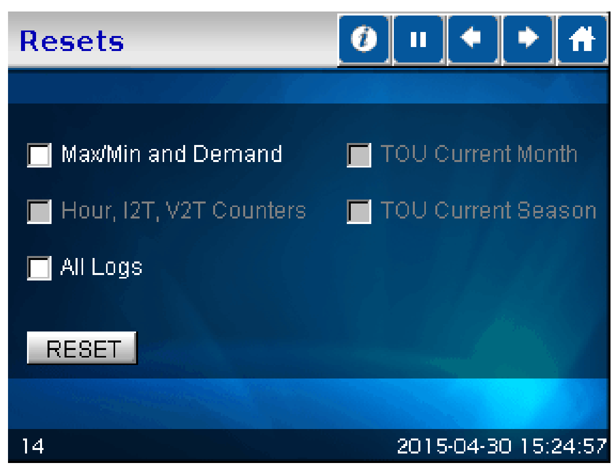
Touch **Show All** to display all of the bars in the screen.

Touch **Volts PH-PH** to view the Voltage Phase-to-Phase Bargraph screen.

Touch **Current** to view the Amps Bargraph screen. (The Current button is displayed on the Voltage Phase-to-Phase Bargraph screen.)

Reset:

Brings you to the Meter Reset Command screen. From this screen, you can reset the following values:

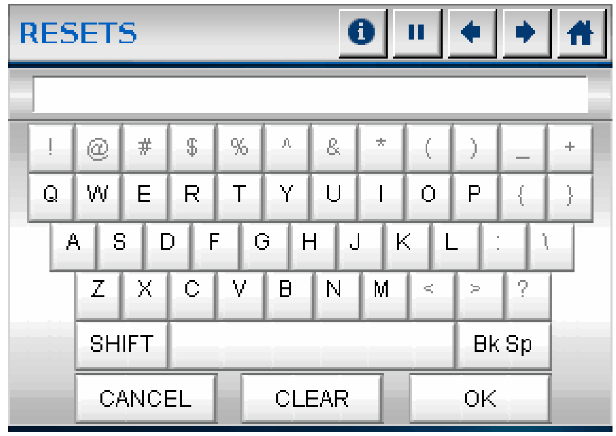


- Max/Min and Demand
- Hour, I2T and V2T counters
- All logs
- TOU for current month
- TOU for current season

WARNING! RESETS CAUSE DATA TO BE LOST.

1. Touch the box(es) to select the Reset you want to perform.
2. Touch **Reset**. All boxes are unchecked after a reset is performed and a check mark is displayed next to each item that was reset.

NOTE: If password protection is enabled for the meter, a keyboard screen displays, when you press the Reset button. Use the keyboard to enter the password. If a valid password is entered, the reset takes place; otherwise a message displays, indicating that the password is invalid.



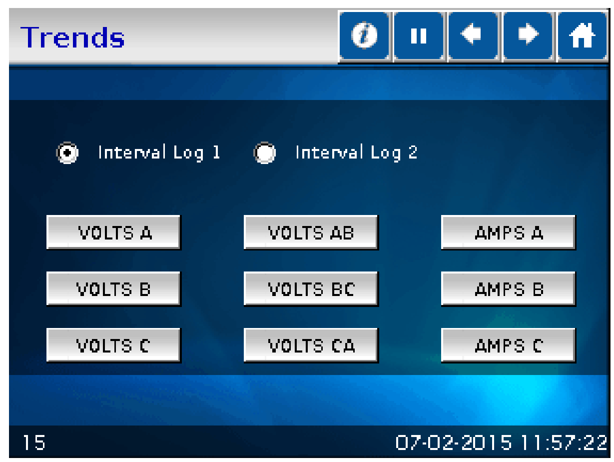
Trends:

Brings you to the Trends Setting screen. From this screen, you can set the following for viewing:

1. Interval Log 1 or Log 2: touch the radio button of the log you want.

2. Channel: select a channel by touching its button.

You will see the Trends - Graphic screen, showing the data you selected in an X-Y graph, where x is the timestamp and y is the magnitude of the channel.



NOTES:

- The data for Interval logs 1 and 2 comes from the meter's Historical logs 1 and 2, respectively. If Historical logs 1 or 2 have not been configured to log the voltage and current channels shown in the screen, i.e., one second updated volts A/B/C, volts A-B/B-C/C-A, current channels A/B/C; or if they have been configured, but no data has been logged yet, you will see a message that there is no available data.

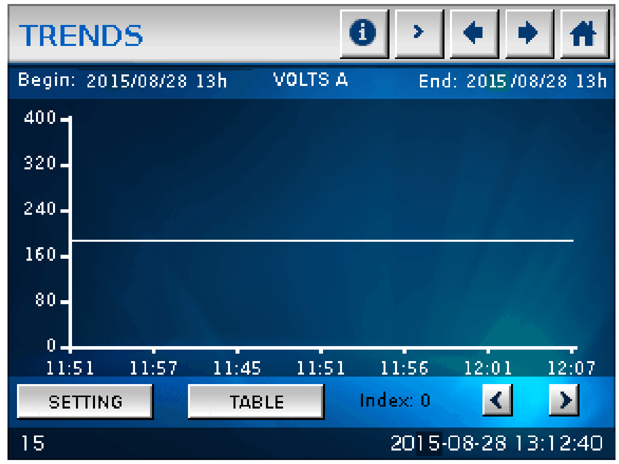
- The active channel appears at the lower right of the display.

- Data from the previously active channel is lost if the channel is changed.

Real Time Trending Graphic:

Trending for the channel selected from the Trends - Setting screen is shown on this screen.

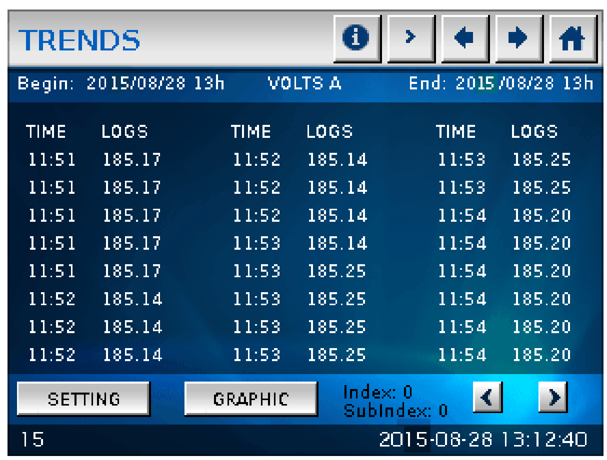
- Touch the **Directional** arrows to see additional points on the graph. You can view up to 240 points at a time.
- To see a table of logs for the Selected Channel, touch **Table** to view the Trends - Table screen.
- Touch **Setting** to select another log and/or channel.



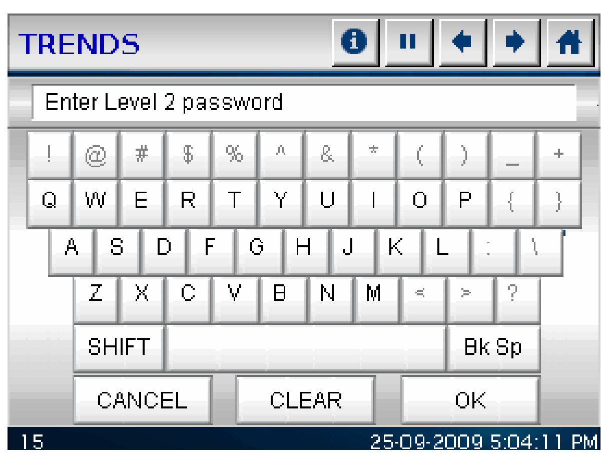
Real Time Trending Table:

A Table of logs for the selected channel (volts AN is shown here).

- Touch **Graphic** to return to the Trending - Graphic screen.
- Touch **Setting** to select another log and/or channel.



NOTE: If password protection is enabled for the meter, a keyboard screen displays, when you press any channel button. Use the keyboard to enter the password. If a valid password is entered, the Trend graphic/ Tables are displayed; otherwise a message displays, indicating that the password is invalid.

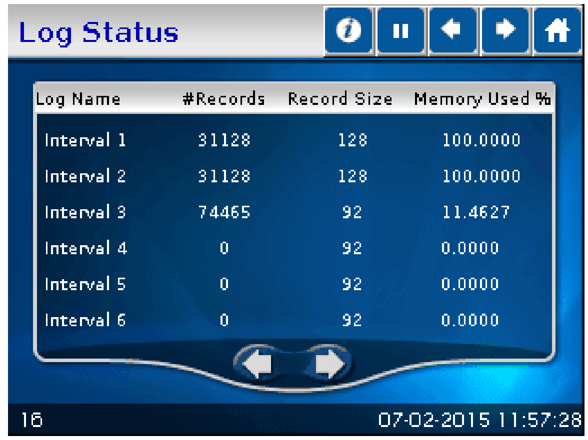


Log Status:

Brings you to Logging Status information, consisting of an overview of the meter's logs. For each log, the following information is listed:

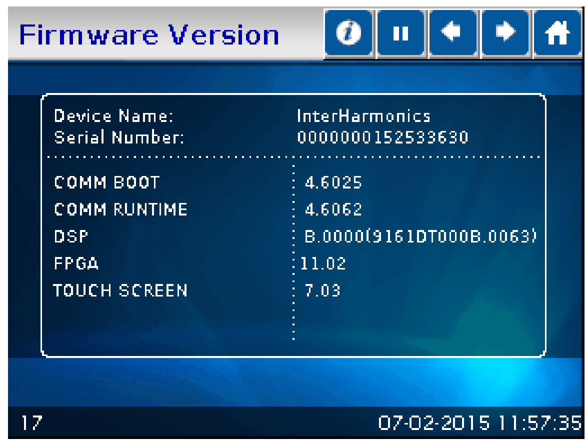
- The number of records Record size
- % of memory used

Touch the **Next/Previous** arrows to view additional logs.



Firmware Version:

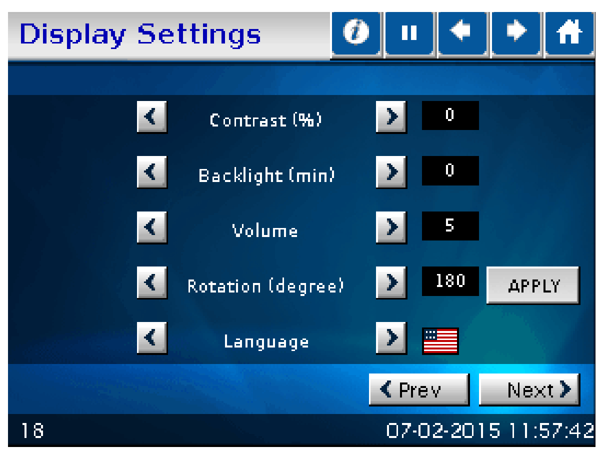
This screen displays the current firmware version for the Nexus® 1500+ meter, as well as the meter designation and serial number. The following information is displayed:



- Device name Serial number
- Comm Boot
- Comm Runtime
- DSP
- FPGA
- Touch Screen

Display Settings:

Brings you to a screen where you can configure settings for the LCD display. Set the following:



- Contrast: touch **Left/Right** arrows to increase/decrease the contrast for the display.
- Backlight: the number of minutes after use that the display's backlight turns off.

1. Touch **Left/Right** arrows to increase/decrease settings. To keep the backlight on, make this setting "0."
2. To turn the Backlight on press and hold the switch on the front panel beside the display for a few seconds.

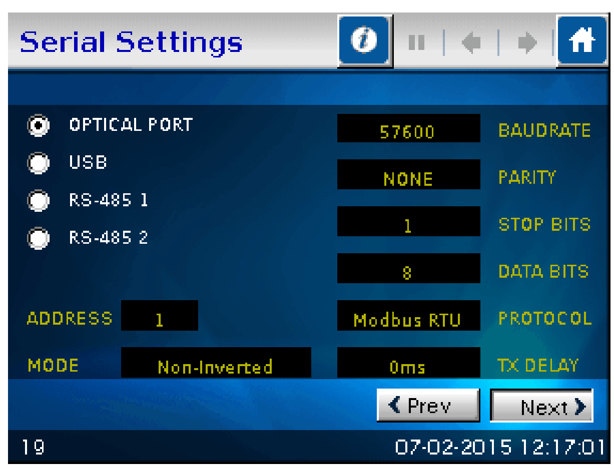
- Volume: touch **Left/Right** arrows to increase/decrease the speaker volume.
- Rotation (degree): touch **Left/Right** arrows to set screen's rotation to 0, 90, 180 or 360 degrees. This allows the meter to be mounted vertically.
- Language: touch **Left/Right** arrows to choose one of the languages for the display. The choices are: English (ENG), Chinese (CHN), Hebrew (HBW), Portuguese (POT), Spanish (SPN), French (FRN), and user's customized 1 (CT1), which is Polish. Note that user's customized 2 (CT2) is currently not used.

NOTE: You must press **Apply** for your Rotation and Language settings to be implemented. Once you press **Apply**, the screen darkens momentarily and then the Home screen is redisplayed with the selected rotation/language.

Touch **Next/Prev** to go to the Serial Setting/Network Setting screens.

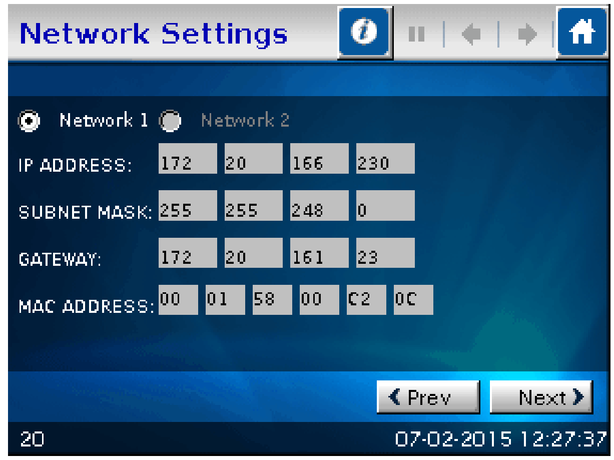
NEXUS® Serial Communication Settings:
Select the serial communication mode you want to configure, by checking the **Radio Button** to the left of it. The setting for each port is described below:

- Optical port (Baud, Parity, Stop bit, Data size, Protocol, Tx delay, Address, Mode)
- USB (Baud, Parity, Stop bit, Data size, Protocol, Tx delay, Address)
- COMM 1 (Baud, Parity, Stop bit, Data size, Protocol, Tx delay, Address)
- COMM 2 (Baud, Parity, Stop bit, Data size, Protocol, Tx delay, Address, Mode)



Touch **Next/Prev** to go to the Network Setting/Display Setting screens.

NEXUS® Network Communication Settings:
Use the following fields to configure the meter's Network settings:

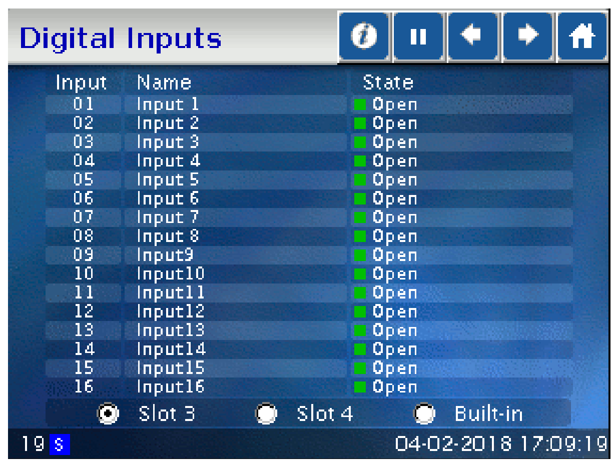


- Network: click the **Radio Button** next to Network 1 or Network 2.
- IP address
- Subnet mask
- Default gateway
- MAC address

Touch **Next/Prev** to go to the Display Setting/Serial Setting screens.

Digital Inputs:

This screen displays the status of the meter's digital inputs: the eight built-in digital inputs or the digital inputs from an installed Option board. The meter supports up to 2 optional digital input boards (each with 16 status inputs), in addition to the built-in inputs.



- Inputs - 01 - 16
- Name - the name configured for the input
- State - the input's state, e.g., Open or Closed. The State names are configured in the meter's Device Profile settings - see Chapter 11 in the *CommunicatorPQA® and Meter-ManagerPQA® Software User Manual*, for instructions.
- Slots - Select Slot 3, Slot 4, or Built In to see the digital inputs for those options. Note that you will only see the buttons for slots 3 and 4 if there is a digital input board installed in that slot.

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7: Transformer Loss Compensation

7.1: Introduction

The Edison Electric Institute's Handbook for Electricity Metering, Ninth Edition defines Loss Compensation as:

> A means for correcting the reading of a meter when the metering point and point of service are physically separated, resulting in measurable losses including I2R losses in conductors and transformers and iron-core losses. These losses may be added to or subtracted from the meter registration.

Loss compensation may be used in any instance where the physical location of the meter does not match the electrical location where change of ownership occurs. Most often this appears when meters are connected on the low voltage side of power transformers when the actual ownership change occurs on the high side of the transformer. This condition is illustrated in Figure 7.1.

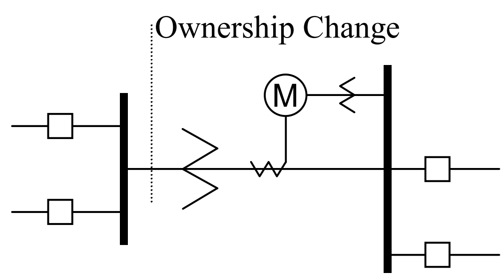


Figure 7.1: Low Voltage Metering Installation Requiring Loss Compensation

It is generally less expensive to install metering equipment on the low voltage side of a transformer and in some conditions other limitations may also impose the requirement of low-side metering even though the actual ownership change occurs on the high voltage side.

The need for loss compensated metering may also exist when the ownership changes several miles along a transmission line where it is simply impractical to install metering equipment. Ownership may change at the midway point of a transmission line where there are no substation facilities. In this case, power metering must again be compensated. This condition is shown in Figure 7.2.

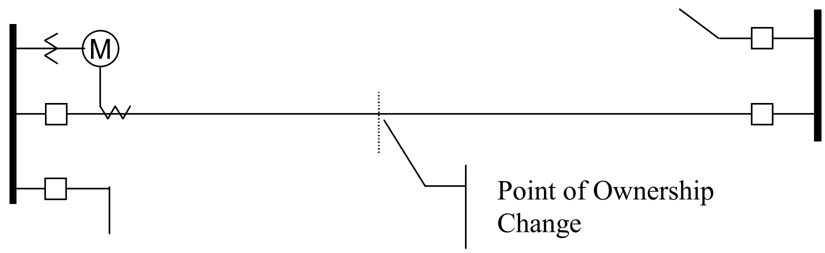


Figure 7.2: Joint Ownership Line Meeting Requiring Loss Compensation

A single meter cannot measure the losses in a transformer or transmission line directly. It can, however, include computational corrections to calculate the losses and add or subtract those losses to the energy flow measured at the meter location. This is the method used for loss compensation in the Nexus® 1500+ meter.

The computational corrections used for transformer and transmission line loss compensation are similar. In both cases, no-load losses and full-load losses are evaluated and a correction factor for each loss level is calculated. However, the calculation of the correction factors that must be programmed into the meter differ for the two different applications. For this reason, the two methodologies will be treated separately in this chapter.

In the Nexus® 1500+ meter, Loss Compensation is a technique that computationally accounts for active and reactive power losses. The meter calculations are based on the following formulae. These equations describe the amount of active (watts) and reactive (VARs) power lost due to both iron and copper effects (reflected to the secondary of the instrument transformers).

$$W_{TotalTransformerLoss} = VA_{TransformerFullScale} \times \left[\%\mathrm{LFWE} \times \left(\frac{Vmeasured}{Vnominal}\right)^2 + \%\mathrm{LWCU} \times \left(\frac{Imeasured}{Inominal}\right)^2 \right]$$

$$VAR_{TotalTransfomerLoss} = VA_{TransformerFullScale} \times \left[\%\mathrm{LVFE} \times \left(\frac{Vmeasured}{Vnominal}\right)^4 + \%\mathrm{LVCU} \times \left(\frac{Imeasured}{Inominal}\right)^2 \right]$$

The Values for %LWFE, %LWCU, %LVFE, and %LVCU are derived from the transformer and meter information, as demonstrated in the following sections.

The calculated loss compensation values are added to or subtracted from the measured Watts and VARs. The selection of adding or subtracting losses is made through the meter's profile when programming the meter (see the following section for instructions). The meter uses the combination of the add/subtract setting and the directional definition of power flow (also in the profile) to determine how to handle the losses. Losses will be "added to" or "subtracted from" (depending on whether add or subtract is selected) the Received Power flow. For example, if losses are set to "Add to" and received power equals 2000 kW and losses are equal to 20 kW then the total metered value with loss compensation would be 2020 kW; for these same settings if the meter measured 2000 kW of delivered power the total metered value with loss compensation would be 1980 kW.

Since transformer loss compensation is the more common loss compensation method, the meter has been designed for this application. Line loss compensation is calculated in the meter using the same terms but the percent values are calculated by a different methodology.

7.2: Nexus® 1500+ Meter's Transformer Loss Compensation

- Performs calculations on each phase of the meter for every measurement taken; unbalanced loads are handled accurately.
- Calculates numerically, eliminating the environmental effects that cause inaccuracies in electromechanical compensators.
- Performs bidirectional loss compensation.
- Requires no additional wiring; the compensation occurs internally.
- Imposes no additional electrical burden when performing loss compensation.

Loss Compensation is applied to watt/VAR readings and, because of that, affects all subsequent watt/VAR readings. This method results in loss compensation being applied to the following quantities:

- Total power
- Demands, per phase and total (Block (Fixed) window and Rolling (Sliding) window)
- Maximum and minimum Demand
- Energy accumulations
- KYZ output of energy accumulations

The meter provides compensation for active and reactive power quantities by performing numerical calculations. The factors used in these calculations are derived either:

- By clicking the TLC Calculator button on the Transformer Loss screen of the Device Profile, to open the EIG Loss Compensation Calculator in Microsoft Excel
- By figuring the values from the worksheet shown in 7.2.1.1: Three-Element Loss Compensation Worksheet on page 7-7, and in Appendix B of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual*

Either way, you enter the derived values into the CommunicatorPQA® software through the Device Profile Transformer and Line Loss Compensation screen.

The CommunicatorPQA® software allows you to enable transformer loss compensation for losses due to copper and iron, individually or simultaneously. Losses can either be added to or subtracted from measured readings. Refer to Appendix B in the *software manual* for instructions.

Loss compensation values must be calculated based on the meter installation. As a result, transformer loss values must be normalized to the meter by converting the nominal voltage and current and taking into account the number of elements used in the metering installation. For three-element meters, the installation must be normalized to the phase-to-neutral voltage and the phase current; in two-element meters the installation must be normalized to the line-to-line voltage and the line current. This process is described in the following sections.

7.2.1: Loss Compensation in Three Element Installations

Loss compensation is based on the loss and impedance values provided on the transformer manufacturer's test report. A typical test report will include at least the following information:

- Manufacturer
- Unit serial number
- Transformer MVA rating (Self-Cooled)
- Test voltage
- No load loss watts
- Load loss watts (or full load loss watts)
- % Exciting current @ 100% voltage
- % Impedance

The transformer MVA rating is generally the lowest MVA rating (the self-cooled or OA rating) of the transformer winding. The test voltage is generally the nominal voltage of the secondary or low voltage winding. For three-phase transformers these values will typically be the three-phase rating and the phase-to-phase voltage. All of the test measurements are based on these two numbers. Part of the process of calculating the loss compensation percentages is converting the transformer loss values based on the transformer ratings to the base used by the meter.

Correct calculation of loss compensation also requires knowledge of the meter installation. In order to calculate the loss compensation settings you will need the following information regarding the meter and the installation:

- Number of meter elements
- Potential transformer ratio (PTR)
- Current transformer ratio (CTR)
- Meter nominal voltage
- Meter nominal current

This section is limited to application of Nexus® 1500+ meters to three-element metering installations. As a result, we know that:

- Number of metering elements = 3
- Meter nominal voltage = 120 Volts
- Meter nominal current = 5 Amps

7.2.1.1: Three-Element Loss Compensation Worksheet

If you are not using the TLC Calculator in the CommunicatorPQA® software, use the worksheet in this section to calculate the values to use for the meter's Transformer and Line Loss compensation. Note that the instructions for one of the worksheet tables directly follows the table.

Company		Station Name	
Date		Trf. Bank No.	
Trf Mfg		Trf Serial No.	
Calculation by			

1. Enter the general information.

Winding	Voltage	MVA	Connection
HV - High			Δ-Y
XV - Low			Δ-Y
YV - Tertiary			Δ-Y

2. Enter Transformer data (from Transformer Manufacturer's Test Sheet).

Value	Watts Loss		
	3-Phase	1-Phase	1-Phase kW
No-Load Loss			
Full Load Loss			

3. Enter 3-Phase or 1-Phase values.

- If 3-Phase values are entered, calculate 1-Phase values by dividing the 3-Phase values by three.

- Convert 1-Phase Watts Loss to 1-Phase kW by dividing the 1-Phase Watts Loss by 1000.

Value	**3-Phase MVA**	**1-Phase MVA**	**1-Phase kVA**
Self-Cooled Rating			

4. Enter 3-Phase MVA or 1-Phase MVA values.

- If 3-Phase MVA values are entered, calculate 1-Phase MVA values by dividing 3-Phase MVA values by three.

- Convert 1-Phase MVA to 1-Phase kVA by multiplying by 1000.

% Exciting Current	
% Impedance	

5. Enter the % Exciting Current and % Impedance values.

Value	Phase-to-Phase	Phase-to-Neutral
Test Voltage (Volts)		
Full Load Current (Amps)		

6. Enter the Phase-to-Phase values for Test Voltage (Volts) and Full Load Currents (Amps). Note that Test Voltage is generally Phase-to-Phase for 3-Phase transformers.

   a. Calculate Phase-to-Neutral Test Voltage by dividing Phase-to-Phase Test Voltage by the square root of 3.

   b. Calculate Full Load Current (Amps) by dividing the 1-Phase kW self-cooled rating by the Phase-to-Neutral Voltage and multiplying by 1000.

Instrument Transformers	Numerator	Denominator	Multiplier
Potential Transformers			
Current Transformers			
Power Multiplier [(PT Multiplier) x (CT Multiplier)]			

7. Meter/Installation Data: enter the Numerator and Denominator for each instrument transformer. For example, a PT with a ratio of 7200/120 has a numerator or 7200, a denominator or 120 and a multiplier of 60 (7200/120 = 60/1).

Meter Secondary Nominal Voltage (Volts)	120 V
Meter Secondary Nominal Current (Amps)	5 A

8. Meter/Installation Data: enter the Meter Secondary Nominal Voltage (Volts) and Meter Secondary Nominal Current (Amps).

Quantity	Transformer	Multiplier	Trf IT Sec (Instrument Transformer Secondary Value)	Meter Nominal	Meter/Trf (Meter-Transfomer Ratio)
Voltage				120	
Current				5	

9. Conversion Factors for Nominal Value:

   a. For Transformer Voltage, enter the Phase-to-Neutral of Test Voltage (Volts) previously calculated (step 6).

   b. For Transformer Current, enter the Full Load Current (Amps) previously calculated (step 6).

   c. For Multiplier, enter the PT and CT Multipliers previously calculated (step 7).

   d. Trf IT Sec is the nominal value of voltage and current at the instrument transformer secondary. These numbers are obtained by dividing the Transformer Voltage and Transformer Current by their respective Multiplier.

   e. The Meter/Trf values for Voltage and Current are obtained by dividing the Meter Nominal by the Trf IT Sec.

10. Normalized Losses: fill out the following section of the worksheet:

No-Load Loss Watts (kW) = 1-Phase kW No-Load Loss = _______________

No-Load Loss VA (kVA) = (%Exciting Current) * (1-Phase kVA Self-Cooled Rating) / 100 = (_______________) * (_________________) / 100

= ________________ kVA

No-Load Loss VAR (kVAR) = SQRT((No-Load Loss kVA)2 - (No-Load Loss kW)2) = SQRT((__________________)2 - (_________________)2)

= SQRT((___________________) - (_________________))

= SQRT (__________________) = _____________________

Full-Load Loss Watts (kW) = 1-Phase Kw Load Loss = _______________

Full-Load Loss VA (kVA) = (%Impedance) * (1-Phase kVA Self-Cooled Rating) / 100 = (_______________) * (_________________) / 100

= ________________ kVA

Full-Load Loss VAR (kVAR) = SQRT((Full-Load Loss kVA)2 - (Full-Load Loss kW)2) = SQRT((__________________)2 - (_________________)2)

= SQRT((___________________) - (_________________))

= SQRT (__________________) = __________________

Quantity	Value at Trf Nominal	M/T Factor	Meter/Trf Value (Meter Transformer Ratio)	Exp	M/T Factor w/Exp	Value at Meter Nominal
No-Load Loss Watts (kW)		Voltage		^2		
No-Load Loss VAR (kVAR)		Voltage		^4		
Full Load Loss Watts (kW)		Current		^2		
Full Load Loss VAR (kVAR)		Current		^2		

11. Normalize Losses to Meter Nominal Power:

   a. Enter Value at Trf Nominal for each quantity from previous calculations (step 10).

   b. Enter Meter/Trf Value from Conversion Factors for Nominal Values (step 9).

   c. Calculate M/T Factor w/Exp by raising the Meter/Trf Value to the power indicated in Exp.

   d. Calculate the Value at Meter Nominal by multiplying the M/T Factor w/Exp by the Value at Trf Nominal.

12. Loss Watts Percentage Values: fill out the following section of the worksheet:

Meter Nominal kVA = 600 * (PT Multiplier) * (CT Multiplier) / 1000

= 600 * (____________) * (___________) / 1000

= ________________

Quantity	Value at Meter Nominal	Meter Nominal kVA	% Loss at Meter Nominal	Quantity
No-Load Loss W (kW)				% Loss Watts FE
No-Load Loss VAR (kVAR)				% Loss VARs FE
Full Load Loss W (kW)				% Loss Watts CU
Full Load Loss VAR (kVAR)				% Loss VARs CU

13. Calculate Load Loss Values:

   a. Enter Value at Meter Nominal from Normalize Losses (step 11).

   b. Enter Meter Nominal kVA from previous calculation (step 12).

   c. Calculate % Loss at Meter Nominal by dividing Value at Meter Nominal by Meter Nominal kVA and multiplying by 100.

d. Enter calculated % Loss at Meter Nominal Watt values into the Shark® 270 meter using CommunicatorPQA® software. Refer to Appendix B of the software manual for additional instructions.

8: Time of Use Function

8.1: Introduction

In response to both higher energy costs and concern for energy conservation (often-times spurred on by governmental regulations), many utilities have adopted strategies for load management. Time of Use (TOU) metering is one of these strategies. TOU is a means of accumulating usage during specified time periods with the purpose of billing with different rates for the different periods; for example, off-peak versus on-peak usage, and weekday versus weekend usage. So, a TOU usage structure takes into account both the quantity of energy used and the time at which it was consumed. TOU metering by utilities lets them charge a higher rate for electricity used when it is more expensive to produce and distribute, i.e., a Peak Demand period. In this way the utility tries to reward usage during lower demand periods and curtail usage during higher demand periods, by charging more or less for equivalent energy use.

The Nexus® 1500+ meter's TOU function, available with the CommunicatorPQA® software application, lets you set up a TOU profile to meet your application needs. It has been developed to offer a variety of programmable rate structures, for maximum flexibility. Once programmed, the Nexus® 1500+ meter's TOU function accumulates data based on the time-scheme you programmed into the meter. See the figure on the next page for a graphical representation of TOU.

See Chapter 15 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for details on programming the Nexus® 1500+ meter's TOU profile and retrieving TOU data.

Time of Use Metering

Energy use is binned according to the time it is used, so that it can be billed for appropriately.

To set up the bins (that is, the rates), you can use:

Seasons 1-4

Months 1-12

Type of Days (Weekend/Weekday/Holiday/Custom (Day Type))

Time of Day Bins (Rates)

For Example: Off-Peak=Lowest Energy Usage Cost
On-Peak=Highest Energy Usage Cost
Shoulder Peak=Middle Energy Usage Cost

TOU example: Season One, Month 1

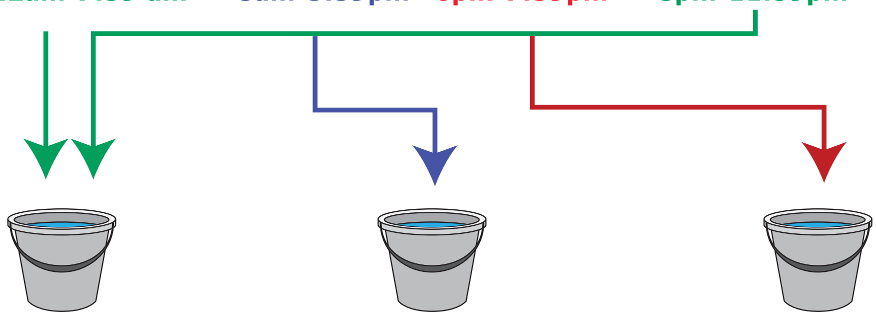
Weekdays
Off Peak 12 am-7:59am
On Peak 8 am - 5:59pm
Shoulder Peak 6 pm - 7:59 pm
Off Peak 8 pm-11:59pm

Weekends
Off Peak 12 am-11:59pm

Holidays
Off Peak 12 am-11:59pm

Monday: the day's usage is binned as shown below:

Energy Used: **12am-7:59 am** **8am-5:59pm** **6pm-7:59pm** **8pm-11:59pm**



Usage Bins (Rates)

Off Peak On Peak Shoulder Peak

Figure 8.1: Time of Use

8.2: The Nexus® 1500+ Meter's TOU Profile

A Nexus® 1500+ meter's TOU profile sets the parameters for TOU data accumulation into rate bins. Features of the meter's TOU implementation include:

- The meter uses a perpetual TOU scheme, so you only need to set up the TOU profile once and then you can apply it to all subsequent years.
- You can save the TOU profile as a file and easily import it into any other Nexus® 1500+ meters that you have.
- You can set up to 16 daily schedules, e.g., Weekday, Weekend, or Holiday, or any type of daily schedule you need.
- You can set up to four Season types, which can also be customized as daily or weekly schedules.
- You can set up to 12 Month types.
- Season and month end time can be customized as needed.
- The meter has 38 available accumulators for TOU; 16 accumulators can be tracked in a TOU profile.

8.3: TOU Prior Season and Month

The Nexus® 1500+ meter stores accumulations for the prior season and the prior month. When the end of a billing period is reached, the current season or month is stored as the prior data. The registers are then cleared and accumulations resume, using the next set of TOU schedules and register assignments from the TOU profile. Prior and current accumulations to date are always available.

8.4: Updating, Retrieving and Replacing the TOU Profile

CommunicatorPQA® software retrieves the TOU Profile from the Nexus® 1500+ meter or from the computer's hard drive for review and edit. Accumulations do not stop during TOU profile updates, but once you have made your changes and updated the meter, the meter performs a self-read and the current month and season data blocks are moved to the prior data blocks, and the current data blocks and all accumulator "buckets" are cleared. See Chapter 15 of the *CommunicatorPQA® and Meter-ManagerPQA® Software User Manual* for instructions on updating the TOU profile.

8.5: Daylight Savings and Demand

To enable Daylight Savings Time for the meter: from the Device Profile menu click **General Settings>Time Settings**. In the Time Settings screen, click Auto DST, which sets Daylight Savings Time automatically (for the United States only). You can also select User Defined and enter the desired dates for Daylight Savings Time.*

To set Demand intervals: from the Device Profile menu click **Revenue and Energy Settings>Demand Integration Intervals** and set the desired intervals.*

To set Cumulative Demand Type, from the Device Profile menu click **Revenue and Energy Settings>Cumulative Demand Type** and select Block or Rolling Window Average.*

*See Chapter 11 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions.

NOTE: The DST rules used by the Nexus® 1500+ meter are as follows:

- Auto DST rules: START: First Sunday in April at 2AM
  END: Last Sunday in October at 2AM
- Manual DST rules: START: user defined
  END: user defined
- Auto DST US EPA 2005 rules: START: Second Sunday in March at 2AM
  END: First Sunday in November at 2AM

9: Network Communications

9.1: Hardware Overview

The Nexus® 1500+ meter can connect to multiple PCs via Modbus/TCP over the Ethernet or via a DNP LAN/WAN connection.

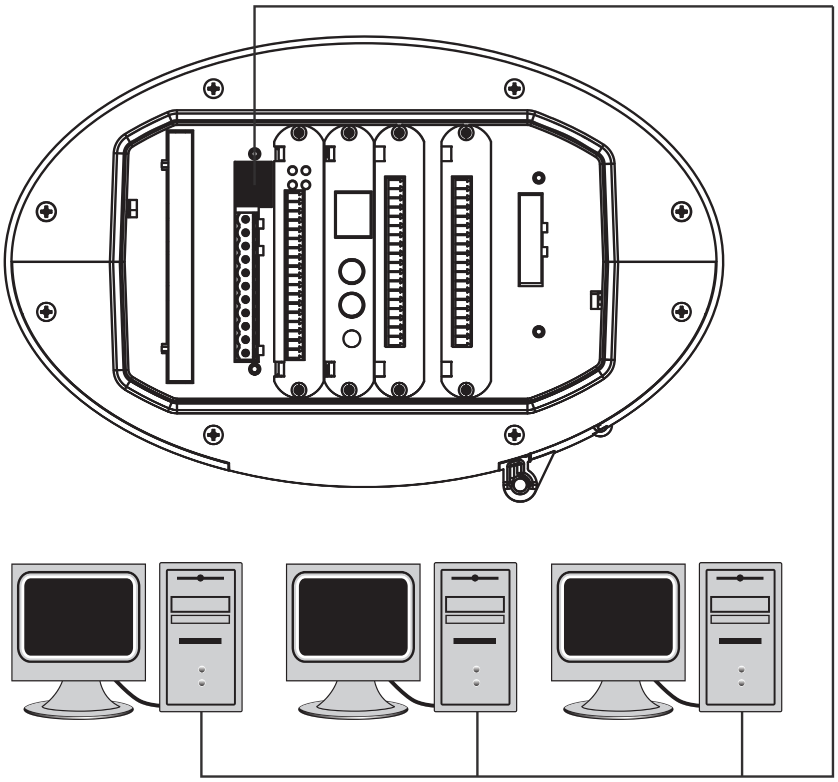


Figure 9.1: Nexus® 1500+ Meter Connected to Network

The Nexus® 1500+ meter's Network is an extremely versatile communications tool. It:

- Adheres to the IEEE 802.3 Ethernet standard using Modbus TCP/IP.
- Utilizes simple and inexpensive 10/100BaseT wiring and connections.
- Plugs into your network using built-in RJ45 jack.
- Is programmable to any IP address, subnet mask and gateway requirements.
- Communicates using the industry-standard Modbus/TCP and DNP LAN/WAN protocols, and with V-Switch™ Key 2 and above, IEC 61850 Protocol. It also supports SNMP (see Appendix D: Using SNMP, on page D-1).

- Multiple simultaneous connections (via LAN) can be made to the Nexus® meter. You can access the Nexus® meter with SCADA, MV90 and RTU simultaneously.
- Multiple users can run CommunicatorPQA® software to access the meter concurrently.

9.2: Specifications

The Nexus® 1500+ meter's main Network card (standard) has the following specifications at 25^{o} C:

Number of Ports:	1
Operating Mode:	10/100BaseT
Connection type:	RJ45 modular (Auto-detecting transmit and receive)
Diagnostic feature:	Status LEDs for LINK and ACTIVE
Number of simultaneous Modbus TCP/IP connections to the meter:	32 (64 total connections over both the main Network card and optional Network card 2)
Number of simultaneous DNP LAN/WAN connections to the meter:	2 TCP and 1 UDP per Network card

NOTE: For details on the Network cards' IEC 61850 Protocol server, see Appendix C.

9.3: Network Connection

Use standard CAT5E network cables to connect with the Nexus® meter. The RJ45 line is inserted into the RJ45 port on the back of the meter (see Figure 9.1).

Set the IP Address using the following steps:
(See Chapter 11 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for more detailed instructions.)

1. From the Device Profile screen, double-click **General Settings> Communications**, then double-click on any of the ports. The Communications Settings screen opens.

2. In the Network Settings section enter the following data.
   NOTE: The settings shown below are the default settings of the main Network card. See 11.5: Ethernet Option Card: RJ45 (NTRJ) or Fiber Optic (NTFO), on page 11-6 for the default settings of optional Network card 2.

   - IP Address: 10.0.0.1
   - Subnet Mask: 255.255.255.0
   - Default Gateway: 0.0.0.0

   NOTES:
   - You can use different settings for the main Network card (check with your Network Administrator for the correct settings).
   - We recommend that the main Network card and Network card 2 be in different subnets, though this is not a necessity.

3. Once the above parameters have been set, CommunicatorPQA® software connects via the network using a Device Address of "1" and the assigned IP Address when you follow these steps:

   a. Open CommunicatorPQA® software.

   b. Click the **Connect** icon in the icon tool bar. The Connect screen opens.

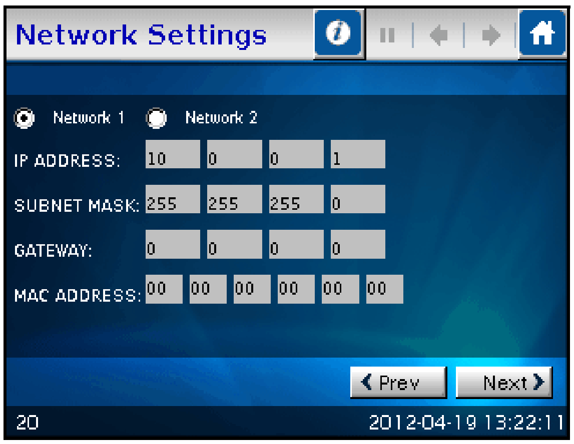
   c. Click the **Network** button at the top of the screen. Enter the following information:
   Device Address: 1
   Host: The Network card's IP Address
   Network Port: 502
   Protocol: Modbus TCP

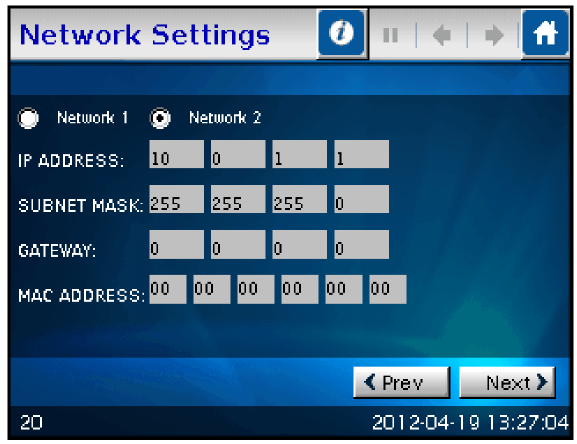
   d. Click the **Connect** button at the bottom of the screen. CommunicatorPQA® software connects to the meter via the network.

Network Information Through Display

You can see the Network settings through the meter's Touch Screen display:

1. From the Main screen, select **Setting**.
2. Press the **Next** button twice to go to the Network Settings screen (shown on the next page).
3. Click the button next to Network 1 to see the settings for the standard Ethernet connection. Click the button next to Network 2 to see the settings for the second, optional Network card, if installed.





9.4: Total Web Solutions

The Nexus® 1500+ meter’s Network card supports EIG’s Total Web Solutions, which is a Web server that lets you view meter information over any standard Web browser. The Nexus® 1500+ meter default webpages can be viewed by Internet Explorer, Firefox, Chrome, and Safari web browsers. They can be viewed on PCs, tablet computers and smart phones.

The default webpages provide real-time readings of the meter's voltage, current, power, energy, power quality, pulse accumulations and high-speed digital inputs, as well as additional meter information, alarm/email information and diagnostic information. You can also upgrade the meter’s firmware through the webpages. You can customize the default webpages - see Chapter 21 in the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions on setting up Total Web Solutions and customizing webpages. Following is information on accessing the default webpages.

IMPORTANT! If Flex Cyber Mode security is enabled for the meter, you must either be an Admin or a user who is able to view the webpages, and you must enter your username and password in order to access the webpages.

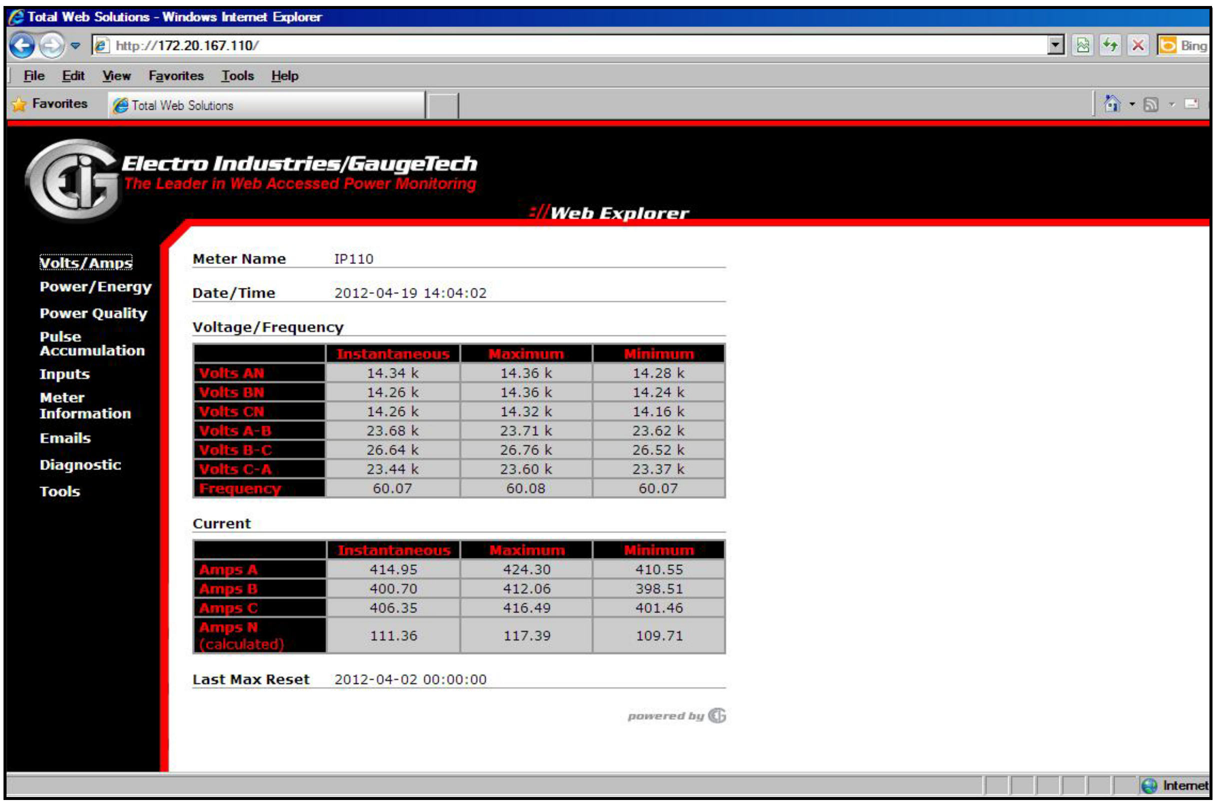
9.4.1: Viewing Webpages

1. Open a Web browser on your PC, tablet computer or smart phone.

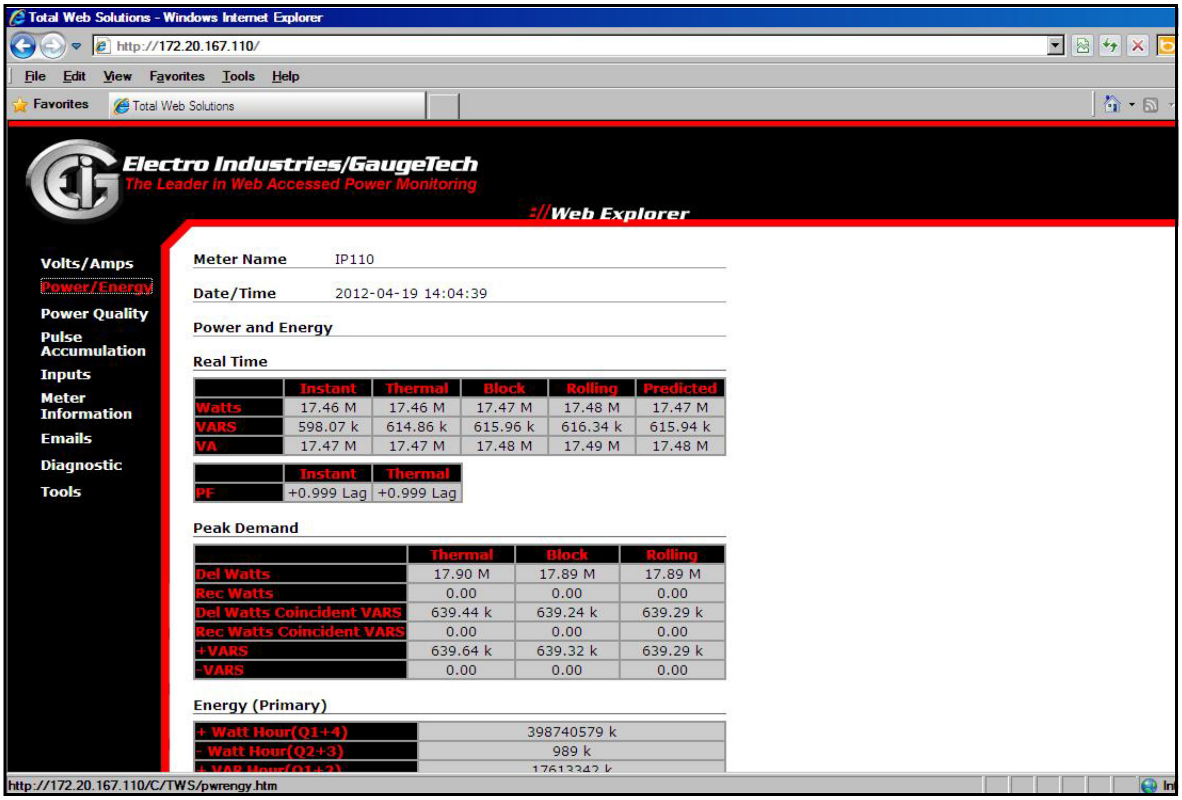
2. Type the Ethernet Card's IP address in the address bar, preceded by "http://".

   For example: http://10.0.0.1

3. You will see the Volts/Amps webpage shown below. It shows voltage and current readings.



4. To view power and Energy readings, click **Power/Energy** on the left side of the webpage. You will see the webpage shown below. Scroll to see all of the information.


Total Web Solutions - Windows Internet Explorer
http://172.20.167.110/
File Edit View Favorites Tools Help
Favorites Total Web Solutions
Electro Industries/GaugeTech
The Leader in Web Accessed Power Monitoring
Web Explorer

Volts/Amps
Power/Energy
Power Quality
Pulse Accumulation
Inputs
Meter Information
Emails
Diagnostic
Tools

Meter Name IP110

Date/Time 2012-04-19 14:04:39

Power and Energy

Real Time

	Instant	Thermal	Block	Rolling	Predicted
Watts	17.46 M	17.46 M	17.47 M	17.48 M	17.47 M
VARS	598.07 k	614.86 k	615.96 k	616.34 k	615.94 k
VA	17.47 M	17.47 M	17.48 M	17.49 M	17.48 M

	Instant	Thermal
PF	+0.999 Lag	+0.999 Lag

Peak Demand

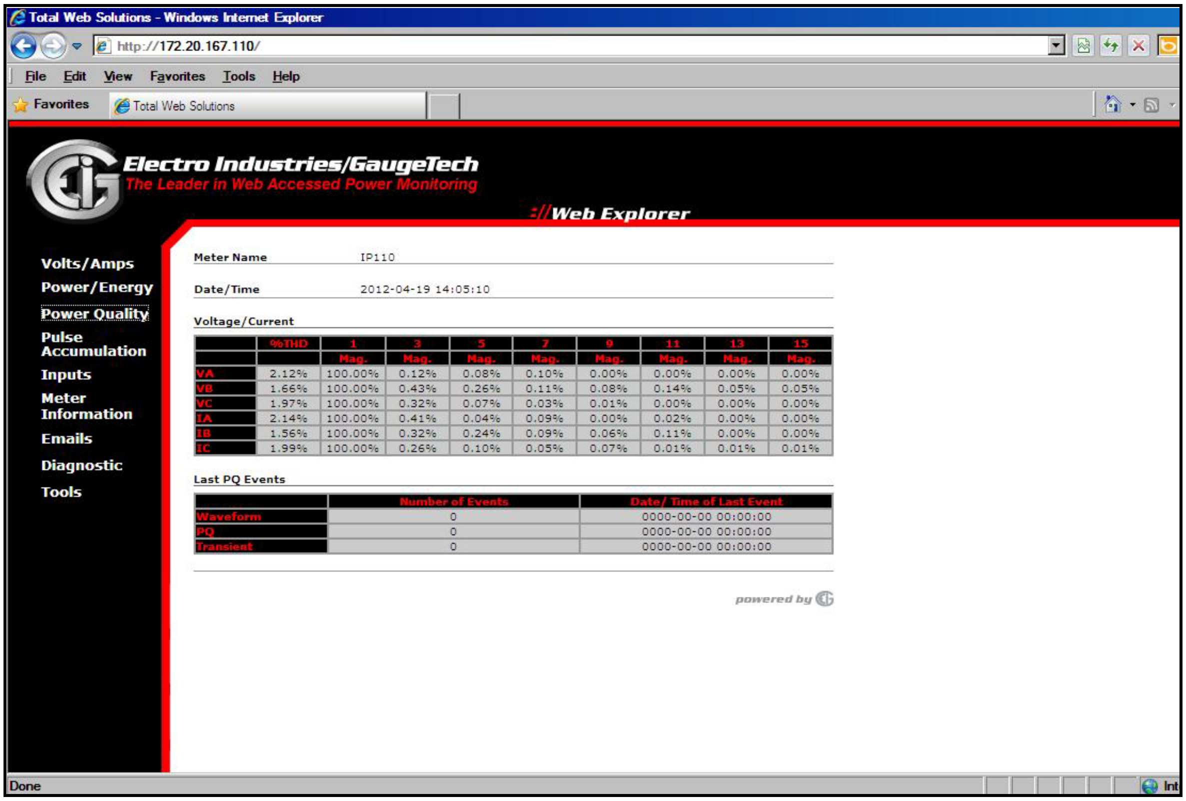
	Thermal	Block	Rolling
Del Watts	17.90 M	17.89 M	17.89 M
Rec Watts	0.00	0.00	0.00
Del Watts Coincident VARS	639.44 k	639.24 k	639.29 k
Rec Watts Coincident VARS	0.00	0.00	0.00
+VARS	639.64 k	639.32 k	639.29 k
-VARS	0.00	0.00	0.00

Energy (Primary)

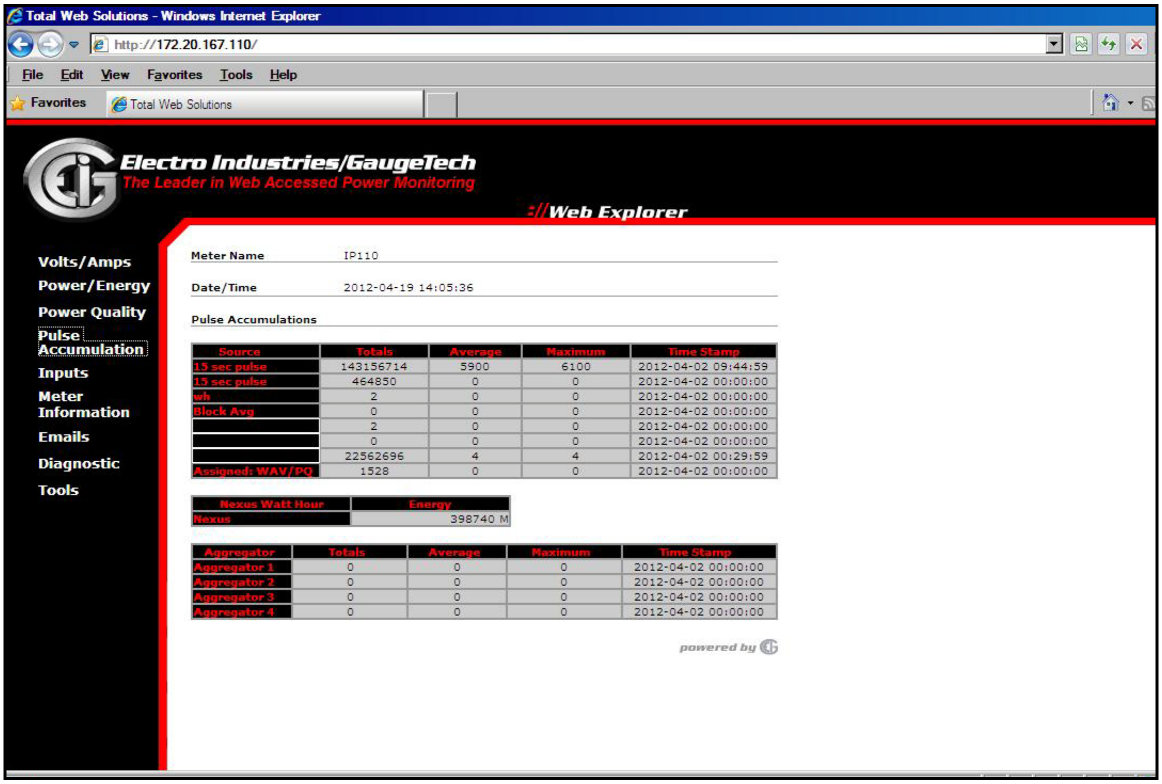
+ Watt Hour(Q1+4)	398740579 k
- Watt Hour(Q2+3)	989 k
+ VAR Hour(Q1+2)	17613342 k

http://172.20.167.110/C/TWS/pwrengy.htm

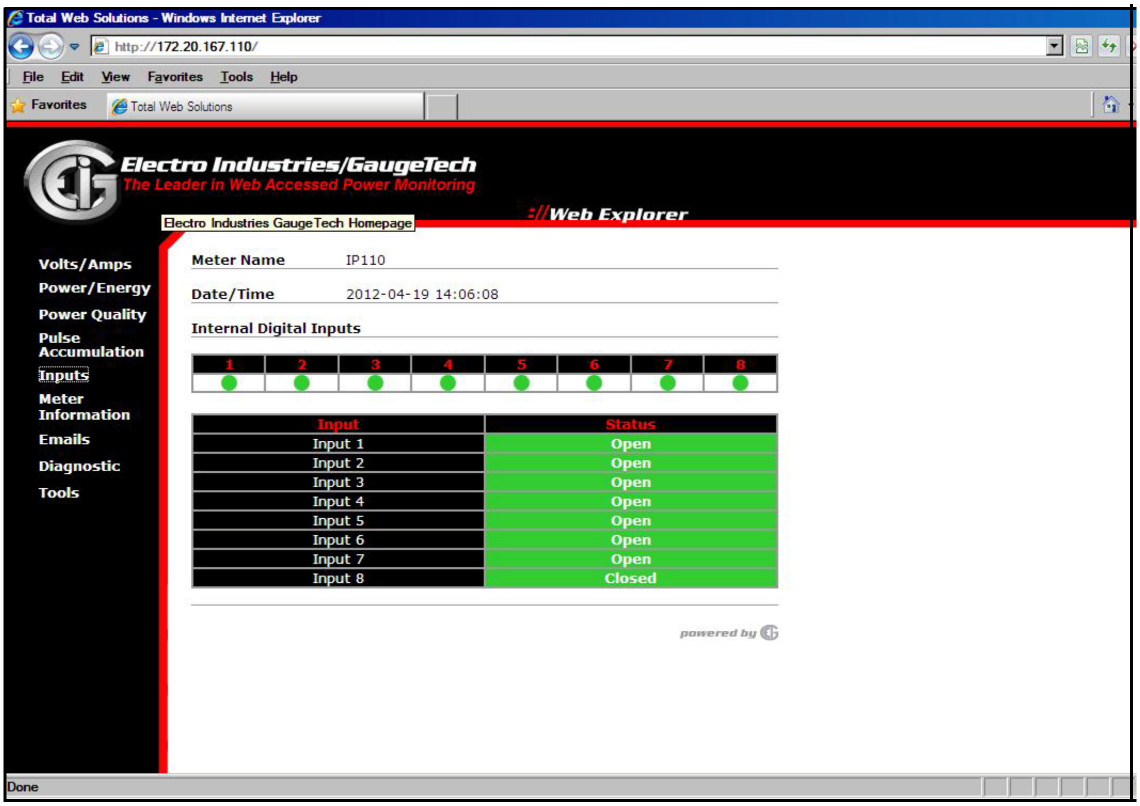
5. To view power quality information, click **Power Quality** on the left side of the webpage. You will see the webpage shown below.



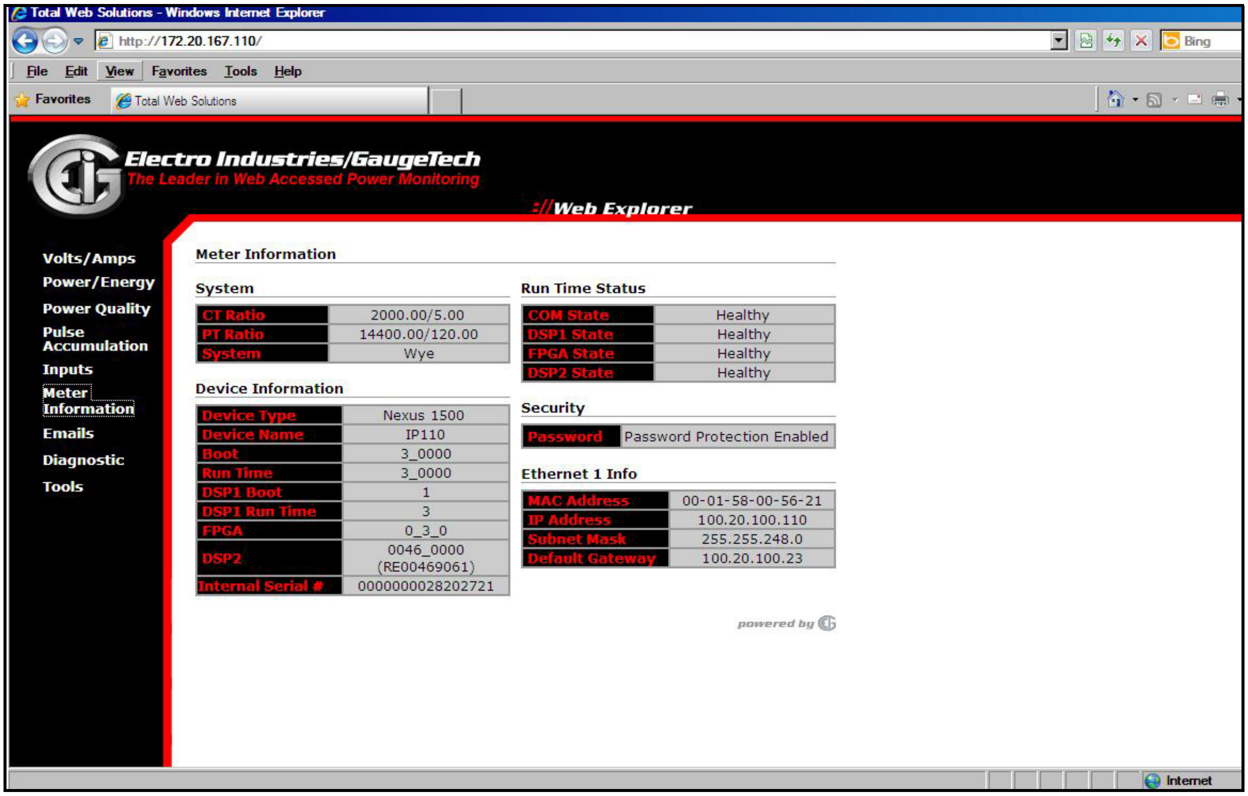
6. To view pulse accumulation data, click **Pulse Accumulation** on the left side of the webpage. You will see the webpage shown below.



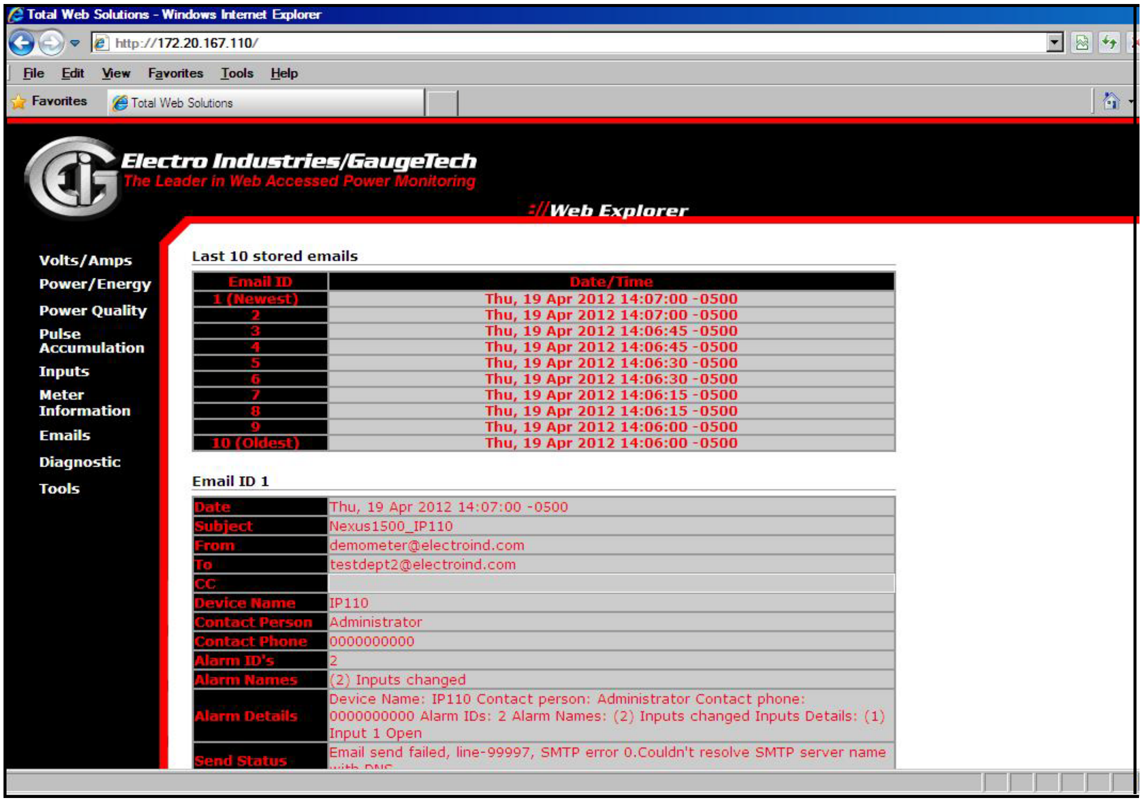
7. To view Inputs data, click **Inputs** on the left side of the webpage. You will see the webpage shown below.



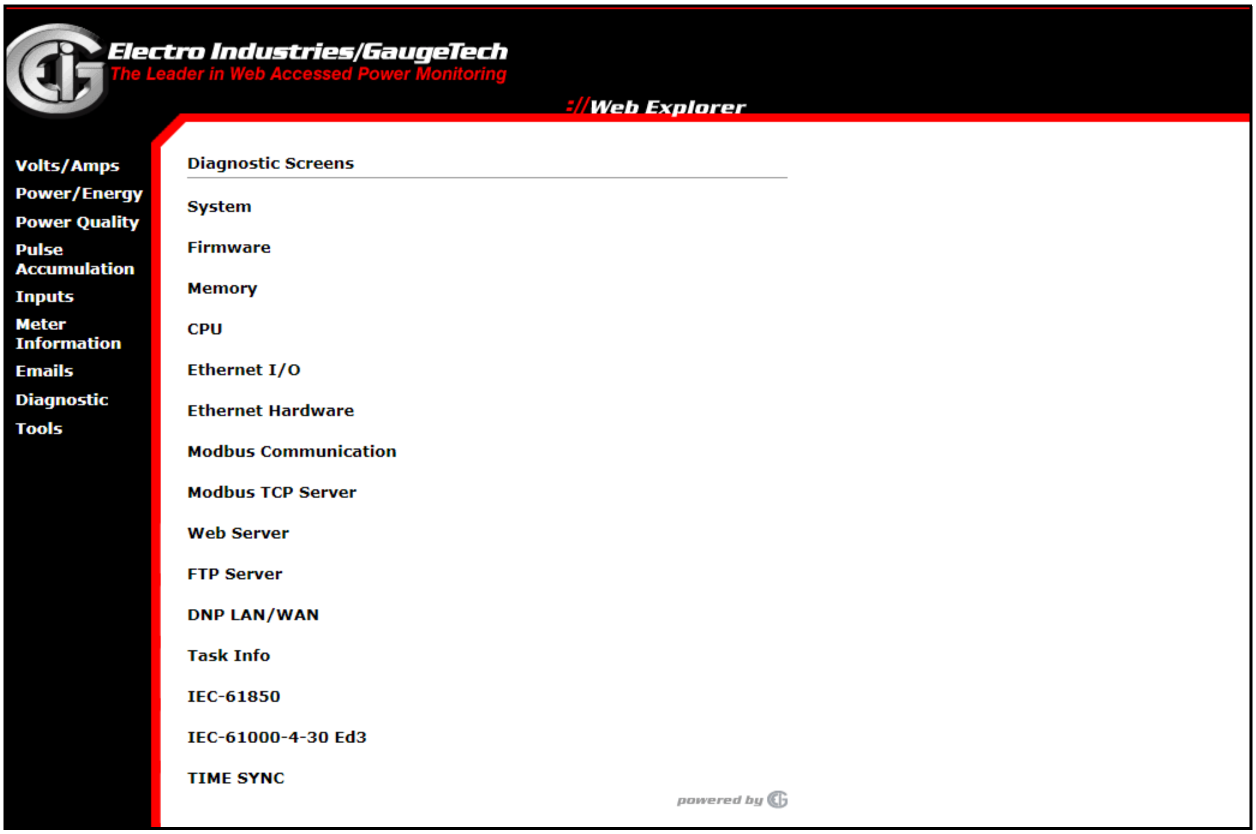
8. To view general meter information, click **Meter Information** on the left side of the webpage. You will see the webpage shown below.



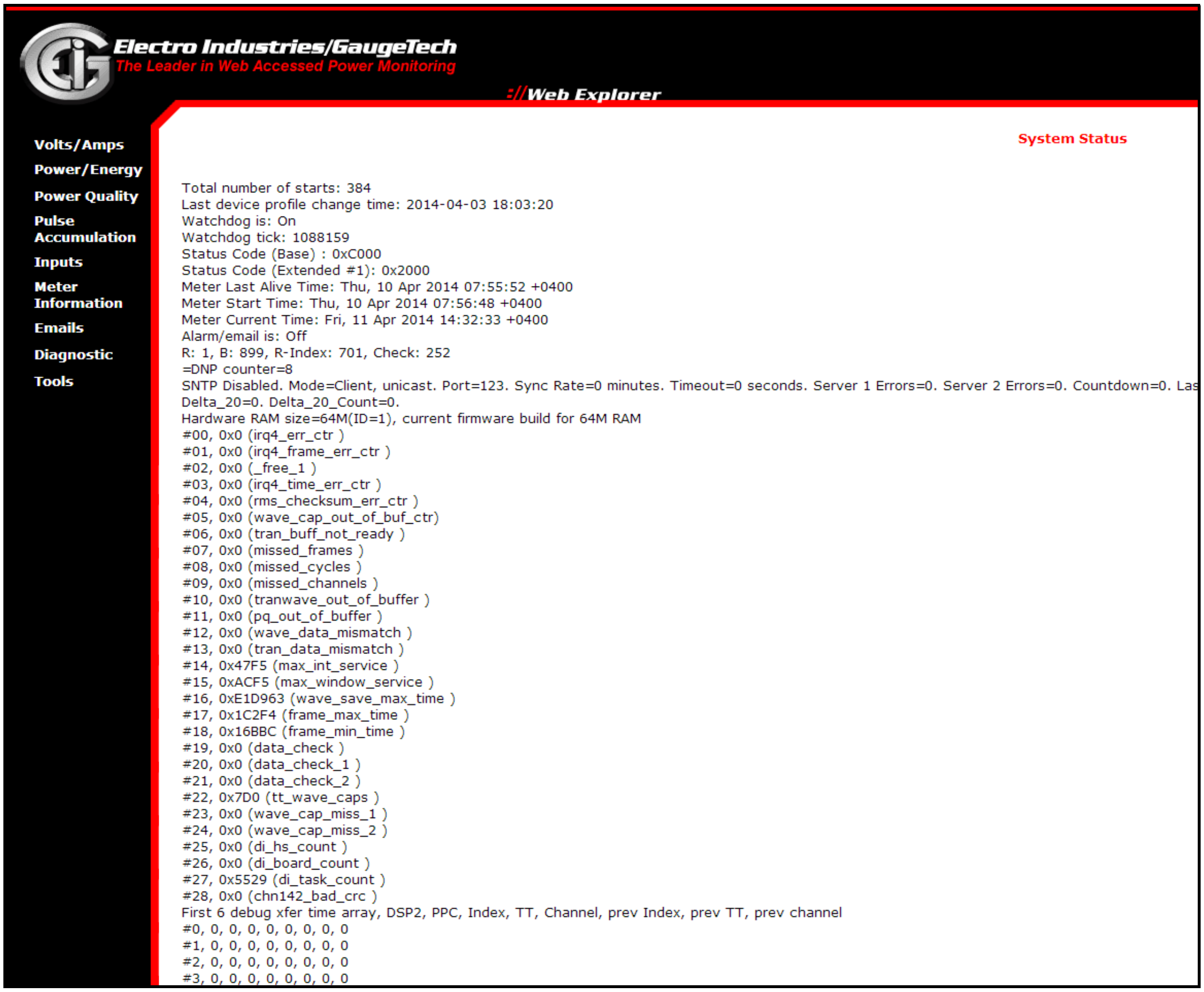
9. To view alarm/email information, click **Emails** on the left side of the webpage. You will see the webpage shown below. Scroll to see all of the information.



10.To view detailed information for the meter, click **Diagnostic** on the left side of the webpage. You will see the webpage shown below. This page lists the available diagnostic information - click on any of the listed items to view its webpage. The Diagnostic webpages are shown on the following pages.

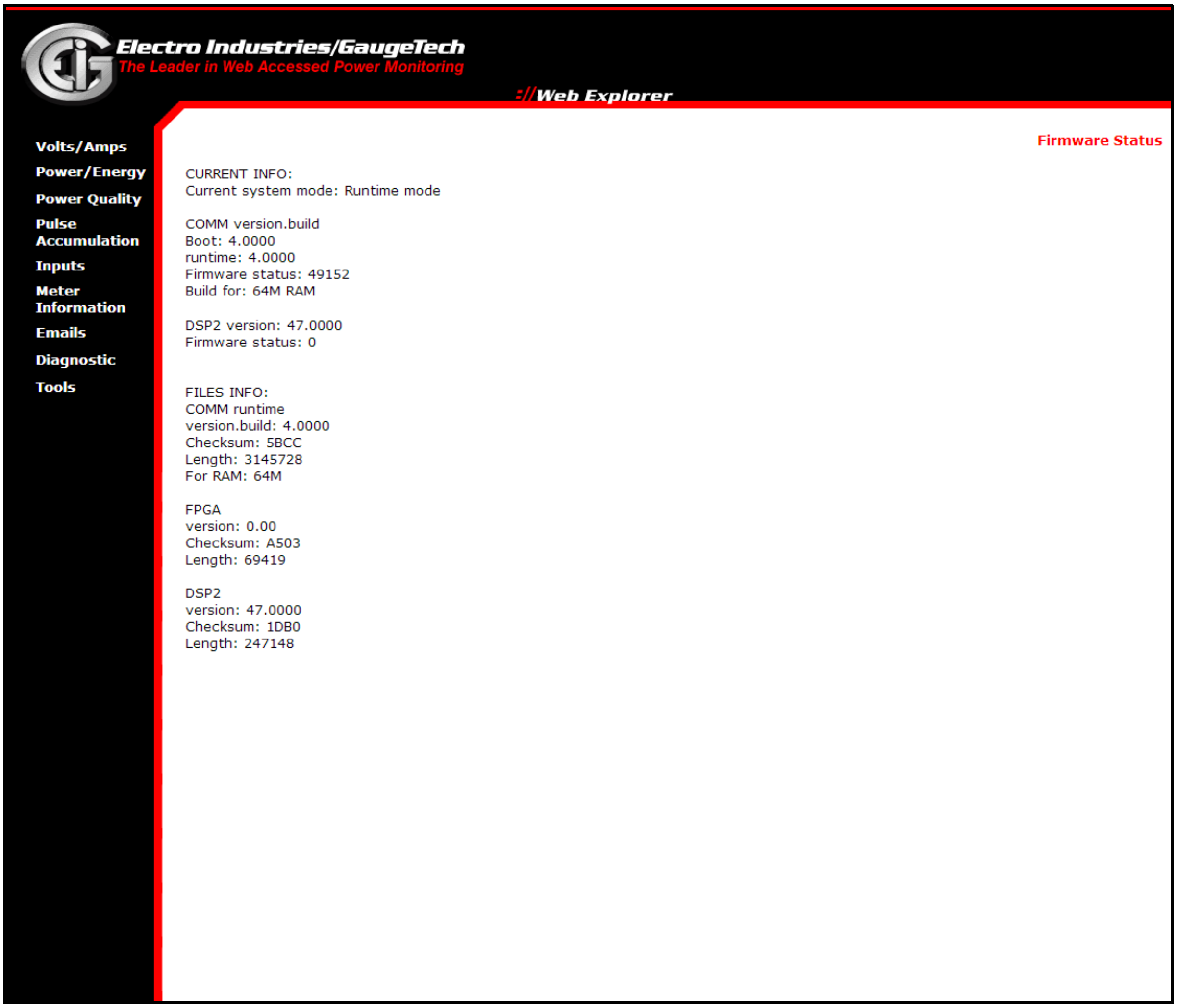


System Webpage



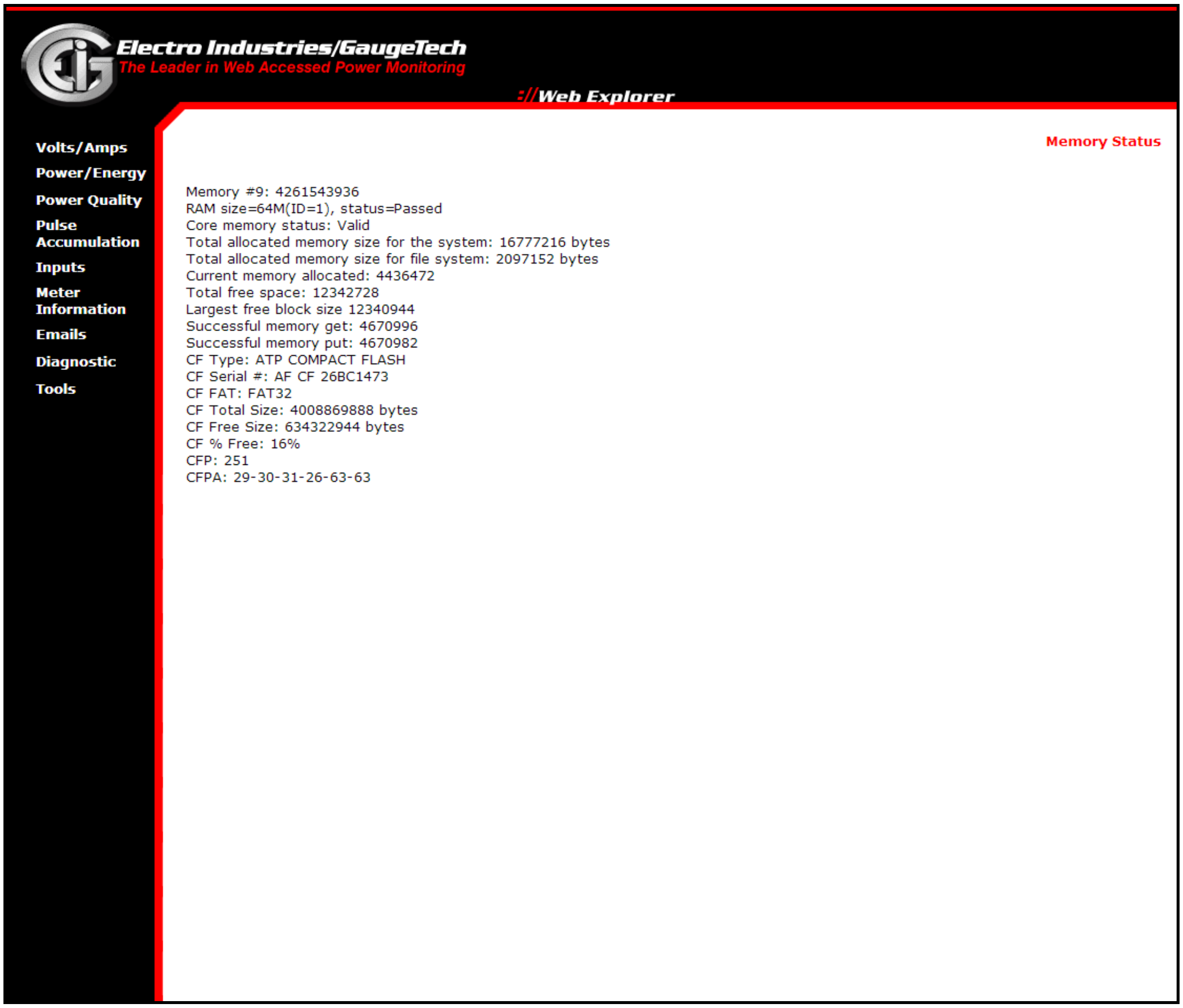
This webpage displays System status information: Number of Device Starts, Last Device Profile Change, Status Codes, etc.

Firmware Webpage



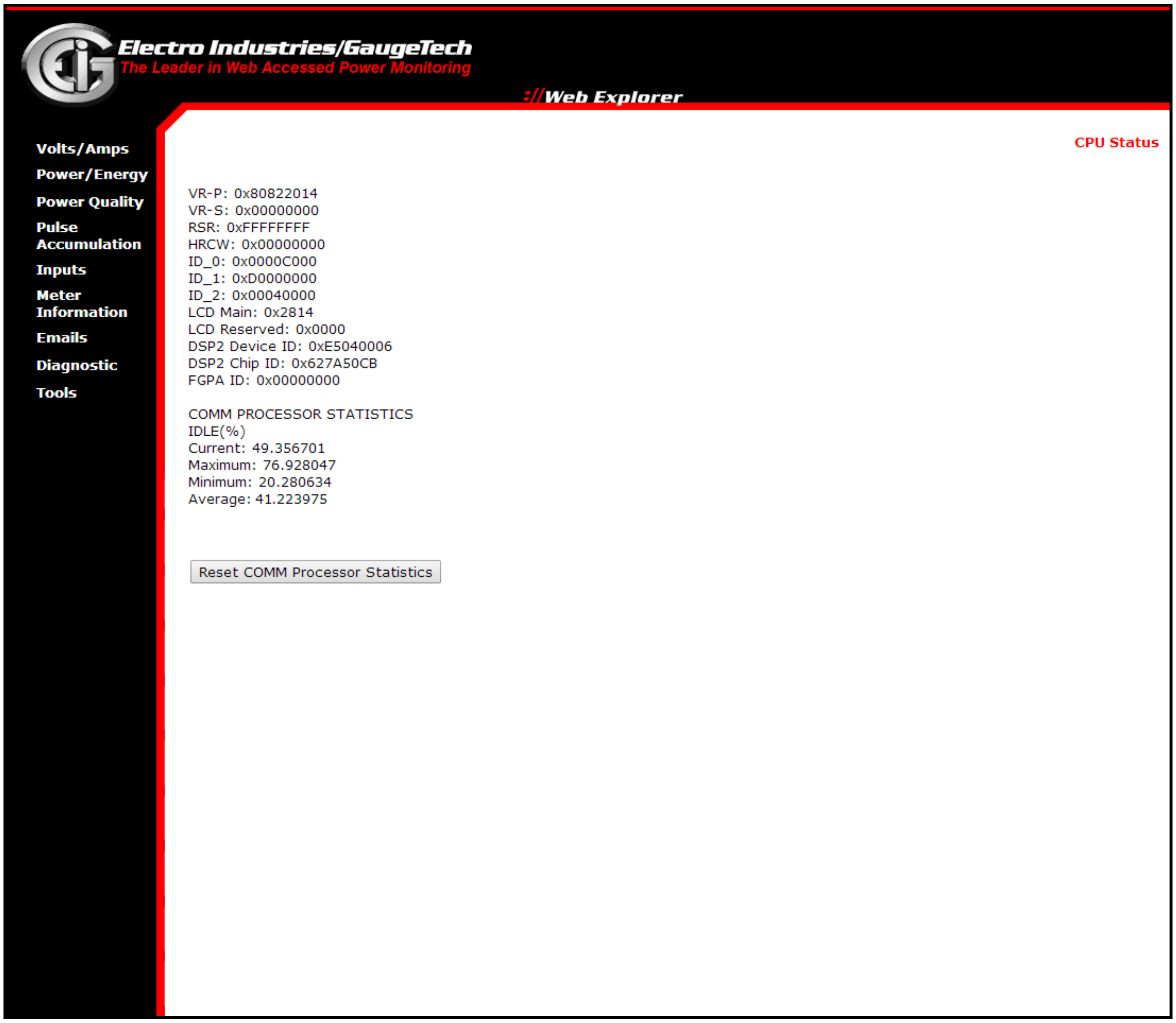
This webpage displays the Firmware version information.

Memory Webpage



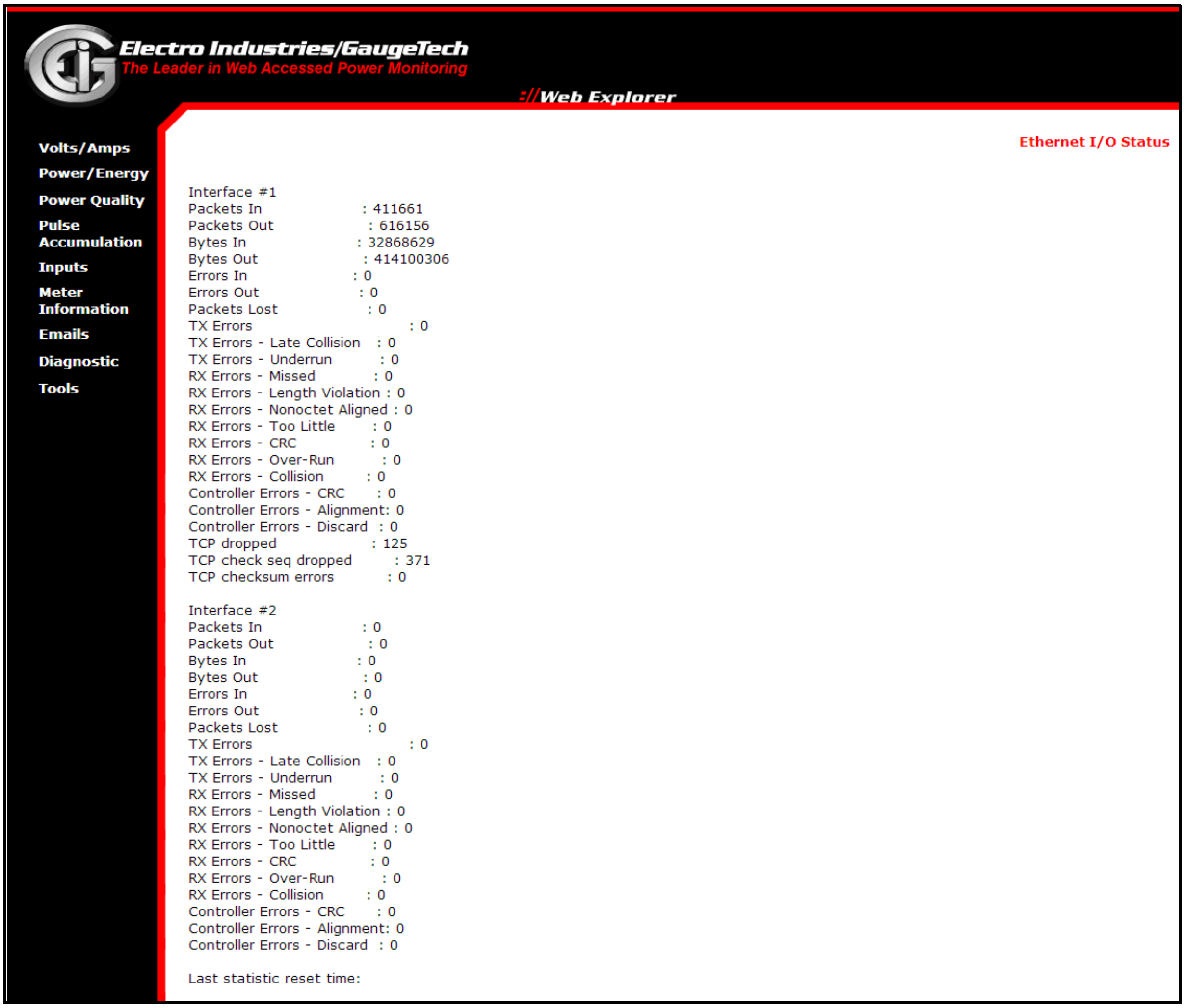
This webpage displays Memory information: amount of free space, Flash status, etc.

CPU Webpage



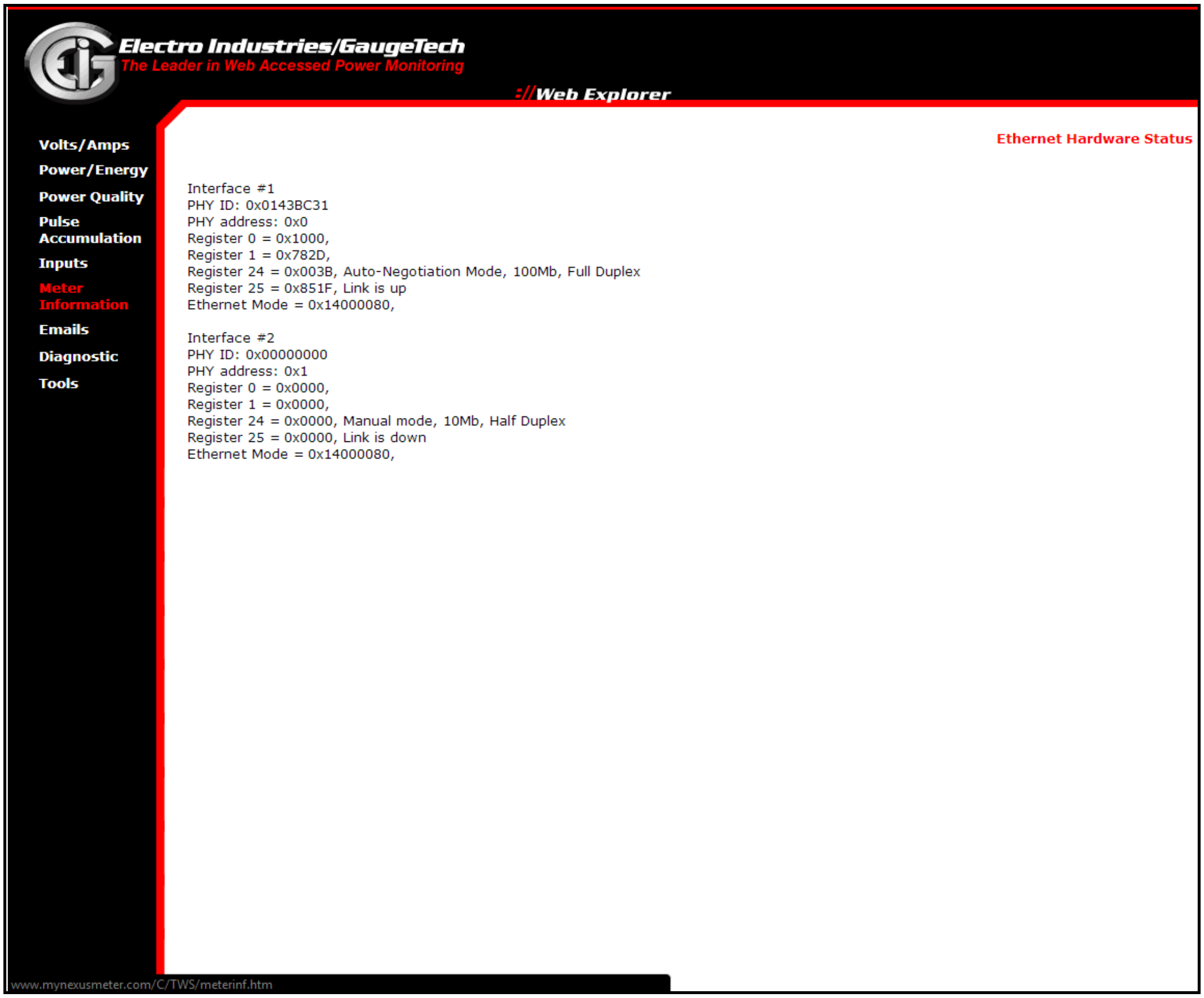
This webpage displays status information for the meter's processors. If you are performing Diagnostic tests and want to clear error codes in between, use the Reset COMM Processor Statistics button at the bottom of the webpage.

Ethernet I/O Webpage



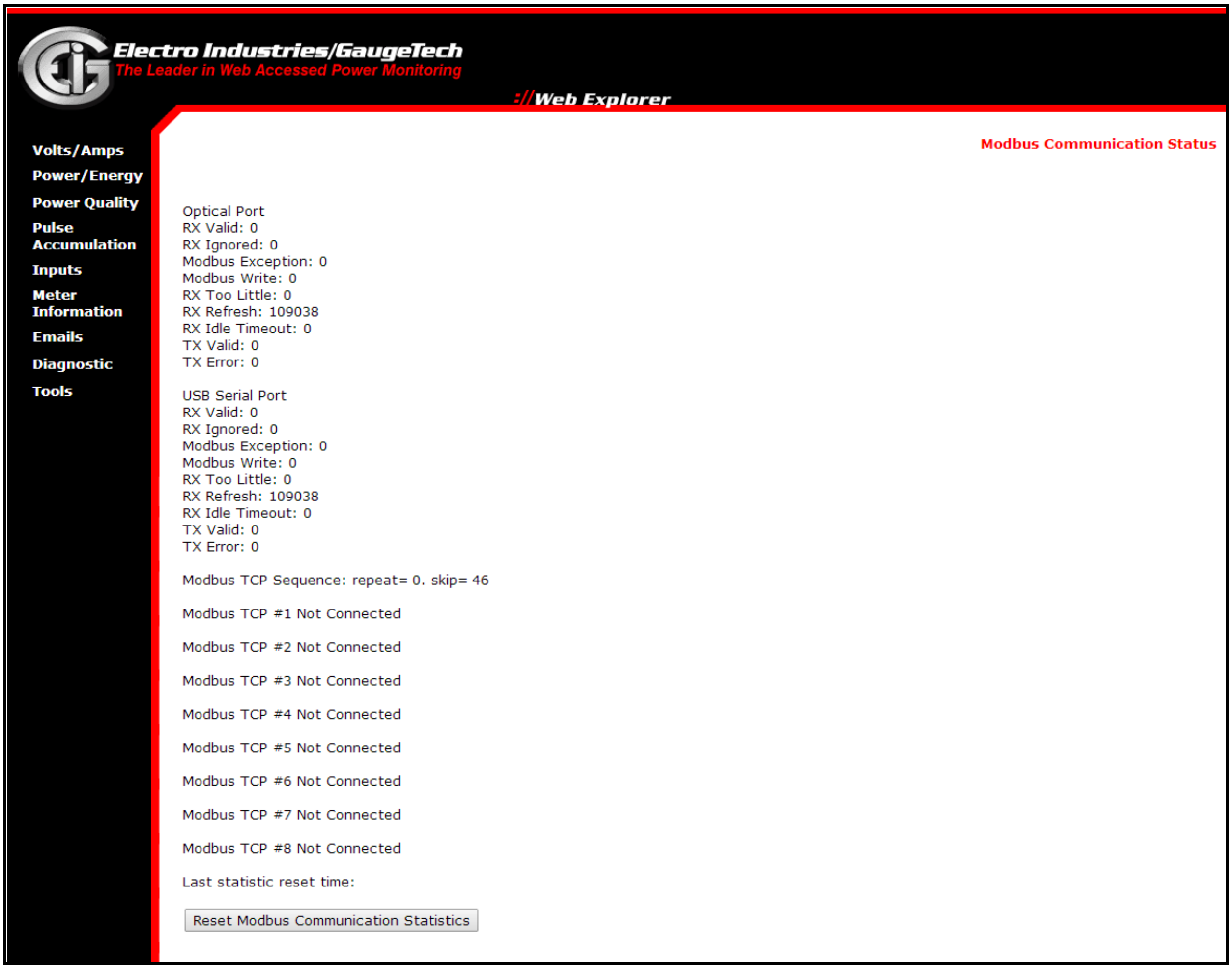
This webpage displays status information for the Ethernet I/O card: packets in and out and error information. If you are performing Diagnostic tests and want to clear error codes in between, use the Reset Network Statistics button at the bottom of the webpage.

Ethernet Hardware Webpage



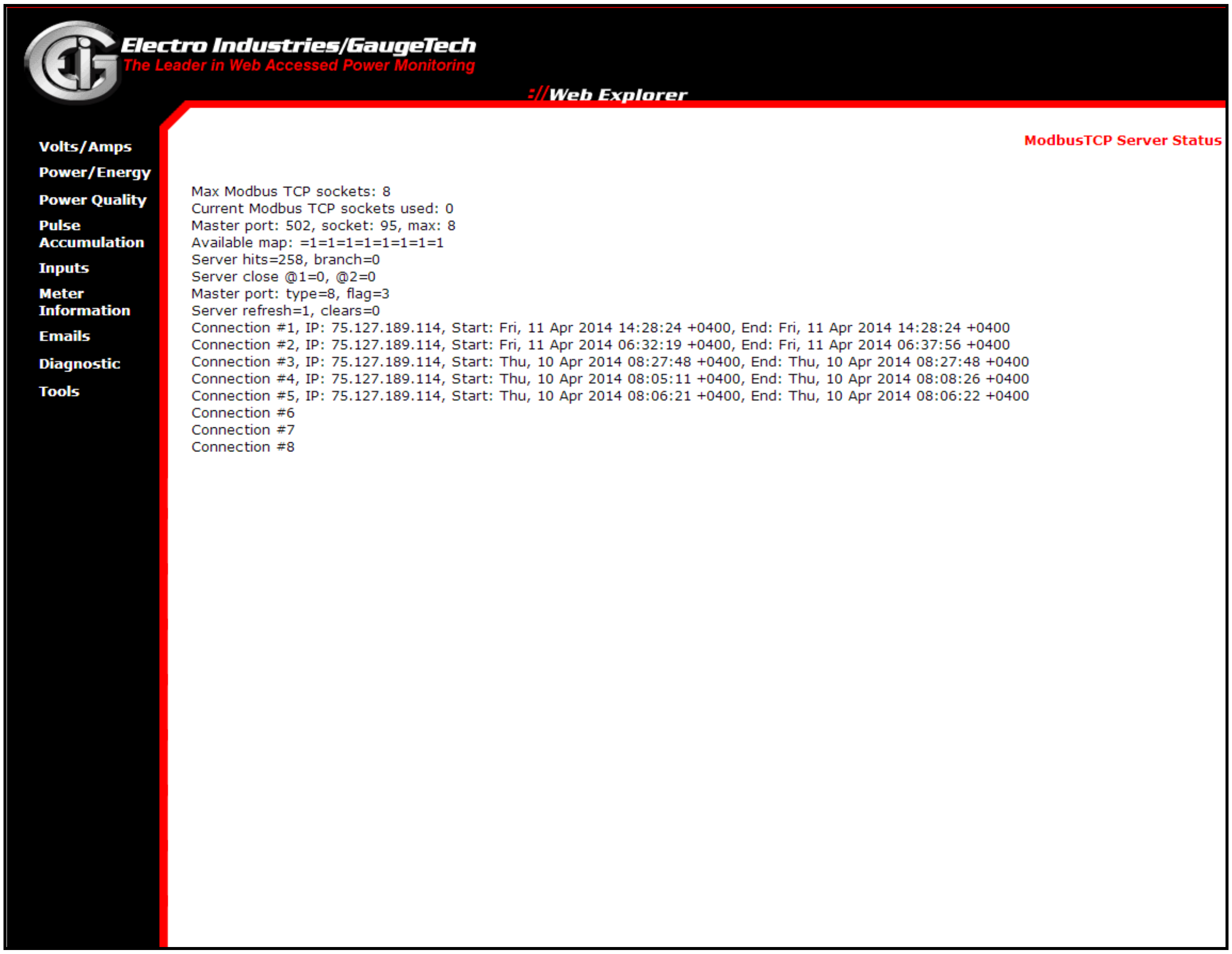
This webpage displays information about the meter’s Ethernet Hardware.

Modbus Communication Webpage



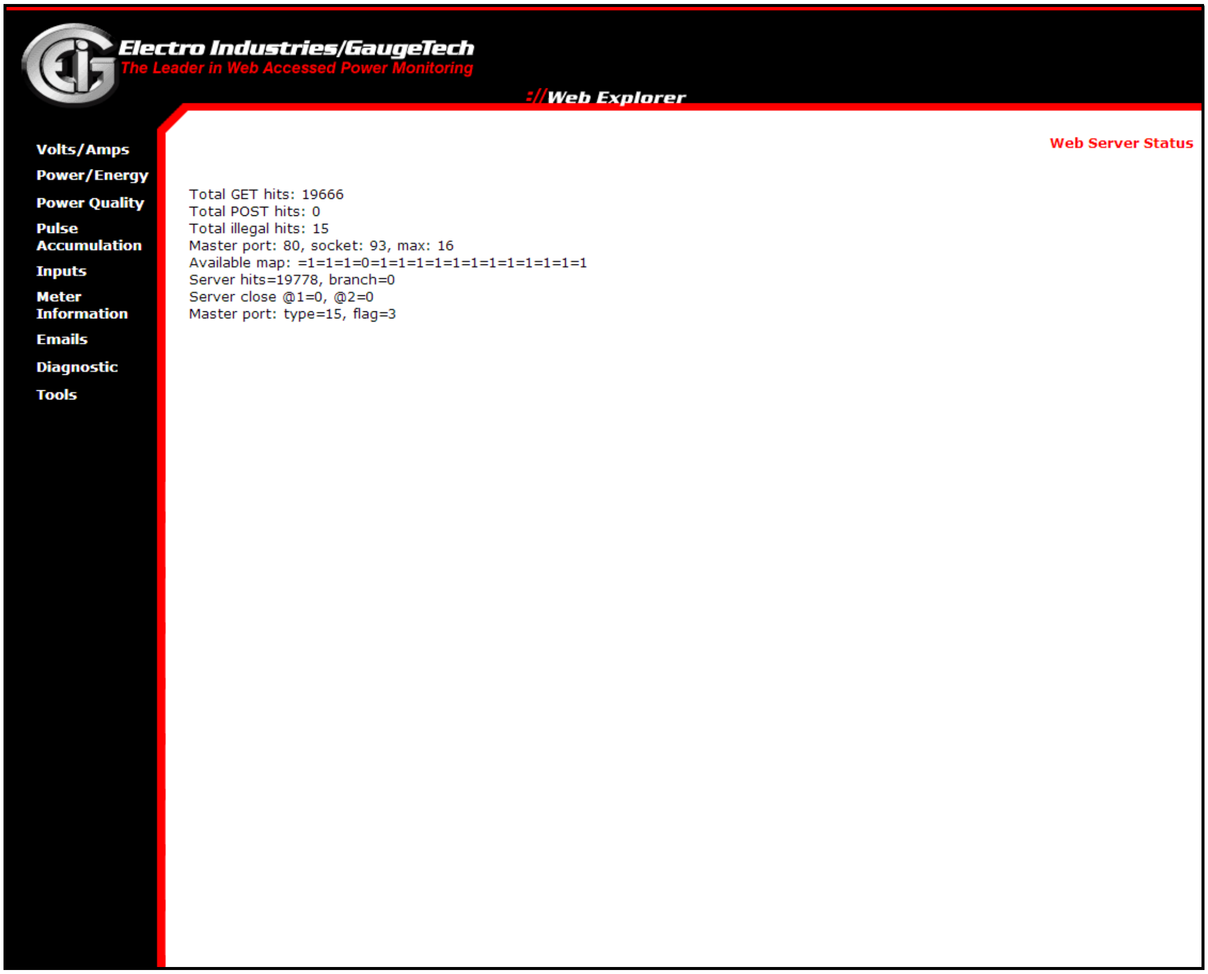
This webpage displays communication information for the meter's Modbus ports. If you are performing Diagnostic tests and want to clear error codes in between, use the Reset Modbus Communication Statistics button at the bottom of the webpage.

Modbus TCP Server Webpage



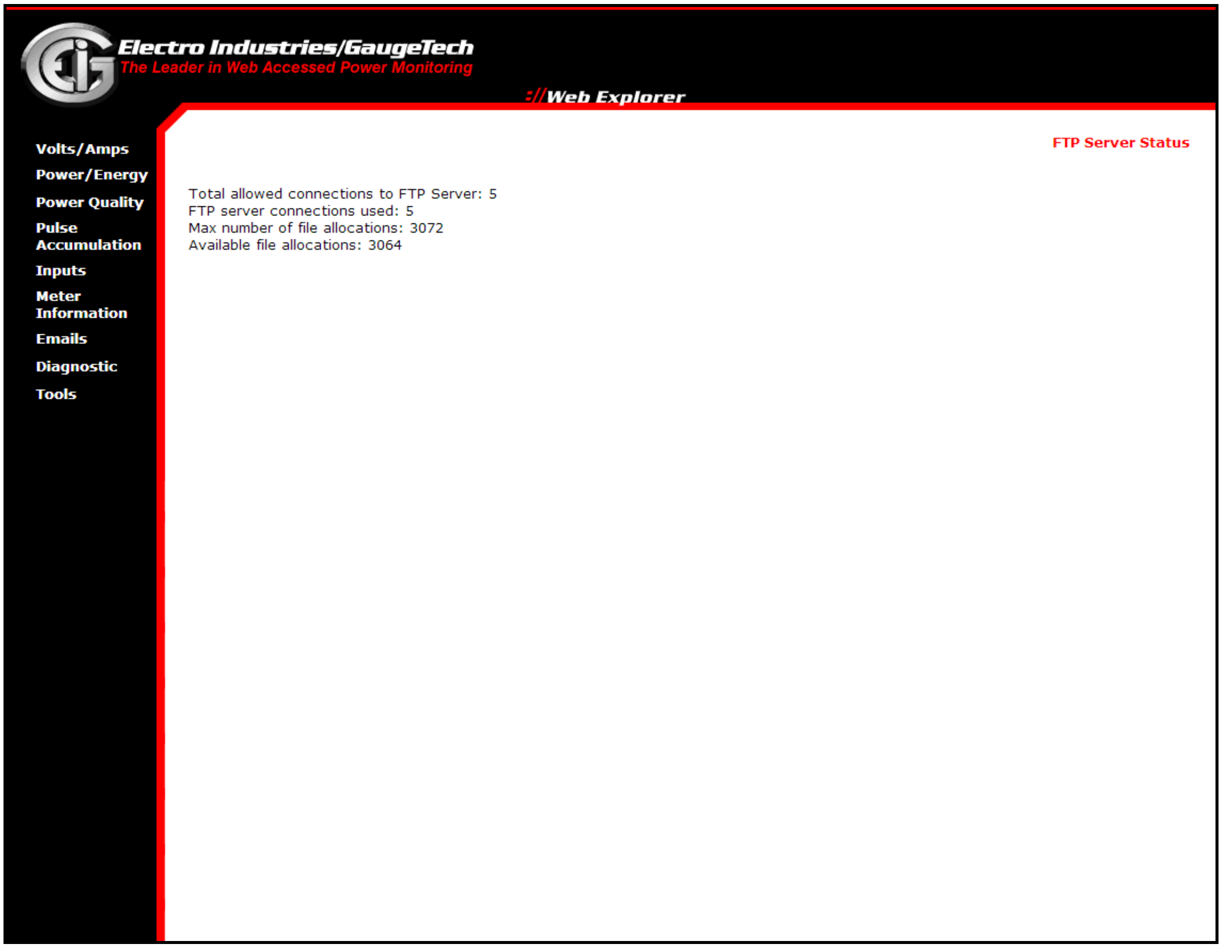
This webpage displays information for the meter's Modbus TCP server.

Web Server Webpage



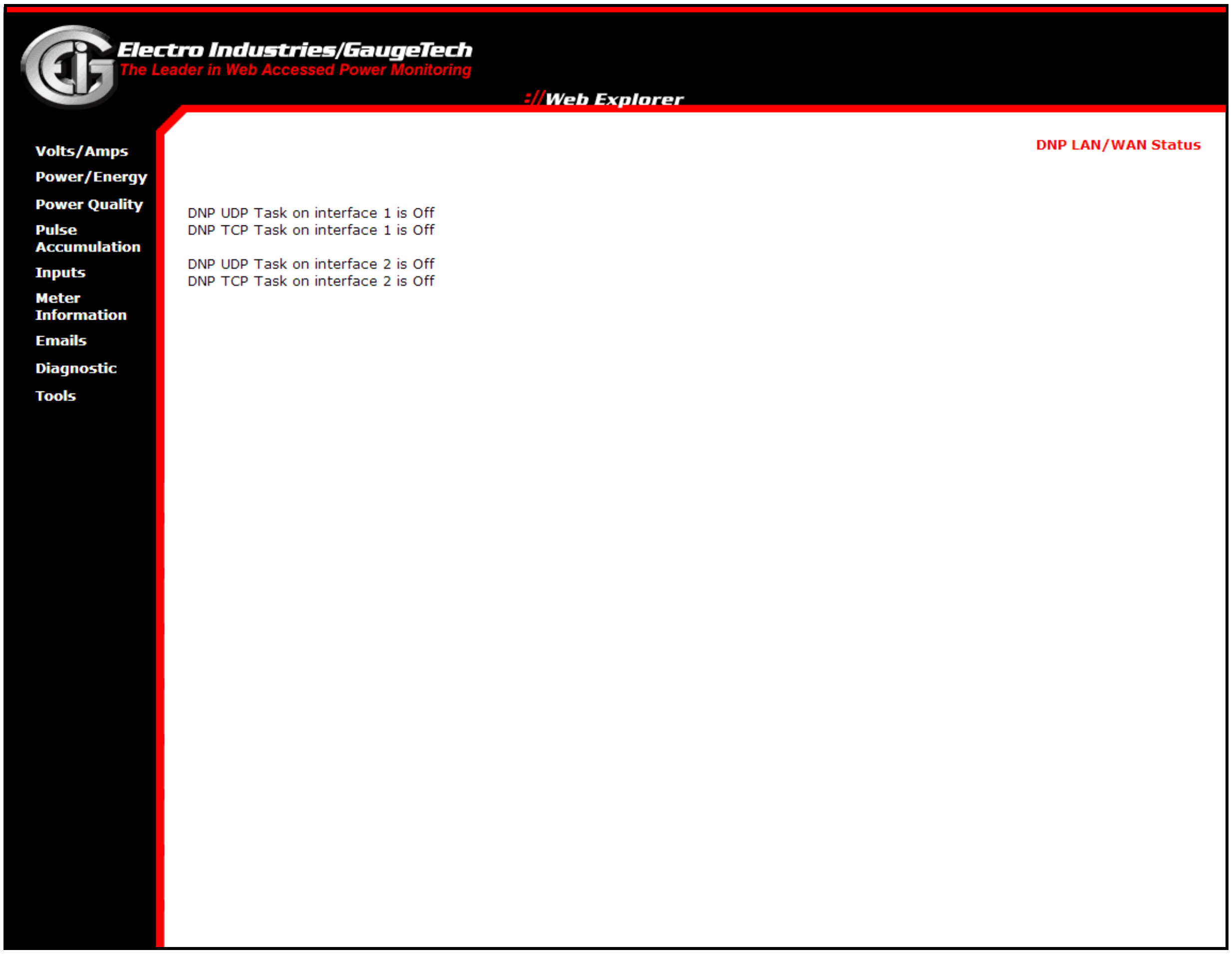
This webpage displays information for the meter’s Web server.

FTP Server Webpage



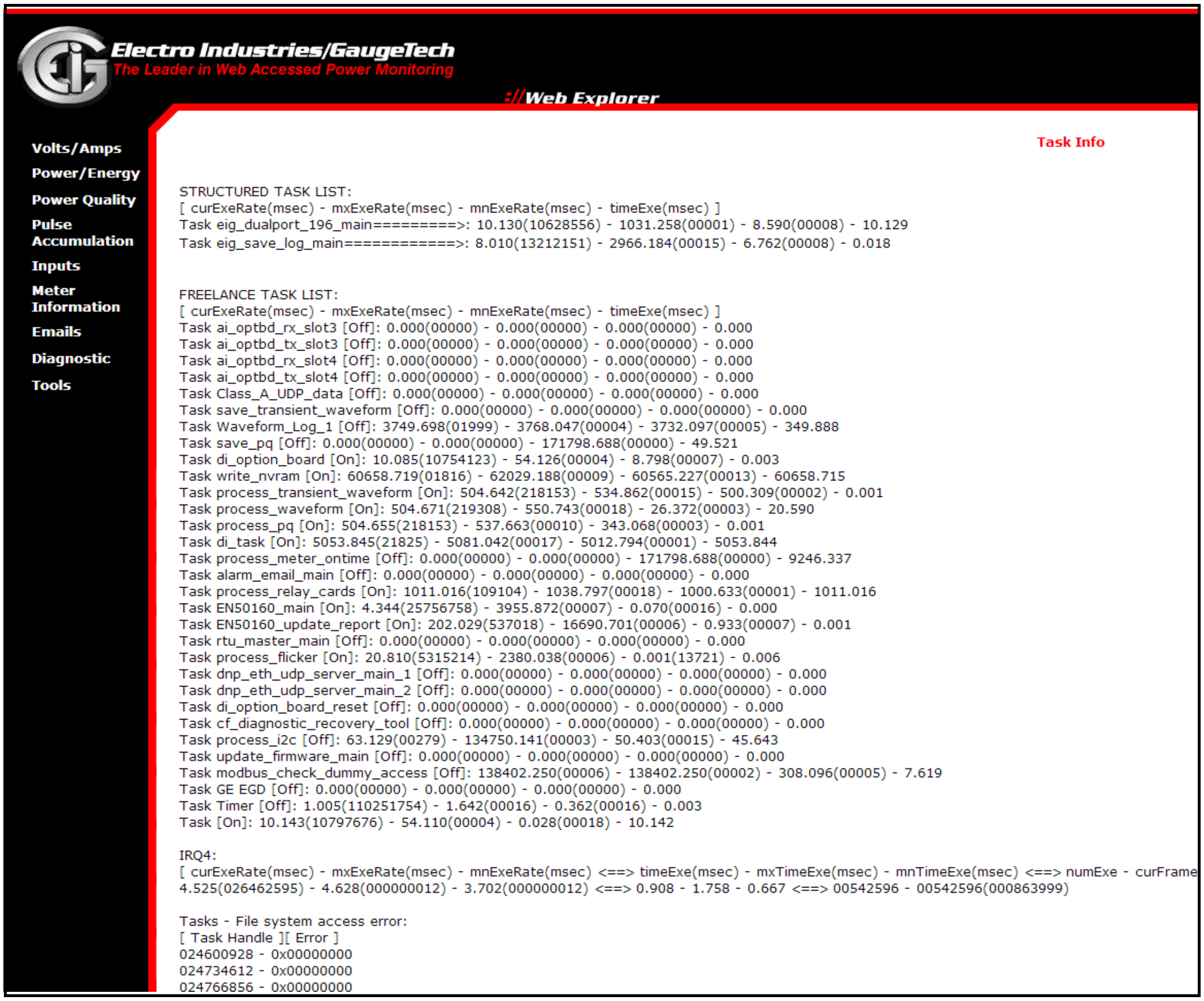
This webpage displays information for the meter's FTP server: total allowed and total used connections; maximum amount and available amount of file allocation.

DNP LAN/WAN Webpage



This webpage displays status information for the DNP UDP and DNP TCP tasks.

Task Info Webpage


Electro Industries/GaugeTech
The Leader in Web Accessed Power Monitoring
://Web Explorer

Volts/Amps
Power/Energy
Power Quality
Pulse Accumulation
Inputs
Meter Information
Emails
Diagnostic
Tools

Task Info

STRUCTURED TASK LIST:
[curExeRate(msec) - mxExeRate(msec) - mnExeRate(msec) - timeExe(msec)]
Task eig_dualport_196_main=========>: 10.130(10628556) - 1031.258(00001) - 8.590(00008) - 10.129
Task eig_save_log_main============>: 8.010(13212151) - 2966.184(00015) - 6.762(00008) - 0.018

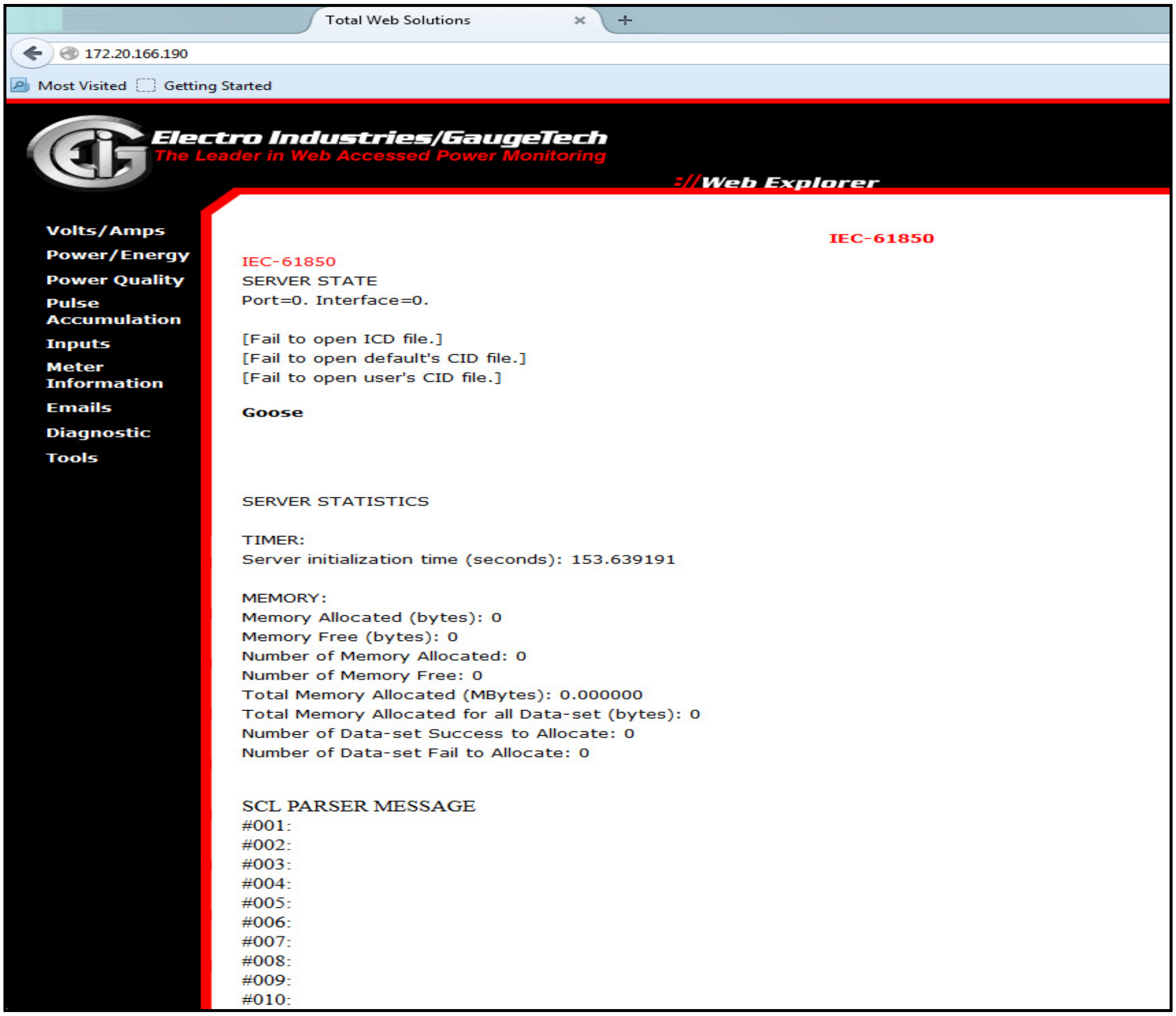
FREELANCE TASK LIST:
[curExeRate(msec) - mxExeRate(msec) - mnExeRate(msec) - timeExe(msec)]
Task ai_optbd_rx_slot3 [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task ai_optbd_tx_slot3 [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task ai_optbd_rx_slot4 [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task ai_optbd_tx_slot4 [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task Class_A_UDP_data [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task save_transient_waveform [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task Waveform_Log_1 [Off]: 3749.698(01999) - 3768.047(00004) - 3732.097(00005) - 349.888
Task save_pq [Off]: 0.000(00000) - 0.000(00000) - 171798.688(00000) - 49.521
Task di_option_board [On]: 10.085(10754123) - 54.126(00004) - 8.798(00007) - 0.003
Task write_nvram [On]: 60658.719(01816) - 62029.188(00009) - 60565.227(00013) - 60658.715
Task process_transient_waveform [On]: 504.642(218153) - 534.862(00015) - 500.309(00002) - 0.001
Task process_waveform [On]: 504.671(219308) - 550.743(00018) - 26.372(00003) - 20.590
Task process_pq [On]: 504.655(218153) - 537.663(00010) - 343.068(00003) - 0.001
Task di_task [On]: 5053.845(21825) - 5081.042(00017) - 5012.794(00001) - 5053.844
Task process_meter_ontime [Off]: 0.000(00000) - 0.000(00000) - 171798.688(00000) - 9246.337
Task alarm_email_main [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task process_relay_cards [On]: 1011.016(109104) - 1038.797(00018) - 1000.633(00001) - 1011.016
Task EN50160_main [On]: 4.344(25756758) - 3955.872(00007) - 0.070(00016) - 0.000
Task EN50160_update_report [On]: 202.029(537018) - 16690.701(00006) - 0.933(00007) - 0.001
Task rtu_master_main [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task process_flicker [On]: 20.810(5315214) - 2380.038(00006) - 0.001(13721) - 0.006
Task dnp_eth_udp_server_main_1 [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task dnp_eth_udp_server_main_2 [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task di_option_board_reset [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task cf_diagnostic_recovery_tool [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task process_i2c [Off]: 63.129(00279) - 134750.141(00003) - 50.403(00015) - 45.643
Task update_firmware_main [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task modbus_check_dummy_access [Off]: 138402.250(00006) - 138402.250(00002) - 308.096(00005) - 7.619
Task GE EGD [Off]: 0.000(00000) - 0.000(00000) - 0.000(00000) - 0.000
Task Timer [Off]: 1.005(110251754) - 1.642(00016) - 0.362(00016) - 0.003
Task [On]: 10.143(10797676) - 54.110(00004) - 0.028(00018) - 10.142

IRQ4:
[curExeRate(msec) - mxExeRate(msec) - mnExeRate(msec) <==> timeExe(msec) - mxTimeExe(msec) - mnTimeExe(msec) <==> numExe - curFrame
4.525(026462595) - 4.628(000000012) - 3.702(000000012) <==> 0.908 - 1.758 - 0.667 <==> 00542596 - 00542596(000863999)

Tasks - File system access error:
[Task Handle][Error]
024600928 - 0x00000000
024734612 - 0x00000000
024766856 - 0x00000000

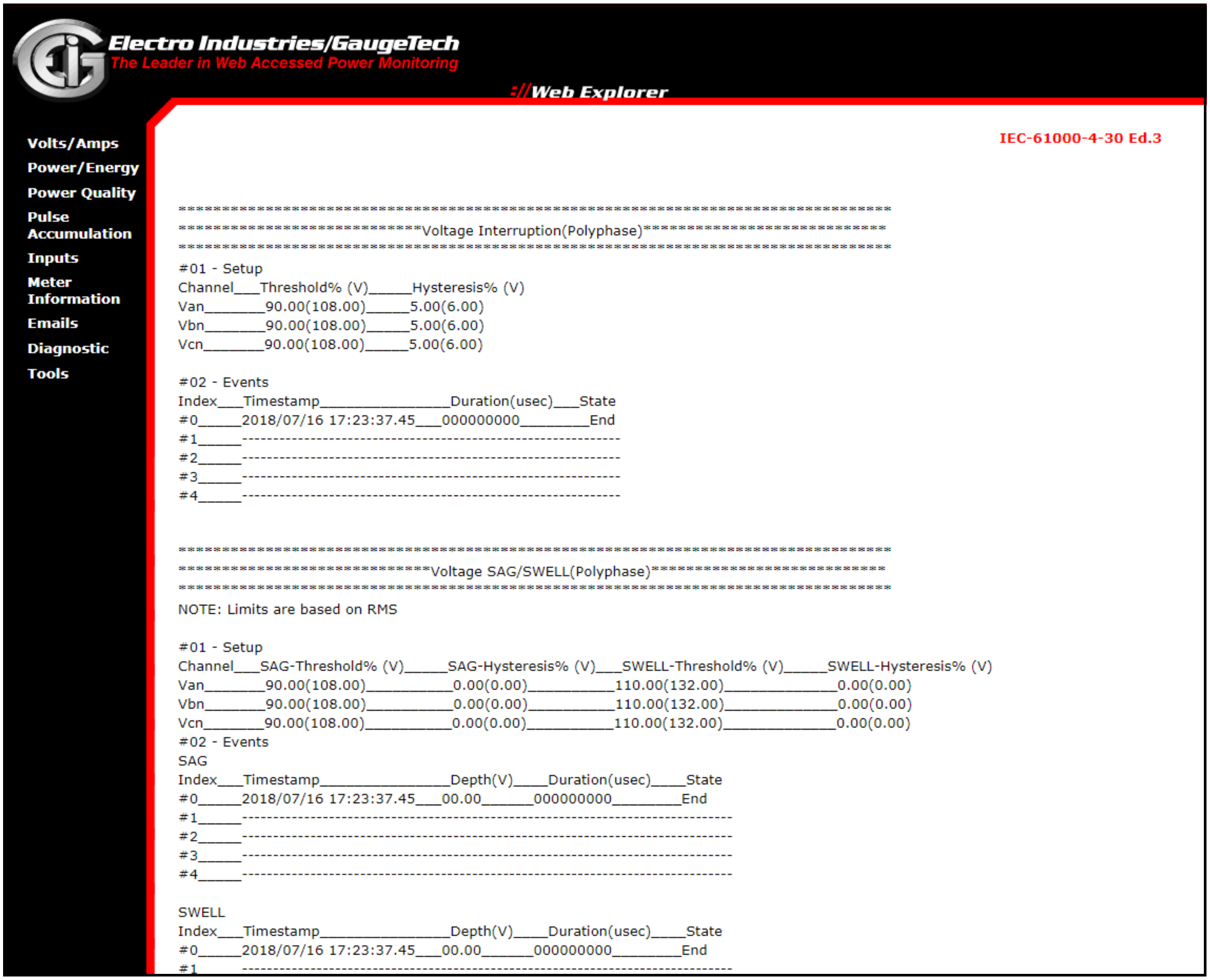
This webpage displays information about the meter’s tasks.

IEC 61850 Webpage



This webpage displays information about the IEC 61850 Server, if enabled.

IEC 61000-4-30 Ed.3 Webpage


Electro Industries/GaugeTech
The Leader in Web Accessed Power Monitoring
://Web Explorer

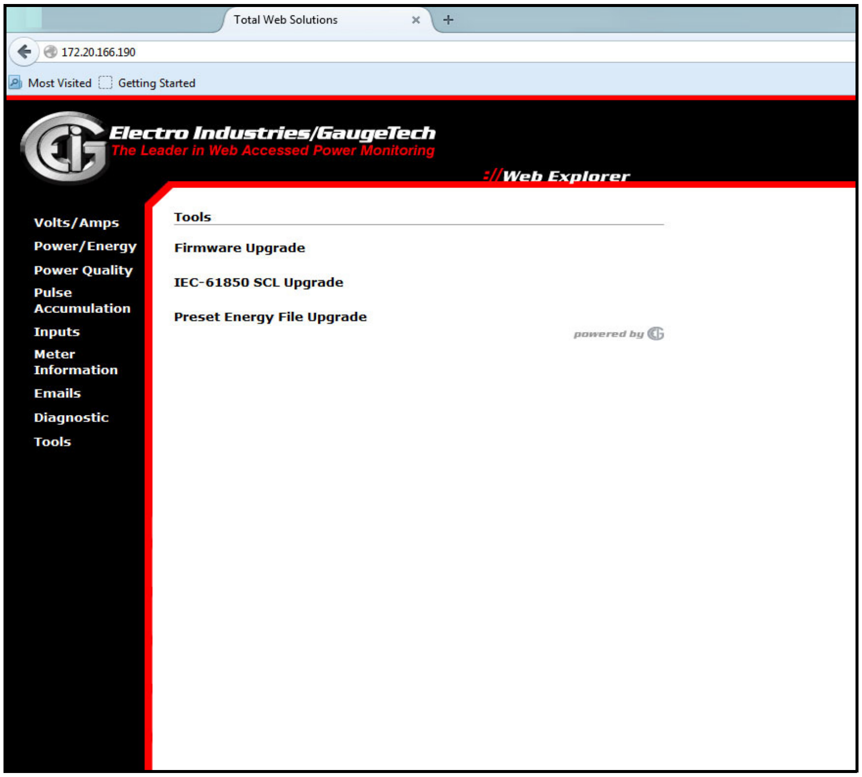
Volts/Amps
Power/Energy
Power Quality
Pulse Accumulation
Inputs
Meter Information
Emails
Diagnostic
Tools

IEC-61000-4-30 Ed.3

```
***********************************************************************************
****************************Voltage Interruption(Polyphase)****************************
***********************************************************************************
#01 - Setup
Channel___Threshold% (V)_____Hysteresis% (V)
Van_______90.00(108.00)_____5.00(6.00)
Vbn_______90.00(108.00)_____5.00(6.00)
Vcn_______90.00(108.00)_____5.00(6.00)

#02 - Events
Index___Timestamp_______________Duration(usec)___State
#0_____2018/07/16 17:23:37.45___000000000________End
#1_____----------------------------------------------------------
#2_____----------------------------------------------------------
#3_____----------------------------------------------------------
#4_____----------------------------------------------------------

***********************************************************************************
****************************Voltage SAG/SWELL(Polyphase)****************************
***********************************************************************************
NOTE: Limits are based on RMS

#01 - Setup
Channel___SAG-Threshold% (V)_____SAG-Hysteresis% (V)___SWELL-Threshold% (V)_____SWELL-Hysteresis% (V)
Van_______90.00(108.00)__________0.00(0.00)__________110.00(132.00)_____________0.00(0.00)
Vbn_______90.00(108.00)__________0.00(0.00)__________110.00(132.00)_____________0.00(0.00)
Vcn_______90.00(108.00)__________0.00(0.00)__________110.00(132.00)_____________0.00(0.00)
#02 - Events
SAG
Index___Timestamp_______________Depth(V)____Duration(usec)____State
#0_____2018/07/16 17:23:37.45___00.00______000000000________End
#1_____---------------------------------------------------------------------------
#2_____---------------------------------------------------------------------------
#3_____---------------------------------------------------------------------------
#4_____---------------------------------------------------------------------------

SWELL
Index___Timestamp_______________Depth(V)____Duration(usec)____State
#0_____2018/07/16 17:23:37.45___00.00______000000000________End
#1_____---------------------------------------------------------------------------
```

This screen shows the settings and current readings for meter's IEC 61000-4-30 Edition 3 power quality measurements. Scroll to see all of the information on the webpage.

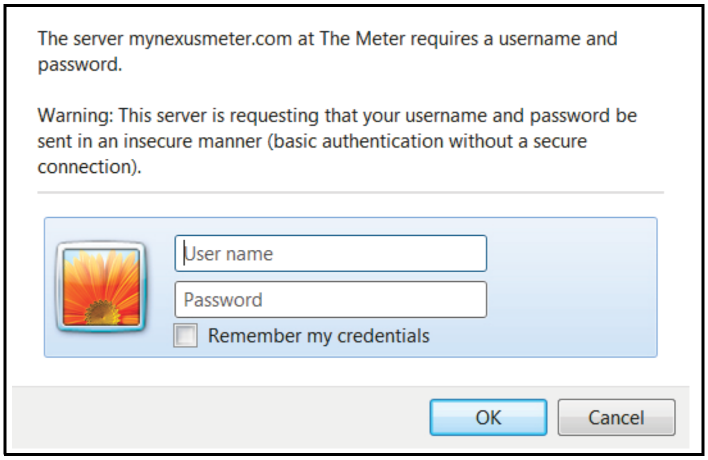
The **Tools** link on the left side of the webpage opens the webpage shown below.



To upgrade the meter's firmware, click **Firmware Upgrade**. See Appendix C for details on the IEC-61850 SCL Upgrade option.

NOTE: You can also upgrade the meter's firmware using CommunicatorPQA® software. Refer to the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions.

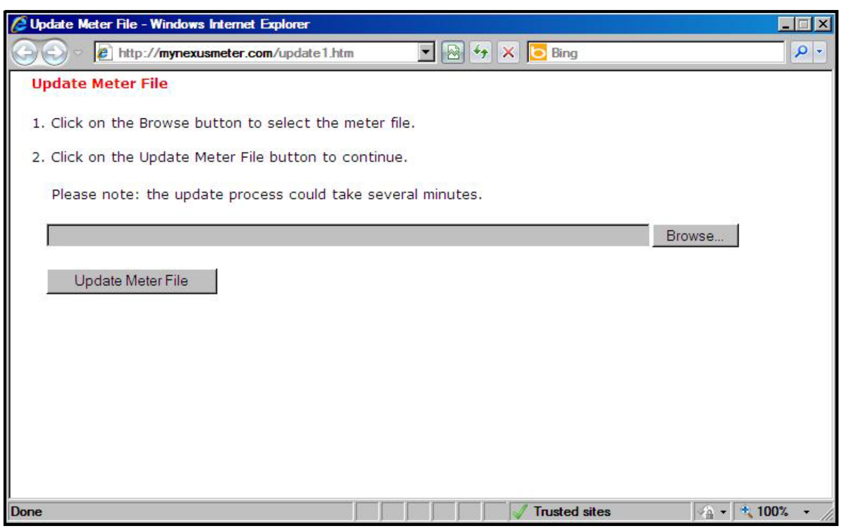
11.You will see a Log On screen. See the example screen shown below.



Enter the correct Username and Password to access the meter and click **OK**.

NOTE: If password protection is not enabled for the meter, the default username and password are both "anonymous".

12. The webpage "update1.htm" opens. See the example webpage shown below.

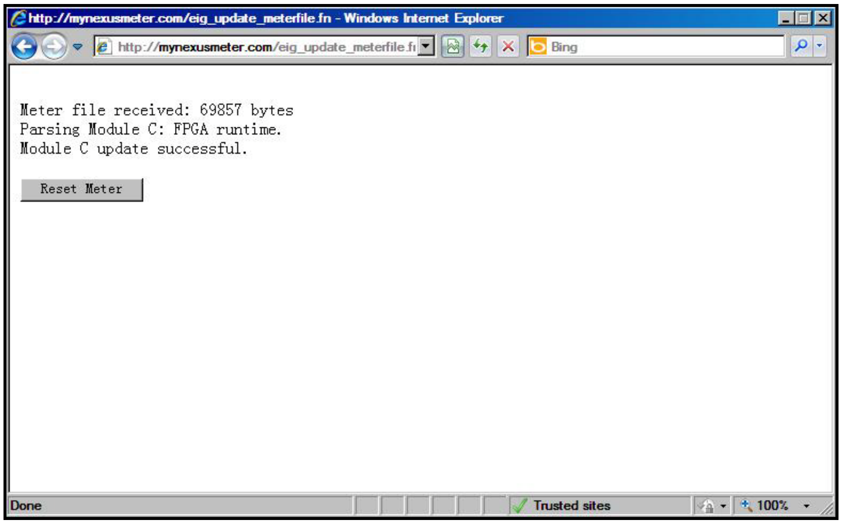


13. Click the **Browse** button to locate the Upgrade file.

NOTE: You must be using the PC on which the upgrade file is stored.

14. Click the **Update Meter File** button to begin the upgrade process. The upgrade starts immediately (it may take several minutes to complete).

15. Once the upgrade is complete, you will see a webpage with a confirmation message, shown below. Click the **Reset Meter** button to reset the meter.



NOTE: The Tools Webpage also gives you the option of updating the IEC 61850 SCL file of a meter with the IEC 61850 Protocol Server, and the Energy Presets of a meter. Click on the option you want - you will be prompted to enter password information and then to select the update file.

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10: EN 50160/IEC 61000-4-30 Class A Ed. 3 Reporting

10.1: Overview

The Nexus® 1500+ meter can record power quality reporting values in two independent logs. When EN 50160/IEC 61000-4-30 reporting is enabled, entries are made into the logs when the associated values occur. All values can be downloaded to the Log Viewer where they are available for graphing or export to another program, such as a spreadsheet. The Nexus® 1500+ meter also lets you customize the EN 50160/IEC 61000-4-30 reporting so that the user can meet specific jurisdictional or regional requirements.

IMPORTANT! Since the EN 50160/IEC 61000-4-30 reporting has specific requirements for programming, EIG recommends that you refer to the IEC 61000-4-30 2008 standard before making changes to the default settings of the meter.

10.2: Flicker Measurement

Flicker is one of the important power quality values that the meter can record. Flicker is the sensation experienced by the human visual system when it is subjected to changes occurring in the illumination intensity of light sources. The primary effects of flicker are headaches, irritability and, sometimes, epileptic seizures. Flicker can be caused by voltage variations that are in turn caused by variable loads, such as arc furnaces, laser printers and microwave ovens.

IEC 61000-4-15 and former IEC 868 describe the methods used to determine flicker severity. This phenomenon is strictly related to the sensitivity and the reaction of individuals. It can only be studied on a statistical basis by setting up suitable experiments among people.

NOTE: The meter is calculating its Flicker measurement based upon the EN 61000-4-15 standard which is referenced in the EN 61000-4-30 standard. The accuracy requirements for this instrument are within the Class A standards for Flicker measurements.

10.2.1: Flicker Theory of Operation

In order to model the eye brain change, which is a complex physiological process, the signal from the power network has to be processed while conforming with Figure 10.1, shown on page 10-5.

- Block 1 consists of scaling circuitry and an automatic gain control function that normalizes input voltages to Blocks 2, 3 and 4.
- Block 2 recovers the voltage fluctuation by squaring the input voltage scaled to the reference level. This simulates the behavior of a lamp.
- Block 3 is composed of a cascade of two filters and a measuring range selector. In this implementation, a log classifier covers the full scale in use so the gain selection is automatic and not shown here. The first filter eliminates the DC component and the double mains frequency components of the demodulated output. For 50 Hz operation, the configuration consists of a first-order high pass filter with 3db cut-off frequency at about 0.05 Hz and a 6-order butterworth low pass filter with 35 Hz 3db cut-off frequency. The second filter is a weighting filter that simulates the response of the human visual system to sinusoidal voltage fluctuations of a coiled filament, gas-filled lamp (60 W - 230 V). The filter implementation of this function is as specified in IEC 61000-4-15.
- Block 4 is composed of a squaring multiplier and a Low Pass filter. The human flicker sensation via lamp, eye and brain is simulated by the combined non-linear response of Blocks 2, 3 and 4.
- Block 5 performs an online statistical cumulative probability analysis of the flicker level. Block 5 allows direct calculation of the evaluation parameters Pst and Plt.

Flicker evaluation occurs in the following forms: Instantaneous, Short Term or Long Term. Each form is detailed below:

Instantaneous Flicker Evaluation

An output of 1.00 from Block 4 corresponds to the reference human flicker perceptibility threshold for 50% of the population. This value is measured in perceptibility units (PU) and is labeled Pinst. This is a real time value that is continuously updated.

Short Term Flicker Evaluation

An output of 1.00 from Block 5 (corresponding to the Pst value) corresponds to the conventional threshold of irritability per IEC 61000-3-3:2008 edition 2 and EN61000-3-3:2008. In order to evaluate flicker severity, two parameters have been defined: one for the short term called Pst (defined in this section) and one for the long term called Plt (defined in the next section).
The standard measurement time for Pst is 10 minutes. Pst is derived from the time at level statistics obtained from the level classifier in Block 5 of the flicker meter. The following formula is used:

$$P_{st} = \sqrt{0.0314P_{0.1} + 0.0525P_{1s} + 0.0657P_{3s} + 0.28P_{10s} + 0.08P_{50s}}$$

where the percentiles P(0.1), P(1), P(3), P(10), P(50) are the flicker levels exceeded for 0.1, 1, 2, 20 and 50% of the time during the observation period. The suffix S in the formula indicates that the smoothed value should be used. The smoothed values are obtained using the following formulas:

P(1s) = (P(.7) + P(1) + P(1.5))/3

P(3s) = (P(2.2) + P(3) + P(4))/3

P(10s) = (P(6) + P(8) + P(10) + P(13) + P(17))/5

P(50s) = (P(30) + P(50) + P(80))/3

The .3-second memory time constant in the flicker meter ensures that P(0.1) cannot change abruptly and no smoothing is needed for this percentile.

Long Term Flicker Evaluation

The 10-minute period on which the short-term flicker severity is based is suitable for short duty cycle disturbances. For flicker sources with long and variable duty cycles (e.g. arc furnaces) it is necessary to provide criteria for long-term assessment. For this purpose, the long-term Plt is derived from the short-term values over an appropriate period. By definition, this is 12 short-term values of 10 minutes each over a period of 2 hours. The following formula is used:

$$P_{lt} = \sqrt[3]{\frac{\sum_{i=1}^{N} P_{sti}^{3}}{N}}$$

where Psti (i = 1, 2, 3...) are consecutive readings of the short-term severity Pst.

10.2.1: Summary

Flicker = changes in the illumination of light sources due to cyclical voltage variations

Pinst = instantaneous flicker values in perceptibility units (PU)

Pst = value based on 10-minute analysis

Plt = value based on 12 Pst values

Measurement Procedure

1. Original signal with amplitude variations

2. Square demodulator

3. Weighted filter

4. Low pass filter 1st order

5. Statistical computing

Data available

- Pst, Pst Max, Pst Min values for long term recording

- Plt, Plt Max, Plt Min values for long term recording

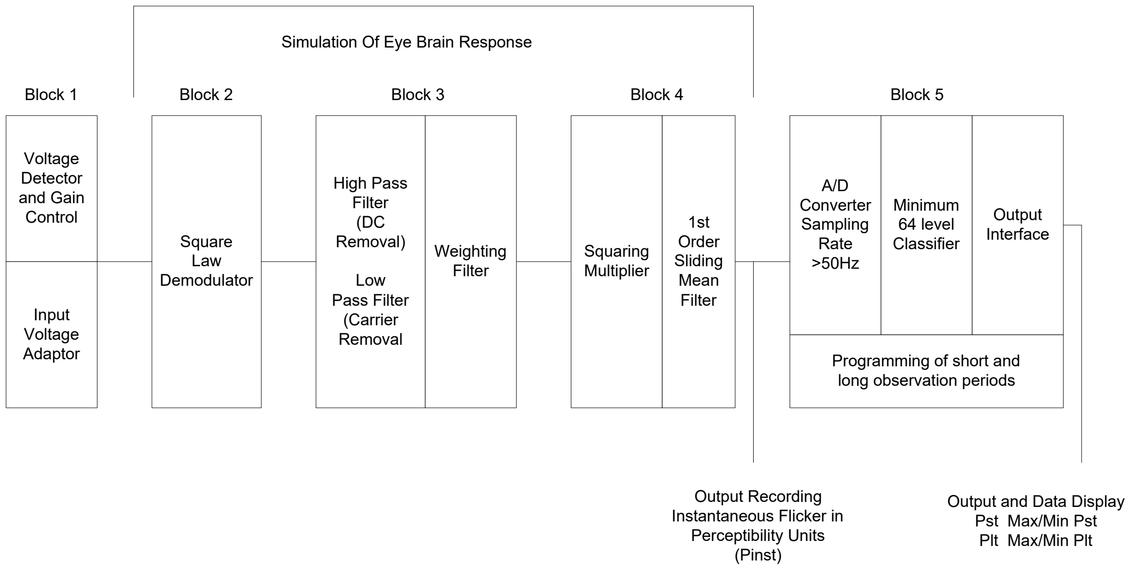


Figure 10.1: Simulation of Eye Brain Response

10.3: EN 50160/IEC 61000-4-30 Setting for the Nexus® 1500+ Meter

The Nexus® 1500+ meter also lets you customize the EN 50160/IEC 61000-4-30 reporting to meet specific jurisdictional or regional requirements. Refer Section 11.3.4.1 in the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions on setting up reporting, and additional information, including viewing and printing the EN 50160/IEC 61000-4-30 data. Note that the meter meets the IEC 61000-4-30 Edition 3.

11: Using the I/O Options

11.1: Overview

The Nexus® 1500+ meter offers extensive I/O expandability. With its four Option card slots, you can easily configure the meter to accept new I/O Option cards without removing it from its installation. The Nexus® 1500+ meter auto-detects any installed Option cards. The meter also offers multiple optional external I/O modules.

11.2: Installing Option Cards

The Option cards are inserted into their associated Option card slots in the back of the Nexus® 1500+ meter.

IMPORTANT! Remove voltage inputs and power supply to the meter before performing card installation.

IMPORTANT! Supprimer les entrées de tension et l'alimentation au compteur avant d'effectuer l'installation de la carte.

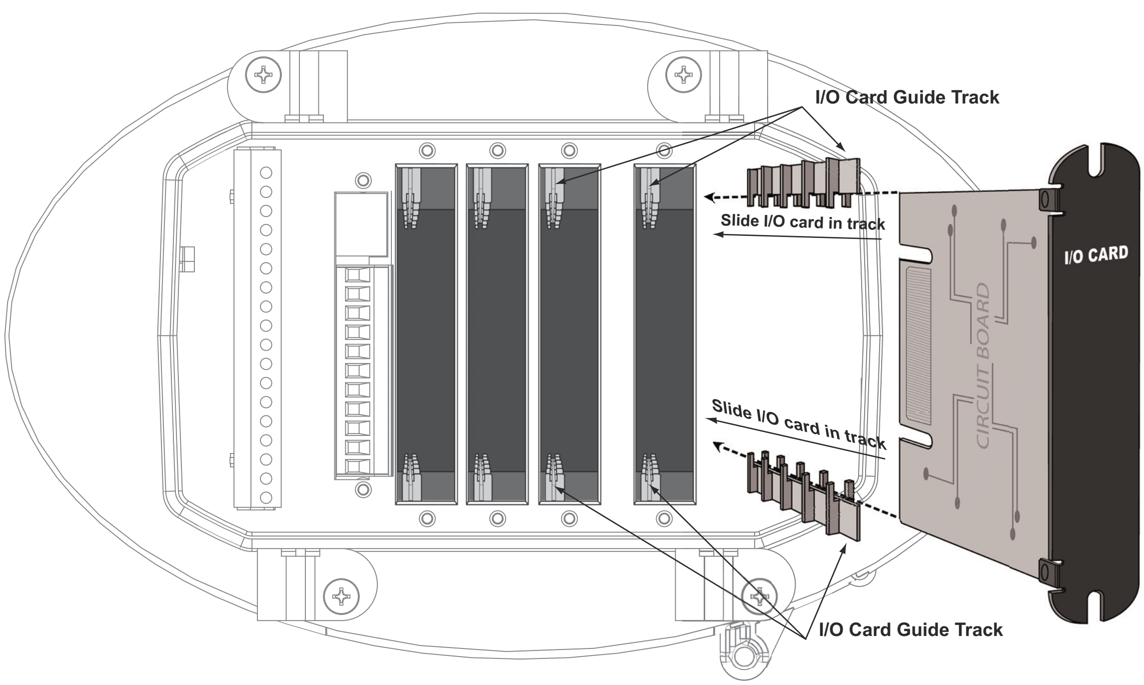


Figure 11.1: Inserting an I/O Card into the Meter

1. Remove the screws at the top and the bottom of the Option card slot covers.

2. There is a plastic "track" on the top and the bottom of the slot. The Option card fits into this track.
   CAUTION! Make sure the I/O card is inserted properly into the track to avoid damaging the card's components.

3. Slide the card inside the plastic track and insert it into the slot. You will hear a click when the card is fully inserted. **Be careful:** it is easy to miss the guide track. Refer to Figure 11.1.

11.3: Configuring Option Cards

CAUTION! FOR PROPER OPERATION, RESET ALL PARAMETERS IN THE UNIT AFTER HARDWARE MODIFICATION.

The Nexus® 1500+ meter auto-detects any Option cards installed in it. Configure the Option cards through CommunicatorPQA® software. Refer to Chapter 11 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for detailed instructions.

11.4: Pulse Output/RS485 Option Card (485P)

The Pulse Output/RS485 option card gives the meter 4 KYZ outputs that can be used for counting operations. It also gives the meter an RS485 Modbus communication port.

Pulse Output/RS485 Port Specifications

Dual RS485 Transceiver; meets or exceeds EIA/TIA-485 Standard:

Type:	Two-wire, half duplex
Min. input impedance:	96 kΩ
Max. output current:	±60 mA
Isolation between channels	AC 1500 V

UL rated up to 60 V DC.

Wh Pulse

4 KYZ output contacts:

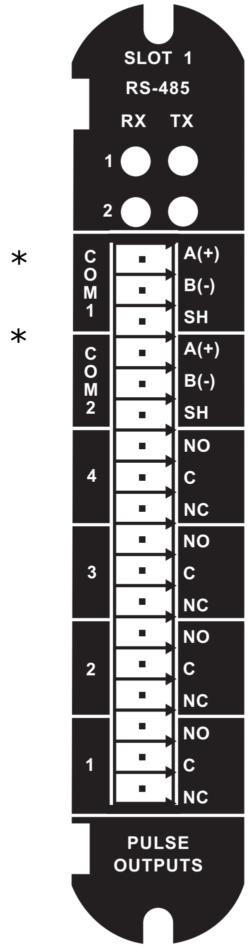
Pulse width:	Programmable from 5 msec to 635 msec
Full scale frequency:	100 Hz
Form:	Selectable from Form A or Form C
Contact type:	Solid State - SPDT (NO - C - NC)
Relay type:	Solid state
Peak switching voltage:	DC ±350 V
Continuous load current:	120 mA
Peak load current:	350 mA for 10ms
On resistance, max.:	35 Ω
Leakage current:	1 µA@350 V

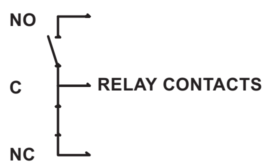
Isolation:	AC 2500 V
Reset state:	(NC - C) Closed; (NO - C) Open

General Specifications for Pulse Output/RS485 Board:

Operating temperature:	(-20 to +70) ^{o}C
Storage temperature:	(-30 to +80) ^{o}C
Relative air humidity:	Maximum 95%, non-condensing
EMC - immunity interference:	EN61000-4-2
Weight:	2.4 oz
Dimensions (inches) W x H x L:	0.75" x 4.02" x 4.98"
I/O card slot:	Option slot 1
External connection:	Wire range - 16 to 26 AWG
	Strip Length - .250"
	Torque - 2.2 lb-in
	18 pin, 3.5 mm pluggable terminal block

11.4.1: Pulse Output/RS485 Option Card (485P) Wiring





*** NOTE:** Refer to Chapter 5 for RS485 setup instructions.

11.5: Ethernet Option Card: RJ45 (NTRJ) or Fiber Optic (NTFO)

The Ethernet Option card provides data generated by the meter via Modbus, offering up to 32 sockets TCP/IP. It offers a second Ethernet port for the meter, which can be controlled independently, and which can alternatively be configured for IEC 61850 and GOOSE messaging (only one of the Ethernet cards can support IEC 61850 at one time). It also offers router functions which let the user decide open and closed ports and protocols to meet specific secure applications. It can be factory configured as a 10/100BaseT or as a 100Base-FX Fiber Optic communication port.

NOTE: Refer to Chapter 21 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions on performing Network configuration. See Chapter 9 of this manual for details on configuring the standard main Network card.

The technical specifications at 25 °C are as follows:

Number of ports:	1
Operating rate:	10/100 Mbit
Diagnostic feature:	Status LEDs for LINK and ACTIVE
Number of simultaneous Modbus TCP/IP connections to the meter:	32 (In addition to the 32 connections over both Ethernet connections.)
Number of simultaneous DNP LAN/WAN connections to the meter:	2 TCP and 1 UDP per Network card

The general specifications are as follows:

Operating modes:	10/100BaseT or 100Base-FX
Operating temperature:	(-20 to +70) °C
Storage temperature:	(-30 to +80) °C
Relative air humidity:	Maximum 95%, non-condensing
EMC - Immunity Interference:	EN61000-4-2

Weight:	2.3 oz
Dimensions (inches) W x H x L:	0.75" x 4.02" x 5.49"
I/O card slot:	Option slot 2
Connection Type:	RJ45 modular (Auto-detecting transmit and receive)10/100BaseT OR Duplex ST Receptacle - 100Base-FX **NOTE:** If both communication ends are not in auto-negotiation mode, communication defaults to half duplex. The meter is always in auto-negotiation mode.

Fiber Optic Specifications are as follows:

Connector:	ST
Fiber Mode:	Multimode Fiber 62.5/125 um
Wavelength:	1310 nm
Max. Distance:	2 km

Default Configuration

The Nexus® 1500+ meter automatically recognizes the installed Option card during power-up. If you have not programmed a configuration for the Ethernet card, the unit defaults to the following configuration:

IP Address: 10.0.1.1

Subnet Mask: 255.255.255.0

Default Gateway: 0.0.0.0

NOTE: The IP addresses of the Nexus® 1500+ meter's standard main Network card and optional Network Card 2 must be in different subnets.

11.6: Relay Output Option Card (6RO1)

The Relay Output option card is used to send a control output (electrical signal) when a limit is exceeded, for example to turn on a breaker or sound an alarm. The card has 6 relay contact outputs for load switching. The outputs are electrically isolated from the main unit.

Accumulators in the CommunicatorPQA® software count the transitions of the outputs. When installing a Relay Output option card, we recommend you reset the accumulators for the card, in order to prevent erroneous counts. See Chapter 20 of the software manual for instructions on resetting the output accumulators.

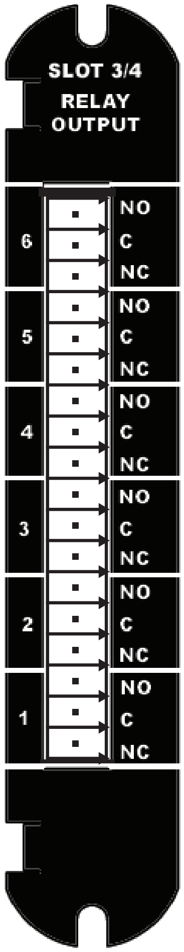
The technical specifications at 25 °C are as follows:

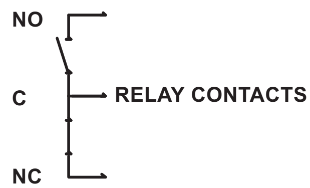
Power consumption:	0.320 W internal
Relay outputs:	
Number of outputs:	6
Contact type:	Changeover (SPDT)
Relay type:	Mechanically latching
Switching voltage:	AC 250 V / DC 30 V
Switching power:	1250 VA / 150 W
Switching current:	5 A
Switching rate max:	10/s
Mechanical life:	5 x 10^7 switching operations
Electrical life:	10^5 switching operations at rated current
Breakdown voltage:	AC 1000 V between open contacts
Isolation:	AC 2500 V surge system to contacts
Reset/Power down state:	No change - last state is retained

The general specifications are as follows:

Operating temperature:	(-20 to +70) °C
Storage temperature:	(-30 to +80) °C
Relative air humidity:	Maximum 95%, non-condensing
EMC - immunity interference:	EN61000-4-2
Weight:	2.7 oz
Dimensions (inches) W x H x L:	0.75" x 4.02" x 4.98"
I/O Card slot:	Option slots 3 and 4
External connection:	Wire range - 16 to 26 AWG
	Strip length - .250"
	Torque - 2.2 lb-in
	18 pin, 3.5 mm pluggable terminal block

11.6.1: Relay Output Option Card (6RO1) Wiring





11.7: Digital Input Option Card (16DI1)

The Digital Input Option card offers 16 wet/dry contact sensing digital inputs. The inputs can be used to either count KYZ pulse or detect the status of a circuit.

Accumulators in the CommunicatorPQA® software count the transitions of the inputs. When installing a Digital Input option card, we recommend you reset the accumulators for the card, in order to prevent erroneous counts. See Chapter 20 of the *software manual* for instructions on resetting the input accumulators.

The technical specifications at 25 °C are as follows:

Power consumption:	0.610 W
Number of inputs:	16
Sensing type:	Wet or dry contact status detection
Wetting voltage:	DC (12-24)V, internally generated
Input current:	1.25 mA - constant current regulated
Minimum input voltage:	0 V (input shorted to V-)
Maximum input voltage:	DC 150 V (diode protected against polarity reversal)
Filtering:	De-bouncing with 10 ms delay time
Detection scan rate:	20 ms
Isolation:	AC 2500 V system to inputs

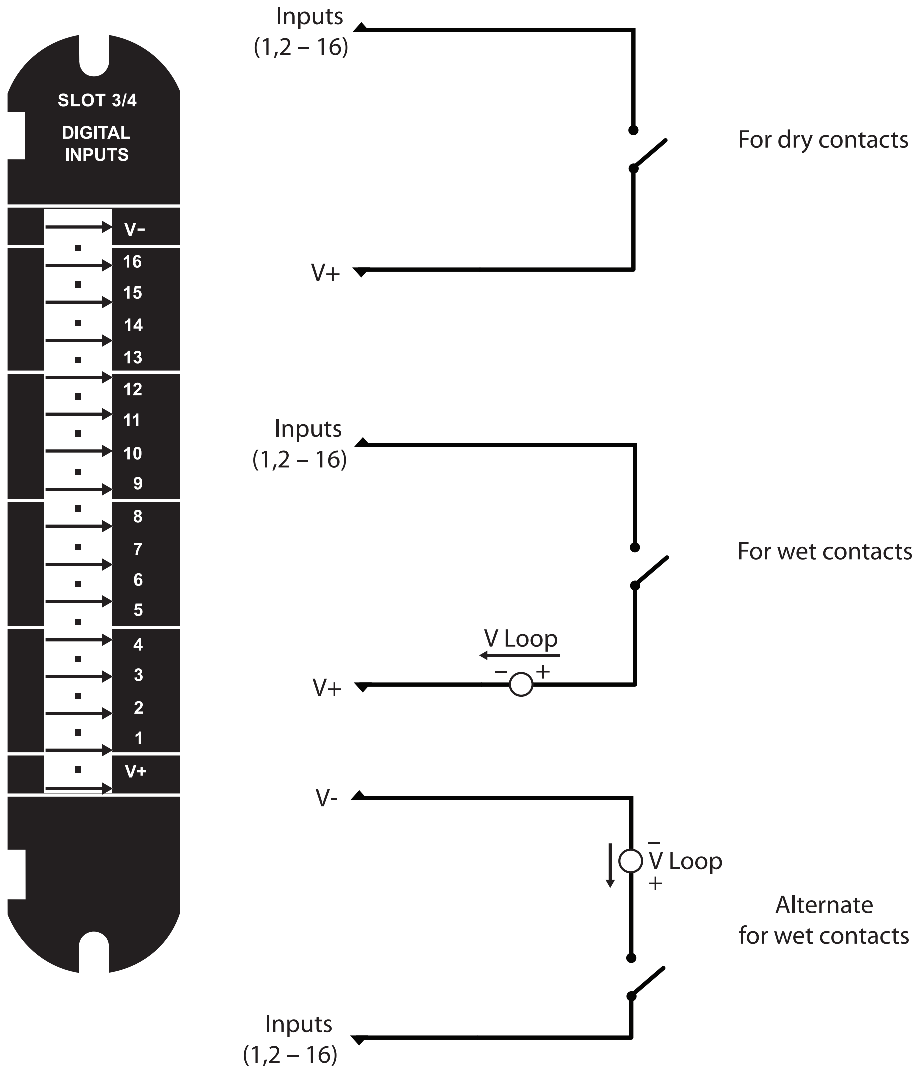
The general specifications are as follows:

Operating temperature:	(-20 to +70) °C
Storage temperature:	(-30 to +80) °C
Relative air humidity:	Maximum 95%, non-condensing
EMC - immunity interference:	EN61000-4-2
Weight:	2.4 oz

Dimensions (inches) W x H x L:	0.75" x 4.02" x 4.98"
I/O card slot:	Option slots 3 and 4
External connection:	Wire range - 16 to 26 AWG
	Strip length - .250"
	Torque - 2.2 lb-in
	18 pin, 3.5 mm pluggable terminal block

NOTE: This feature allows for either status detect or pulse counting. Each input can be assigned an independent label and pulse value.

11.7.1: Digital Input Option Card (16DI1) Wiring



11.8: Optional External I/O Modules

In addition to the Option cards previously explained, the Nexus® 1500+ meter offers external I/O modules. The meter acts as a master to any external I/O modules or Option cards. All Nexus® external I/O modules have the following components:

- Female RS485 Side Port: use to connect to another module's male RS485 side port.
- Male RS485 Side Port: use to connect to the Nexus® 1500+ meter's Port 2 or to another module's female RS485 side port. See Figure 11.2 for wiring details.
- I/O Port: used for functions specific to the type of module. Size and pin configuration vary depending on the type of module.
- Reset Button: press and hold for three seconds to reset the module's baud rate to 57600, and its address to 247 for 30 seconds.
- LEDs: when flashing, the LEDs signal that the module is functioning.
- Mounting Brackets (MBIO): used to secure one or more modules to a flat surface. Comes with 2 DIN rail mounting clips.

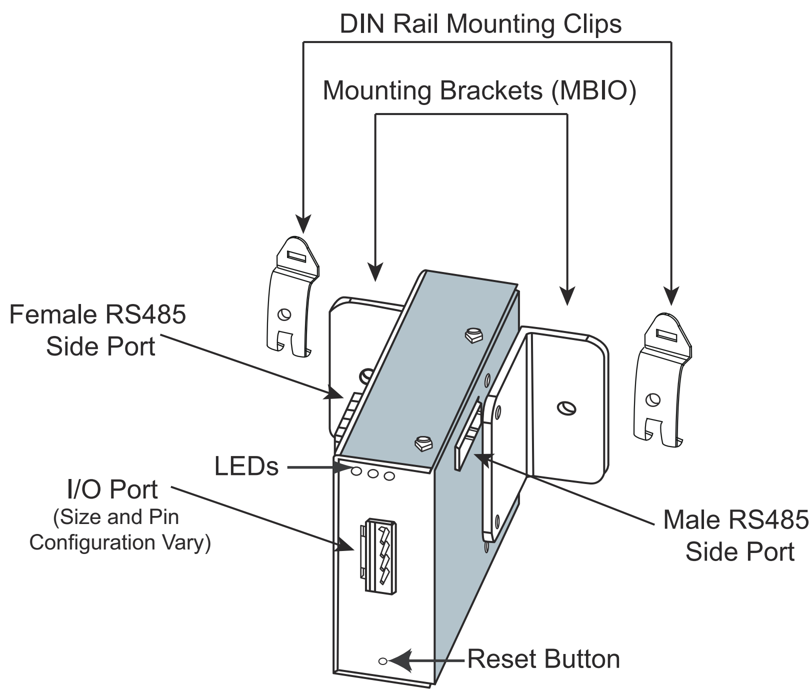
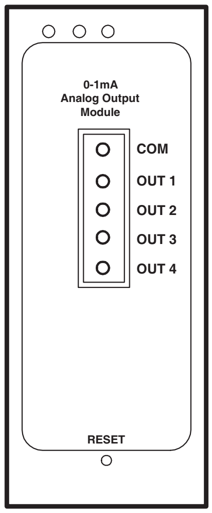


Figure 11.2: I/O Module Components

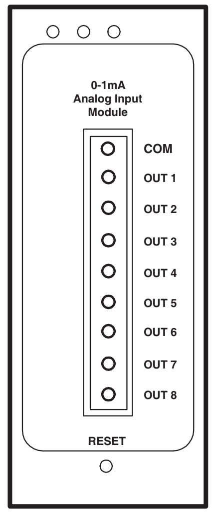
11.8.1: Port Overview

All of the optional external I/O modules have ports through which they interface with other devices. The port configurations are variations of the four types shown below. Refer to following sections 11.8.6 - 11.8.9 for details on the external I/O modules.

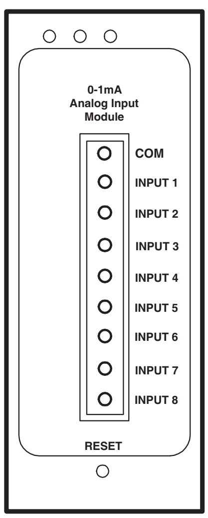
Four Analog Outputs (0-1mA and 4-20mA)



Eight Analog Outputs (0-1mA and 4-20mA)



Eight Analog Inputs (0-1mA, 0-20mA, 0-5Vdc, 0-10Vdc) or Eight Status Inputs



Four Relay Outputs or Four KYZ Pulse Outputs

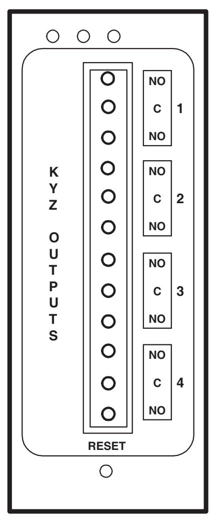


Figure 11.3: External I/O Module Ports

11.8.2: Installing Optional External I/O Modules

External I/O modules must be connected to the Com2 port of an optional 485P RS485/Pulse Output card. See the figure below.

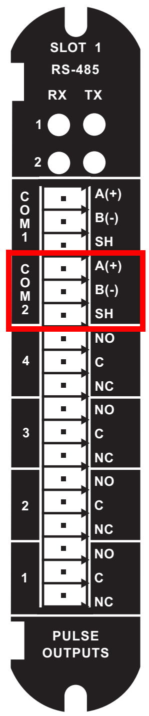


Figure 11.4: Location of RS485P Card's Com 2 Port

Six feet of RS485 cable harness is supplied with, and attached to, the external I/O module. Attach the other end of the cable to the Com2 port's connector. You will need to wire the cable to the connector. Refer to the figure below and the following instructions.

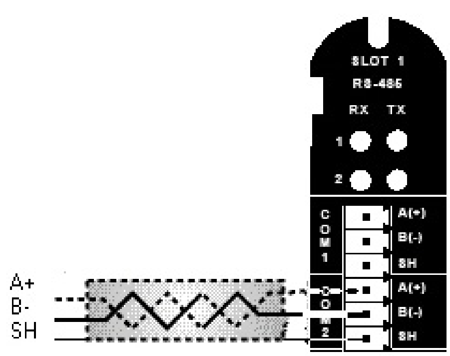


Figure 11.5: Wiring Cable to Com 2 Port

Installing the External I/O Modules

1. Connect the (+) and (-) terminals on the Nexus® meter to the (+) and (-) terminals of the male RS485 port.
2. Connect the shield to the shield (S) terminal. The (S) terminal on the Nexus® meter is used to reference the Nexus® meter's port to the same potential as the source. It is not an earth to ground connection. You must also connect the shield to earth-ground at one point. Vous devez également connecter l'écran à la terre à un endroit donné.
3. Put termination resistors at each end, connected to the (+) and (-) lines. RT is ~120 Ohms.
4. Connect a power source to the front of the module.

See 11.8.4.1: Steps for Attaching Multiple I/O Modules, on page 11-19 for details on using multiple I/O modules.

11.8.3: Power Source for External I/O Modules

The Nexus® 1500+ meter does not have internal power for the external I/O modules. You must use a power supply, such as the EIG PSIO, to power any external I/O modules.

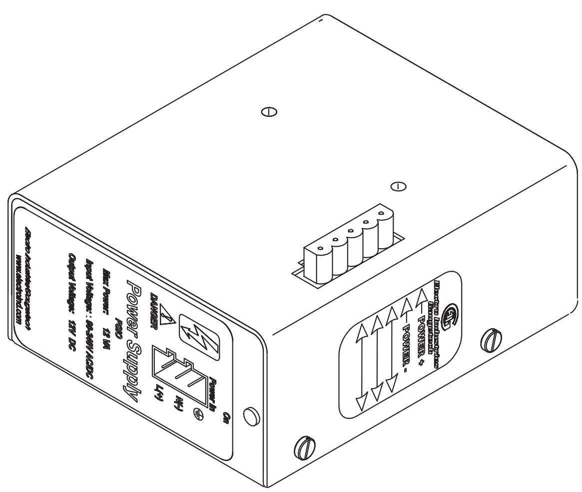


Figure 11.6: PSIO Side View

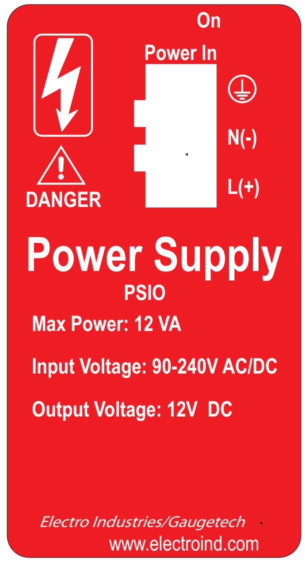


Figure 11.7: PSIO Label

11.8.4: Using PSIO with Multiple I/O Modules

NOTE: PSIO must be to the right of the I/O modules, when viewing its side label (as shown in the figure below).

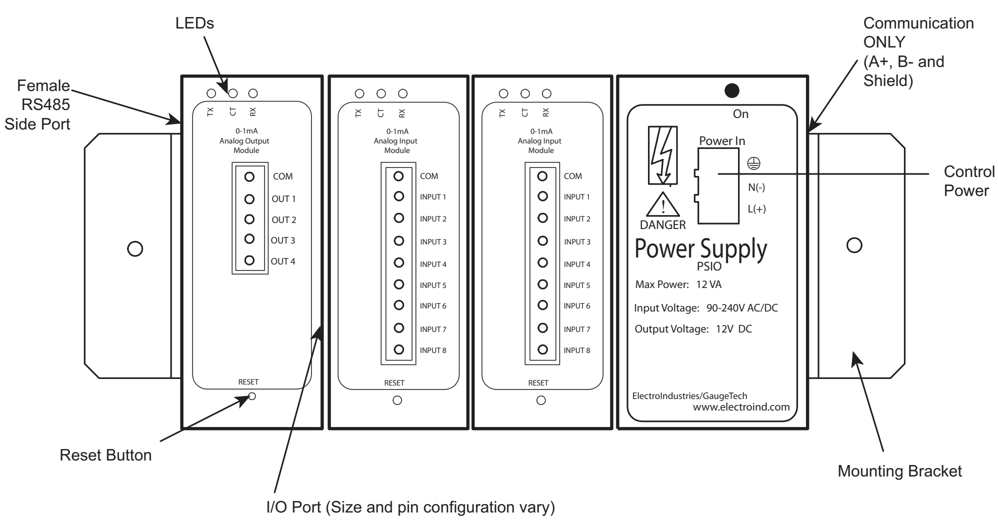


Figure 11.8: PSIO with Multiple External I/O Modules

11.8.4.1: Steps for Attaching Multiple I/O Modules

I/O Module Dimensions

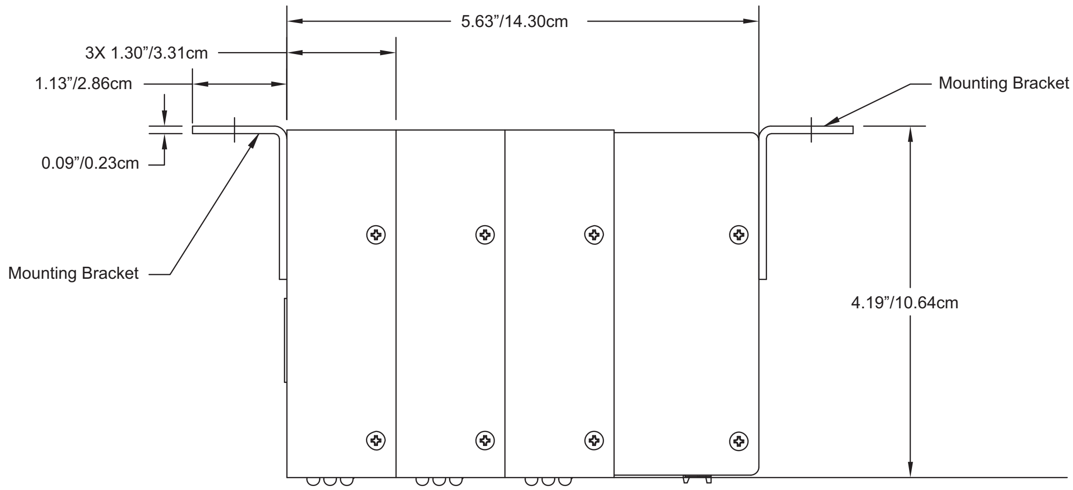


Figure 11.9: I/O Modules, Top View

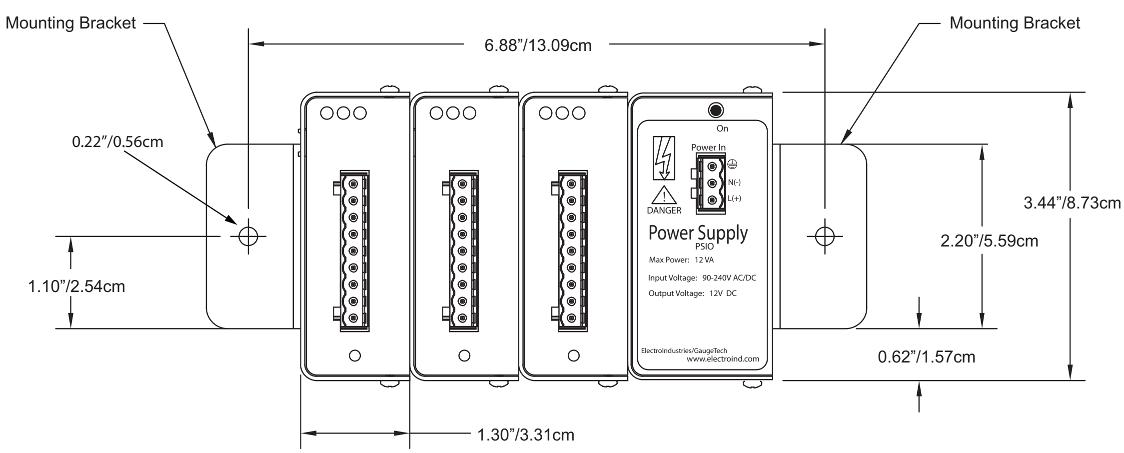


Figure 11.10: I/O Modules, Front View

1. Each I/O module in a group must be assigned a unique address. See Chapter 14 in the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions on configuring and programming the I/O modules.

2. I/O modules can be mounted using either of two methods. The first method is using the mounting brackets provided, to attach directly to a panel. The second method is to attach the Din Rail clips to the mounting brackets to connect the I/O modules to a DIN rail mounting system.

3. Starting with the left module and using a slotted screwdriver, fasten the first I/O module to the left mounting bracket of the MBIO mounting brackets kit. The left mounting bracket is the one with the PEM. Fasten the internal screw tightly into the left mounting bracket.

4. Slide the female RS485 port into the male RS485 side port to connect the next I/O module to the left module. Fasten together enough to grab but do not tighten, yet.

5. Combine the modules together, one by one.

6. Attach a PSIO (power supply) to the right of each group of I/O modules it is supplying with power (see Figure 11.6). The PSIO supplies 12 VA at 125 V AC/DC. See sections 11.8.6 - 11.8.8 for I/O modules power requirements.

7. Once you have combined all of the I/O modules together for the group, fasten them tightly. This final tightening locks the group together as a unit.

8. From the MBIO mounting brackets kit, attach the right mounting bracket to the right side of the group using the small Phillips Head screws provided.

9. If not mounting on a DIN rail, mount the attached group of modules on a secure, flat surface. This insures that all modules stay securely connected.

10. The MBIO mounting brackets kit comes with 2 DIN rail mounting clips and an 8mm screw and lock washer for each clip. The clips let you easily mount the connected I/O modules (or a single I/O module between two brackets) on a DIN rail. See the figure on the next page.

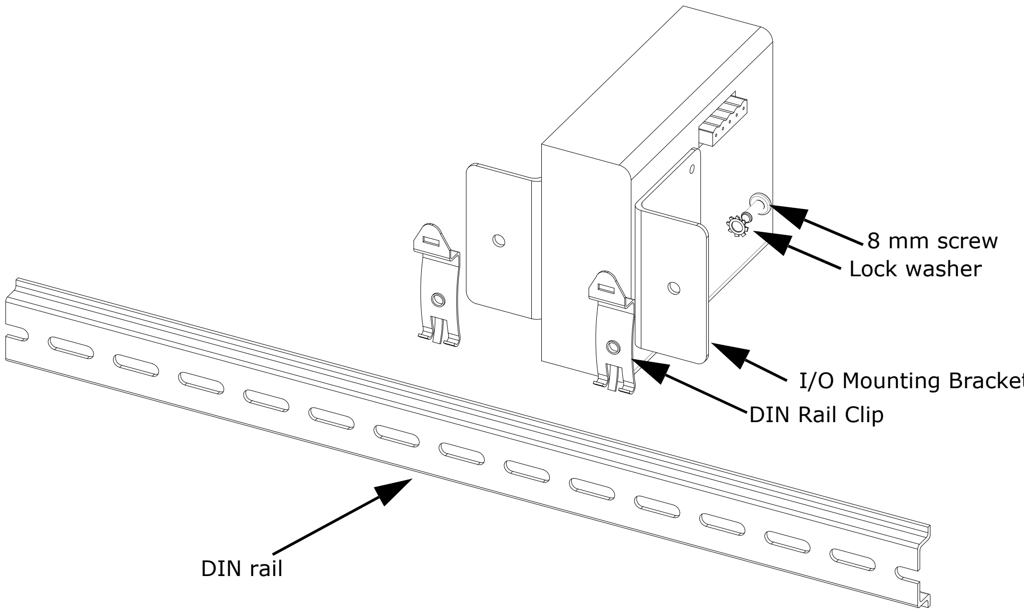


Figure 11.11: Mounting the Brackets on a DIN Rail

To use the DIN rail mounting clips:

a. From the front of either bracket, insert the screw into the lock washer and through the hole, and screw it into the clip using an appropriate screwdriver. Note that the clip should be positioned as shown above, with the indented side facing the back.

b. Repeat step a for the second bracket.

c. Hook the bottom of the clips around the bottom of the DIN rail and then push the top of the clips forward so that they fit over the top of the DIN rail. See the figure below.

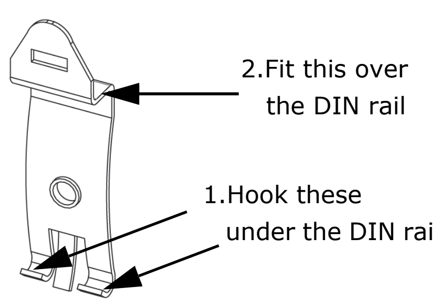


Figure 11.12: Detail of DIN Rail Mounting Clip

11.8.5: Factory Settings and Reset Button

F y Settings

All external I/O modules are shipped with a preset address and a baud rate of 57600. See following sections for I/O Module addresses.

Reset Button:

If there is a communication problem or if you are unsure of a module's address and baud rate, press and hold the **Reset** button for 3 seconds; the module resets to a default address of 247 at 57600 baud rate for 30 seconds.

Ω Ω

11.8.6: Analog Transducer Signal Output Modules

Analog Transducer Signal Output Module Specifications	
Model Numbers	1mAON4: 4-channel analog output 0±1 mA
	1mAON8: 8-channel analog output 0±1 mA
	20mAON4: 4-channel analog output 4-20 mA
	20mAON8: 8-channel analog output 4-20 mA
Accuracy	0.1% of Full Scale
Over-range	±20% of Full Scale
Scaling	Programmable
Communication	RS485, Modbus RTU
	Programmable Baud Rates: 4800, 9600, 19200, 38400, 57600
Power Requirement	12-20 VDC @50-200 mA
Operating Temperature	(-20 to +70) °C/(-4 to +158) °F
Maximum Load Impedance	0±1 mA: 10 k ; 4-20 mA: 500
Factory Settings	Modbus Address: 1mAON4: 128; 1mAON8: 128; 20mAON4: 132; 20mAON8: 132
	Baud Rate: 57600
	Transmit Delay Time: 0
Default Settings (Reset Button)	Modbus Address: 247
	Baud Rate: 57600
	Transmit Delay Time: 20 msec

11.8.6.1: Overview

The Analog Transducer Signal Output module is used to convert digital values from the meter into a variable voltage level presented on the output terminal to be used with analog devices, such as Programmable Logic Controllers (PLCs).

The Analog Transducer Signal Output modules (0±1 mA or 4-20 mA) are available in either a 4- or 8-channel configuration. Maximum registers per request, read or write, is 17 registers.

All outputs share a single common point. This is also an isolated connection (from ground).

11.8.6.2: Normal Mode

Normal mode is the same for the 0-1 mA and the 4-20 mA Analog Output modules except for the number of processes performed by the modules.

Both devices:

1. Accept new values through communication

2. Output current loops scaled from previously accepted values

The 0-1 mA module includes one more process in its Normal mode:

3. Reads and averages the A/D and adjust values for Process 2, above

The device operates with the following default parameters:

Address	247 (F7H)
Baud Rate	57600 Baud
Transmit Delay Time	20 msec

11.8.7: Digital Dry Contact Relay Output (Form C) Module

NOTE: Only one of these modules may be connected to a Nexus® 1500+ meter.

The Digital Dry Contact Relay Output module is used to send a control output (electrical signal) when a limit is exceeded, for example to turn on a breaker or sound an alarm.

Digital Dry Contact Relay Output Module Specifications	
Model Number	4RO1: 4 matching relay outputs
Contact Type	Changeover (SPDT)
Relay Type	Mechanically latching
Communication	RS485, Modbus RTU
	Programmable Baud Rates: 4800, 9600, 19200, 38400, 57600
Power Requirement	12-20 VDC @50-200 mA; 1500+ supports only one module
Operating Temperature	(-20 to +70) ^{o}C/(-4 to +158) ^{o}F
Switching Voltage	AC 250 V/ DC 30 V
Switching Power	1250 VA / 150 W
Switching Current	5 A
Switching Rate Max.	10/s
Mechanical Life	5 x 10^{7} switching operations
Electrical Life	10^{5} switching operations at rated current
Breakdown Voltage	AC 1000 V between open contacts
Isolation	AC 2500 V surge system to contacts
Reset/Power Down State	No change - last state is retained
Factory Settings	Modbus Address: 156
	Baud Rate: 57600
	Transmit Delay Time: 0
Default Settings (Reset Button)	Modbus Address: 247
	Baud Rate: 57600
	Transmit Delay Time: 20 msec

11.8.7.1: Overview

The Relay Output module consists of four latching relay outputs. In Normal mode, the device accepts commands to control the relays. Relay Output modules are triggered by limits programmed with the CommunicatorPQA® software. See Chapter 11 in the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for details on programming limits.

Each latching relay will hold its state in the event of a power loss.

11.8.7.2: Communication

Maximum registers per request, read or write, is 4 registers.

The device operates with the following default parameters:

Address	247 (F7H)
Baud Rate	57600 Baud
Transmit Delay Time	20 msec

11.8.7.3: Normal Mode

Normal mode consists of one process: the device accepts new commands to control the relays.

11.8.8: Digital Solid State Pulse Output (KYZ) Module

Digital Solid State Pulse Output Module Specifications	
Model Number	4PO1
Communication	RS485, Modbus RTU
	Programmable Baud Rates: 4800, 9600, 19200, 38400, 57600
Power Requirement	12-20 VDC @50-200 mA
Operating Temperature	(-20 to +70) ^{o}C/(-4 to +158) ^{o}F
Voltage Rating	Up to 300 VDC
Commands Accepted	Read and Write with at least 4 registers of data per command
Memory	256 Byte IC EEPROM for storage of programmable settings and non-volatile memory
Factory Settings	Modbus Address: 160
	Baud Rate: 57600
	Transmit Delay Time: 0
Default Settings (Reset Button)	Modbus Address: 247
	Baud Rate: 57600
	Transmit Delay Time: 20 msec

11.8.8.1: Overview

The KYZ Pulse Output modules have 4 KYZ pulse outputs and accept Read and Write commands with at least 4 registers of data per command. Digital Solid State Pulse Output (KYZ) modules are user programmed to reflect VAR-hours, watt-hours, or VA-hours. An example use of the Pulse Output/Digital Input Card is in a sub-metering application where a pulse output is needed.

NC = Normally Closed; NO = Normally Open; C = Common.

11.8.8.2: Communication

Maximum registers per request, read or write, is 4 registers.

The device operates with the following default parameters:

Address	247 (F7H)
Baud Rate	57600 Baud
Transmit Delay Time	20 msec

11.8.8.3: Normal Mode

Energy readings are given to the device frequently. The device generates a pulse at each channel after a certain energy increase.

Normal operation consists of three processes:

1. The first process accepts writes to registers 04097 - 04112. Writes can be up to four registers long and should end on the fourth register of a group (register 04100, or registers 04103-04112 or registers 04109-04112). These writes can be interpreted as two-byte, four-byte, six-byte or eight-byte energy readings. The reception of the first value for a given channel provides the initial value for that channel. Subsequent writes will increment the residual for that channel by the difference of the old value and the new value. The previous value is then replaced with the new value. Attempting to write a value greater than the programmed rollover value for a given channel is completely ignored and no registers are modified. If the difference is greater than half of the programmed rollover value for a given channel, the write does not increment the residual but does update the last value. Overflow of the residual is not prevented.

2. The second process occurs in the main loop and attempts to decrement the residual by the programmed Energy/Pulse value. If the residual is greater than the programmed Energy/Pulse value and the Pending Pulses value for that channel has not reached the maximum limit, then residual is decremented appropriately and the Pending Pulses value is incremented by two, signifying two more transitions and one more pulse.

3. The third process runs from a timer that counts off pulse widths from the Programmable Minimum Pulse Width values. If there are pulses pending for a

channel and the delay has passed, then the Pending Pulses value is decremented for that channel and the output relay is toggled.

Operation Indicator (0000H = OK, 1000H = Problem):

Bit 1:	1 = EEPROM Failure
Bit 2:	1 = Checksum for Communications settings bad
Bit 3:	1 = Checksum for Programmable settings bad
Bit 4:	1 = 1 or more Communications settings are invalid
Bit 5:	1 = 1 or more Programmable settings are invalid
Bit 6:	1 = 1 or more Programmable settings have been modified
Bit 7:	1 = Forced default by reset value
Bit 15:	1 = Normal operation of the device is disabled

11.8.9: Analog Input Modules

Analog Input Module Specifications	
Model Numbers	8AI1: 8-channel analog input 0±1 mA
	8AI2: 8-channel analog input 0±20 mA
	8AI3: 8-channel analog input 0±5 VDC
	8AI4: 8-channel analog input 0±10 VDC
Accuracy	0.25% of Full Scale
Scaling	Programmable
Communication	RS485, Modbus RTU
	Programmable Baud Rates: 4800, 9600, 19200, 38400, 57600
Power Requirement	12-20 VDC @50-200 mA; 1500+ supports up to four modules
Operating Temperature	(-20 to +70) ^{o}C/(-4 to +158) ^{o}F
Maximum Load Impedance	0±1 mA: 10k Ohms; 4-20 mA: 500 Ohms
Factory Settings	Modbus Address: 8AI1: 136; 8AI2: 140; 8AI3: 144; 8AI4: 148
	Baud Rate: 57600
	Transmit Delay Time: 0
Default Settings (Reset Button)	Modbus Address: 247
	Baud Rate: 57600
	Transmit Delay Time: 20 msec

11.8.9.1: Overview

The Analog Input module converts a voltage level from a device, e.g., a temperature or pressure meter, into a digital value that can be stored and processed in the meter. The Analog Input Modules (0±1 mA, 0±20 mA, 0±5 VDC and 0±10 VDC) are available in 8-channel format. Maximum registers per request, read or write, is 17 registers.

All inputs share a single common point. This is also an isolated connection (from ground).

11.8.9.2: Normal Mode

In Normal Mode, the Input Module:

1. Reads and averages the A/D and adjusts values for process 2.

2. Calculates the percentage of Input Value.

NOTE: The percentage value of the Input is stored in Input Value Registers (Registers 04097-04104).

The device operates with the following default parameters:

Address:	247 (F7H)
Baud Rate:	57600 Baud
Transmit Delay Time:	20 msec

11.9: Additional External I/O Module Specifications

Analog Transducer Signal Outputs (Up to four modules can be used.)

1mAON4: 4 Analog Outputs, scalable, bidirectional

1mAON8: 8 Analog Outputs, scalable, bidirectional

20mAON4: 4 Analog Outputs, scalable

20mAON8: 8 Analog Outputs, scalable

Digital Dry Contact Relay Outputs (One module can be used.)

4RO1: 4 Relay Outputs 10 amps, 125 VAC, 30 VDC, Form C

Digital Solid State Pulse Outputs (Up to four modules can be used.)

4PO1: 4 Solid State Pulse Outputs, Form A KYZ pulses

Analog Transducer Inputs (Up to four modules can be used.)

- 8AI1: 8 Analog Inputs 0–1 mA, scalable and bidirectional
- 8AI2: 8 Analog Inputs 0–20 mA, scalable
- 8AI3: 8 Analog Inputs 0–5 VDC, scalable
- 8AI4: 8 Analog Inputs 0–10 VDC, scalable

Other I/O Module Accessories

MBIO: Bracket for surface-mounting external I/O modules to any enclosure or to a DIN rail.

PSIO: 12 V external power supply, which is necessary whenever you are connecting an external I/O module to a Nexus® 1500+ meter.

12: Test Mode

12.1: Introduction

The Nexus® 1500+ meter offers a Test Mode that lets you verify the meter's accuracy without affecting billing data. When a meter is put into Test Mode, all of the energy registers are frozen, the display is set to 0, and the user can access the energy measurement test sequences. The meter's accuracy is determined by comparing energy accumulated values provided by it against a well-known source also monitored by the meter.

The Energy Preset, or Preset Accumulators, feature supports Test Mode. This feature allows a user to preset the energy accumulators to a desired value. This is important because when a meter is in Test Mode, it is out of service and not monitoring accumulations. You can use the Test Mode Preset Accumulations screens to enter a new value that adjusts for those not monitored while the meter was in Test Mode. You can preset single or multiple accumulators. The new values will take effect after you leave Test Mode. If no preset values are entered, the Normal Mode energy accumulator values will have the same values they had when you entered Test Mode.

This feature is also useful when removing a meter from service and replacing it with a new meter. You can use the Preset Accumulators screen to set the new meter with the accumulation values from the old meter. This way, the new meter can continue to accumulate where the old meter left off.

All Test Mode data can be monitored either:

- Through the meter's display
- By polling the Modbus registers through the meter's communication ports (see the *Nexus® 1500+ Meter's Modbus User Manual* for detailed information on the Modbus registers)

Some of the Test Mode data (-Wh (Q2,3), +Wh (14), +VARh (Q1,2), -VARh (Q3,4)) can also be measured using the LED pulse outputs (see the following section, 12.1.1).

All Test Mode data is provided in binary secondary units (i.e., W, Wh, VA, VAh, VAR, VARh): no kilo-units or mega-units are used. All Test Mode energy accumulators are formatted as 15 digit integers with 7 decimal digits; Test Mode demand is formatted as 4 digit integers with 4 decimal digits.

The Nexus® 1500+ meter's Test Mode implementation has a security feature which allows you to block Test Mode access for one or both of the Ethernet ports, if necessary.

12.1.1: LED Pulse Outputs and Test Mode

The Nexus® 1500+ meter provides 2 LED pulse outputs (KYZ outputs 1 and 2), which in Normal Mode can be enabled and programmed to send a light pulse with a certain width every time a certain amount of energy has been accumulated. For Test Mode use, the LEDs are set up as shown on the following table. The energy source used for each LED constitutes a unique Test Mode operation.

There are four available Test Modes, as shown in the table below. The default Test Mode is 1.

Test Mode Settings

Test Mode	Mode*	Form*	Pulse Width (msec)*	Factor (Wh per pulse)**	Source***	
					LED 1	LED2
1	Always enabled*	Pulse (FORM A)*	100*	as programmed in device profile**	+Wh Q14	+VARh Q12
2	Always enabled*	Pulse (FORM A)*	100*	as programmed in device profile**	+Wh Q14	-VARh Q34
3	Always enabled*	Pulse (FORM A)	100*	as programmed in device profile**	-Wh Q23	+VARh Q12
4	Always enabled*	Pulse (FORM A)*	100*	as programmed in device profile**	-Wh Q23	-VARh Q34

*These are the default values for these fields - they cannot be changed. If the Mode, Form, and Pulse Width have been set to different values in the meter's Device Profile, those settings are ignored for Test Mode, and the values in the table are used.

**If LED pulse output is disabled in the device profile, factor settings default to 1.8 Wh per pulse (for WYE systems) and 1.2 Wh per pulse (for DELTA systems) for Class 20 units and 0.36 Wh per pulse (for WYE systems) and 0.24 Wh per pulse (for DELTA systems) for Class 2 units.

***The Source can be set either from the Test Mode setting through CommunicatorPQA® software or through the display.

NOTES:

- No KYZ output can be programmed for End of Interval Pulse.
- No KYZ output can be programmed for Operation Status Output.

12.2: Test Mode Operation

The Nexus® 1500+ meter can enter Test Mode either through software, through the display, or through a communication port via a Modbus command. With any of these methods, before starting Test Mode, you need to select a compensation type for Test Mode. It should be the same as the compensation that has been set up for the meter in the device profile. The choices are:

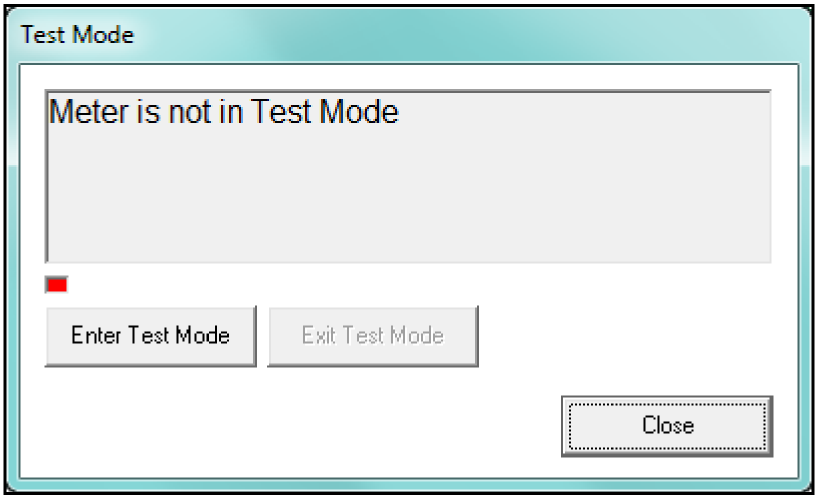
- Test with No Compensation
- Test with Transformer Loss Compensation
- Test with CT/PT Compensation
- Test with Transformer Loss and CT-PT Compensation

For Test Mode demand, the interval configured in the meter’s device profile will be synchronized either when the meter starts Test Mode, when a new Test Mode operation is selected, or when resetting Test Mode data. If the meter has been configured for block window computation through a digital input, the Test Mode block window interval will default to 15 minutes.

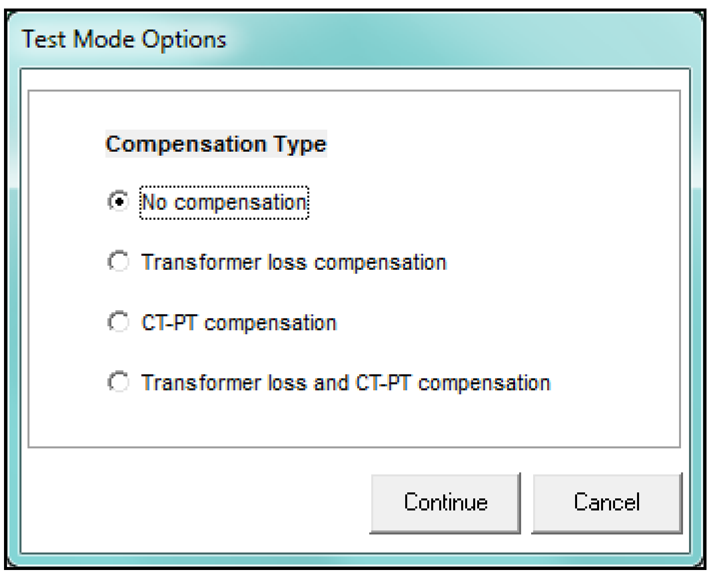
12.2.1: Entering Test Mode through CommunicatorPQA® Software

To enter Test Mode through software:

1. From the Main screen, click Tools>Test Mode>Set Test Mode. The screen shown below opens.



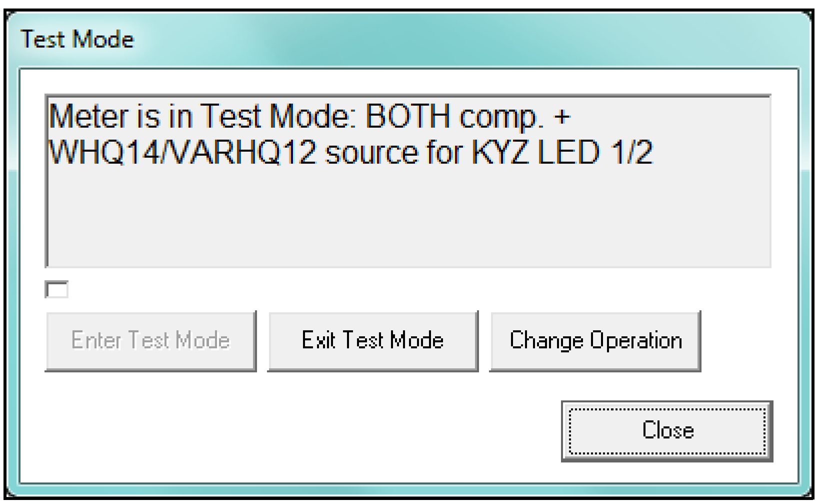
2. Click Enter Test Mode. The screen shown below opens.



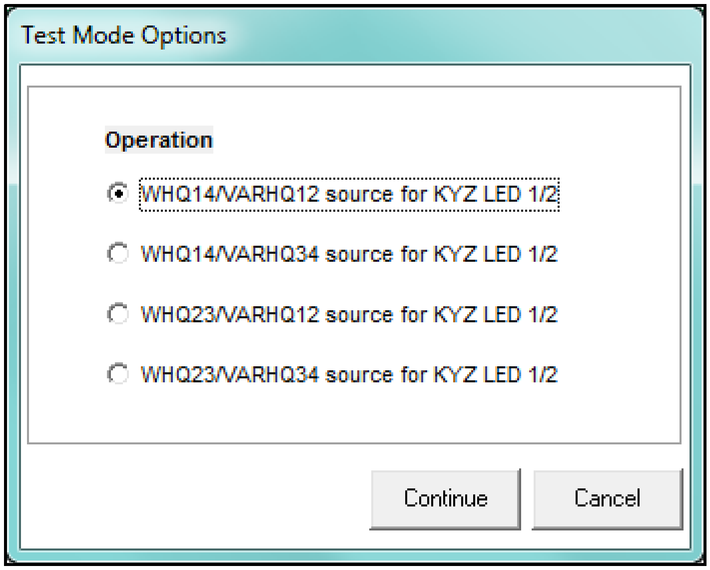
3. Use this screen to select the type of compensation to apply to the Test Mode. You should select the same compensation you are using for the meter (refer to sections 11.2.5 and 11.2.6 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions on setting the meter's Transformer and CT/PT compensation). Another option would be to test the meter with no compensation at all. Your choices are:

- No compensation - Test Mode readings will be obtained without any compensation applied.
- Transformer loss compensation - your setting for Transformer Loss compensation will be applied to the readings in Test Mode.
- CT-PT compensation - your setting for CT/PT compensation will be applied to the readings in Test Mode.
- Transformer loss and CT-PT compensation - both your settings for Transformer Loss compensation and CT-PT compensation will be applied to the readings in Test Mode.

4. Click Continue. You will see the Test Mode screen again. You will see a message that Test Mode is starting and then you will see a message that the meter is in Test Mode, with the compensation you selected and the values that are being read, also displayed. See the example screen on the next page.



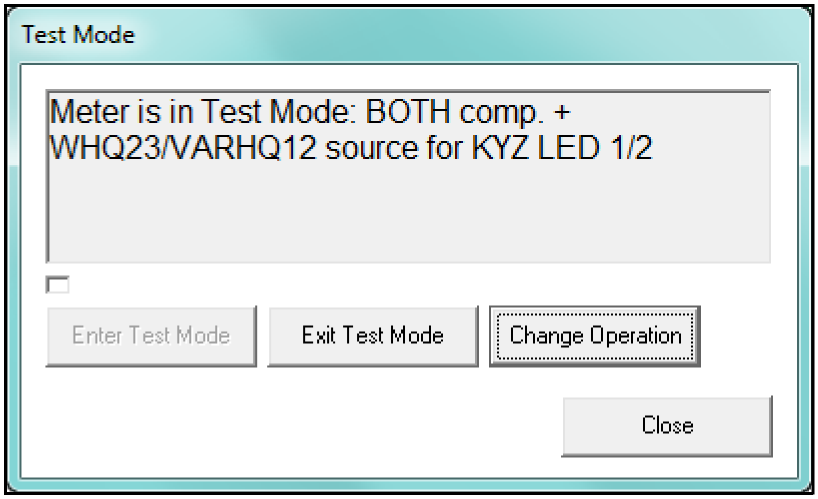
5. WHQ14/VARHQ12 above indicates that the watt-hour readings from quadrants 1 and 4, and the VAR-hour readings from quadrants 1 and 2 are being read in Test Mode. The BOTH comp means that both Transformer loss and CT-PT compensations are being applied. To choose a different energy reading source, click the Change Operation button. You will see the screen shown below.



6. The options on this screen are:

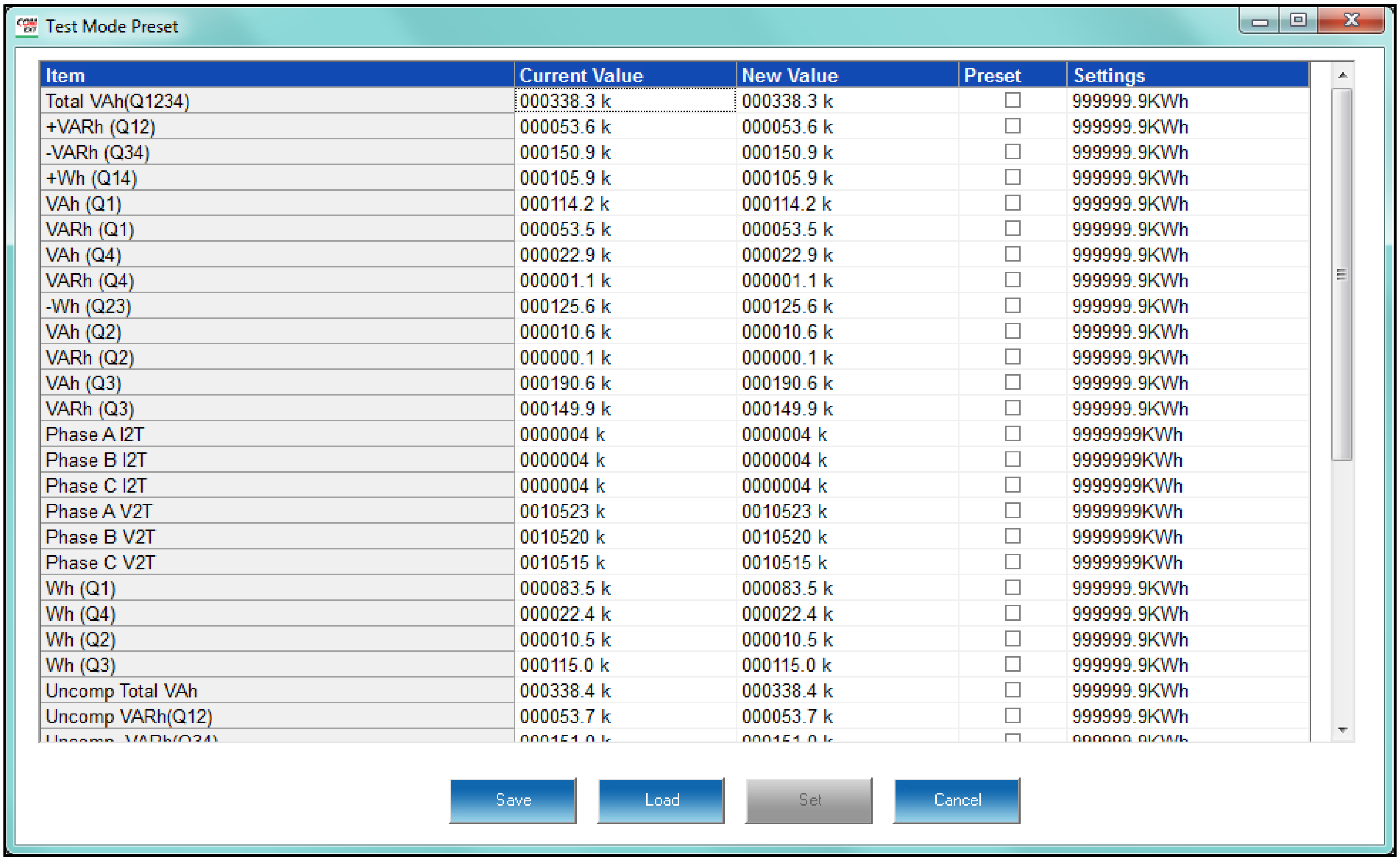
- WHQ14/VARHQ12
- WHQ14/VARHQ12
- WHQ14/VARHQ12
- WHQ14/VARHQ12

7. Make your selection and click Continue. The Test Mode screen is redisplayed, with the current reading source reflecting your selections.



8. If you want to set Energy Presets, click Close to close the Test Mode screen (Test Mode will still be active) and continue to step 9. If you do not want to set Energy Presets, once you are done with Test Mode, click Exit Test Mode. You will see a message that the meter is exiting Test Mode and then Test Mode will stop. Note that the timeout value that you set up in Test Mode Configuration in the meter's Device Profile (see Section 11.2.11 of the *CommunicatorPQA® and MeterManager-PQA® Software User Manual* for instructions on setting the timeout value and Section 12.4 for more information on Test Mode timeout) will cause the meter to exit Test Mode after a certain amount of time with no activity, even if you do not actively exit Test Mode.

9. Click Tools>Test Mode>Energy Presets. You will see the screen shown below.



Item	Current Value	New Value	Preset	Settings
Total VAh(Q1234)	000338.3 k	000338.3 k		999999.9KWh
+VARh (Q12)	000053.6 k	000053.6 k		999999.9KWh
-VARh (Q34)	000150.9 k	000150.9 k		999999.9KWh
+Wh (Q14)	000105.9 k	000105.9 k		999999.9KWh
VAh (Q1)	000114.2 k	000114.2 k		999999.9KWh
VARh (Q1)	000053.5 k	000053.5 k		999999.9KWh
VAh (Q4)	000022.9 k	000022.9 k		999999.9KWh
VARh (Q4)	000001.1 k	000001.1 k		999999.9KWh
-Wh (Q23)	000125.6 k	000125.6 k		999999.9KWh
VAh (Q2)	000010.6 k	000010.6 k		999999.9KWh
VARh (Q2)	000000.1 k	000000.1 k		999999.9KWh
VAh (Q3)	000190.6 k	000190.6 k		999999.9KWh
VARh (Q3)	000149.9 k	000149.9 k		999999.9KWh
Phase A I2T	0000004 k	0000004 k		9999999KWh
Phase B I2T	0000004 k	0000004 k		9999999KWh
Phase C I2T	0000004 k	0000004 k		9999999KWh
Phase A V2T	0010523 k	0010523 k		9999999KWh
Phase B V2T	0010520 k	0010520 k		9999999KWh
Phase C V2T	0010515 k	0010515 k		9999999KWh
Wh (Q1)	000083.5 k	000083.5 k		999999.9KWh
Wh (Q4)	000022.4 k	000022.4 k		999999.9KWh
Wh (Q2)	000010.5 k	000010.5 k		999999.9KWh
Wh (Q3)	000115.0 k	000115.0 k		999999.9KWh
Uncomp Total VAh	000338.4 k	000338.4 k		999999.9KWh
Uncomp VARh(Q12)	000053.7 k	000053.7 k		999999.9KWh
Uncomp VARh(Q34)	000151.0 k	000151.0 k		999999.9KWh

10. The accumulators that can be pre-set are listed on the left of the screen with their current values. You can scroll to see accumulators not displayed.

11. To enter a preset value, click the preset box on the same line with the value and enter the preset value in the New Value field. The Settings field shows the format your entry needs to be in, that is, the number of digits and decimal places; for example, 999999.9kWh.

12. When you have entered all of the preset values you want, click Set to send them to the meter's memory. Once the meter is out of Test Mode, these new values will take effect.

13. You can also save the preset values in a .csv file or load preset values that are already saved in a .csv file to this screen:

- To save the values, click the Save button and give the file a name when you are prompted.

- To load a .csv file, click the Load button and locate the file you want to use.

14. When you have finished with the Test Mode Preset screen, click the X in the right corner of the screen to close it.

15. When you want to exit Test Mode, click Tools>Set Test Mode to open the Test Mode screen, and then click the Exit Test Mode button.

12.2.1.1: Alternative Methods of Updating Meter with Energy Presets

There are additional ways to update a meter with preset values. When you enter the preset values using the method just described, the values are saved in a file (prstene.bin) which can be used to update the meter in one of the following ways. This is useful if you have multiple meters to update - you can set up the preset values once and then import the file into the other meters.

- Through the meter's webpage: access the meter webpage (http://meter_ip_address) and go to Tools>Energy Preset File Upgrade. Type the password information and browse for the prstene.bin file to update to the meter. See section 20.1.18.1 in the software manual for instructions.

- Through the Modbus holding registers. The file is divided into blocks of 64 bytes each. The current file size for v1 is 1408 bytes, which contains 22 blocks. This method is available to support any customized software application that uses the energy preset values accessed through the Modbus registers. Follow this procedure:

  a. Start to send the file to the meter by writing the first block number (0x0000) to Modbus address 0xAE00.

  b. Write the block to Modbus register 0xAE01-0xAE20.

  c. If all blocks have been written, then go to step e; otherwise continue to step d.

  d. Continue to send the file to the meter by writing the next block number to Modbus address 0xAE00. When finished writing the blocks, proceed to step e.

  e. Compute the CRC-16 checksum for the entire file and write it to the Modbus address 0xAE21

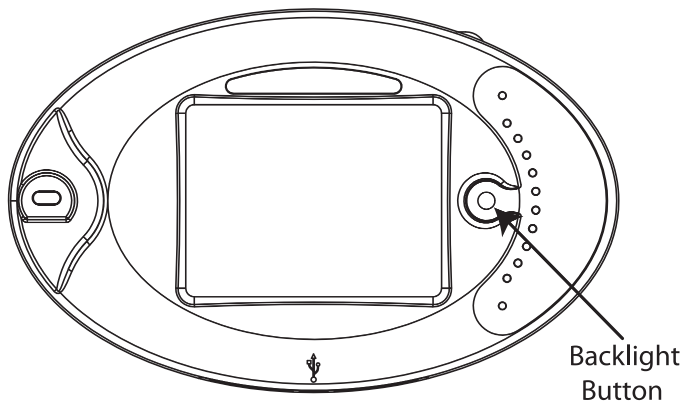
f. After the checksum is written, the meter will compute the checksum for all blocks received and compare it with the value written into the Modbus register 0xAE21. If they match and the received block has the format described above, then the meter will save the file into the compact flash.

Note that access to the Energy Presets can be password restricted for security (see Chapter 6 in the software manual for instructions).

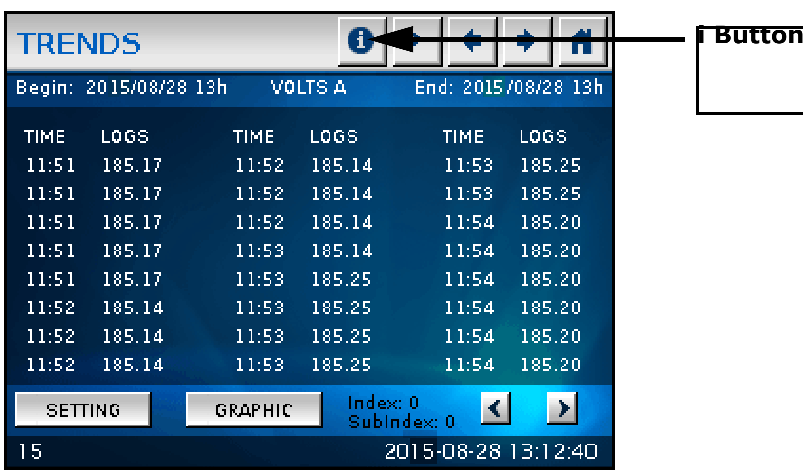
12.2.2: Entering Test Mode through the Display

1. To avoid a user accidentally entering Test Mode, the Test Mode button on the display is hidden until you perform the following actions:

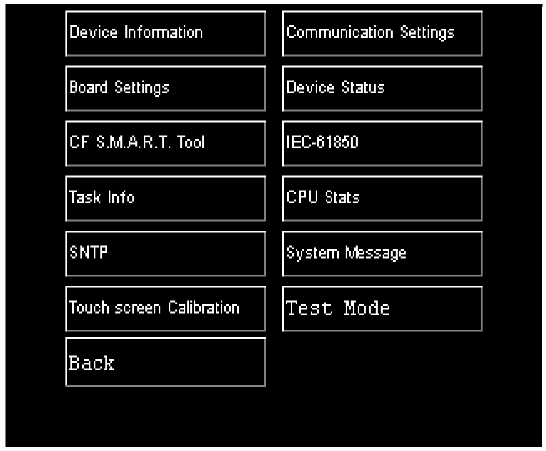
   a. While on a Dynamic screen, press the Backlight button on the front panel for 2 seconds.



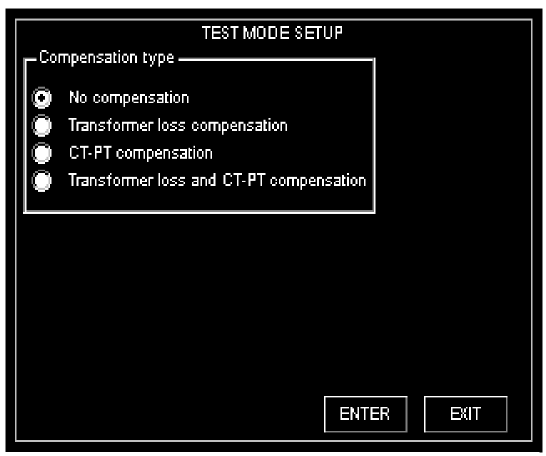
   b. Then, within 5 seconds, press the **i** button on the Dynamic screen.



2. The System screen will be displayed, now showing the Test Mode button. Enter Test Mode by pressing the Test Mode button.

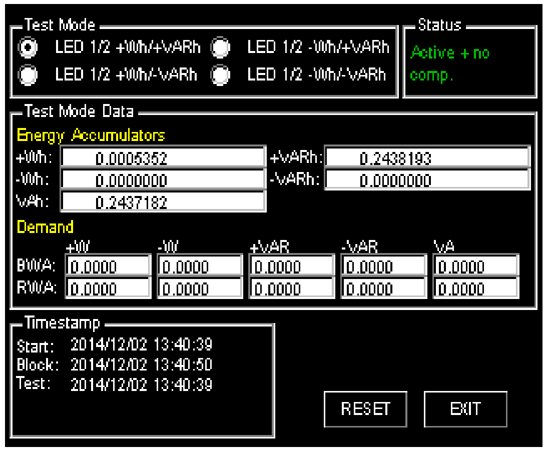


3. Select the energy compensation type (it should be the same as the compensation that has been set up for the meter in the device profile).



4. Press ENTER to start Test Mode. If password protection has been enabled, after you press ENTER you will be prompted to enter the password.

5. The display shows a screen with Test Mode data and timestamp, your Mode of Operation selection, Exit and Reset Buttons, and Test Mode status, e.g., Active - no comp(ensation).



You can:

- Exit Test Mode by pressing EXIT. (Note that the meter will time out of Test Mode after the programmed amount of time - see Section 12.4.)
- Reset Test Mode data by pressing RESET.
- Change the Test Mode's Mode of Operation by pressing one of the radio buttons at the top of the screen.

12.2.3: Entering Test Mode through a Communication Port

To enter Test Mode through a communication port:

1. Connect to the meter through Modbus via any of its communication ports.

2. Send a write command to address E031H to enter Test Mode and to select a compensation type. If a password is enabled, the meter will request that you enter the Level 2 password. The meter's display will automatically show the Test Mode screen.

3. While in Test Mode, you can:

   - Send a write command to address E031H to select a specific Test Mode operation
   - Send a read command to address E031H to verify that the meter is in Test Mode

- Exit Test Mode by sending a write command to address E031H
- Reset Test Mode data to zero by sending a write command to address E031H

Note that access to Test Mode through a communication port can be password restricted for security (see Chapter 6 in the *CommunicatorPQA® and MeterManager-PQA® Software User Manual* for instructions); additionally, access to Test Mode through an Ethernet card can be disabled (see Section 11.2.11 in the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for instructions).

12.3: Power Loss During Test Mode

In the event of a power outage, Test Mode data is not saved. Upon power up the meter returns to Normal Mode. The Test Mode data is lost, and all registers are restored to their pretest values.

12.4: Test Mode Timeout

Test Mode timeout enables the meter to return from Test Mode to Normal Mode when there is no user interaction with the meter either through the display or through a communication port for a certain period of time, called the Timeout Delay. The Timeout Delay is programmed in the device profile. There are two conditions that activate the Test Mode Timeout Delay:

- Total power is zero: when the meter doesn't recognize a measurable load (total power is equal to zero) and it doesn't observe any user interaction, the meter exits Test Mode automatically after the Timeout Delay.
- Total power is not zero: when the meter does recognize a measurable load (total power is more than zero) but it does not observe any user interaction, the meter exits Test Mode automatically after an extended delay, which consists of the Timeout Delay plus the time it takes to perform either one full block or a sliding window demand average.

12.5: Test Mode Restrictions

While the meter is in Test Mode it is restricted from resetting the following values:

- Meter energy
- TOU accumulations
- Max/Min values
- Pulse accumulations
- KYZ count
- Cumulative demand
- Logs
- Total Average PF
- Flicker values

In addition, while in Test Mode, the meter will not trigger limits, update Thermal Average values, or perform One Cycle and Tenth Second value updates.

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A: Resilient Cyber Security™

A.1: Introduction

The Nexus® 1500+ meter with Firmware V20 and above offers an advanced security option - Resilient Cyber Security™, which enables role-based user accounts protected with an encryption key. Some of the features of Resilient Cyber Security™ are:

- An Admin user with full rights and a programmable password of up to 24 characters.
- Ten user IDs with passwords of up to 24 characters.
- Encrypted communication of sensitive data, such as passwords, usernames, roles, and rights.
- Customizing of the encryption key by the Admin user.
- Expiration programming of passwords and/or the encryption key by the Admin user.
- A security lock feature is available to prevent security from being disabled.

In addition to Resilient Cyber Security™, V20 of the meter's firmware provides security to ensure firmware integrity. The Firmware is "signed" with a digital signature embedded in the firmware file/package.

  - The digital signature is an encryption of a hash value computed over the firmware contents.
  - The digital signature is decrypted by the firmware currently in the meter and the hash value is compared to make sure it is as expected.

- Firmware is checked for integrity by the meter on startup and firmware update.
  - On startup, if the firmware integrity check fails, the meter stays in Boot mode, and a System Failure message is displayed on the meter's screen and in the meter's status screen.
  - In firmware update, if the firmware integrity check fails, the meter will not accept the uploaded firmware file.

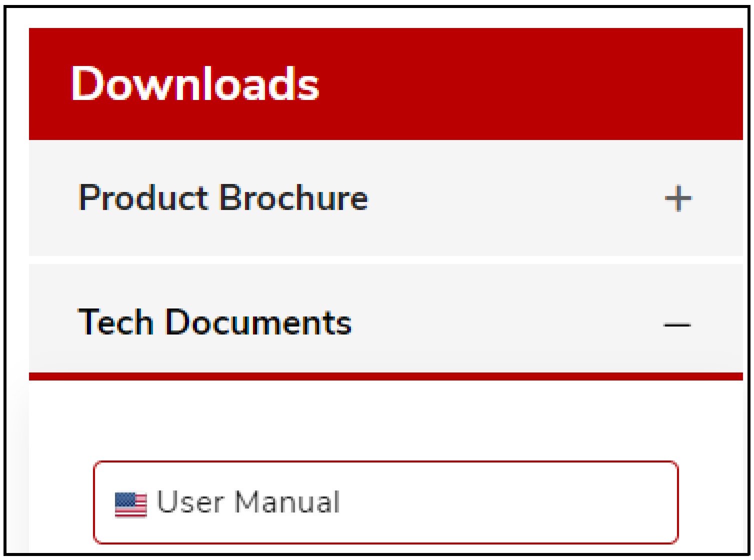
In addition to security, the meter has a sealing switch physical seals/lockouts, and an anti-tampering Events log that records all user logins and attempted logins, as well as other meter actions.

A.2: Programming Resilient Cyber Security

You use the CommunicatorPQA® application to program the meter's Resilient Cyber Security. Detailed instructions for doing so can be found in Chapter 6 of the *CommunicatorPQA® and MeterManagerPQA® Software User Manual*:

https://www.electroind.com/products/communicatorpqa-power-monitoring-software/

Click Downloads>Tech Documents from the right side of the webpage to access the software manual.



B: Power Supply Options

The Nexus® 1500+ meter offers the following power supply options:

Option	Description
115AC	UL Rated AC Power Supply (100-240) V AC @50/60 Hz / 17 W Max
D2	UL Rated High-Voltage DC Power Supply (100-240) V DC, (90-264) V AC @50/60 Hz / 17 W Max
D	UL Rated Low-Voltage DC Power Supply (18-60) V DC (24-48 V DC Systems) / 25 VA Max

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C: Using the IEC 61850 Protocol Network Server

C.1: Overview of IEC 61850

With V-Switch™ keys 2 and 3, either of the Nexus® 1500+ meter's two Network cards (Main or optional) has the ability to function as an IEC 61850 Protocol Network server, certified to Edition 2 of the IEC 61850 protocol. (Note that only one of the cards at a time can be enabled as the IEC 61850 Protocol server.) With the IEC 61850 Protocol Network server added to the Nexus® 1500+ meter, the unit becomes an advanced intelligent device that can be networked on an IEC 61850 standard network, within an electrical distribution system, or other application.

IEC 61850 was developed as a standard for the design of electrical substation automation, including the networking of substation devices. Edition 2 of the protocol expands its utility, supporting additional processes, beyond substation automation. The Nexus® 1500+ meter's IEC 61850 implementation is compatible with any IEC 61850 Edition 2 application.

The IEC 61850 standard is part of the International Electrotechnical Commission's (IEC) Technical Committee 57 (TC57). It consists of a suite of protocols (MMS [Manufacturing Message Specification], SMV [Sampled Measured Values], GOOSE [Generic Object Oriented Substation Event], etc.) and abstract definitions that provide a standardized method of communication and integration to support intelligent electronic devices (IEDs) from any vendor, networked together to perform protection, monitoring, automation, metering and control in a substation environment. For more information on IEC 61850 go to http://iec61850.ucaiug.org/.

IEC 61850 was developed to:

- Specify a design methodology for automation system construction.
- Reduce the effort for users to construct automation systems using devices from multiple vendors.
- Assure interoperability between components within the automation system.
- "Future-proof" the system by providing simple upgrade paths as the underlying technologies change.

- Communicate information rather than data that requires further processing. The functionality of the components is moved away from the clients (requesters) toward the servers (responders).

Features of the IEC 61850 include:

- The GOOSE communication used by IEC 61850 is a unique and powerful tool that communicates information system-wide. GOOSE sends messages via Ethernet packets to all the devices in the system, in multicast mode, and the appropriate devices respond to those messages.
- It specifies all aspects of the automation system from system specifications, through device specifications, and then through the testing regime.
- The IEC 61850 standard specifies a layered approach to the specification of devices. The layered approach allows "future-proofing" of basic functionality by allowing individual "stack" components to be upgraded as technology progresses.
- The individual objects within devices are addressed through a hierarchy of names rather than numbers.
- Each object has precise, standard terminology across the entire vendor community.
- Devices can provide an online description of their data model.
- A complete (offline) description language defines the way all of the parts of the system are handled, giving a consistent view of all components within the system.

Edition 2 of the standard was released to:

- Correct errors and omissions in the first release of the standard.
- Add functionality to the standard, including support for hierarchical logical devices and for security.
- Support the standard's use in systems other than substation automation.

In summary, the IEC 61850 standard was originally developed for electrical substation automation, but has been applied to Distributed Energy resources, distribution line equipment, hydro-electric power plants, and wind power plants. Edition 2 of IEC 61850 further supports the IEC 61850 protocol being used for processes other than substation automation.

C.1.1: Communication in IEC 61850

Understanding the role of clients and servers, and publishers and subscribers, is key to understanding the communication between IEC 61850 devices.

C.1.1.1: Client/Server Communication

A client is the requester (sink) of information while the server is the responder (source) of information. Information generally flows on a request-response basis with the client issuing the request and the server issuing the response. However, the concept of servers is extended to provide autonomous transmissions when “interesting” events occur within the server. This information flow is always to the client requesting this “interesting information.” Clients are the devices or services which “talk” to IEC 61850 servers. The function of the client is to configure the server “connection,” set up any dynamic information in the server, enable the reporting mechanisms, and possibly interrogate specific information from the server. Most clients are relatively passive devices which await information from the server but perform little direct ongoing interactions with them except for control operations.

Some clients are used for diagnostic purposes. These devices generally perform ongoing direct interrogation of the servers. A specific example is the “desktop client,” where the engineer remotely diagnoses system problems or retrieves data which is not normally sent from the server (for example, power quality information).

IEC 61850 clients are highly interoperable with IEC 61850 servers. Clients are able to retrieve the server object directory (when needed) and then perform any allowable operation with that server.

Example clients include: Omicron IED scout, SISCO AX-S4 61850, TMW Hammer, KalkiTech gateway, Siemens DIGSI

An example of the object model display on a diagnostic client is shown in Figure C.1

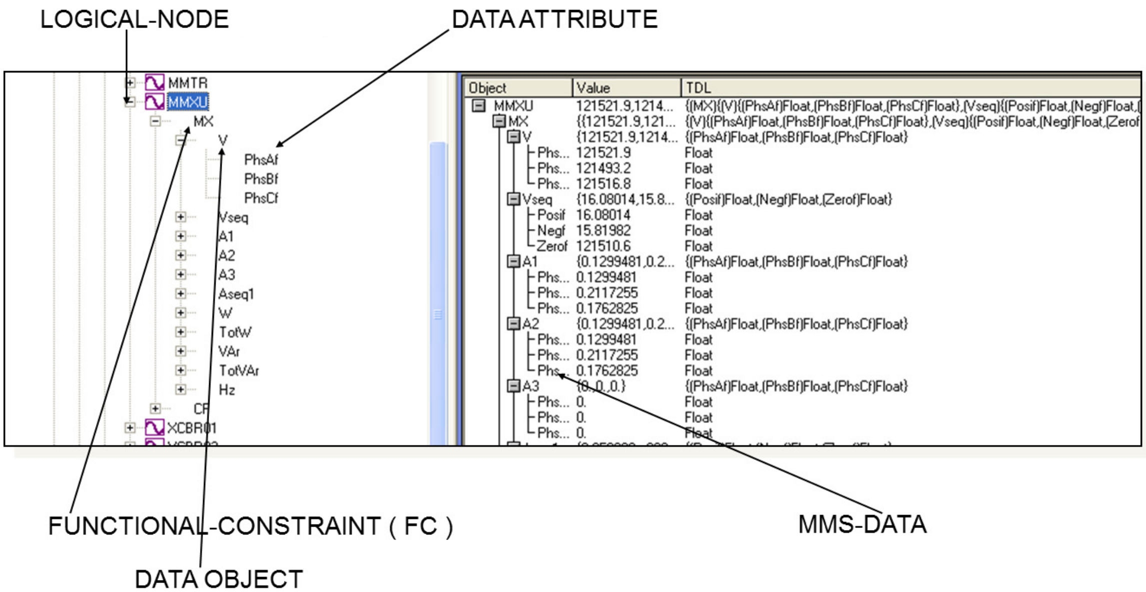


Figure C.1: Object Model Display on a Diagnostic Browser

C.1.1.2: Publisher/Subscriber Communication (GOOSE)

There is an additional, essential relationship in IEC 61850, known as publisher and subscriber, which is the method used in GOOSE messaging. The publisher/subscriber relationship differs from the client/server in that there is no explicit one-to-one relationship between the information producer and consumer. Publishers issue data without knowledge of which devices will consume the data, and whether the data has been received. Subscribers use internal means to access the published data. From the viewpoint of IEC 61850, the publisher/subscriber mechanism uses the Ethernet multicast mechanism (i.e., multicast MAC addresses at layer 2). The communication layer of the system is responsible for transmitting this information to all interested subscribers and the subscribers are responsible for accepting these multicast packets from the Ethernet layer.

The publish/subscribe mechanism is used both for GOOSE and Sampled Value services. GOOSE is fully supported by the Nexus® 1500+ meter's IEC 61850 Protocol Ethernet Network server. In addition, the Nexus® 1500+ meter adds a unique, powerful implementation to GOOSE, by using it to send alarm/limit messages that trigger waveforms whenever there is a power quality event. In this way, if there is a power anomaly, there will be multiple captures of the event so that a detailed analysis can be performed. See Section C.1.4.2: GOOSE on page C-15, for information on the Nexus® 1500+ meter's GOOSE implementation.

C.1.2: Structure of an IEC 61850 Network

As mentioned before, IEC 61850 lets you set up an automated communication structure for devices from any vendor. In order to set up this network, IEC 61850 renames devices (e.g., meters), measured parameters (e.g., Phase to Phase voltage), and functions (e.g., reporting) into a specific language and file structure. This way all of the elements of the network can function together quickly and effectively. The language that the IEC 61850 network uses is structured, that is it is very specific in how the system information is entered, and hierarchical, which means that it has different levels for specific information; for example, meter information is entered on one level, and the information about the actual physical connection between meters and other hardware is entered on another level.

The structure of the IEC 61850 network is composed of different kinds of files, each containing information that the system needs in order to function. IEC 61850 configuration uses text-based (XML) files known as the System Configuration Language (SCL). SCL files use the concept of an XML schema, which defines the structure and content of an XML file. The schema used by SCL files describes most (though not all) of the restrictions required to ensure a consistent description file. An SCL file superficially looks like an HTML file. It consists of 6 parts:

- Prologue: XML declaration, (XML) namespace declarations, etc.
- Header element: Names the system and contains the file version history
- Substation element: defines the physical structure of the system
- Communication element: defines all device-to-device communication aspects
- IED element: defines the data model presented by each communicating device
- DataTypeTemplates element: contains the detailed definition of data models

After it is written, the XML file can be checked by "validators" against the schema using freely available tools.

The IEC 61850 network uses four types of SCL files, each with identical structure:

- SSD - System Specification Description: used during the specification stage of a system to define physical equipment, connections between physical equipment, and Logical Nodes which will be used by each piece of equipment.

- ICD - IED Capability Description: this is provided by the communication equipment vendor to specify the features of the equipment and the data model published by the equipment. Each of the devices in the network has an ICD file which describes all of the information about the device, for example, IP address on the network and Com ports. The (vendor supplied) ICD variation of the SCL file contains a Communication section specifying the lower-layer selectors and default addressing and also an IED section containing the data model of the device. See Section C.4.2 for information on the Nexus® 1500+ meter's .icd file.

- SCD - System Configuration Description: a complete description of the configured automation system including all devices (for example, meters, breakers, and relays) and all needed inter-device communications (for example, the measured parameters and the actions to be performed, such as turning on a relay when a certain reading is obtained). It can also include elements of the SSD file. The SCD file is created by a System Configurator, which is a software application that takes the information from the various devices along with other configuration parameters and generates the SCD file.

- CID - Configured IED Description: the file used to configure an individual device. It is a pure subset of the SCD file and a smaller subset of the device's ICD file. The CID file describes the exact settings for the device in this particular IEC 61850 network. The Nexus® 1500+ meter's IEC 61850 Protocol Ethernet Network card uses a CID file. See Section C.2.2.2 for instructions for uploading the Nexus® 1500+ meter's .cid file.

Each type of SCL file has different required elements with only the prologue and Header element required in every file type.

C.1.2.1: Elements of an IEC 61850 Network

- A physical device has a name (IEDname) and consists of one or more AccessPoints.

- An AccessPoint has an IP address and consists of one or more Logical Devices

- A Logical Device contains LLN0 and LPHD1 and optional other Logical Nodes.

- LLN0 (Logical Node Zero) is a special object which "controls" the Logical Device. It contains all of the datasets used for unsolicited transmission from the device. It also contains the report, SV, and GOOSE control blocks (which reference the data-sets).

- LPHD1 (Physical Device) represents the hardware "box" and contains nameplate information.

- Logical Nodes (LNs) are standardized groups of "Data Objects" (DOs). The grouping is used to assemble complex functions from small groups of objects (think of them as building blocks). The standard defines specific mandatory and optional DOs for each LN. The device may instantiate multiple LNs of the same type differentiated by either a (named) prefix or (numerical) suffix.

- Data Objects represent "real-world" information, possibly grouped by electrical object. The IEC 61850 standard has specific semantics for each of the DOs. For example, the DO named "PhV" represents the voltage of a point on a three-phase power system. The DOs are composed of standardized Common Data Classes (CDCs) which are groups of low-level attributes of the objects. For example, the DO named "Hz" represents system frequency and is of CDC named "MV" (Measurement Value).

- Common Data Classes (CDCs) consists of standardized groups of "attributes" (simple data types). For example, the attribute "instMag" represents the instantaneous magnitude of the underlying quantity. The standard specifies mandatory and optional attributes for each CDC. For example, the DO named "Hz" in Logical Node class MMXU contains a mandatory attribute named "mag" which represents the deadbanded value of the frequency. The physical device contains a database of data values which map to the various structures described above. The database values are manipulated by the device to perform actions such as deadbanding (holding a constant value until the underlying value changes by more than a specified amount) or triggering of reports.

- As explained earlier, GOOSE messaging is essential to an IEC 61850 Network. That is because GOOSE messaging allows very rapid communication to all devices in the system, allowing the appropriate devices to respond to the messages. For example, in the Nexus® 1500+ IEC 61850 implementation, GOOSE is used to transmit alarm/limit information when a programmed limit is exceeded, so that all enabled

Nexus® 1500+meters can capture a waveform at the time of the alarm. See Section C.1.4.2: GOOSE on page C-15, for detailed information.

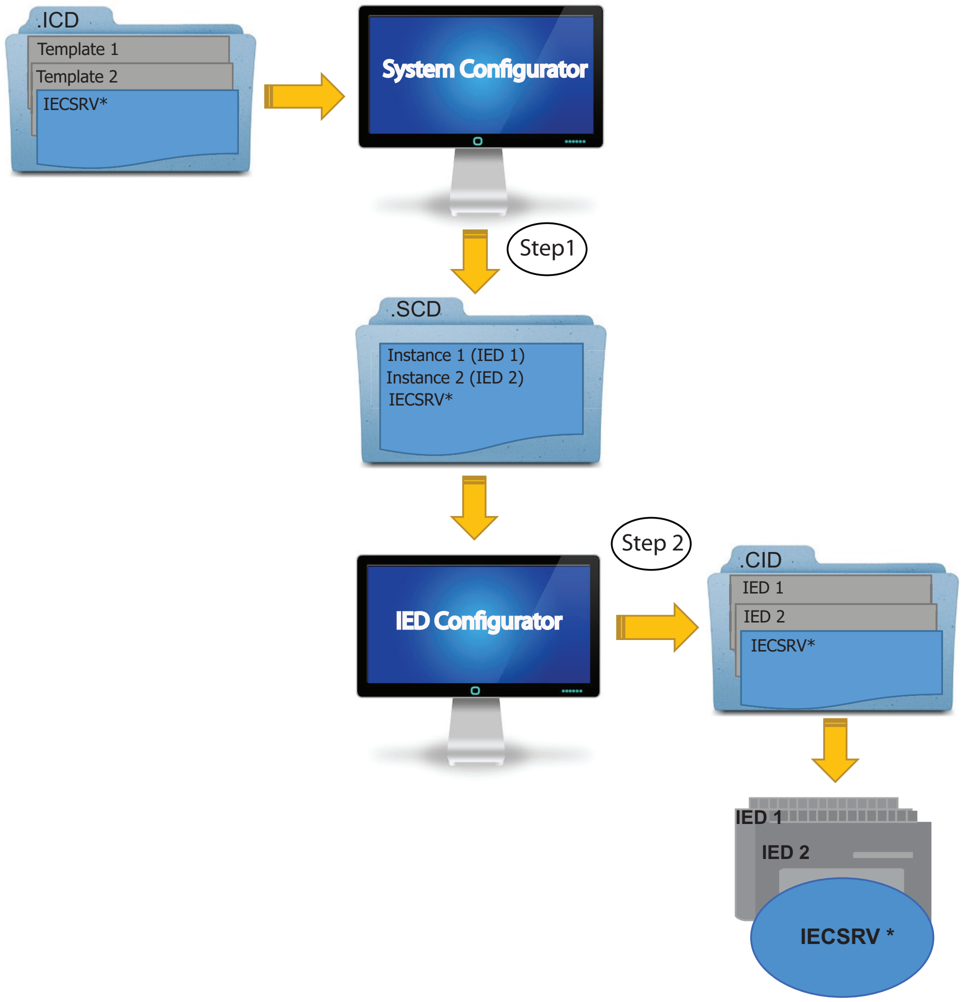
C.1.3: Steps in Configuring an IEC 61850 Network

1. The first thing needed is the SSD for physical connections, then the vendor-provided ICD files which are combined into a SCD file by a vendor-independent System Configurator. The System Configurator assigns addresses to the equipment and sets up datasets, reports, etc. for inter-device communication. The system configurator will create an "instance" of the configured device by applying the following information:

   - The name of the device
   - The IP address, subnet mask, and IP gateway of the device
   - Datasets: the user must decide which information within the IED will be included in reports, etc. and place this information into datasets. The System Configurator should allow the selection of information using a "pick list" from information within the ICD file.

2. The resulting SCD file is then imported by vendor-specific tools into the various devices.
   Some vendors add the additional step of filtering the SCD file into a smaller file containing only information needed by the specific device, resulting in a CID file which is used to configure the device. The actual configuration of the device is left unspecified by IEC 61850 except to require that the SCD file remains the source of the configuration information. In this way, consistency of the information across the whole system is maintained.

See Figure C.2 for a graphical illustration of the process.



*IECSRV is the name of the meter in the IEC 61850 System

Figure C.2: Configuration Process

Referring to Figure C.2:

In Step 1, the IED template is provided by the vendor (or sometimes created by a vendor tool). This file is imported into the vendor-independent tool, the System Configurator, along with other device templates. The System Configurator uses these templates to set up the correct number of IEDs in the system and then provides configuration information. The configuration information consists of providing addresses for all IEDs in the system, creation of datasets, configuring control blocks, and setting individual device parameters such as analog deadbands. The System Configurator then creates a SCD file with a consistent view of the entire system.

In Step 2, the SCD file is used to configure each device using vendor-supplied tools. Vendors are free to choose the configuration mechanism, but the configuration information MUST be derived from the SCD file.

NOTE: In the Nexus® 1500+ meter's IEC 61850 Protocol Ethernet Network server implementation, every service and object within the server is defined in the standard (there is nothing non-standard in the device).

Also in step 2, the user sets up report control blocks, buffered and unbuffered, for each of the clients. Setup information includes the dataset name, a report identifier, the optional fields to be used in the report, the trigger options, buffer time (delay from first event to report issuance), and integrity time (server periodic reports of all data in dataset). The decision whether to use buffered or unbuffered must be decided by the user.

Finally, in step 2 the System Configurator performs a consistency check and then outputs the SCD file. The SCD file is imported by the "ScdToCid" tool where the user specifies the device name.

The resulting CID file is then imported into the target device.

C.1.4: Electro Industries' IEC 61850 Implementation

EIG's IEC 61850 implementation for the Nexus 1500+ meter is certified for IEC 61850 Edition 2, for:

- 1 - Basic Exchange
- 2 - Data Sets
- 5 - Unbuffered Reporting
- 6 - Buffered Reporting
- 9a - GOOSE Publish
- 9b - GOOSE Subscribe
- 13 - Time Synchronization
- 14 - File Transfer

There are two overall parts to the implementation- the IEC 61850 Protocol Server and GOOSE.

C.1.4.1: IEC 61850 Protocol Server

Following are features of EIG's implementation of the IEC 61850 Protocol Server:

- The lower-level addressing uses PSEL=00000001, SSEL=0001, and TSEL=0001.
- At the server level, each implements a single Logical Device name formed by concatenating the IED name (chosen by the System Configurator) and "Meas" (ex, "MyDeviceMeas").
- The Logical Nodes implemented within the Logical Device include the standard LLN0 and LPHD1 with optional standard logical nodes in the "M" class (ex, "MMXU") and "T" class (ex, "TVTR"). Each Logical Node contains only standardized objects of standardized types (Common Data Class, CDC). The device is based upon the first edition of the IEC 61850 standards.
  Examples of Logical Nodes within the Nexus® 1500+ family include eneMMTR1 (energy metering) and nsMMXU1 (normal speed Measurement Unit).
- The Nexus® 1500+ device will get its IED name from the first <IED> section in the configuration file (.cid). This name will be used for accessing its access point (IP address) and its single Logical Device named "Meas". The IED name can be composed of any string of up to 32 (alphanumeric only) characters.
- The logical nodes implemented in the Nexus® 1500+ meter are listed below:
  - The node LLN0 keeps common information for the entire logical device. In this node Datasets and Reports can be defined, based on the limitations provided in the ICD file: the Nexus® 1500+ meter supports up to 32 datasets with up to 256 attributes each, and up to 16 report control blocks. The report control blocks and datasets must be configured in the CID file, although the options, triggers and integrity period can be dynamically configured by IEC client. (The Nexus® 1500+ meter does not support Journals.)
  - The node LPHD1 defines physical parameters such as vendor, serial number, device name plate and the software revision number.

- The node nsMMXU1 contains the "normal-speed" basic electrical measurements such as volts / amps / watts / VARs / frequency / power factor / etc. The electrical measurements are data objects in hierarchical structure as per the IEC 61850 specifications.
  For example, Phase A voltage:
    - which is in the object "PhV"
    - which is of type "WYE_ABC_mag_noDC"
    - which in turn has the object "phsA"
    - which again has an attribute named "instVal" to represent instantaneous values, and also the "mag" attribute, which represents the magnitude as an analog magnitude, with the attribute "f" to get the value in 32-bit floating point.

  Thus the voltage of phase A, would be referred in this nested structure as "Meas/nsMMXU1.PhV.phsA.instVal.mag.f".

- The node hsMFLK1 is used for short term flicker (per phase) and long term flicker (per phase); hs stands for "high speed" (200msec).

- The node nsMHAI1 groups together the THD per phase measurements taken at normal speed.
  Following the previous example, the THD for phase A would be referred as "Meas/nsMHAI1.ThdPhV.phsA.instCVal.mag.f".

- The node 1sMSQI1 is used for voltage/current symmetrical components per-phase (zero, positive and negative); 1s stands for “low speed” (3 seconds).

- The node eneMMTR1 groups together all measurements related to energy counters, like +/- Watt;hours, +/- VAr-hours and Total VA-hours.

- The node intGGIO1 is used for the built-in high-speed digital inputs; the node extGGIO1 is used for the slot 3 option board’s digital inputs; the node extGGIO2 is used for the slot 4 option board’s digital inputs.

  - The nodes setTCTR1, setTCTR2, setTCTR3 and setTCTR4 contain the ratio of the current used by the measuring device, for phases A,B,C and Neutral, respectively. In this way, the user can take the IEC measurements (primary) and convert them to Secondary using the ratios contained in these nodes.

  - The nodes setTVTR1, setTVTR2 and setTVTR3 contain the ratio of the voltage used by the measuring device.

- Any of the defined objects/ attributes can be placed within a dataset.

- The normal-speed in the Nexus® 1500+ meter is measurements taken every second. The energy counters are also updated every second.

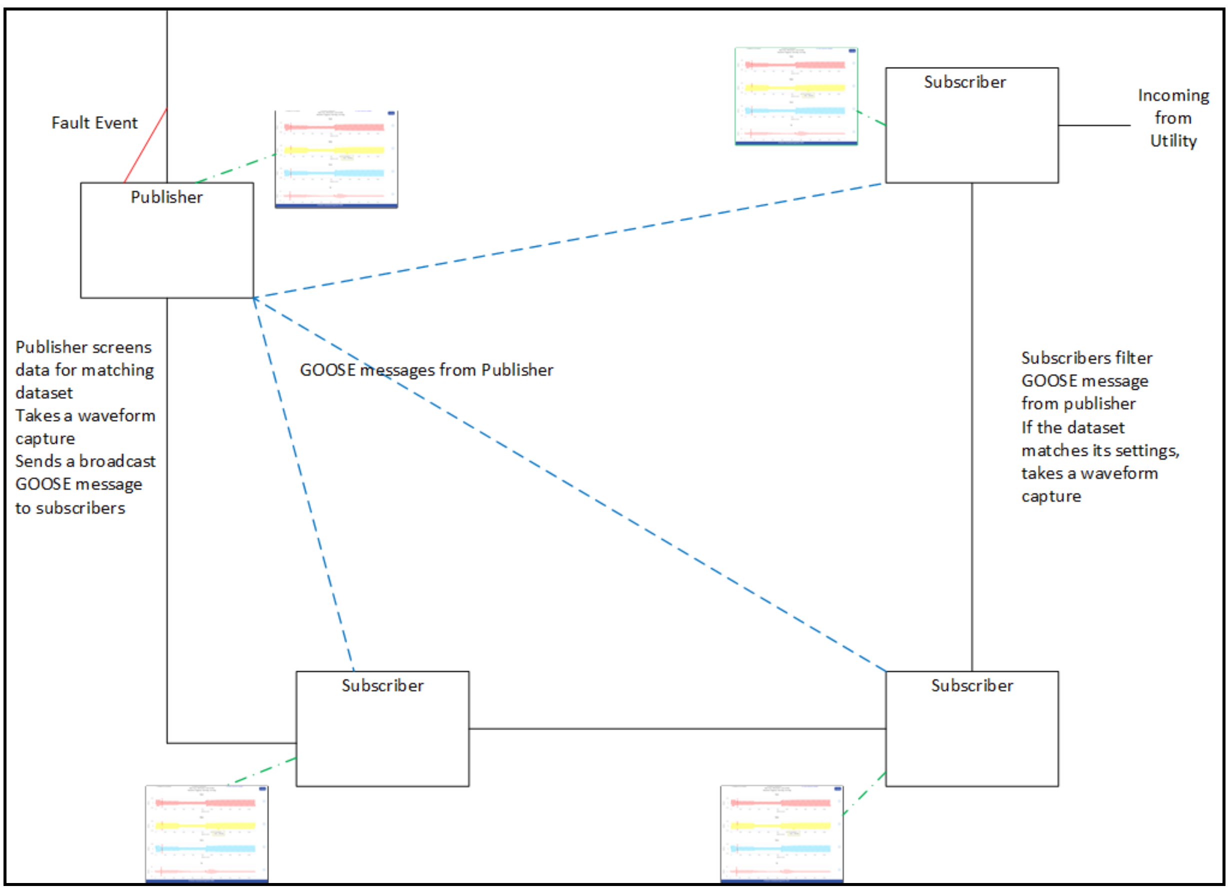
- The configuration of the devices takes place by converting the SCD file exported by the System Configuration tool into a CID file. This CID file contains all of the information from the SCD file which is needed for configuration by the EIG device. The tool is named "SCDtoCIDConverter" and is a simple, publicly available program. The resulting CID file is then sent to the EIG device using HTTP file transfer.

C.1.4.2: GOOSE

The GOOSE implementation enables the Nexus® 1500+ meter with the IEC 61850 server to:

- Send and receive (publish/subscribe) messages
- Send messages when programmed limits have been exceeded
- Receive messages of exceeded limits and trigger waveforms in response to them
  - Enabling GOOSE, configuring limits, and selecting the limits that will trigger waveform capture is done in the Device Profile. See Section C.1.4.1: IEC 61850 Protocol Server on page C-12, for instructions.
  - The programming of the GOOSE send and receive of messages is done in the CID file.

Refer to the figure below for an illustration of GOOSE functionality.



C.3: GOOSE Cross-Triggering of Waveforms

C.1.4.3: Nexus® 1500+ Meter IEC 61850 Server Configuration

The configuration file (CID) should be stored in the Nexus® 1500+ meter in order to configure the server. At power up the server reads the file, parses it and configures all the internal settings for proper functionality.

Storing the CID file in the Nexus® 1500+ meter is accomplished through its webpage. The webpage allows the user to locate the CID file, and submit it to the Nexus® 1500+ meter for storage.

After storing the CID file, access the Nexus® 1500+ meter's webpage again, to make sure that the file has been stored, and to see if there is any problem with it, by checking its status. The CID file will be successfully updated if the IP address inside the .cid file matches with the one programmed into the device profile.

- A common problem you may see is IP mismatch (the IP address in the CID file does not match the IP configured in the Nexus® 1500+ meter's device profile). In this case the Nexus® 1500+ meter will use the IP address from its device profile, and the IEC Server will work only with that address.

- If there is a critical error in the stored CID file, which prevents the IEC Server from running, the CID file will not be used, and instead the Default CID file (embedded in the server) will be used. The webpage will alert you to this situation.

- If further details are needed, for example, information on the reason the CID storage failed, the web server provides a link to the system log. In the system log screen you can view messages from the IEC 61850 parser, and you can take actions to correct the error.

See Section C.2: Using the Nexus® 1500+ Meter's IEC 61850 Protocol Ethernet Network Server on page C-19, for instructions on configuring the Nexus® 1500+ meter's IEC 61850 Protocol Ethernet Network server.

C.1.5: Reference Materials

Following is a list of background information on IEC 61850 that is available on the Internet:

- http://www.sisconet.com/downloads/IEC61850_Overview_and_Benefits_Paper_-General.pdf

- http://www.sisconet.com/downloads/CIGRE%202004%20Presentations.zip (IEC618650 Presentation IEC 61850 û Data Model and Services.pdf)

- http://www.ucaiug.org/Meetings/Austin2011/Shared%20Documents/IEC_61850-Tutorial.pdf (pages 24-32 and 40-161)

- http://brodersensystems.com/wordpress/wp-content/uploads/DTU-Master-Thesis-RTU32.pdf (pages 9-36)

Additionally, there is a good article on the predecessor to IEC 61850 (UCA 2.0) at http://www.elp.com/index/display/article-display/66170/articles/utility-automation-engineering-td/volume-5/issue-2/features/uca-20-for-dummies.html.

Another good article on multi-vendor IED integration can be found at http://www.gedigitalenergy.com/smartgrid/Aug07/EIC61850.pdf.

C.1.6: Free Tools for IEC 61850 Start-up

The Internet also provides some free IEC 61850 configuration tools:

- Schema validation tools: http://notepad-plus-plus.org/
  go to plug-in manager and install XML tools (however, there is no (legal) public copies of the schema available). However, a web search file the filename SCL_Basetypes.xsd turns up many copies and the entire set of XSD file is often nearby.

- http://opensclconfig.git.sourceforge.net/
  Apparent open-source project, not tested

- http://www.sisconet.com/downloads/SCDtoCIDConverter0-9.exe
  filters SCD file to a CID file

- http://www.sisconet.com/downloads/skunkworks2-8.exe Ethernet analyzer

C.1.7: Commercial Tools for IEC 61850 Implementation

Following is a list of tools for IEC 61850 configuration which you can purchase:

- http://www.sisconet.com/ax-s4_61850.htm
  Client for IEC 61850

- http://products.trianglemicroworks.com/documents/TMW%2061850%20Test%20Suite%20Combined.pdf
  Clients and servers for IEC 61850

- http://www.omicron.at/en/products/pro/communication-protocols/iedscout/
  test client

- http://kalkitech.com/products/sync-6000-series-scl-manager--iec61850-substation-design-tool
  SCL editing tool

C.2: Using the Nexus® 1500+ Meter's IEC 61850 Protocol Ethernet Network Server

This section contains instructions for understanding and configuring the Nexus® 1500+ meter's IEC 61850 Protocol Ethernet Network server.

C.2.1: Overview

The IEC 61850 Protocol Ethernet Network card is a Nexus® 1500+ standard I/O board. It is available via Ethernet port 1 with V-Switch™ keys 2 and 3. The IEC 61850 Protocol Ethernet Network server has the following features:

- Standard Ethernet 10/100 Mbps connector is used to link the unit into an Ethernet network.
- Standard operation port 102, which can be reconfigured to any valid TCP/IP port.
- Up to 6 simultaneous connections can be established with the unit.
- Configurable via the .CID file (XML formatted)
- Embedded Capabilities File (.ICD downloadable from the unit)
- Supports MMS protocol.
- Supports the following Logical Nodes:
    - LLN0 (with predefined Sets and Reports)
    - LPHD (Identifiers)
    - MMXU with
        - Phase-to-N voltages
        - Phase-to-Phase voltages
        - Phase currents
        - Per Phase VA
        - Total VA
        - Per Phase VAR

        - Total VAR
        - Per Phase W
        - Total W
        - Per Phase PF
        - Total PF
        - Frequency
    - MHAI with Per Phase THD for voltage and current
    - MSQI with
        - Voltage symmetrical components per phase (zero, positive and negative)
        - Current symmetrical components per phase (zero, positive and negative)
    - MMTR with
        - Demand Wh
        - Supplied Wh
        - Demand Varh
        - Supplied VArh
        - Total VAh
    - GGIO with built-in and option board digital inputs and virtual inputs
- Supports polled (Queried Requests) operation mode.
- Supports Buffered Reports
- Supports Unbuffered Reports

C.2.2: Configuring the IEC 61850 Protocol Ethernet Network Server

You need to configure the IEC 61850 Protocol Ethernet Network server for communication, both from the standpoint of the device (the Device Profile) - see Section C.2.2.1: Configuring the Device Profile IEC 61850 Protocol Ethernet Network Server Settings on page C-21, and of the network (the SCL configuration file, which is a .cid file uploaded to the meter) - see Section C.2.2.2: Configuring the Meter on the IEC 61850 Network on page C-25.

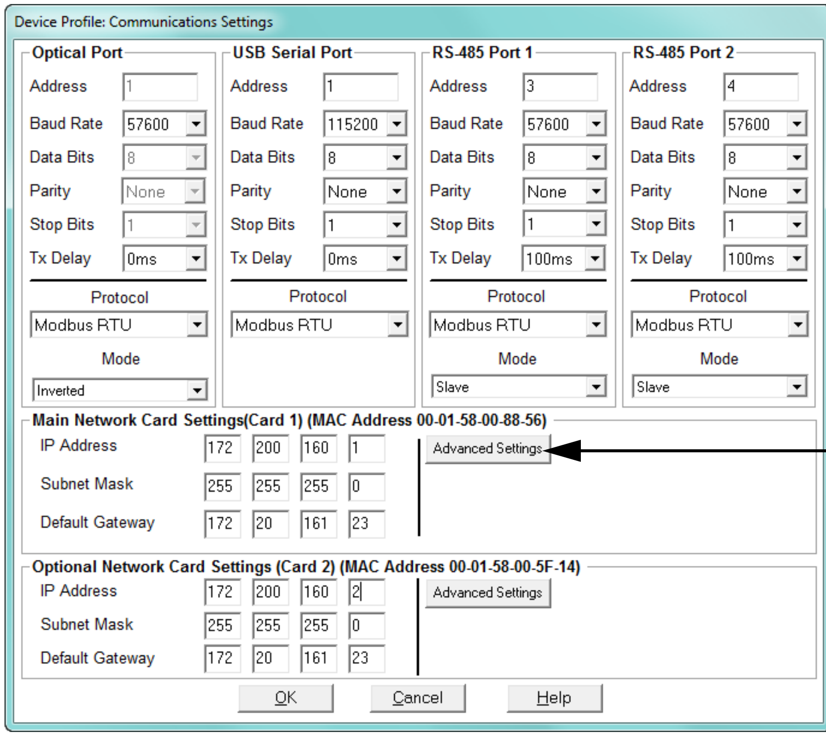
C.2.2.1: Configuring the Device Profile IEC 61850 Protocol Ethernet Network Server Settings

You use the CommunicatorPQA™ application to set the card's network parameters, including the IEC 61850 and GOOSE features. Basic instructions are given here, but you can refer to the *CommunicatorPQA® and MeterManagerPQA® Software User Manual* for additional information. You can view the manual online by clicking Help>Contents from the CommunicatorPQA® software's Main screen.

1. Using CommunicatorPQA® software, connect to the meter through its USB port, RS485 serial port, or Ethernet 2 port (see Chapter 5 for instructions on connecting to your meter with CommunicatorPQA® software).

2. Click the Profile icon to open the meter's Device Profile screen The profile is retrieved from the Nexus® 1500+ meter. Double-click General Settings,

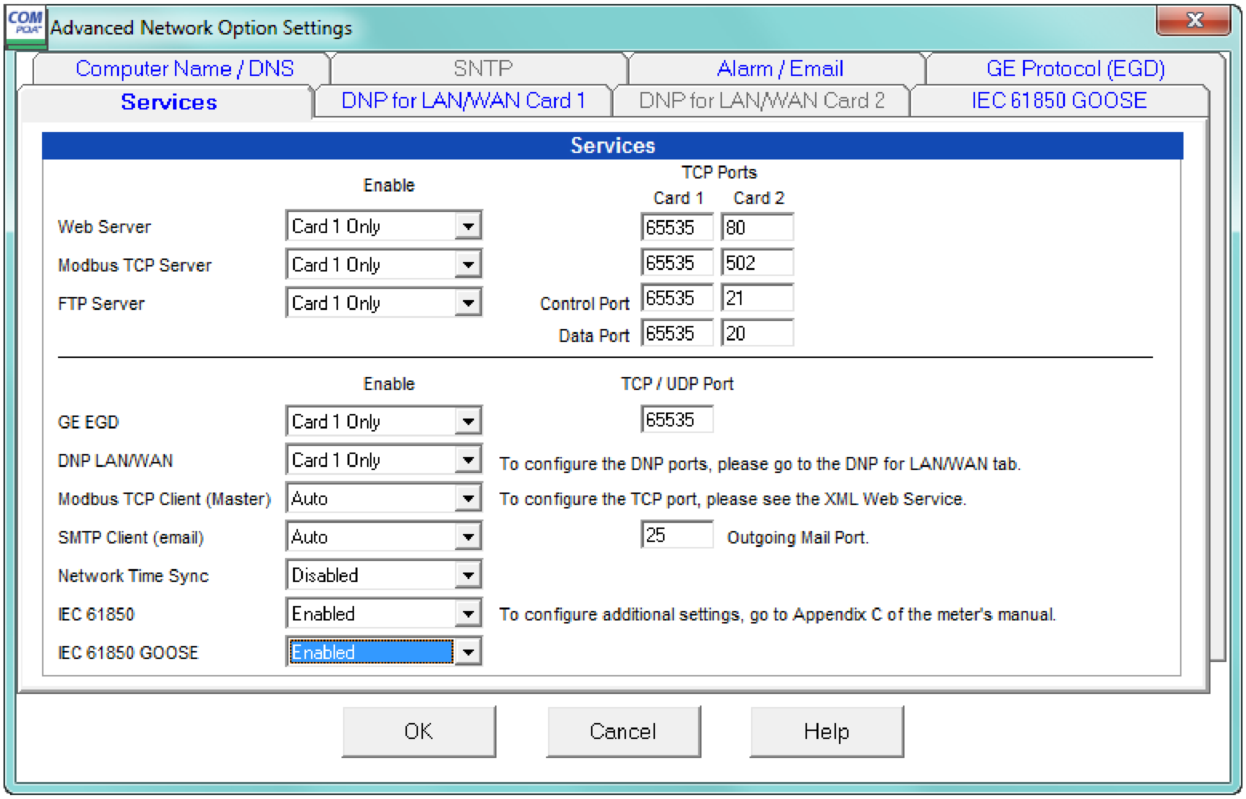
Communications, and then one of the lines under Communications, to display the screen shown below.



Click this button

3. Click the Advanced Settings button next to the Main Network Card. You will see the screen shown on the next page.

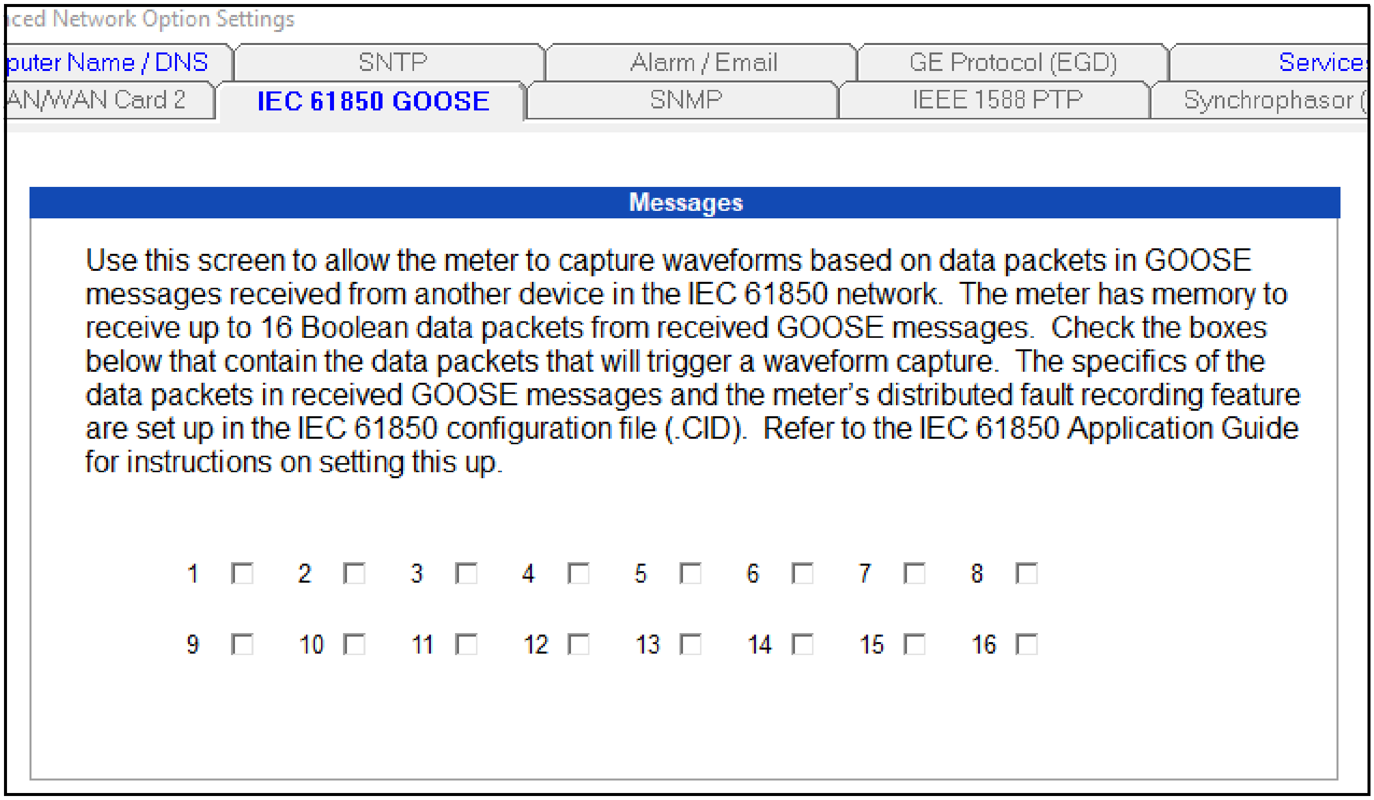
4. Use this screen to enable both IEC 61850 and GOOSE.



a. You need to enable the Web Server, Modbus TCP Server, and FTP Server for whichever card you will be using for IEC 61850. Select the card by clicking in the pull-down menu next to these settings.

b. Enable IEC 61850 and IEC 61850 GOOSE by selecting Enabled from the pull-down menu next to these settings.

5. Click the IEC 61850 GOOSE tab to set up waveform capture based on Boolean data embedded in a received GOOSE messages sent from another device in the IEC 61850 network. The Boolean data the meter receives will be related to limits/ alarms or digital inputs state. You will see the screen shown below.



6. The meter has memory to accept sixteen pieces of Boolean data from received GOOSE messages. The specifics of the Boolean data in specific GOOSE messages is set up in the IEC 61850 configuration file (.CID). Refer to the IEC 61850 Application Guide for instructions on setting this up.

7. Check the boxes (1-16) which contain the Boolean data that you want to trigger a waveform capture. In addition, you can program the IEC 61850 configuration file to send out a GOOSE message that will cause other GOOSE-enabled Nexus® 1500+ meters in the IEC 61850 Network to record a waveform, giving you multiple views of an event. Refer to the IEC 61850 Application Guide for instructions on doing this.

8. Click OK and then click Update Device to send the settings to the Nexus® 1500+ meter. The meter will reboot. The IEC 61850 Protocol Network server is now configured properly to work on an IEC 61850 network.

C.2.2.2: Configuring the Meter on the IEC 61850 Network

The System Integrator must configure the Nexus® 1500+ meter within the substation IEC 61850 network. To do this, the System Integrator needs the Nexus® 1500+ capabilities file (.icd) (as well as information about the rest of the devices on the network).

This .icd file, as mentioned earlier, is the SCL file that contains the IEC 61850 nodes, objects, and parameters implemented in the Nexus® 1500+ meter, including the Network IP address.

The IP address for the Nexus® 1500+ meter is contained in the Communication section of this .icd file. See the example Communication section, below.

```
<Communication>
  <SubNetwork name="Subnet_MMS" type="8-MMS">
    <BitRate unit="b/s" multiplier="M">10</BitRate>
    <ConnectedAP iedName="Nexus1500+IECSRV" apName="S1">
      <Address>
        <P type="OSI-PSEL" xsi:type="tP_OSI-PSEL">00000001</P>
        <P type="OSI-SSEL" xsi:type="tP_OSI-SSEL">0001</P>
        <P type="OSI-TSEL" xsi:type="tP_OSI-TSEL">0001</P>
        <P type="IP" xsi:type="tP_IP">172.20.167.199</P>
      </Address>
    </ConnectedAP>
  </SubNetwork>
</Communication>
```

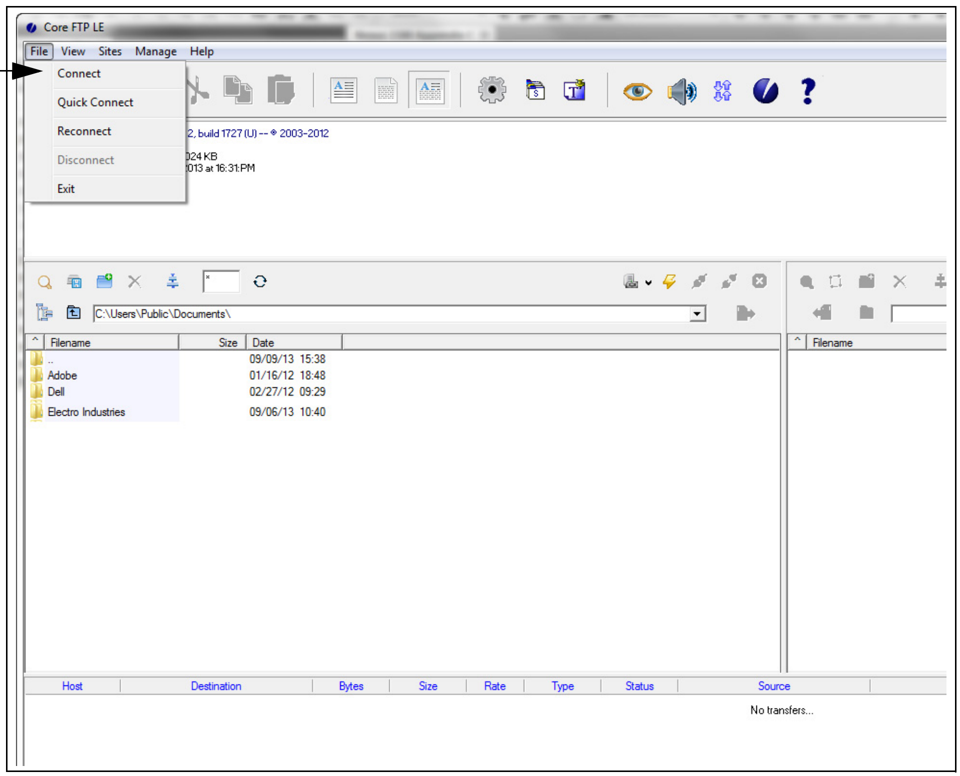
The node <P type="IP" xsi:type="tP_IP"> (bolded in the example above) defines the meter’s IP address. This IP address **must** be the same as the IP address configured in the meter’s Device Profile.

The Nexus® 1500+ meter's .icd file (NX1500+.icd) can be downloaded directly from the meter. To download the file, use FTP to access the file: the file is located in the meter's compact flash under C:\IEC61850\SCL folder. This folder contains both the meters .icd file and its default .cid file. See the instructions that follow.

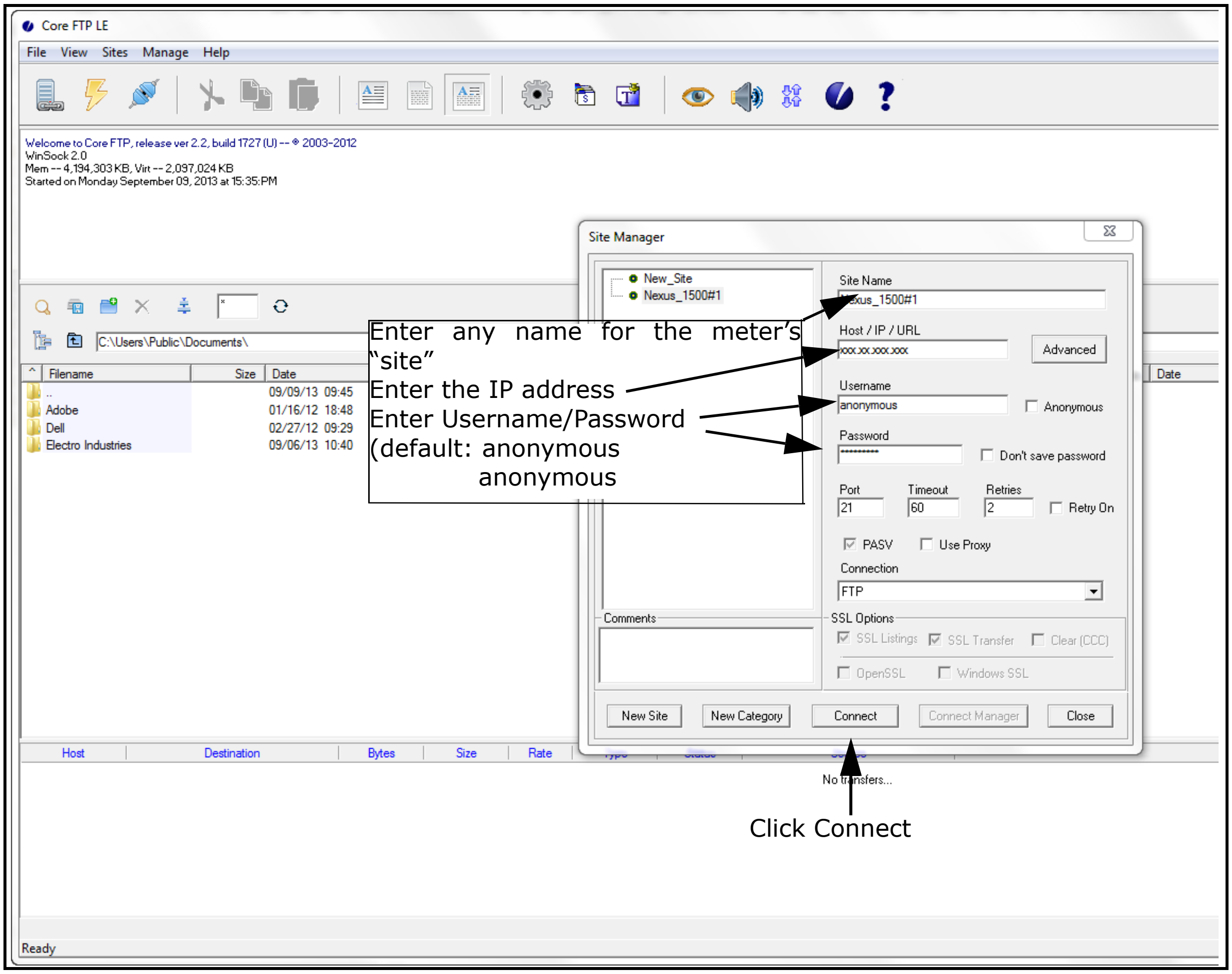
NOTE: The most recent version of a Nexus® 1500+ meter's default .icd file can be downloaded directly from Electro Industries' website: http://www.electroind.com/nexus1500+.html.

1. Open the FTP application and select the Connect option. See the example screen below.

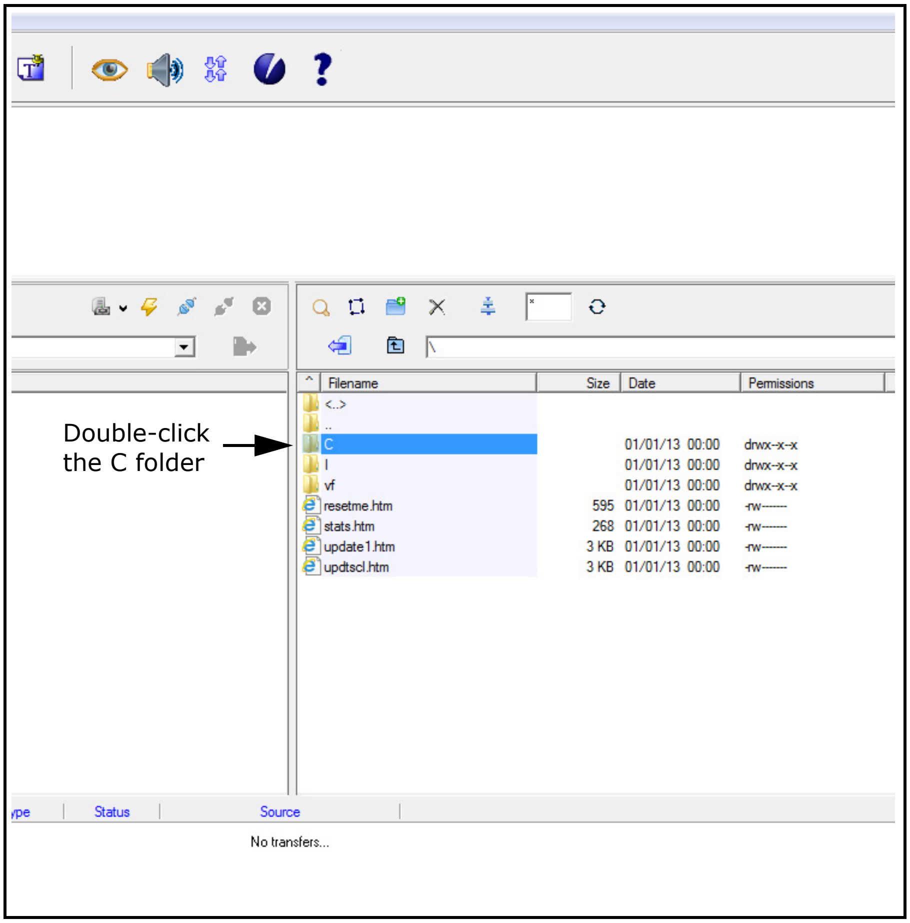
Click Connect



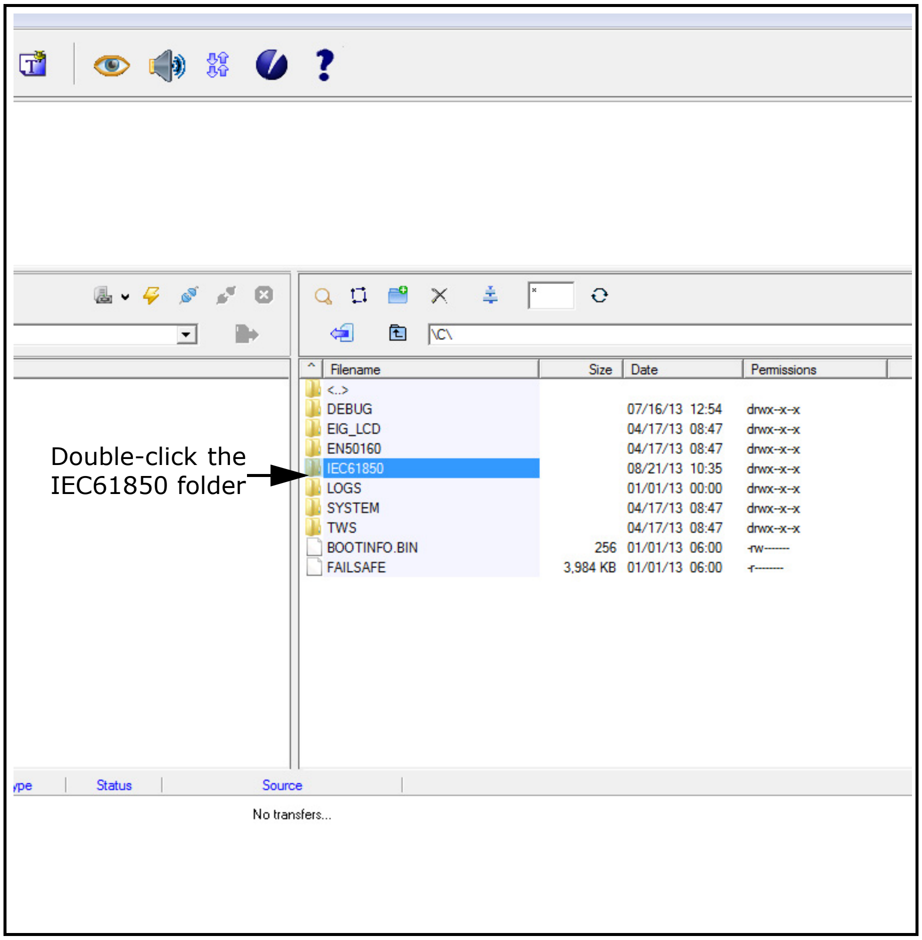
2. You will be prompted for the connection information - meter's Main Ethernet card's IP address, username and password (the default value is anonymous/anonymous), etc. See the example screen on the next page.


Core FTP LE
File View Sites Manage Help
Welcome to Core FTP, release ver 2.2, build 1727 (U) -- © 2003-2012
WinSock 2.0
Mem -- 4,194,303 KB, Virt -- 2,097,024 KB
Started on Monday September 09, 2013 at 15:35:PM
Site Manager
New_Site
Nexus_1500#1
Site Name
Nexus_1500#1
Host / IP / URL
xxx.xx.xxx.xxx
Advanced
Username
anonymous
Anonymous
Password
Don't save password
Port
21
Timeout
60
Retries
2
Retry On
PASV
Use Proxy
Connection
FTP
SSL Options
SSL Listings
SSL Transfer
Clear (CCC)
OpenSSL
Windows SSL
Comments
New Site
New Category
Connect
Connect Manager
Close
C:\Users\Public\Documents\
Filename
Size
Date
Adobe
Dell
Electro Industries
09/09/13 09:45
01/16/12 18:48
02/27/12 09:29
09/06/13 10:40
Host
Destination
Bytes
Size
Rate
No transfers...
Ready
Enter any name for the meter's "site"
Enter the IP address
Enter Username/Password
(default: anonymous
anonymous
Click Connect

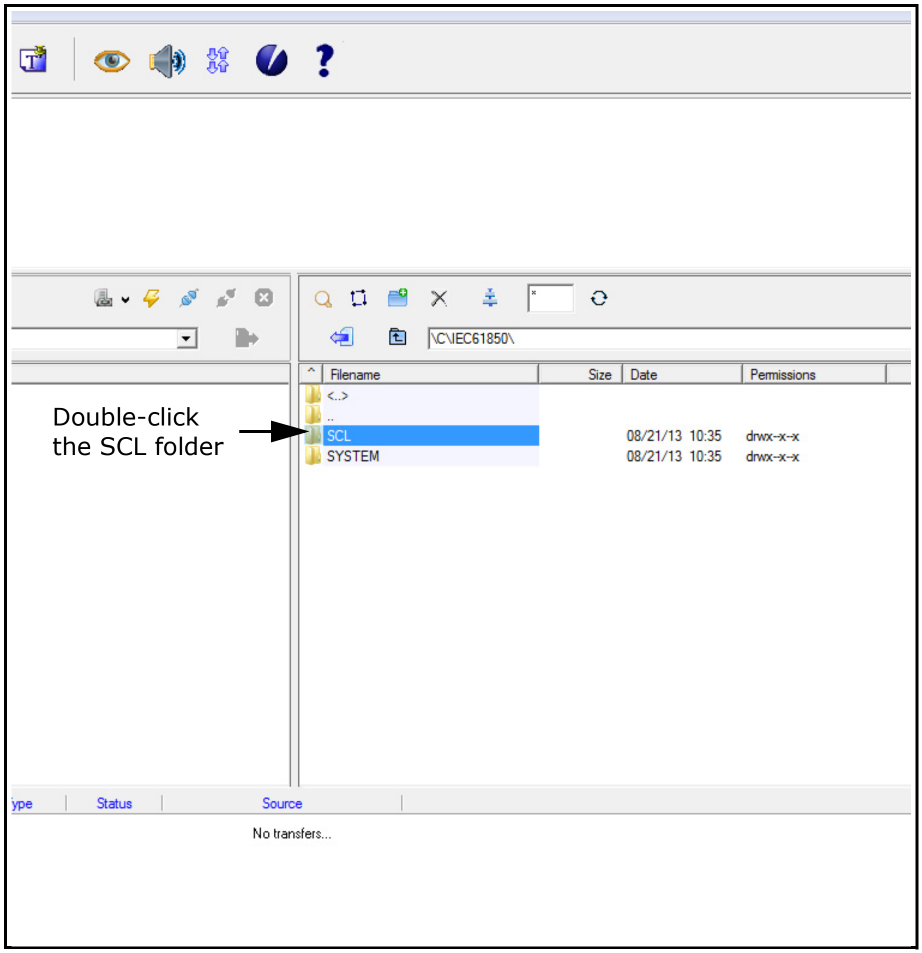
3. The FTP application will connect to the meter and you will see the folders contained in the Ethernet card. Double-click the C folder.



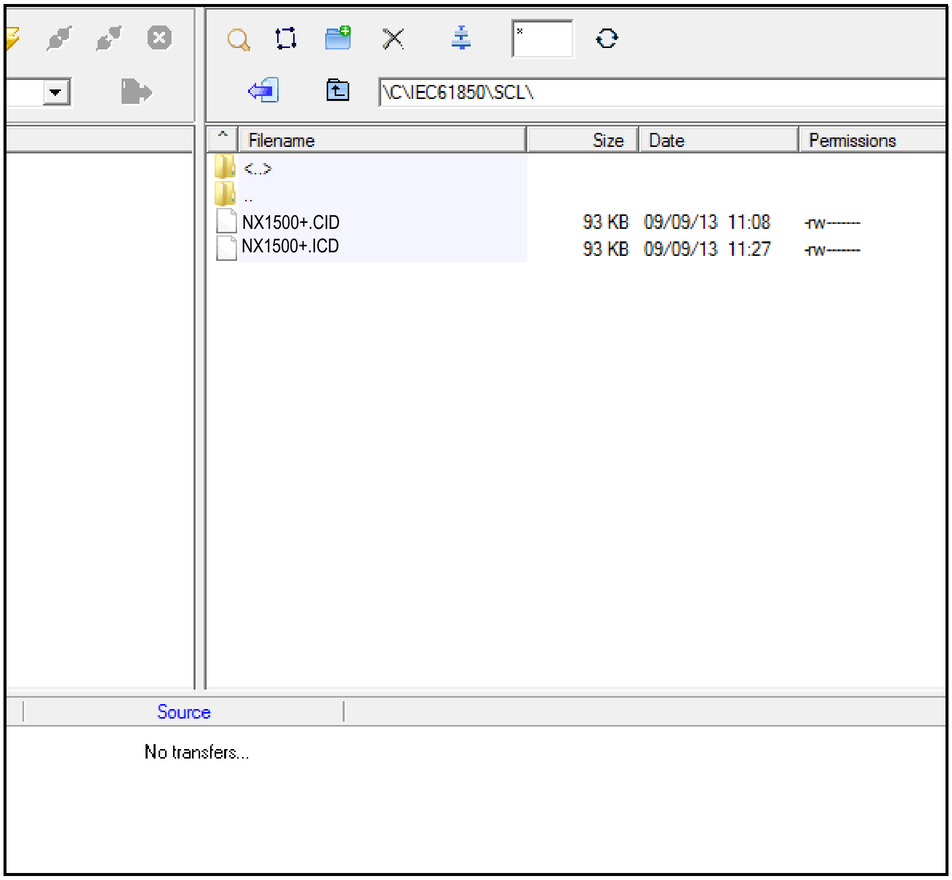
4. The screen will now show the folders contained in the C folder. Double-click the IEC61850 folder.



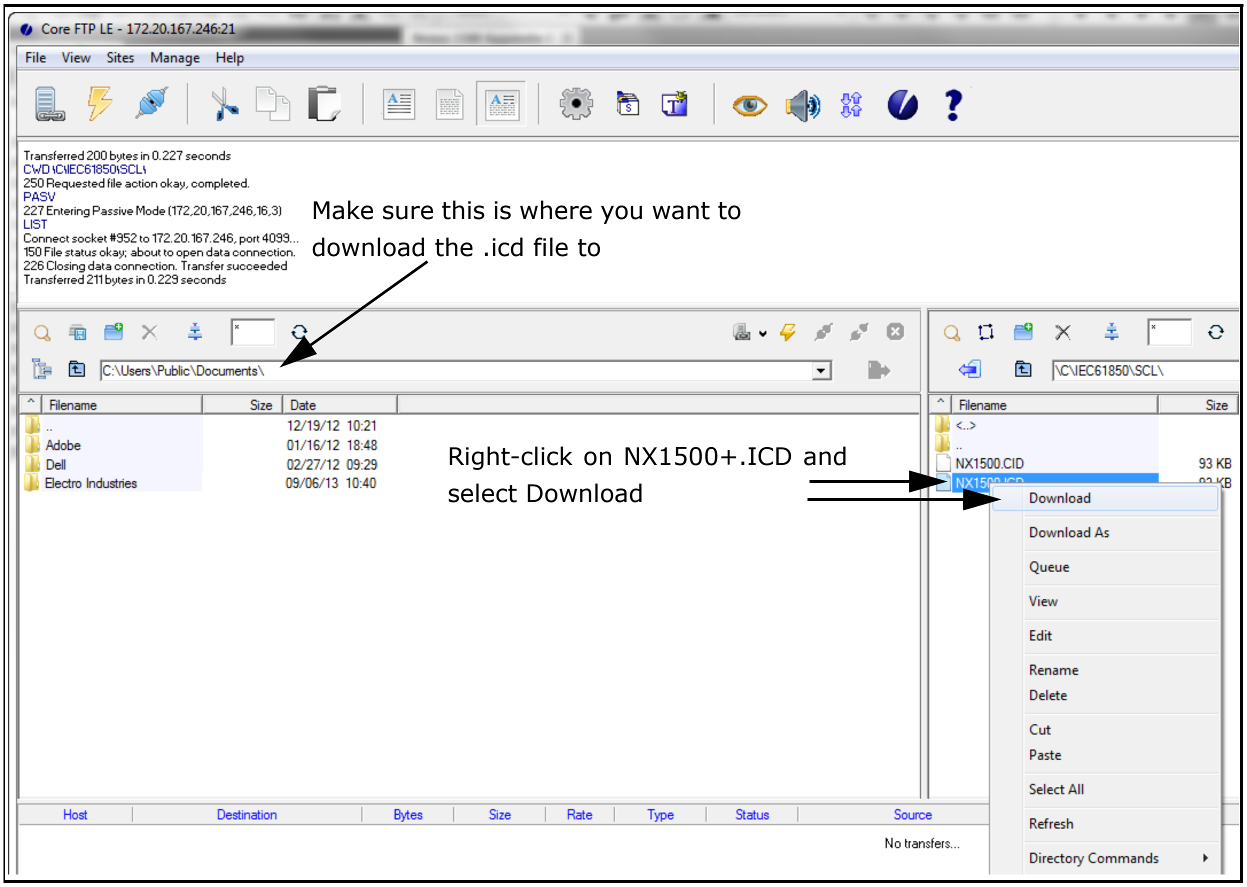
5. The screen will show the contents of the IEC61850 folder. Double-click the SCL folder.



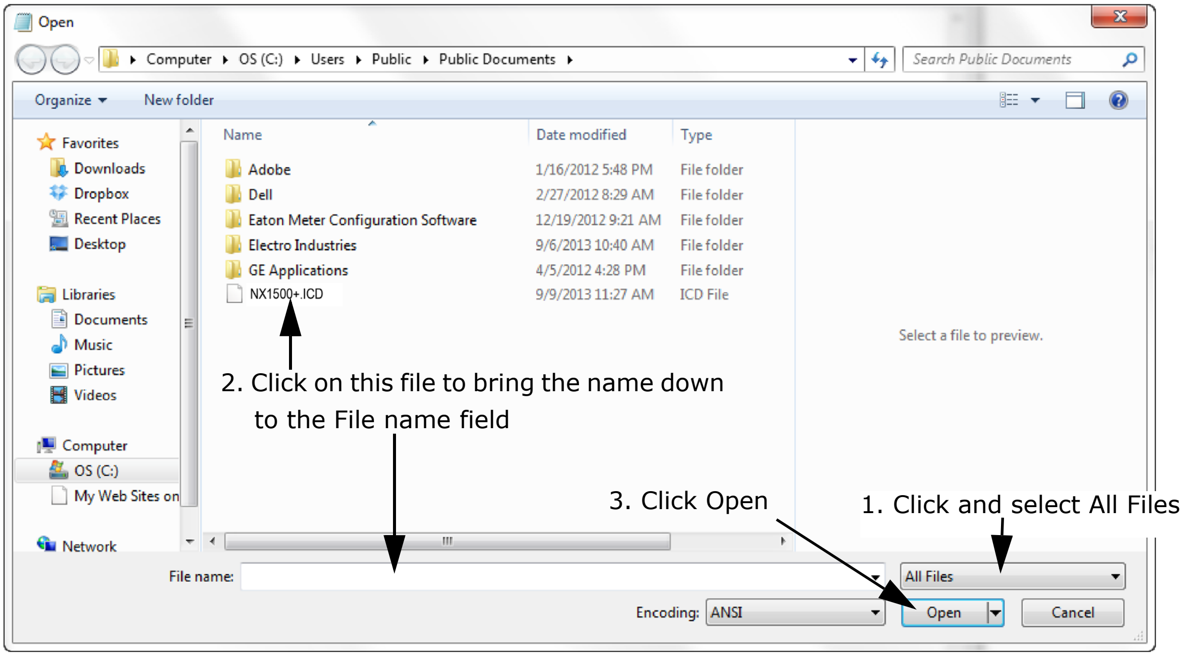
6. The screen will show two files - NX1500+.CID which is the default CID file, and NX1500+.ICD which is the file you want to download and edit.



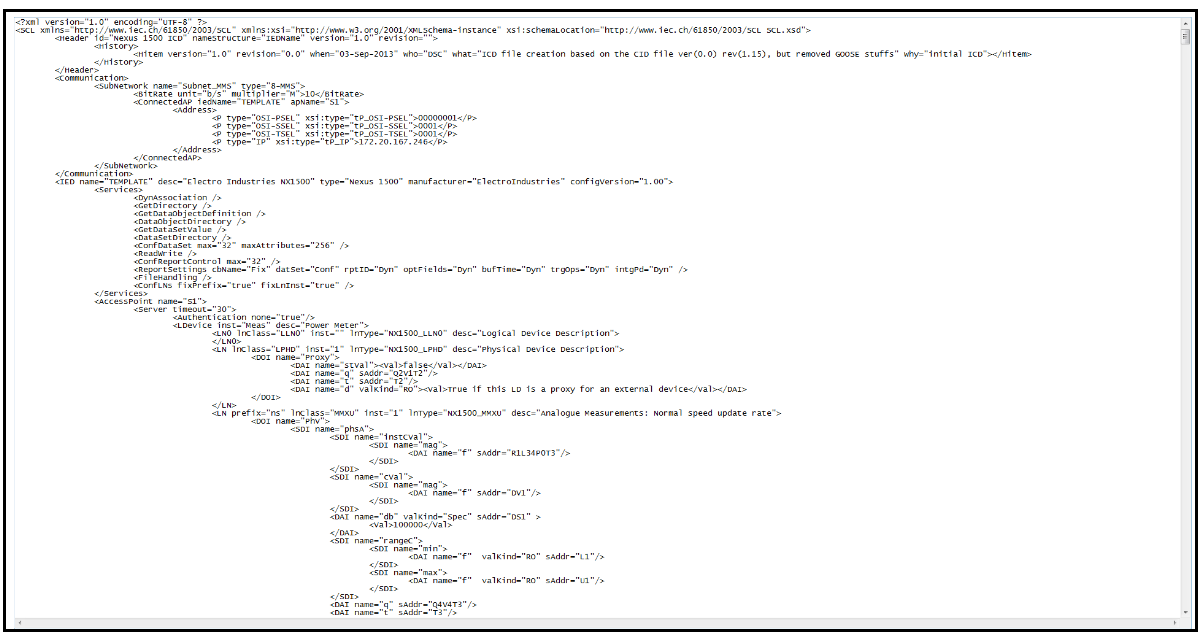
7. Make sure the left side of the screen has the location on your PC that you want to copy the .icd file. Then right-click on NX1500+.ICD and select Download.



8. The file will be downloaded to your PC, in the location specified. To edit the .icd file, open it in Notepad or any text editor. See the example below.



9. The .icd file will open in Notepad.



```
<?xml version="1.0" encoding="UTF-8" ?>
<SCL xmlns="http://www.iec.ch/61850/2003/SCL" xmlns:xsi="http://www.w3.org/2001/XMLSchema-instance" xsi:schemaLocation="http://www.iec.ch/61850/2003/SCL SCL.xsd">
	<Header id="Nexus 1500 ICD" nameStructure="IEDName" version="1.0" revision="">
		<History>
			<Hitem version="1.0" revision="0.0" when="03-Sep-2013" who="DSC" what="ICD file creation based on the CID file ver(0.0) rev(1.15), but removed GOOSE stuffs" why="initial ICD"></Hitem>
		</History>
	</Header>
	<Communication>
		<SubNetwork name="Subnet_MMS" type="8-MMS">
			<BitRate unit="b/s" multiplier="M">10</BitRate>
			<ConnectedAP iedName="TEMPLATE" apName="S1">
				<Address>
					<P type="OSI-PSEL" xsi:type="tP_OSI-PSEL">00000001</P>
					<P type="OSI-SSEL" xsi:type="tP_OSI-SSEL">0001</P>
					<P type="OSI-TSEL" xsi:type="tP_OSI-TSEL">0001</P>
					<P type="IP" xsi:type="tP_IP">172.20.167.246</P>
				</Address>
			</ConnectedAP>
		</SubNetwork>
	</Communication>
	<IED name="TEMPLATE" desc="Electro Industries NX1500" type="Nexus 1500" manufacturer="ElectroIndustries" configVersion="1.00">
		<Services>
			<DynAssociation />
			<GetDirectory />
			<GetDataObjectDefinition />
			<DataObjectDirectory />
			<GetDataSetValue />
			<DataSetDirectory />
			<ConfDataSet max="32" maxAttributes="256" />
			<ReadWrite />
			<ConfReportControl max="32" />
			<ReportSettings cbName="Fix" datSet="Conf" rptID="Dyn" optFields="Dyn" bufTime="Dyn" trgOps="Dyn" intgPd="Dyn" />
			<FileHandling />
			<ConfLNs fixPrefix="true" fixLnInst="true" />
		</Services>
		<AccessPoint name="S1">
			<Server timeout="30">
				<Authentication none="true"/>
				<LDevice inst="Meas" desc="Power Meter">
					<LN0 lnClass="LLN0" inst="" lnType="NX1500_LLN0" desc="Logical Device Description">
					</LN0>
					<LN lnClass="LPHD" inst="1" lnType="NX1500_LPHD" desc="Physical Device Description">
						<DOI name="Proxy">
							<DAI name="stVal"><Val>false</Val></DAI>
							<DAI name="q" sAddr="Q2V1T2"/>
							<DAI name="t" sAddr="T2"/>
							<DAI name="d" valKind="RO"><Val>True if this LD is a proxy for an external device</Val></DAI>
						</DOI>
					</LN>
					<LN prefix="ns" lnClass="MMXU" inst="1" lnType="NX1500_MMXU" desc="Analogue Measurements: Normal speed update rate">
						<DOI name="PhV">
							<SDI name="phsA">
								<SDI name="instCVal">
									<SDI name="mag">
										<DAI name="f" sAddr="R1L34P0T3"/>
									</SDI>
								</SDI>
								<SDI name="cVal">
									<SDI name="mag">
										<DAI name="f" sAddr="DV1"/>
									</SDI>
								</SDI>
								<DAI name="db" valKind="Spec" sAddr="DS1" >
									<Val>100000</Val>
								</DAI>
								<SDI name="rangeC">
									<SDI name="min">
										<DAI name="f"  valKind="RO" sAddr="L1"/>
									</SDI>
									<SDI name="max">
										<DAI name="f"  valKind="RO" sAddr="U1"/>
									</SDI>
								</SDI>
								<DAI name="q" sAddr="Q4V4T3"/>
								<DAI name="t" sAddr="T3"/>
```

An example of a downloaded .icd file is shown below.


```
<?xml version="1.0" encoding="UTF-8"?>

<SCL xmlns="http://www.iec.ch/61850/2003/SCL" xmlns:xsi="http://
www.w3.org/2001/XMLSchema-instance" xsi:schemaLocation="http://
www.iec.ch/61850/2003/SCL SCL.xsd" xmlns:ext="http://nari-relays.com">

<Header id="Nexus 1500+ ICD" nameStructure="IEDName" version="1.0"
revision="">

  <History>

    <Hitem version="0.1" revision="13" when="9-May-2012" who="BAM"
what="initial draft" why="initial ICD">

    </Hitem>

  </History>

</Header>

<Communication>

  <SubNetwork name="Subnet_MMS" type="8-MMS">

    <BitRate unit="b/s" multiplier="M">10</BitRate>

    <ConnectedAP iedName="Nexus1500+IECSRV" apName="S1">

      <Address>

        <P type="OSI-PSEL" xsi:type="tP_OSI-PSEL">00000001</P>

        <P type="OSI-SSEL" xsi:type="tP_OSI-SSEL">0001</P>

        <P type="OSI-TSEL" xsi:type="tP_OSI-TSEL">0001</P>

        <P type="IP" xsi:type="tP_IP">10.0.0.24</P>

      </Address>

    </ConnectedAP>

  </SubNetwork>
```

```
</Communication>

<IED name="Nexus1500+IECSRV" desc="Electro Industries Nexus 1500+"
type="N1500+"
manufacturer="ElectroIndustries" configVersion="1.00">

 <Services>

   <DynAssociation/>
```

10. You need to make the following changes to the .icd file:

- Change "TEMPLATE" to the iedName alphanumeric string in 2 places:
  - In <Communication>

    ```
    <SubNetwork name="Subnet_MMS" type="8-MMS">
    <BitRate unit="b/s" multiplier="M">10</BitRate>
    <ConnectedAP iedName="alphanumeric string" apName="S1">
    ```

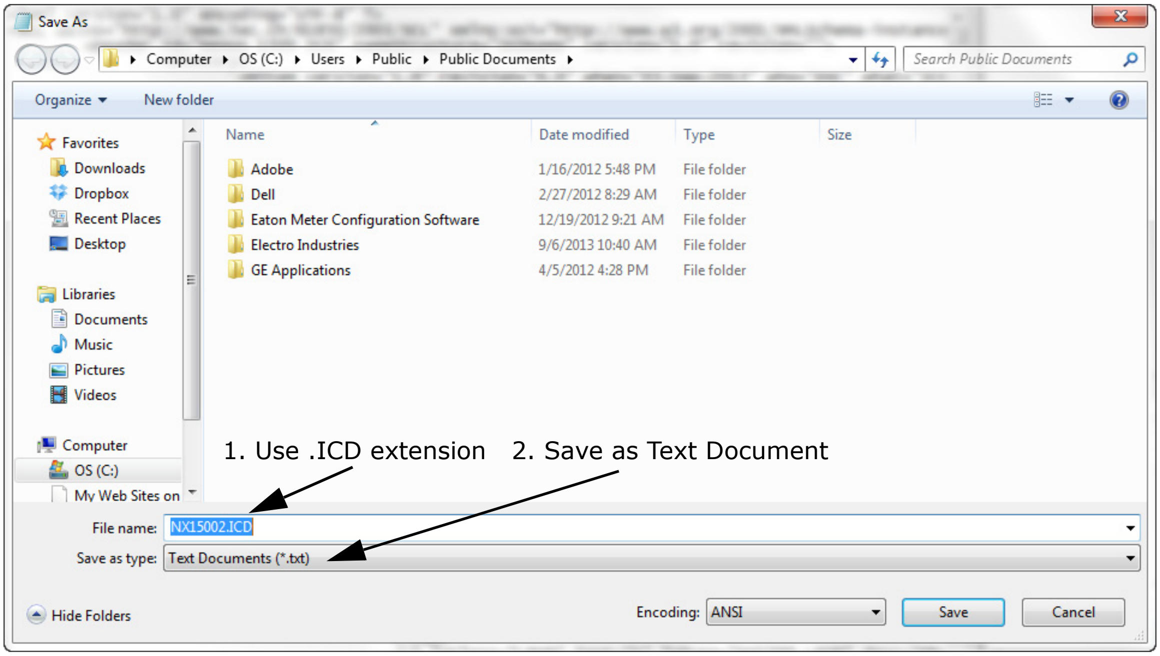
  - <IED name="**alphanumeric string**" desc="Electro Industries NX1500+" type="Nexus 1500+" manufacturer="ElectroIndustries" configVersion="1.00">

- Change the IP address to the IP address of the meter's Ethernet card that will be the IEC 61850 Protocol server:

  ```
  <Communication>
  <SubNetwork name="Subnet_MMS" type="8-MMS">
  <BitRate unit="b/s" multiplier="M">10</BitRate>
  <ConnectedAP iedName="NX1500+IECSRV" apName="S1">
  <Address>
  <P type="OSI-PSEL" xsi:type="tP_OSI-PSEL">00000001</P>
  <P type="OSI-SSEL" xsi:type="tP_OSI-SSEL">0001</P>
  <P type="OSI-TSEL" xsi:type="tP_OSI-TSEL">0001</P>
  <P type="IP" xsi:type="tP_IP">192.168.0.50</P>
  ```

- Any modifications needed for your specific configuration: creating datasets, reports, etc.

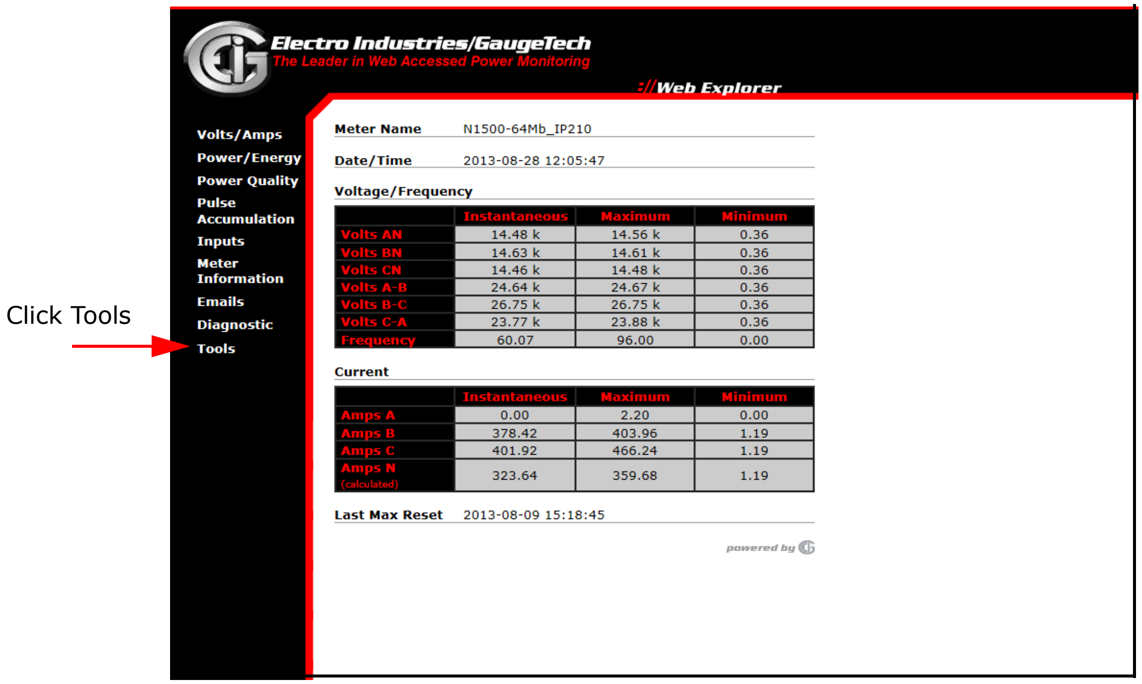
11. When you have made your changes to the file, save it as a txt file but with the extension .ICD, as shown below.



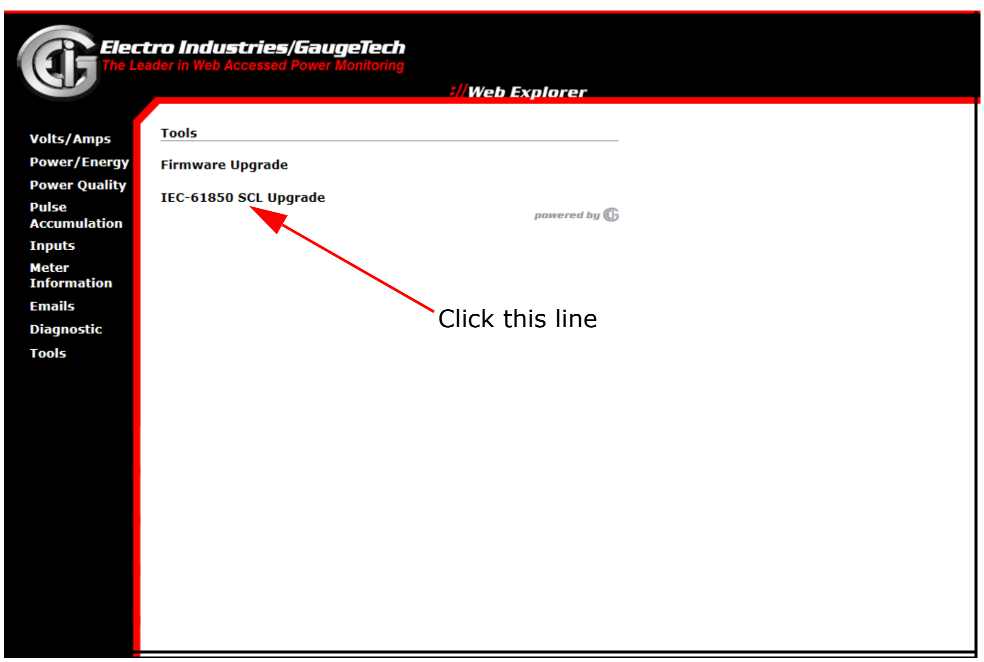
12. Once the System Integrator has processed the Nexus® 1500+ meter's .icd file and the information of the other devices on the network (using either automated tools or manually), the final result is a configuration file with the extension ".cid". This file must now be uploaded to the Nexus® 1500+ meter's IEC 61850 Protocol Ethernet network card.

13. You upload the .cid file to the meter via its webpage. To do this, use a web browser and key:
http://aa.bb.cc.dd/
,where aa.bb.cc.dd is the IP address assigned to the main Network card, which is acting as the IEC 61850 Protocol Ethernet Network server.

See Section 9.4.1: Viewing Webpages on page 9-5, for details regarding the meter's webpages.

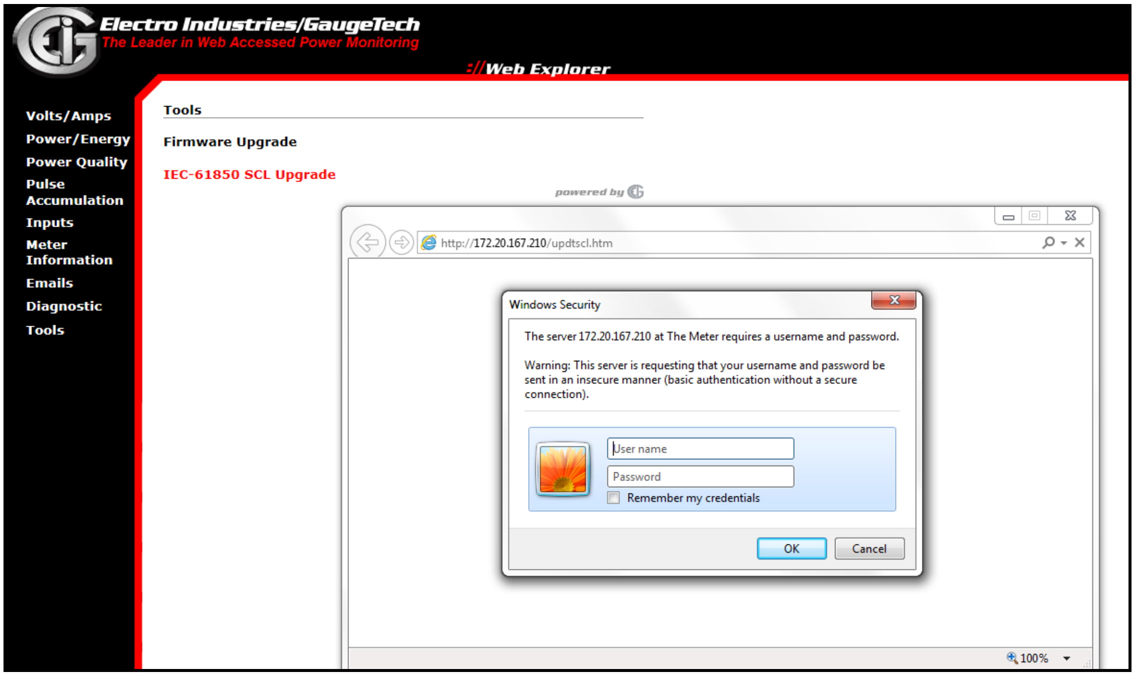


14. From the left side of the screen, click Tools to display the webpage shown below.

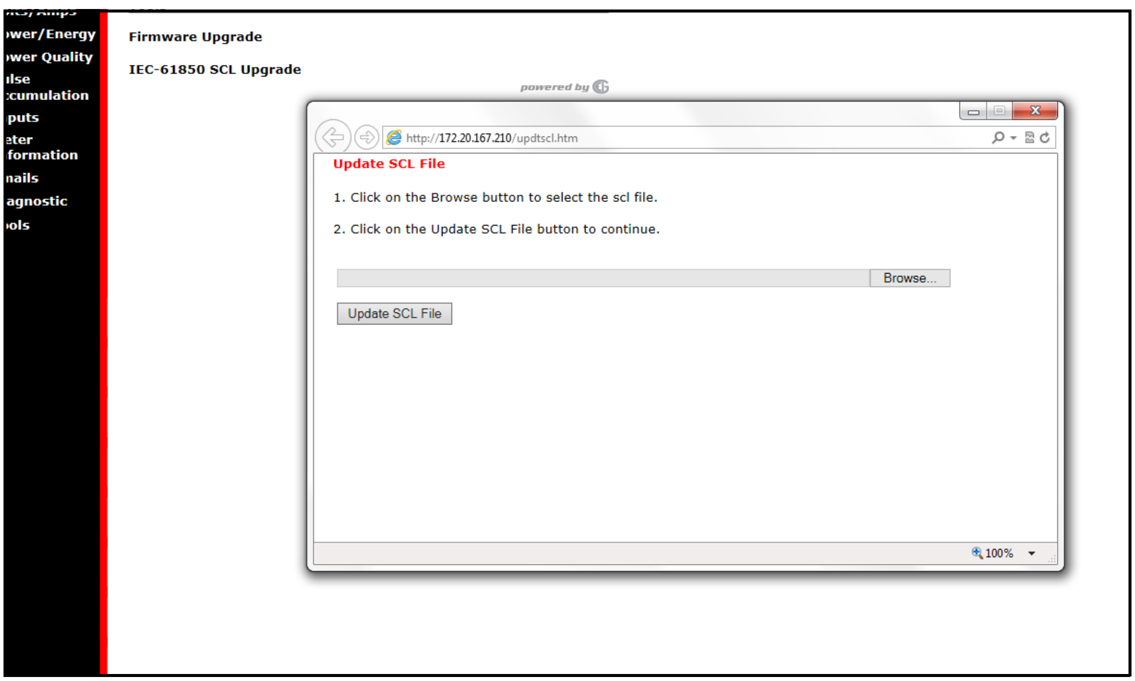


15. Click the IEC-61850 SCL Upgrade line. A screen will open asking for a username and password. If none has been set, you can use the default which is anonymous

for both the username and password. Then click OK.

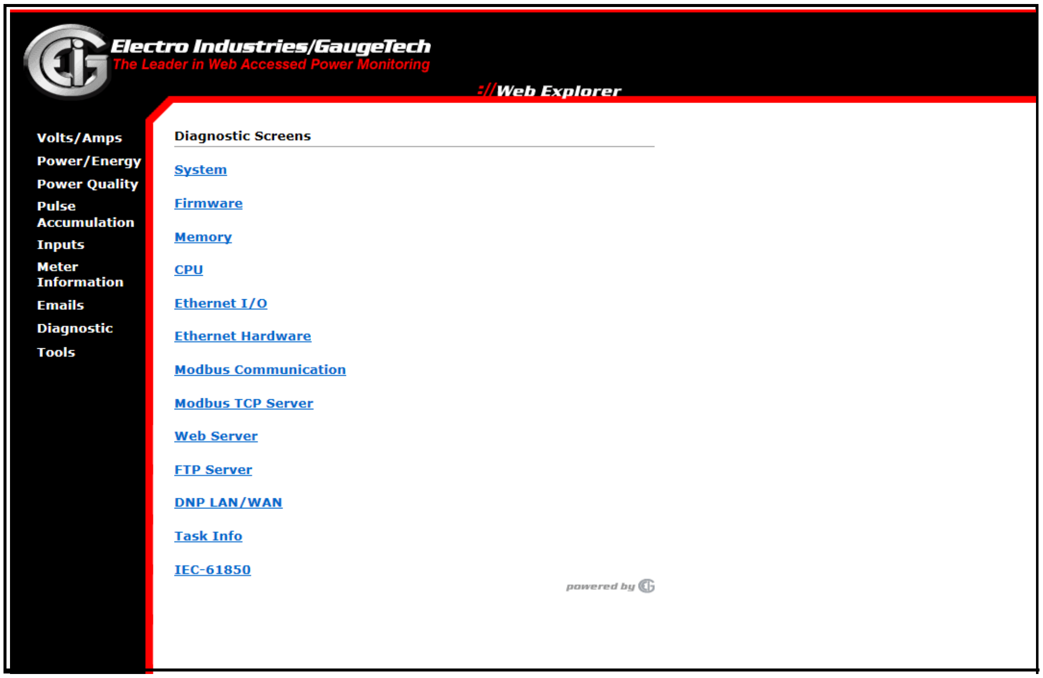


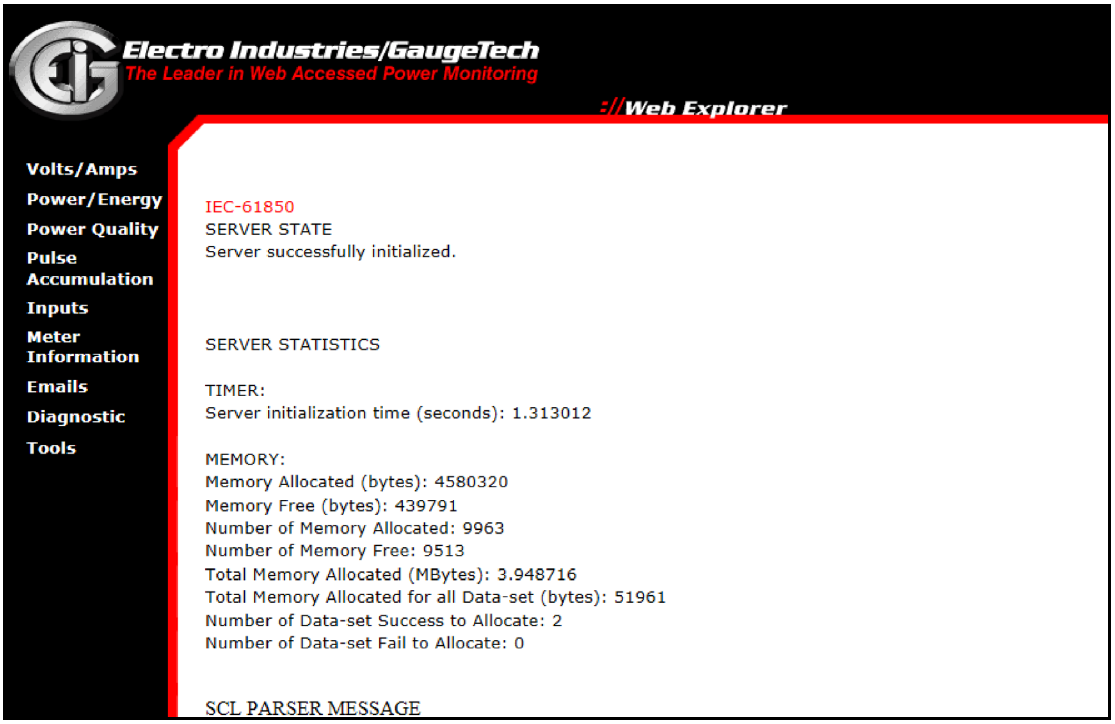
16. You will see the screen shown below. Click the Browse button to locate the .cid file you want to upload and click Update SCL File to upload it to the meter.



IMPORTANT NOTES!

- The IP address configured into the IEC 61850 Protocol Ethernet Network server with the CommunicatorPQA™ software **must be the same** as the IP address configured in the .cid file. This is necessary to insure proper communication. If there is a communication problem it will be reported on the touch screen display's IEC 61850 screen (see Chapter 6) and on the IEC 61850 Protocol Ethernet Network server's Diagnostic screen. You access this screen by clicking Diagnostic from the left side of the Web server webpage, and then clicking the IEC- 61850 line. See the example screens that follow.





- The sAddr fields in each object of the .icd file must be preserved when generating the .cid file. **Do not change these,** because they are used internally by the IEC 61850 server.

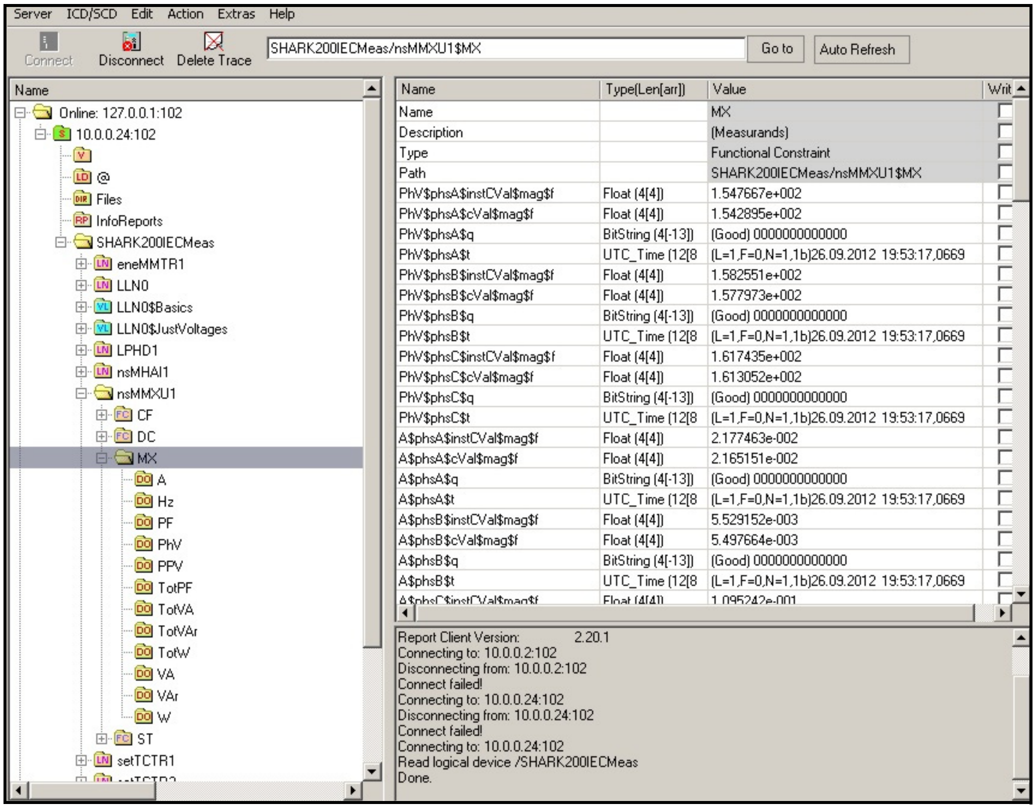
- Do not use non-ASCII characters in your .cid file (such as punctuation marks). Non-ASCII characters can cause the parsing of the .cid file to fail.

- If the uploaded .cid file has non-critical errors, the IEC 61850 Protocol Ethernet Network server will use the file anyway and will start up. Any errors can be seen in the Start Up log (see instructions below).

- If the uploaded .cid file has critical errors, the IEC 61850 will use the default .cid file (not the uploaded file) and it will start up. The errors can be seen in the IEC 61850 Diagnostic webpage (example shown above) and on the touch screen display's IEC 61850 screen (see Chapter 6).

C.3: Testing

You can use any IEC 61850 certified tool to connect to the Nexus® 1500+ meter and test out the IEC 61850 protocol (see example screen below). There are numerous commercial tools available for purchase.



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D: Using SNMP

D.1: Overview

Simple Network Management Protocol (SNMP) is an Internet standard communication protocol used to manage devices over an IP computer network. It supports data collection and organization from managed devices, and enables modifications to the data in order to cause the managed device to change its behavior, e.g., for a switch to turn on.

SNMP is often employed in network monitoring of routers, switches, and large banks of servers, for example, in data centers. The results of that monitoring can then be conveyed to interested parties, for example, via a computer dashboard.

The Nexus® 1500+ meter supports SNMPv2 communication over either its standard or optional Ethernet ports, or over both ports. This capability lets the Nexus® 1500+ meter seamlessly integrate into an existing SNMP managed network. For example, if SNMP is managing all of the servers in a data center, a Nexus® 1500+ meter can be installed at the bank of data servers, and configured so that power anomalies will be communicated to the user, enabling correction of the problem before it escalates and causes all of the servers to fail.

This appendix provides the specific SNMP elements as they relate to the Nexus® 1500+ meter's SNMP implementation.

D.2: Basics of SNMP

- An SNMP network links SNMP managers, also known as SNMP browsers, with remote devices, also known as SNMP agents. The SNMP managers can then access data from the remote devices and can also manipulate data in the devices. The managers and devices must all use the SNMP protocol. The Nexus® 1500+ meter with SNMP acts as an agent in an SNMP network.

- The SNMP protocol consists of standards contained in Request for Comments (RFCs). The SNMP standards set out the rules for the protocol's three main components - an application layer language, a database model, and data objects. The RFCs used in the Nexus® 1500+ meter's SNMP implementation are listed in D.4: RFCs, on page D-8.

- The data used by the SNMP manager is defined as Managed Objects, each of which is represented by an object identifier (OID). The Managed Objects are divided into groups; each group consists of variables and tables. The details of the Managed Objects, groups, variables, etc. are defined in Management Information Bases (MIBs). The MIBs used with the Nexus® 1500+ meter are explained in D.3.1: MIBs, on page D-3.

- Communication between the SNMP manager and the meter takes place using standard Protocol Data Units (PDUs). The PDUs used with the Nexus® 1500+ meter are explained in D.3.2: PDUs, on page D-6.

- One of the PDUs is traps, i.e., events/alarms that occurred in the meter. Once SNMP communication is enabled for one or both of the meter's Ethernet ports, traps can be configured to be sent to up to eight SNMP manager devices. The traps used by the Nexus® 1500+ meter are explained in D.3.3: Traps, on page D-7.

- Security of the SNMP network is maintained by community fields, which act as passwords for the system.

- The Nexus® 1500+ meter's SNMP implementation is compatible with off-the-shelf SNMP managers, e.g., iReasoning. The SNMP manager is used to set up the SNMP network and can also be used to view SNMP communications, such as traps.

D.3: Details of the Nexus® 1500+ Meter's SNMP Implementation

This section explains the MIBs, PDUs, and Traps used in the Nexus 1500+ meter's SNMPv2 implementation.

D.3.1: MIBs

The Nexus® 1500+ meter MIB groups are: Enterprise MIB and Implemented Network MIBs, some of which are modifiable. You can download the meter's MIB file from EIG's website:

- Enterprise MIB- MIBs specific to the Nexus® 1500+ meter. There are 64 fixed items available from the meter:
    - One sec VAN
    - One sec VBN
    - One sec VCN
    - One sec VAB
    - One sec VBC
    - One sec VCA
    - One sec IA
    - One sec IB
    - One sec IC
    - One sec INm
    - One sec Freq
    - One sec Voltage imbalance
    - One sec Current imbalance
    - One sec VA
    - One sec VAR
    - One sec W
    - One sec PF A
    - One sec PF B
    - One sec PF C

- One sec PF
- Pulse accumulation 1-8
- Pulse accumulation Aggregation 1-4
- Block Window Average (BWA) VA
- BWA VAR
- BWA W
- BWA Pulse accumulation 1-8
- BWA Pulse accumulation Aggregation 1-4
- +W(Q14) Cumulative demand
- -W(Q23) Cumulative demand
- +W(Q14) Continuous Cumulative demand
- -W(Q23) Continuous Cumulative demand
- VAh
- +VARh(Q12)
- -VARh(Q34)
- +Wh(Q14)
- -Wh(Q23)
- 3 Sec Positive symmetrical Component Magnitude Voltage PN
- 3 Sec Negative symmetrical Component Magnitude Voltage PN
- 3 Sec Zero symmetrical Component Magnitude Voltage PN
- 3 Sec Positive symmetrical Component Phase Voltage PN
- 3 Sec Negative symmetrical Component Phase Voltage PN
- 3 Sec Zero symmetrical Component Phase Voltage PN
- 3 Sec Zero symmetrical Component Ratio Voltage PN
- 3 Sec Negative symmetrical Component Ratio Voltage PN

- The Implemented Network MIBs are:
  - System Group - provides information such as computer/equipment location, contact person, etc.
    - The following MIB items from the System Group can be modified by an SNMP manager browser. These are the only modifiable items in the meter's SNMP configuration:
      - system.sysContact
      - system.sysName
      - system.sysLocation
    - Modifications to these items are stored in a file, so that the modified values will be retained through a meter reboot.
  - Interface Group - provides information about the hardware interfaces, i.e., device name, type, MTU, Ethernet address, statistics etc.
  - Cidr Group - provides information about the IP Routing Table. The Routing Table provides information on interface and IP address to send a packet to.
  - Internet Protocol (IP) Group - provides interface information and statistics which include the following Tables:
    - Internet Address Table: lists IP addresses, information and statistics.
    - Address Translation Table: ARP cache, i.e., IP to Ethernet address translation.
    - Default Router Table: default routes in routine table which is used when sending packets.
    - ICMP Statistics.
  - TCP Group - provides TCP statistics as well as TCP socket listener and connection information.
  - UDP Group - provides UDP statistics as well as UDP socket connection information.

- SNMP Group - provides SNMP statistics as well as capability to enable SNMP Traps.
- Transmission Group - provides device driver statistics for RS232 and Ethernet.

D.3.2: PDUs

PDUs, also referred to as “packets,” belong to one of two categories: PDUs sent from the SNMP manager to the meter, and PDUs sent from the meter to the SNMP manager.

- PDUs sent from the SNMP manager to the meter are:
  - GetMessage (Message ID 0) - this retrieves the objects specified by the OIDs in the message.
  - GetNextRequest (Message ID 1) - this retrieves objects which are next in lexical order in the MIB, to the objects specified by the OID in the message.
  - GetBulkRequest (Message ID 5) - this retrieves a large number of objects specified by the OID in the message.
  - SetRequest (Message ID 3) - this message modifies internal meter data specified by an OID and value in the message.
- PDUs sent from the meter to the SNMP manager are:
  - Response (Message ID 2) - this sends values in response to a GetRequest, GetNextRequest, GetBulkRequest, or SetRequest command.
  - Trap (Message ID 4) - this is sent in response to predefined events (see D.3.3: Traps, on page D-7).

D.3.3: Traps

The meter generates traps when certain things occur. The following conditions can be programmed to generate traps (see D.4: RFCs, on page D-8):

- Limit/Alarm State Change
- Digital Input Change
- Waveform Capture
- PQ (CBEMA) Event
- Relay Output Change of State
- Transient Capture

In addition, the meter generates network traps when the following conditions occur:

- Cold Start - this trap is generated when the meter has been initialized.
- Authentication Failure - this trap is generated when an SNMP message was received with an incorrect community field.

D.4: RFCs

The RFCs used in the meter's SNMP implementation are:

- RFC 1213 - MIB-II
- RFC 4022 - TCP
- RFC 4113 - UDP
- RFC 4292 - IP Forwarding Table MIB (replaces RFC 1213, RFC 1354, RFCs 2096, 2011, and 2465)
- RFC 4293 - IP Group (replaces RFCs 2011, 2465, and 2466)

Details of the RFCs are shown in the two following tables.

RFC	GROUPS	TABLES	DESCRIPTION
1213	System	----	Provides system information; contact location, etc.
	Interfaces	Interfaces	Provides information regarding the meter's hardware interfaces, i.e. device name, type, MTU, Ethernet address, statistics, etc.
	Internet Protocol (IP) Group	----	Misc statistics; all tables in this group were dep-recated
	SNMP Group	----	Provides SNMP statistic information
1650	etherStats	dot3Stats	Statistics for Ethernet interfaces
4022	TCP	TCP Connection Table	Provides information regarding connected TCP sockets
		TCP Listener Table	Provides information regarding listening TCP sockets
4113	UDP	UDP Endpoint Table	Provides information regarding UDP sockets
4292	IP Forwarding	IP Forwarding Table	Provides routing table information
4293	ipSystemStats	ipSystemStat-sTable	Provides meter wide traffic for interfaces
	ipIfStats	ipIfStatsTable	Provides traffic statistics for each interface
	ipAddress	ipAddressTable	Provides address information about a meter's hardware interfaces
	ipNetToPhysical	ipNetToPhysical Table	Provides IP to Ethernet address information
	ipDefaultRouter	ipDefaultRouter Table	Provides default router information
	icmpStats	icmpStats Table	ICMP statistics
	USEC Basic	----	Contains information relevant to the user based security model for SNMPv2u. SNMPv2u was not widely implemented so SNMPv2u is disabled but is in this table for completeness.

RFC	TRAP	Description
1157	Cold	Meter startup
	Warm	Meter restarted (will not be generated by meter)
	Link Down	Interface closed (will not be generated by meter)
	Link Up	Interface reset (will not be generated by meter)
	Authentication Failure	Authentication failure (SNMPv1 or SNMPv2c)

The table below lists managed objects that have been deprecated; i.e., they are not being used currently and are included only for historical purposes, and the managed objects that are replacing the deprecated items in this implementation.

Deprecated Item	OID of deprecated item	Replacement Item	OID of replacement item	RFC of replacement item
atTable	mib-2.3	ipNetToMediaTable	mib-2.4.22	RFC1213
ipInReceives	mib-2.4.3	ipSystemStatsInRecieves	ipSystemStatsEntry.3	RFC4293
ipInHdrErrors	mib-2.4.4	ipSystemStatsInHdrErrors	ipSystemStatsEntry.7	RFC4293
ipInAddrErrors	mib-2.4.5	ipSystemStatsInAddrErrors	ipSystemStatsEntry.9	RFC4293
ipForwDatagrams	mib-2.4.6	ipSystemStatsInForwDatagrams	ipSystemStatsEntry.12	RFC4293
ipInUnknownProtos	mib-2.4.7	ipSystemStatsInUnknownProtos	ipSystemStatsEntry.10	RFC4293
ipInDiscards	mib-2.4.8	ipSystemStatsInDiscards	ipSystemStatsEntry.17	RFC4293
ipInDelivers	mib-2.4.9	ipSystemStatsIndelivers	ipSystemStatsEntry.18	RFC4293
ipOutRequests	mib-2.4.10	ipSystemStatsOutRequests	ipSystemStatsEntry.20	RFC4293
ipOutDiscards	mib-2.4.11	ipSystemStatsOutDiscards	ipSystemStatsEntry.25	RFC4293
ipOutNoRoutes	mib-2.4.12	ipSystemStatsOutNoRoutes	ipSystemStatsEntry.22	RFC4293
ipReasmReqds	mib-2.4.14	ipSystemStatsReasmReqds	ipSystemStatsEntry.14	RFC4293

ipReasmOKs	mib-2.4.15	ipSystemStatsRea-smOKs	ipSystem-StatsEntry.15	RFC4293
ipReasmFails	mib-2.4.16	ipSystemStatsReasm-Fails	ipSystem-StatsEntry.16	RFC4293
ipFragOKs	mib-2.4.17	ipSystemStatsOut-FragOKs	ipSystem-StatsEntry.27	RFC4293
ipFragFails	mib-2.4.18	ipSystemStatsOut-FragFails	ipSystem-StatsEntry.28	RFC4293
ipFragCreates	mib-2.4.19	ipSystemStatsOut-FragCreates	ipSystem-StatsEntry.29	RFC4293
ipAddrTable	mib-2.4.20	ipAddressTable	mib-2.4.34	RFC4293
ipNetToMediaTable	mib-2.4.22	ipNetToPhysicalTable	mib-2.4.35	RFC4293
ipRouteDiscards	mib-2.4.23	inetCidrROuteDis-cards	mib-2.4.24.8	RFC4292
ipForwardNumber	mib-2.4.24.1	ipCidrRouteNumber	mib-2.4.24.3	RFC2096
ipCidrRouteNumber	mib-2.4.24.3	inetCidrRouteNumber	mib-2.4.24.6	RFC4292
ipRouteTable	mib-2.4.21	ipForwardTable	mib-2.4.24.2	RFC1354
ipForwardTable	mib-2.4.24.2	ipCidrRouteTable	mib-2.4.24.4	RFC2096
ipCidrRouteTable	mib-2.4.24.4	inetCidrRouteTable	mib-2.4.24.7	RFC4292
tcp.tcpConnTable	mib-2.6.13	tcpConnectionTable	mib-2.49.19	RFC4022
		tcp.tcpConnTable	mib-2.49.20	
udp.udpTable	mib-2.7.5	udpEndpointTable	mib-2.50.7	RFC4113

D.5: Modbus Map Location of SNMP Settings

The following table shows where in the Modbus map the SNMP settings from the Device Profile are stored. For more information on the meter's Modbus map, refer to the Nexus® 1500+ Meter's Modbus Manual.

SNMP Settings			
Name	**Settings**	Description	Modbus
Device Profile			
SNMP enable	0 = all interfaces disabled 1 = enable interface 1 2 = enable interface 2 3 = both interfaces enabled	Enable/Disable SNMP service. Refers Nexus 1500+ Network feature rev3 document	B3BCH
SNMP TRAPS enable	0 = all interfaces disabled 1 = enable interface 1 2 = enable interface 2 3 = both interfaces enabled	Enable/Disable TRAPS service. Refers Nexus 1500+ Network feature rev3 document	7614H
SNMP TRAPS Manager[1]	0.0.0.0	1-8 IP addresses	75CCH – 75DBH
SNMP TRAPS	Bit 15: 1 (Enabled) 0 (Disabled)(Default)	Enable/Disable traps for limits status changes	75F0H
	Bit 14: 1 (Enabled) 0 (Disabled)(Default)	Enable/Disable traps for digital input status changes	
	Bit 13: 1 (Enabled) 0 (Disabled)(Default)	Enable/Disable traps for waveform capture	
	Bit 12: 1 (Enabled) 0 (Disabled)(Default)	Enable/Disable traps for PQ(CBEMA) event	
	Bit 11: 1 (Enabled) 0 (Disabled)(Default)	Enable/Disable traps for relay output changes	
	Bit 10: 1 (Enabled) 0 (Disabled)(Default)	Enable/Disable traps for transient capture	
SNMP Agent Community Name	20 bytes "public"(default) padding with null (0x00)	Expected community name in input SNMP GET, GETN and SET messages.	75DCH-75E5H

SNMP TRAPS Community Name	20 bytes “public”(default) padding with null (0x00)	Community name set in output SNMP trap messages	75E6H-75EFH

[1] The IP address for traps manager set to 0.0.0.0 means that trap is disabled.

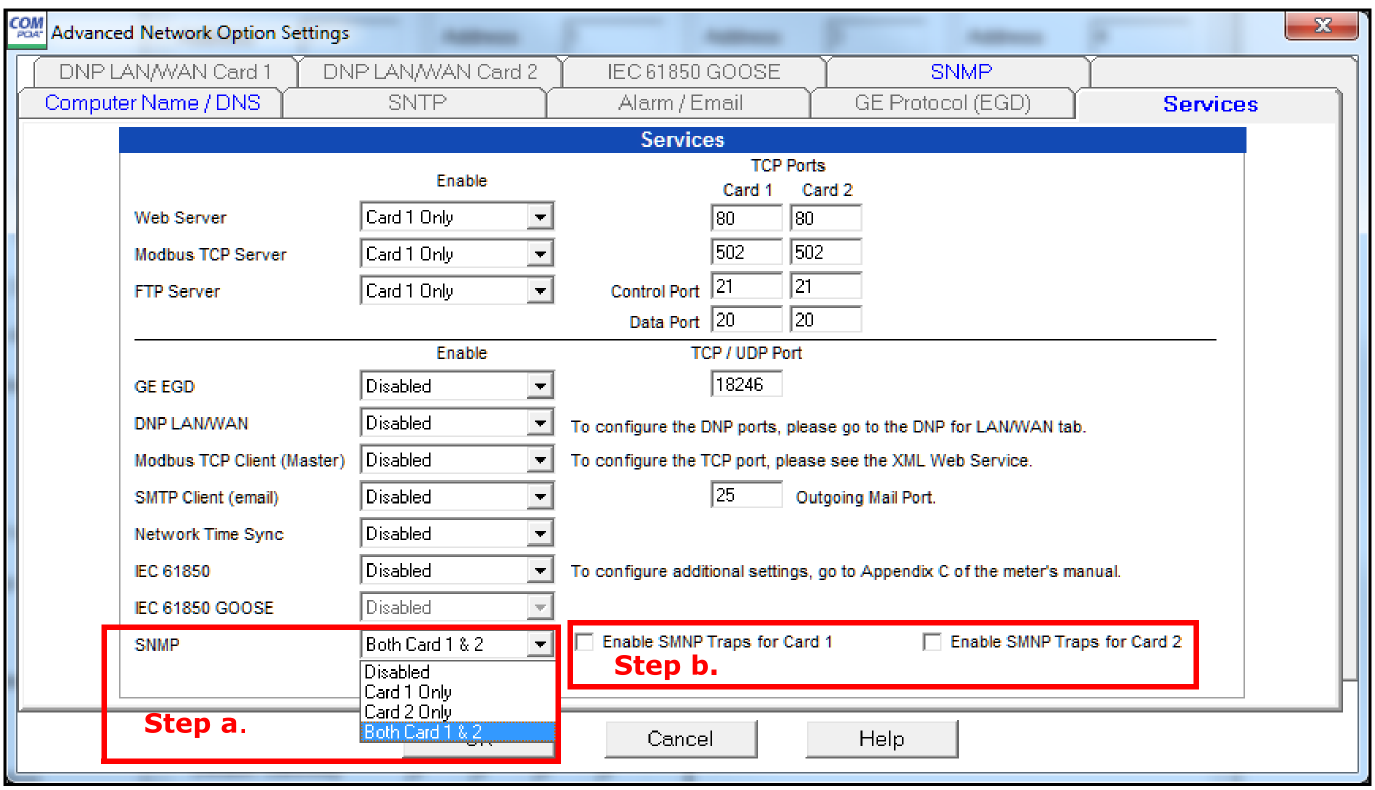
D.6: Setting up SNMP

This section shows how to set up SNMP for your meter, and how to set up your SNMP network to communicate with your meter.

D.6.1: Configure SNMP for the Meter

You configure the meter's SNMP settings using CommunicatorPQA® software (version 4.0.356 and higher). Note that Chapter 21 of the *CommunicatorPQA®, MeterManagerPQA®, and EnergyPQA.com® Software User Manual* contains instructions for this, but the basic steps are in this example.

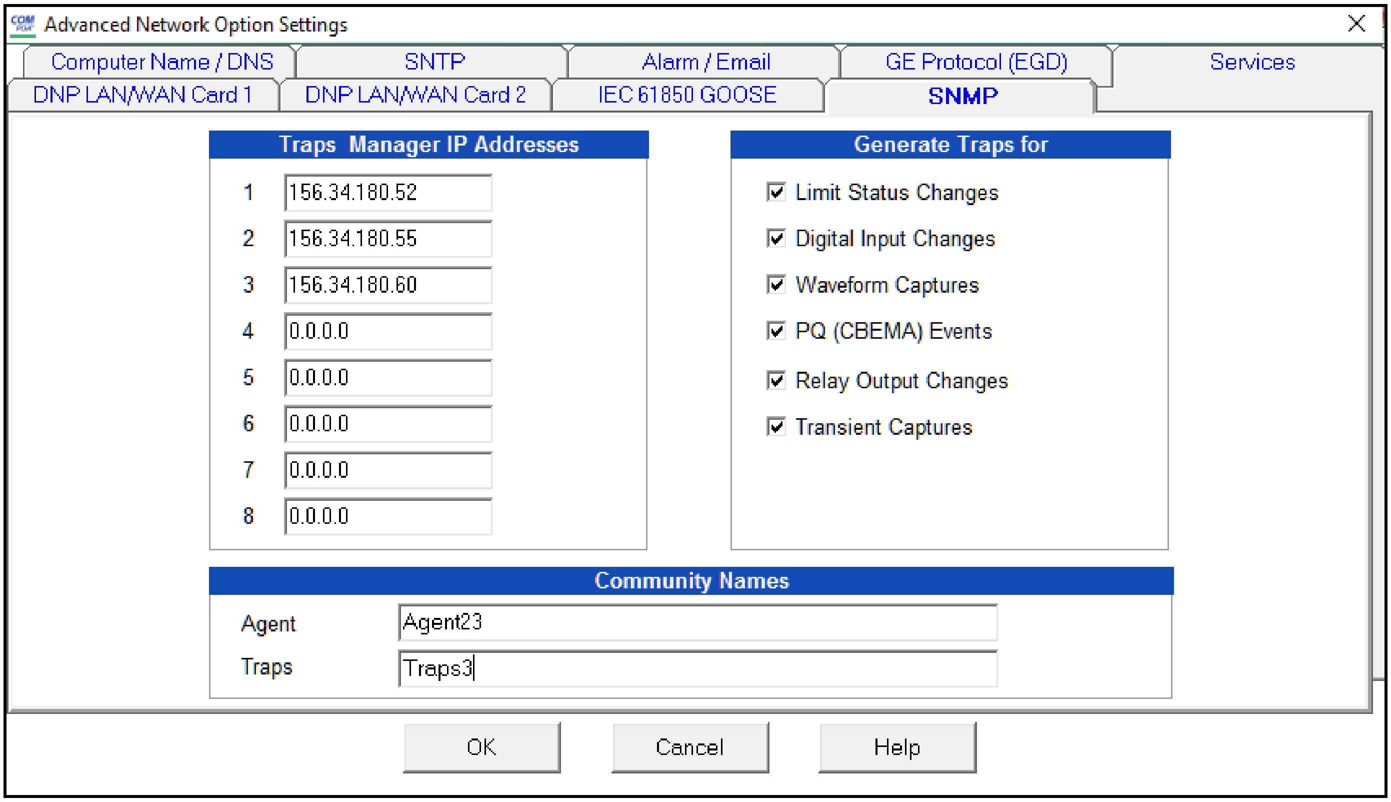
1. Enable SNMP for either or both of the meter's Ethernet cards in the Services tab of the Advanced Network Settings screen, shown below. (Access this screen from the meter's Device Profile Communications setting screen - see Chapter 8 or Chapter 21 in the *CommunicatorPQA®, MeterManagerPQA®, and EnergyPQA.com® Software User Manual* for instructions.)



a. To enable SNMP, select Card 1 Only, Card 2 Only, or Both Card 1 & 2.

b. Once SNMP is enabled, checkboxes for enabling traps for the selected cards are displayed. To enable traps for a card, check the card's box. Note that you can enable traps for both cards.

2. Once you have enabled SNMP for one or both of the Ethernet cards, use the SNMP tab to configure SNMP settings for the meter.



a. Enter IP address(es) for one or more Trap Managers. These are the devices that will receive any traps messages from the meter.

b. Check the boxes of the traps you want to generate.

c. Enter a Community Name for both Agent and Traps.

- The Agent Community name provides security by ensuring that the SNMP manager will only read (the manager's Read Community name)/write (the manager's Write Community name) from/to a managed object if it matches the Agent community name.

- The Traps Community name provides security by ensuring that only traps that match the Traps Community name of the Agent are received by the SNMP manager.

NOTES:

- The default for both community names is: public.
- The Agent community name should be the same as the SNMP Network Agent device's Read and Write community name - see D.6.2: Set up SNMP Network, on page D-16.

d. Click OK to save your settings.

D.6.2: Set up SNMP Network

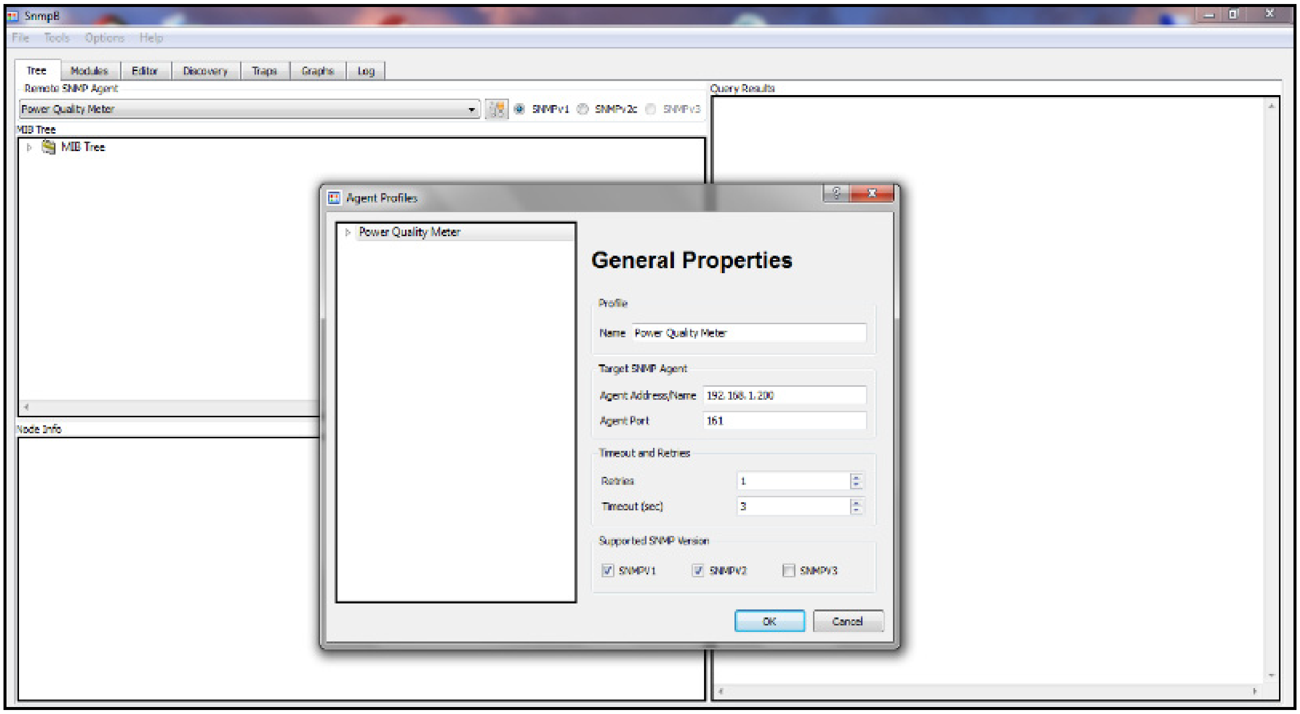
Use an SNMP manager application to make the settings that will let the meter work within the SNMP network. The example in this manual uses a free SNMP manager called SnmpB, but you can perform the same steps with whatever SNMP manager you currently use.

You need to have the following MIBs:

- EtherLike-MIB – RFC 3635
- IP-FORWARD-MIB – RFC 4292
- IANA-RTPROTO-MIB – RFC 2932
- INET-ADDRESS-MIB - RFC 4001
- IP-MIB – RFC 4293
- EIG-MIB
- SNMPv2-SMI – RFC 2578
- TCP-MIB – RFC 4022
- UDP-MIB – RFC 4113

1. Open the SNMP manager application (SnmpB in this example).
2. Click Options in the Tool Bar.

3. Click Manage Agent Profile.



4. In the General Properties section, enter:

a. A name for this SNMP profile.

b. The Agent device's IP address.

c. Agent Port number 161.

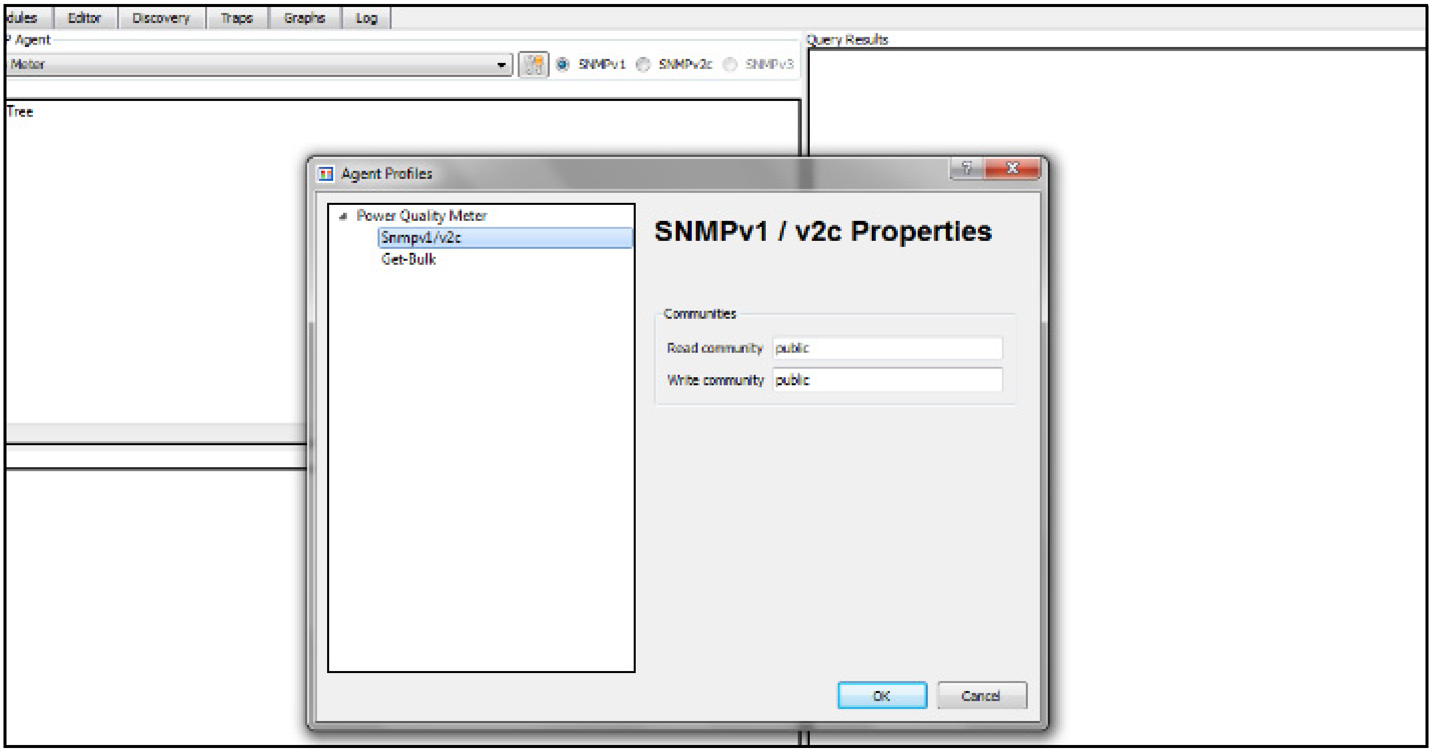
d. The number of communication retries you want.

e. The number of seconds until a communication attempt times out.

f. Check SNMPv1 and SNMP v2 as the supported SNMP versions.

5. Click on the triangle to the left of the Profile name.

6. SNMPv1 and SNMPv2 are listed under the Profile name and the right side of the screen lets you enter information.



a. Enter the Read and Write Community name. The name you entered for the Agent Community name (see D.6.1: Configure SNMP for the Meter, on page D-14) should be the same as the Read and Write Community name. Otherwise, reading/writing from/to the managed object will not be allowed by the Agent device.

NOTES:

- Note that the default value for the Agent community name in the meter is: public.
- Though the SnmpB application doesn't support this, Traps Community names can also be configured for the SNMP Manager to match the meter's Traps Community name (see D.6.1: Configure SNMP for the Meter, on page D-14).

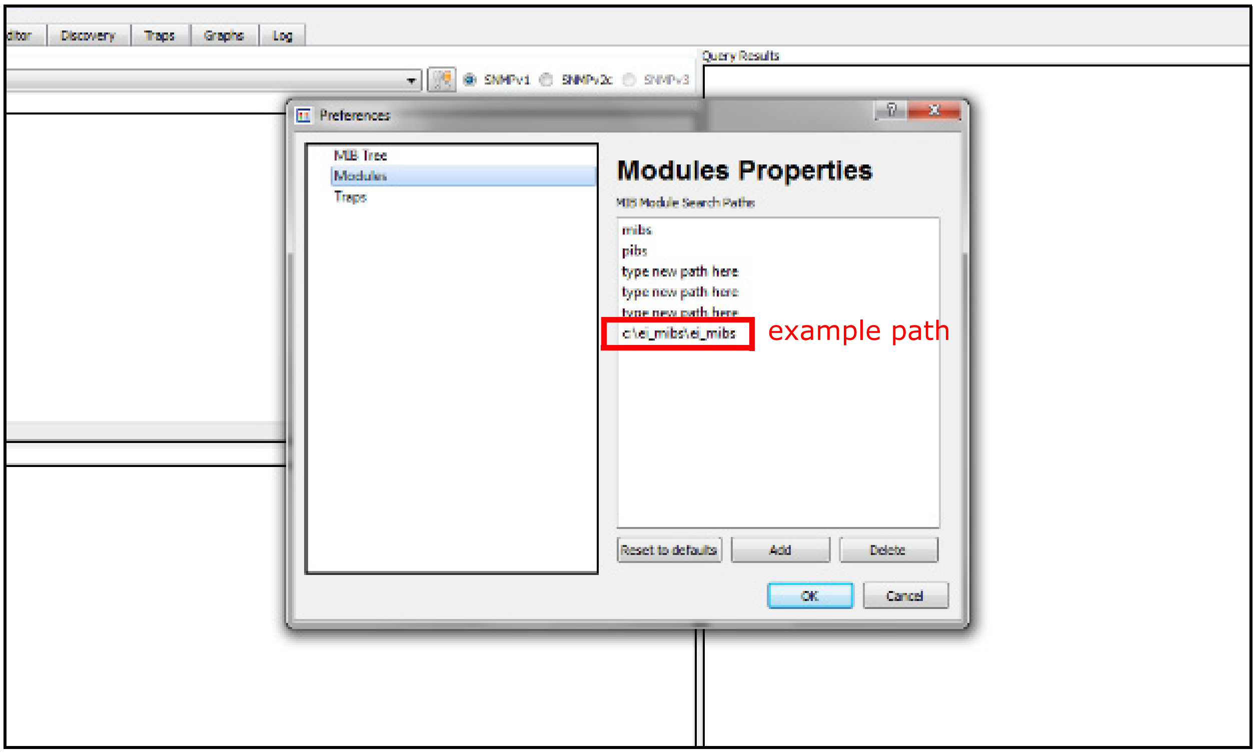
b. Click OK.

7. You can copy the MIBs mentioned earlier in this section into the directory that the SNMP manager application (in this example, SnmpB) uses, or you can set up a directory for the MIB files in this way:

a. Click Options in the SnmpB tool bar.

b. Click the Preference box in the pull-down menu.

c. Click Modules in the box on the left side and click Add.

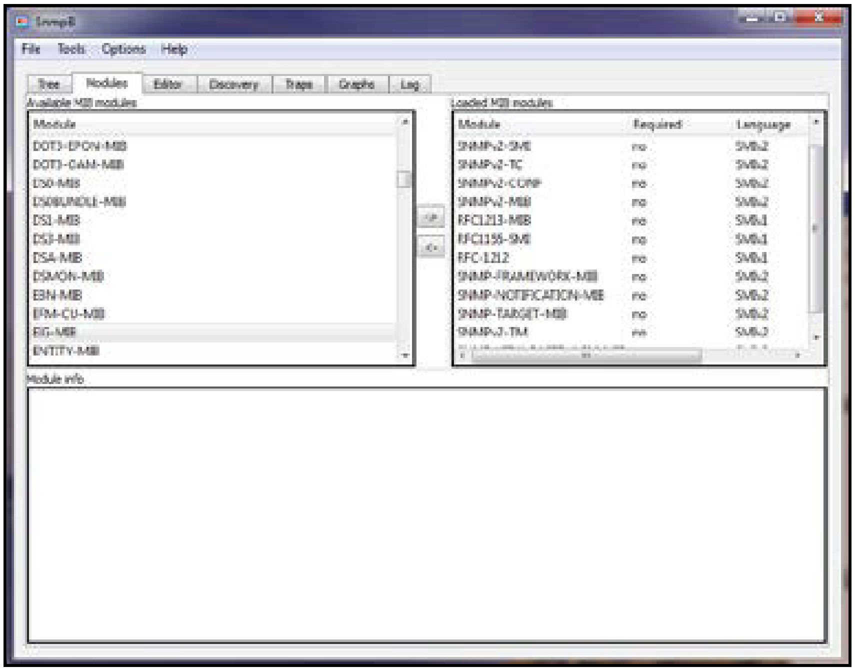


d. Type in your new path in one of the “type new path here” lines. An example path is shown in the above screen.

10. Click OK.

11. Load the new MIBs to the SNMP network in this way:

a. Click the Modules tab.



b. The available MIBs are listed in the box on the right, and the ones that have been loaded are shown in the box on the right. Use the arrows between the boxes to move load MIBs (or unload the MIBs), by moving them into (or out of) the loaded MIBs box.

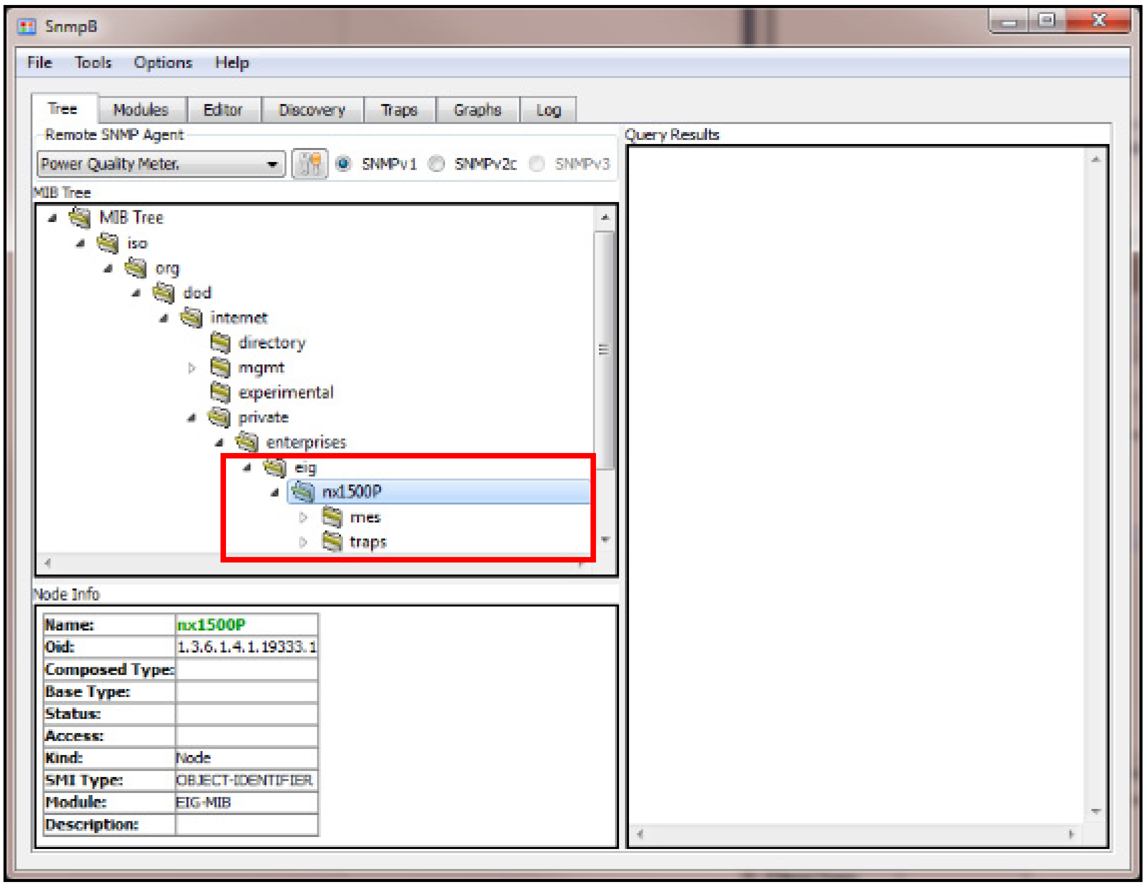
D.6.3: Examples

This section gives an example of viewing meter readings and traps. Again, these examples were generated using the SnmpB application, but you can use any SNMP manager application to view meter and SNMP network communications/status.

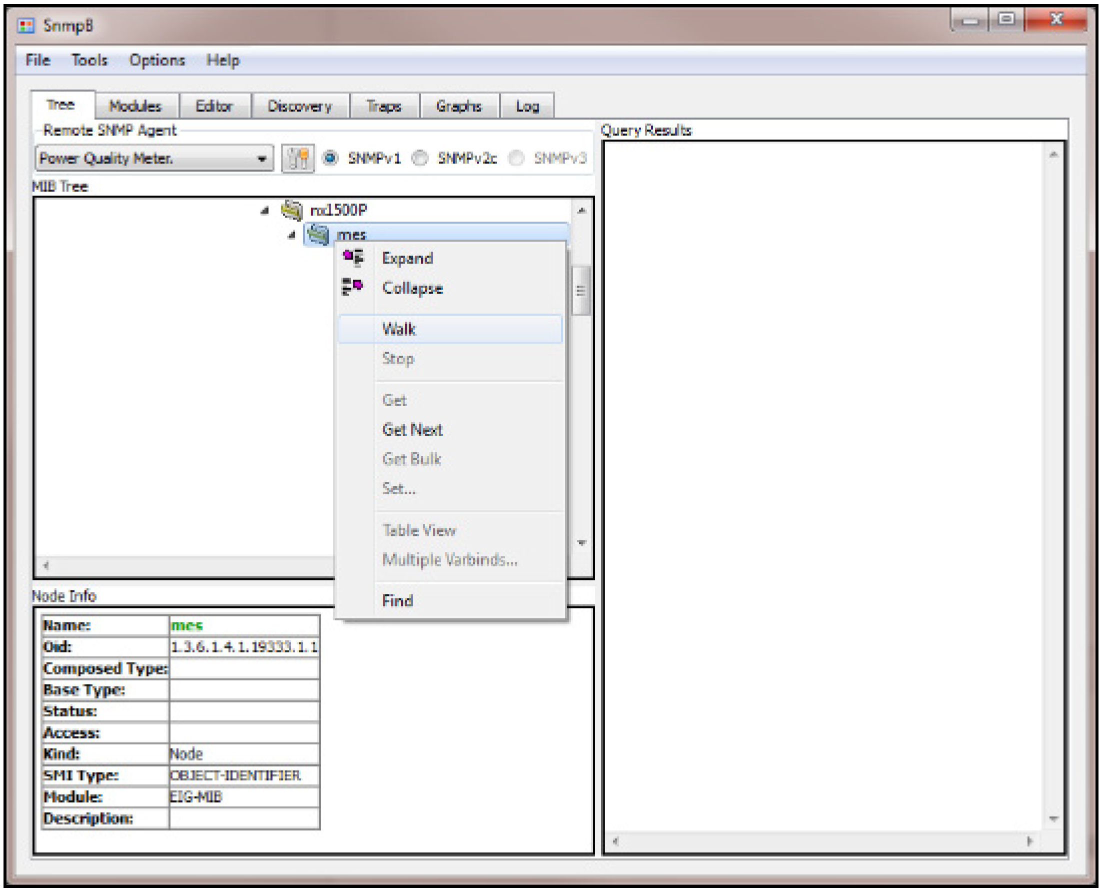
These examples assume that the steps listed in D.6.2: Set up SNMP Network, on page D-16 have been followed and the EIG-MIB is loaded into the SNMP network.

D.6.3.1: Retrieving a Meter Reading

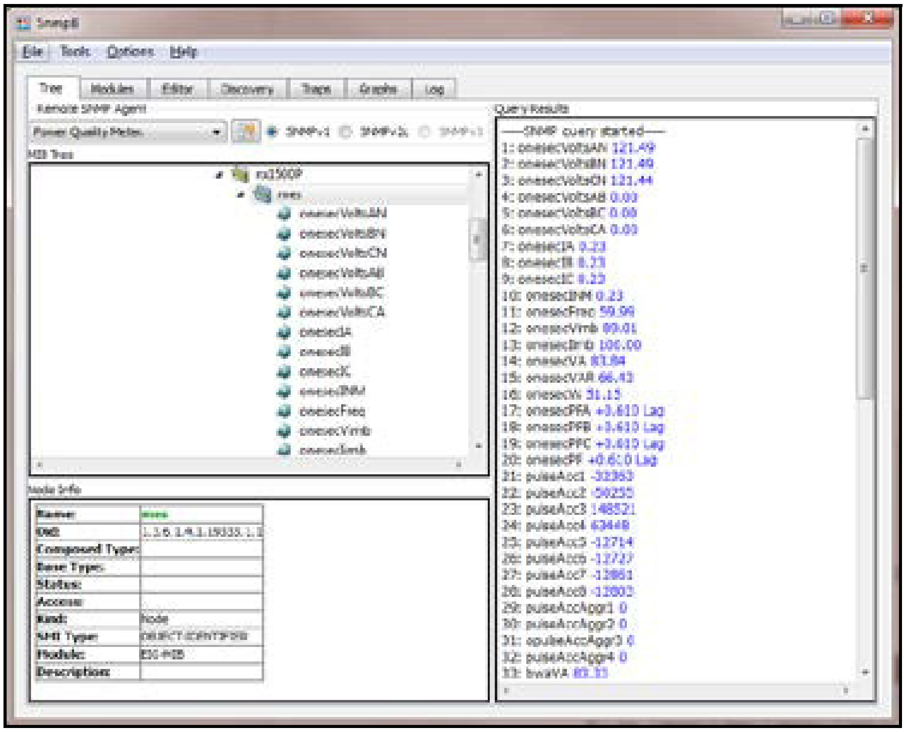
1. In the SnmpB application, click the Tree tab and expand it as shown below, so that you are seeing the EIG folder>nx1500P folder>mes and traps folders.



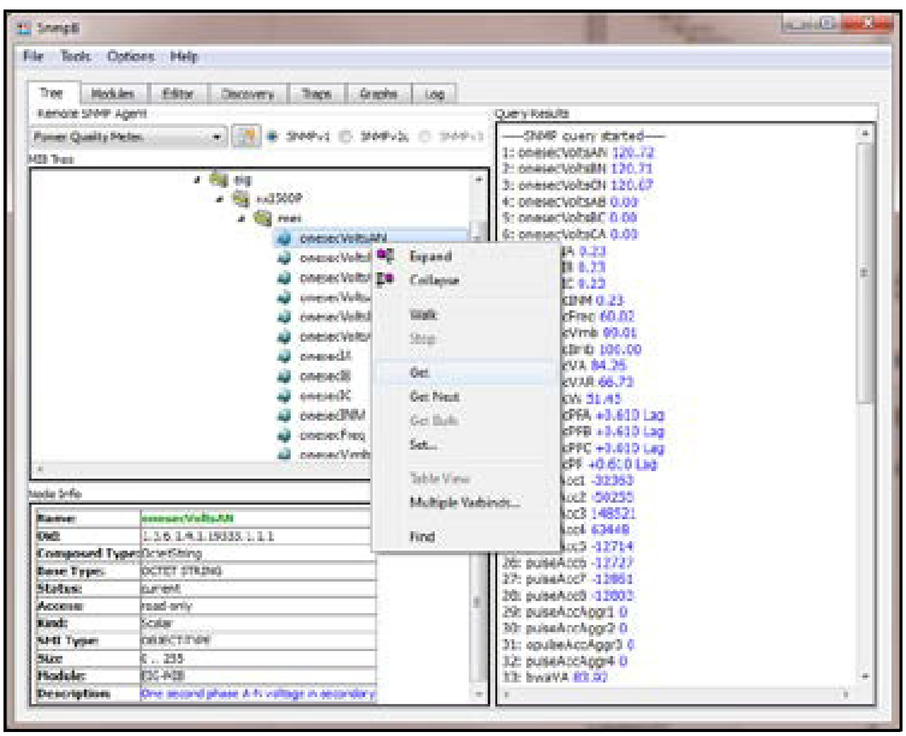
2. Click on the mes folder and right-click it.



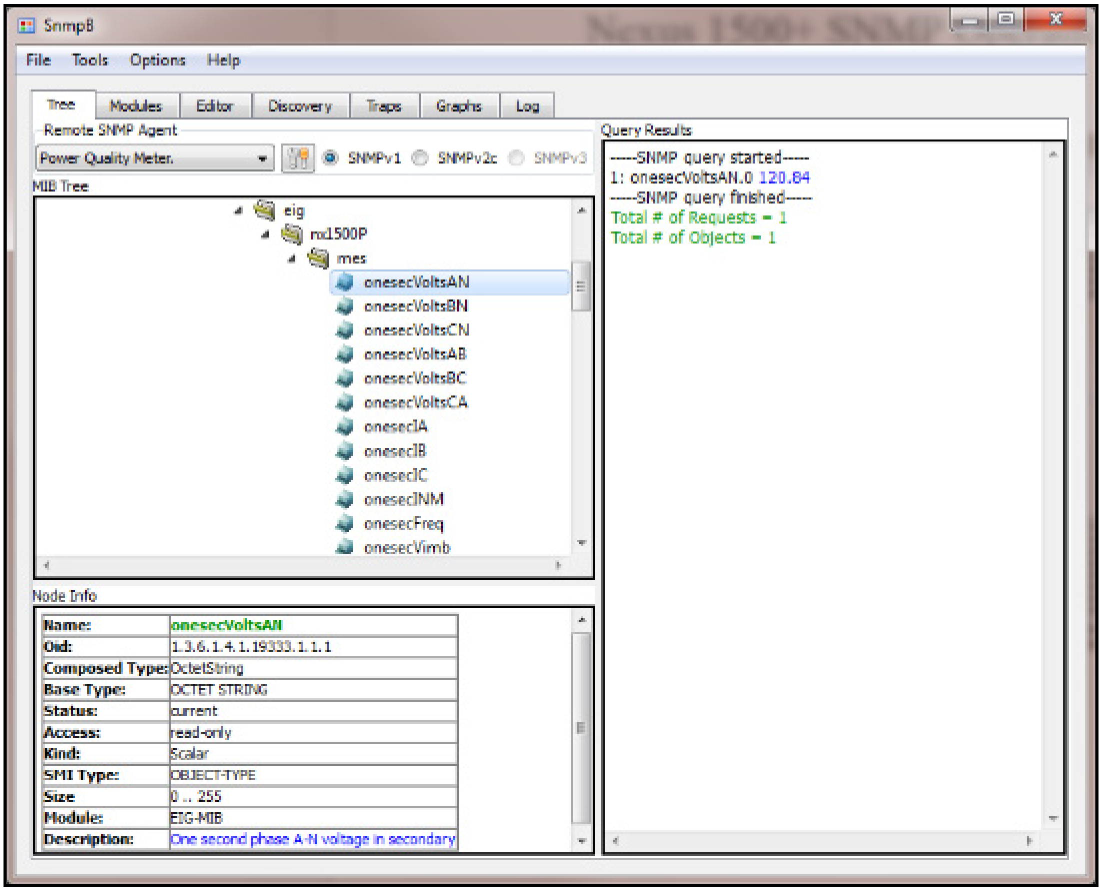
3. Select Walk to retrieve all of the readings in the mes folder.



4. Right-click on one of the readings under the mes folder.

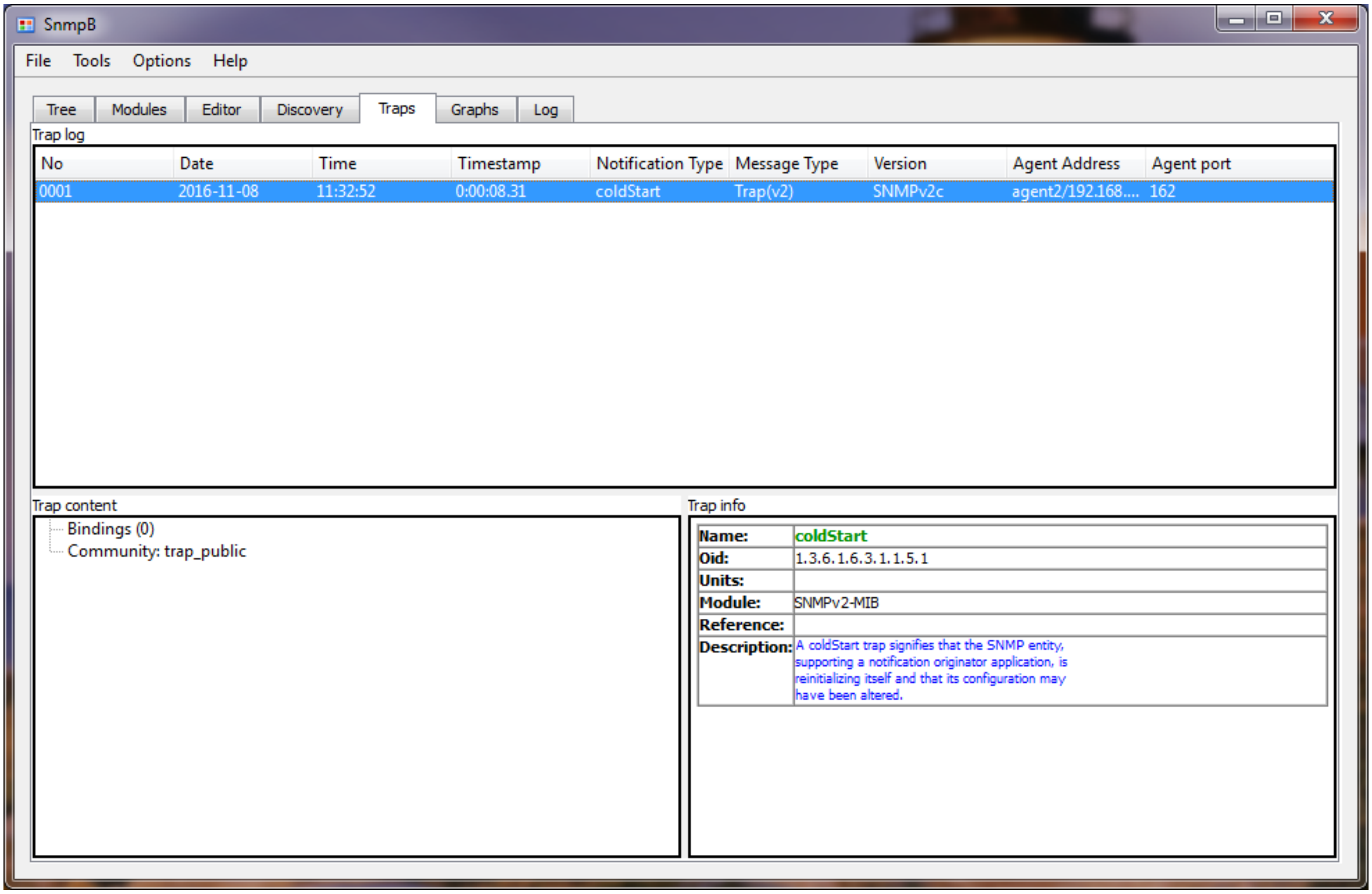


5. Select Get. The reading is shown on the right side of the screen.



D.6.3.2: Retrieving Traps

1. Click the Traps tab. Any traps sent to the device's IP address are displayed.



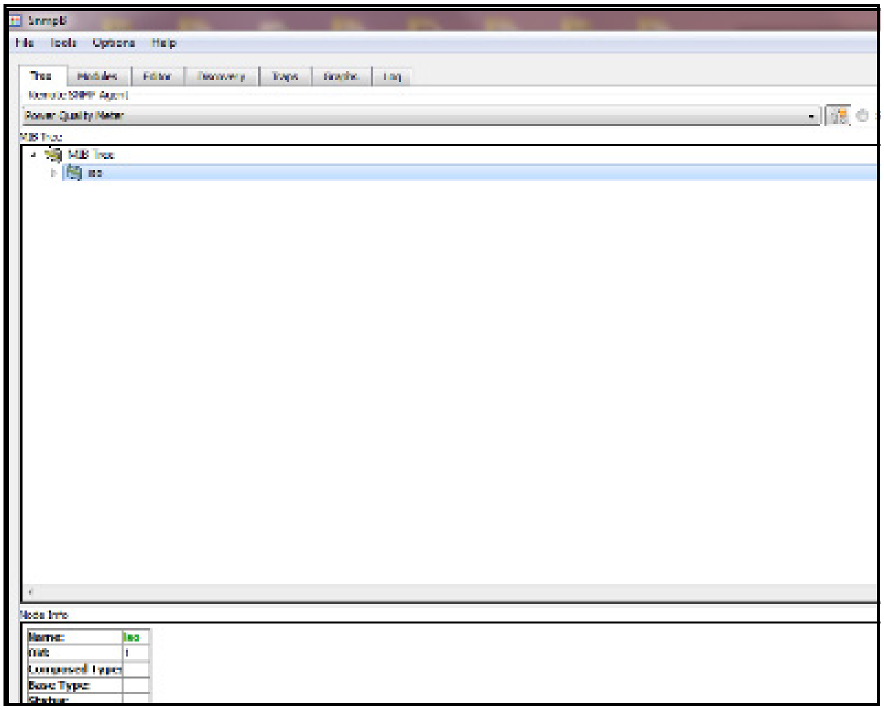
2. Click on a trap to view details about the trap, which are displayed in the Trap Info box in the lower right of the screen.

NOTE: If traps are enabled in only one card, the traps will be sent out over that one card. If both cards are enabled, then traps will be sent out over either card depending upon the trap manager's IP address. In other words, each trap is sent over a card that best matches the traps manager's IP address and gateway; i.e., the trap will either be sent over a card which has the same subnet address as the trap manager; if no card is on the same subnet with the trap manager, the trap will be sent over a gateway (if one is configured).

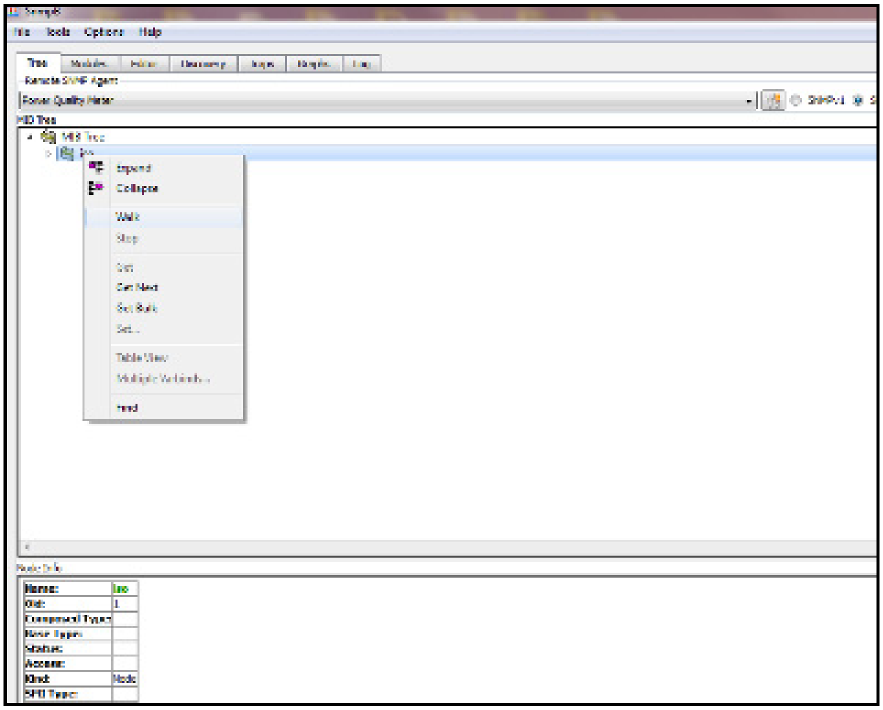
D.6.3.3: Displaying All MIBs ("Walking the MIBs")

To display all of the system MIBs, using the SnmpB application as an example:

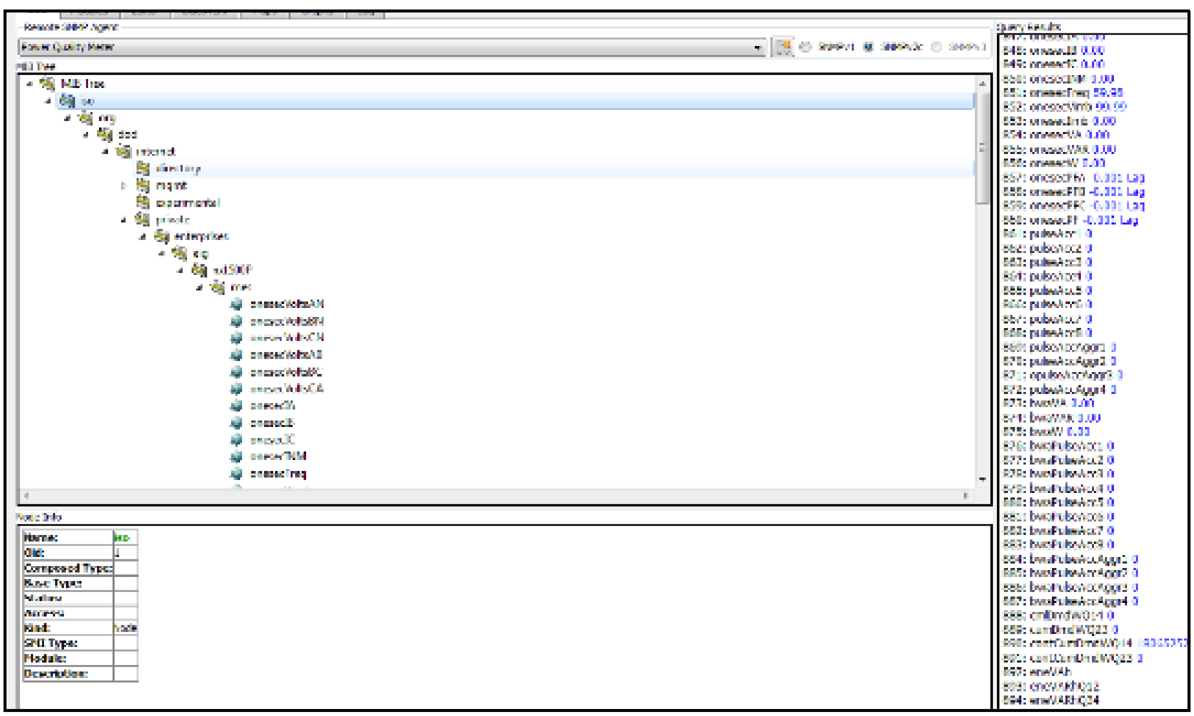
1. Click the Tree tab>click SNMPv1 or SNMPv2 (whichever your system is using)>click MIB Tree>click iso (see example below).



2. Right-click on iso.



3. Click Walk. The MIB values are shown in the box on the right - see the example below.



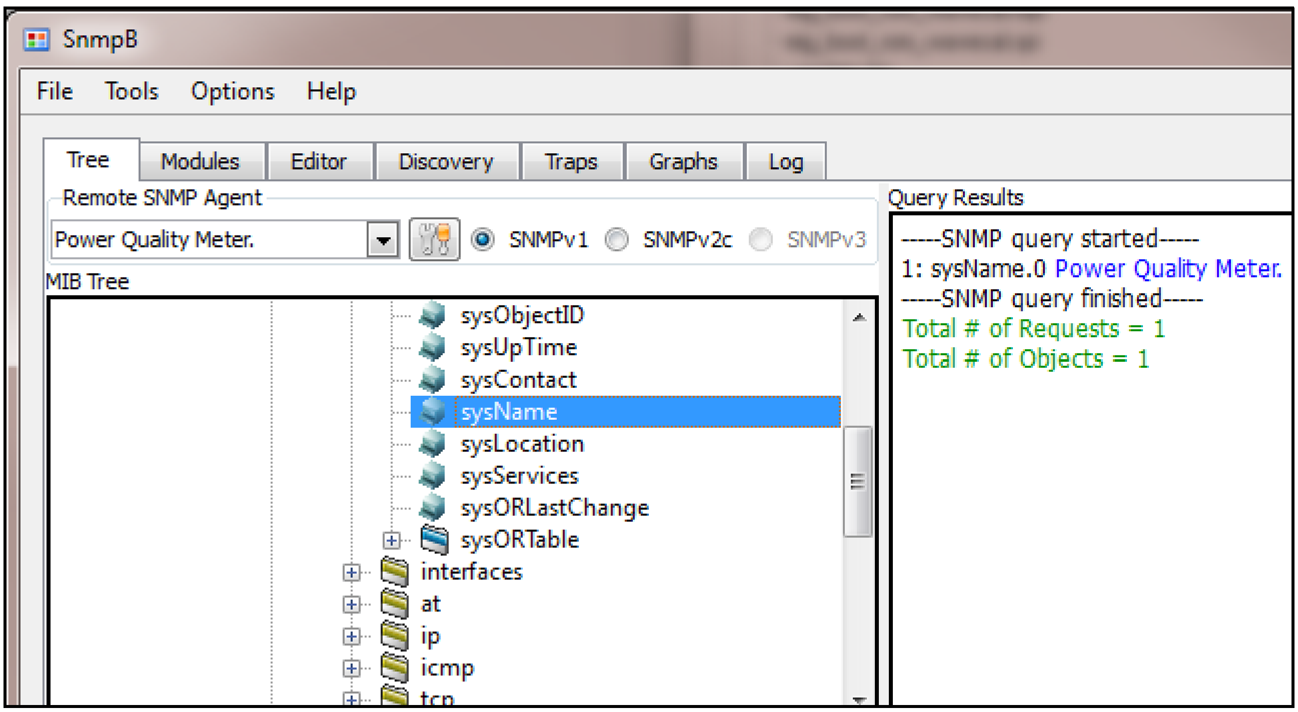
D.6.3.4: Reading from and Writing to the EIG SNMP File

The only information which can be written to the EIG SNMP file is the system contact, system name, and/or system location. This section shows how to read that information first, and then how to write new information into the file.

To read from the file, using the SnmpB application as an example:

1. From the MIB Tree, click iso>org>dod>internet>mgmt>mib-2>system.

2. Select either sysContact (system contact), sysName (system name), or sysLocation (system location). Right-click on the item you selected and the defaults of Manager in Office (sysContact) Power Quality Meter (sysName), and Meter in the field (sysLocation) are shown on the right side of the screen (see the example below).

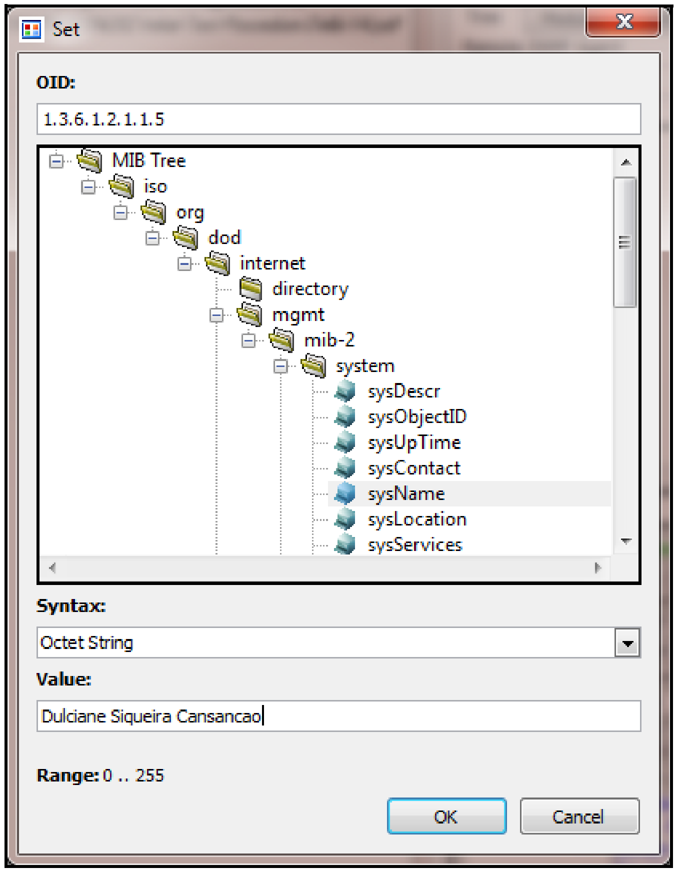


To write to the file:

1. From the MIB Tree, click iso>org>dod>internet>mgmt>mib-2>system.

2. Select either sysContact (system contact), sysName (system name), or sysLocation (system location) and right-click on it; select Set.

3. The Set window opens - type a new setting inside the Value field and press OK. this setting will be kept even after meter reset or power down/up. See the example below.



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E: Synchrophasor Systems

E.1: Overview

Synchrophasor systems use high speed phasor readings taken from multiple locations on the electrical grid and synchronized to a highly accurate time source. Synchrophasors are used to analyze electrical grid performance. They provide wide-area situational awareness for system operators, giving them tools to adjust and improve power stability, e.g., by letting them:

- Determine stress points in the transmission system.
- View phase divergence in different parts of the system.
- Detect islanding.
- Address power system weaknesses to ensure reliable power.

This appendix explains the history, functionality, and applications for synchrophasors. It also explains the Nexus® 1500+ meter's synchrophasor support (see E.5: Nexus® 1500+ Meter's Synchrophasor Support, on page E-8.) Appendix F gives instructions for programming the meter's synchrophasor function.

E.2: History of Synchrophasors

The synchronized phasor measurement in substations was first standardized in 1995 in the IEEE 1344 standard. This standard was improved upon over the years and in 2012 IEC 61850-90-5 was published. IEC 61850-90-5 presented a way to migrate earlier synchrophasor standards to the IEC 61850 architecture, in order to take advantage of faster sampling and data transmission rates, as well as improved Cyber security.

However, the idea behind synchrophasors arose in the 1970s, when the use of computers to implement protection and control functions was in the early stages of its development. The perceived need was the development of a measurement of the fundamental quantities of voltage and current. Then protection and control algorithms could be based on that measurement.

The first step toward synchrophasors was when Dr. Arun Phadke of American Electric Power proposed using a discrete Fourier transform (DFT) function to compute a “phasor” view of voltage and current.[1] When this calculation was implemented in a minicomputer, it was noted that the “phasor” computed by the DFT would rotate over time. The possibility of synchrophasors developed with the realization that the phasor measurement could be synchronized to absolute time throughout the power grid, giving a wide-area view of the actual conditions throughout it. Though this inspired idea took place in 1979, it took roughly eight years before the necessary high-accuracy time synchronization technology would arrive, in the form of GPS. It was then possible to measure the phasors across the grid at a synchronized time. That is when synchrophasors became an invaluable tool for electrical grid analysis.

E.3: Basics of a Synchrophasor System

A typical synchrophasor system consists of:

- Multiple phasor measurement units (PMU)s
- One or more phasor data concentrators (PDC)s
- A communication framework for transmitting data
- A control, monitoring, or visualization application

From its specific location on the electrical grid, each PMU estimates phasor (magnitude and phase angle of voltage and current) and related data that is accurately synchronized to a common time source. The time-synchronized estimated phasor is called a synchrophasor. Multiple PMUs transmit the synchrophasors and related data to a PDC, which aggregates and time-aligns the data for real time and post analysis. Local PDCs receive data from multiple PMUs inside a substation, and another PDC, referred to as the SPDC, receives the data from multiple local PDCs.

1. PHADKE, Arun & BI, Tianshu. (2018). Phasor measurement units, WAMS, and their applications in protection and control of power systems. Journal of Modern Power Systems and Clean Energy. 6. 10.1007/s40565-018-0423-3.

E.3.1: Synchrophasor System Requirements

The most recent synchrophasor measurement standards are IEEE C37.118.1-2011 and its modification IEEE C37.118.1a-2014. Synchrophasor communication requirements are given in IEEE C37.118.2-2011. The Nexus® 1500+ meter's PMU functions meet these requirements.

E.3.1.1: PMU Hardware Requirements

Time Synchronization:

As mentioned earlier, a synchrophasor system requires a highly accurate time source for time synchronization of measurements. IRIG-B and PTP are the usual time sources in synchrophasor systems. The Nexus® 1500+ meter supports both of these time sources.

The time accuracy of the time source and PMU must meet the synchrophasor standard's requirements. For instance, a time error of either +/- 26 µs for a 60 Hz system or +/- 31 µs for a 50 Hz system will cause a phase error of 0.51 degrees. This phase error will cause a Total Vector Error (TVE) of 1%, which is the limit for TVE in some of the standard's requirements. The synchrophasor standard highly recommends that the time source should have a time accuracy at least 10 times better.

Equipment Specification and Resilience:

Power supply:

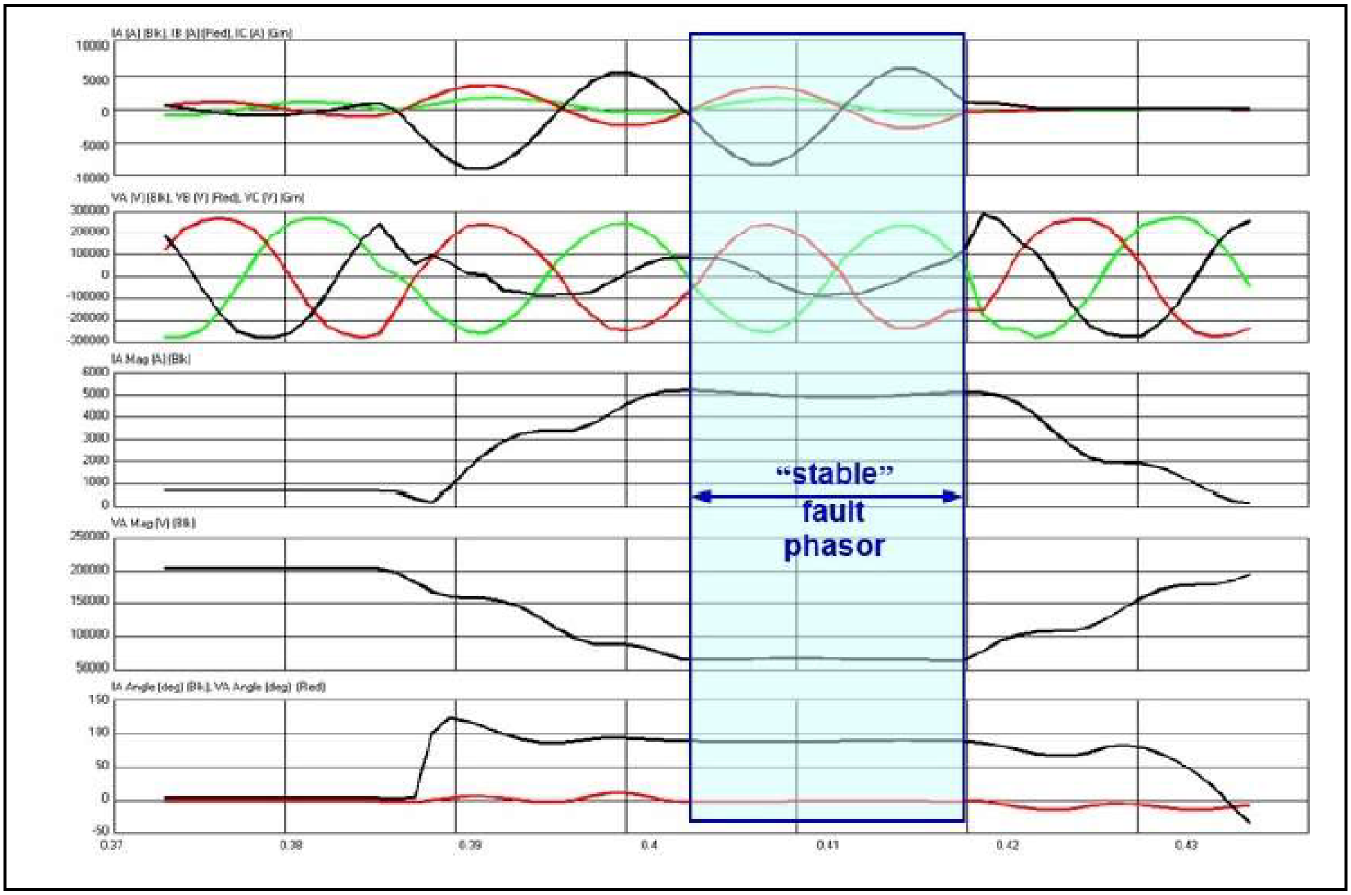
- As specified in the C 37.90 standard
  - DC contact rating threshold
  - Transient suppression requirements
  - Debounce requirements

E.3.1.2: PMU Software Requirements

Data Classes and Characteristics:

IEEE C37.118.1 standard defines two classes of synchrophasors that can be streamed or captured by a PMU. These classes are known as:

- The P Class or Protection Class Synchrophasors – this class utilizes a 2-cycle "triangular" data filtering window. Given the small window size, a synchrophasor or two can be computed during most fault cases and subsequently be used in a double or triple ended fault location (see Figure E.1 below). P Class synchrophasors can be emitted at rates of 120 measurements/sec or higher.



E.1: Use of P Class Synchrophasors for Fault Calculation

- The M Class or Measurement Synchrophasors – the M Class synchrophasor integrates sample values over a 7-cycle window. Additionally, the M Class provides a bandpass filter to eliminate frequency components around the nominal frequency. With such a large integration window, an M-Class Synchrophasor will NOT see fault quantities. Moreover, the M-Class measurements will tend to "average" over the fault window. The M Class can be emitted at rates up to 60 measurements per second. Figure E.2 shows a sample comparison of IEEE C 37.118.1 "P" and "M" class data for 120 frames and 60 frames per second, respectively, from field measurements.

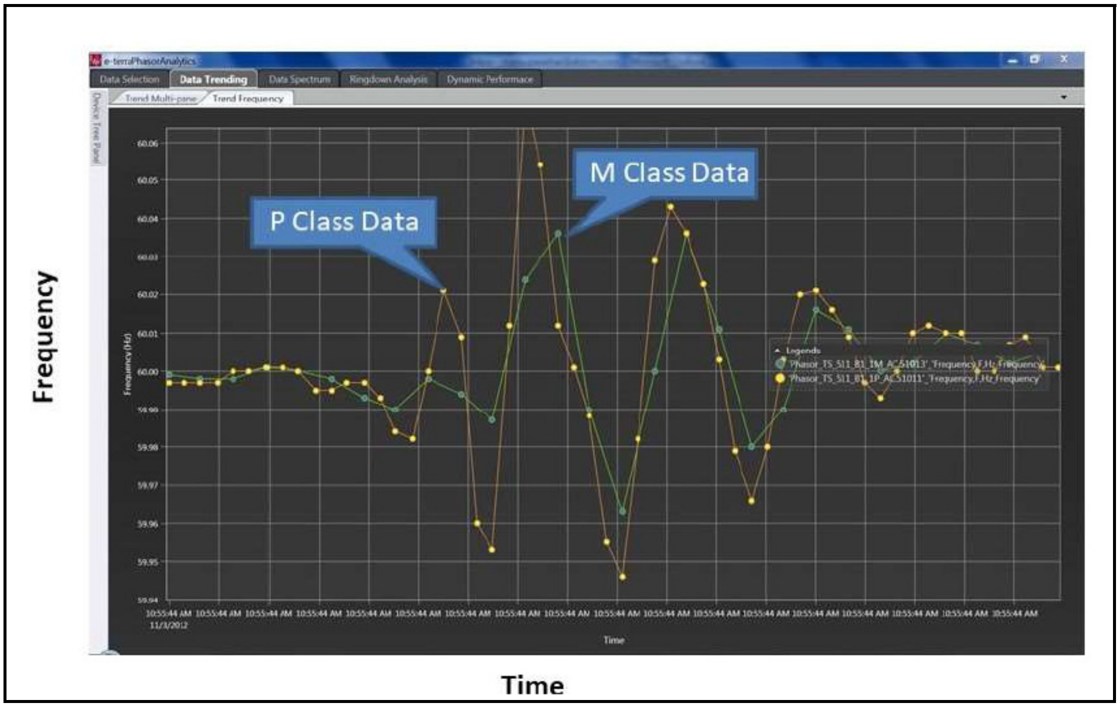


Figure E.2: P and M Class Data Comparison

Auto Stream on Power Up

In secure installations in which data communication is only allowed outbound, the PMU needs to be able to automatically transmit the message Configuration Frame and then start streaming data, immediately on startup. This is configurable through a setting in the PMU device. (see step d in F.2.2: Step Two - Enable Synchrophasors, on page F-8.) Any change in configuration will result in the setting of the Configuration Change flag in the streaming message, a re-transmission of the Configuration Frame containing the changed data, and a restart of data streaming.

Communication Options

IEEE C37.118.2, defines the most frequently used communication protocol for synchrophasors. C37.118.2 can work with either TCP (packet re-transmission on failure to acknowledge) or UDP (no re-transmission on lost packets). The Nexus® 1500+ meter as PMU adheres to the IEEE C37.118.2 standard. It does not support IEC 61850 protocol in its synchrophasor implementation.

E.4: Capabilities/Benefits of a Synchrophasor System

As the electrical grid becomes more complex and more based on inverter sources of power, its fragility increases. An example of this is a recent frequency disturbance in California that resulted in over a Giga-Watt of inverters taking themselves offline. A 99 kV line in Southern California had tripped and this resulted in a power outage in the southern part of the state. Synchronized measurements of the event enabled rapid analysis of the causes of the outage.

The tripping of a line connected to a generator can cause the acceleration of the generator into instability. Being able to monitor the acceleration of the generator, allows a system operator to detect the incipient over-speed and take corrective action immediately, before the problem escalates. Synchrophasor measurements enable such monitoring. Some benefits of a synchrophasor system are reliability, constraint relief, stability, and post-event analysis.

- Some of the reliability benefits are:
  - Situational awareness - the data streamed by a synchrophasor system provides wide-area visibility of the electrical grid which can’t be matched by systems such as SCADA, which can’t supply the high-speed dynamic measurements that PMUs can.
  - Early warning of instability - monitoring the synchrophasor data provides advance warning of power system stability issues.
  - Oscillation detection - low frequency oscillation threatens the reliability of the electrical grid. Synchrophasor data analysis can determine if oscillation exists on the grid, if it will negatively impact the grid, and the location and type of oscillation[1].

- Synchrophasor data enables post -event analysis, which in turn leads to better planning to address, and steps to mitigate, power system events.

- Islanding recovery - when a distributed generator delivers power to a location that is no longer being powered by the electrical grid, an islanding condition has occurred. Synchrophasors enable detection of islanding that leads to quick response to address this critical and unsafe (for both people and machinery) situation.

- One of the constraint relief benefits is:

  - Improved congestion management - congestion occurs when areas of the grid are receiving less power than they should. Synchrophasors help to detect and address this situation by providing the data needed to determine the cause of the congestion, as well as helping system operators to integrate renewables, such as wind power, into the grid to provide additional sources of power..

- The stability benefits are:

  - Voltage stability - maintaining stable voltage after a grid disturbance is essential to avoid cascading failure. Synchrophasor data provides real time monitoring of the grid that gives system operators the information they need to maintain voltage stability and prevent the grid disturbance from becoming a catastrophic power outage.[1]

  - Impact of renewables on grid stability, specifically visibility of wind and solar interconnection - synchrophasor data provides both real time monitoring of frequency and detection of oscillation and low damping conditions.

- The system analysis benefits include:

  - Post-event analysis - in addition to real time data, the synchrophasor data is extremely useful post-event, for conducting forensic analysis.

1. “Using Synchrophasor Data for Oscillation Detection”, North American Synchrophasor Initiative, September 2017.https://www.naspi.org/sites/default/files/reference_documents/crstt_oscillation_detection_20180129_final.pdf
1. USMAN, M.U., FARUQUE, M.O. Applications of synchrophasor technologies in power systems. J. Mod. Power Syst. Clean Energy 7, 211–226 (2019). https://doi.org/10.1007/s40565-018-0455-8

- Model validation – e.g., impact of renewables on the electrical grid. The ability of synchrophasors to provide high-speed and localized data make them ideal for power system model validation studies. These models are important for utilities' long-term planning.

E.5: Nexus® 1500+ Meter's Synchrophasor Support

The Nexus® 1500+ meter with Firmware version 20 and later and V-Switch keys 4-6 meets the IEEE C37.118.1a-2014 Class P and M standard, acting as a PMU that provides real time synchrophasor outputs. Features of the meter's PMU functions include:

- Provides the following data:
  - Individual voltage/current phasors (VA, VB, VC, IA, IB, IC)
  - Symmetrical components phasors (V0, V1, V2, I0, I1, I2)
  - Frequency
  - ROCOF (Rate of change of frequency)
  - Built-in high-speed digital inputs
  - Analog:
    - Fundamental Power:
      - Watt total and per phase
      - VA total and per phase
      - VAR total and per phase
    - Displacement power factor: total and per phase
- . Supports both P and M classes
- Data Frame Rates for 50 Hz: 10/25/50 frames per second; for 60 Hz: 10/12/15/20/30/60 frames per second.
- Data Format: Configurable Float or Integer, Polar or Rectangular
- Time Sync Standard: IRIG-B or IEEE 1588 PTPv2

- Supports Ethernet or Fiber over Ethernet, with:
    - TCP communication for header, configuration, and command
    - UDP communication for data, including unicast, broadcast, and multicast
- Number of Sessions: Up to two clients can communicate with the Nexus® 1500+ meter/PMU at one time, i.e., send requests or commands via TCP. In Unicast mode only, up to two clients can receive the PMU data via UDP.
- Supports auto-sending of data upon startup.

See F: Setting up the PMU, on page F-1 for PMU programming instructions.

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F: Setting up the PMU

F.1: Overview

As explained in E.5: Nexus® 1500+ Meter's Synchrophasor Support, on page E-8, the Nexus® 1500+ meter with Firmware version 20 and later and V-Switch keys 4-6 meets the IEEE C37.118.1a-2014 Class P and M standard, acting as a PMU that provides real time synchrophasor outputs. This appendix explains how to set up the meter as a PMU. For details on Synchrophasor Systems, see E: Synchrophasor Systems, on page E-1.

F.1.1: Details of the Nexus® 1500+ Meter's Synchrophasor PMU Implementation

The Nexus® 1500+ meter allows synchrophasor communication on either of its two Ethernet ports (only one port at a time can be enabled for synchrophasors). The header (outgoing from the meter), configuration (outgoing from the meter) and command (incoming from another device) frames will be sent/received over TCP/IP protocol and the data (outgoing from the meter) frame will be sent over UDP.

The user can configure the meter's listening port for TCP/IP communication (by default the port is 4712) and for UDP communication (by default the port is 4713).The user needs to configure whether the data frame will be sent to unicast, multicast, or broadcast addresses and either local or global broadcast address types.

- If unicast is selected, up to two clients (destination) can simultaneously receive the same data frame from the PMU over UDP. The user needs to program two UDP destination IP address and listening ports.
- If multicast is selected, the user needs to program the multicast address and one UDP port. In multicast, multiple destinations can simultaneously receive the same data frame from the PMU over UDP.
- If broadcast is selected, the user needs to select between local or global (255.255.255.255) broadcast address and multiple destinations can simultaneously receive the same data frame from the PMU over UDP.

The user can configure the meter to send out synchrophasor data automatically, as soon as the meter starts up.

The client (normally a PDC device) is the device that sends the command via TCP/IP to “start sending synchrophasor data.” That client can also send other commands, including “stop sending synchrophasor data.” TCP disconnection will not stop the synchrophasor data frame from being transmitted over UDP.

F.2: Programming the Meter’s Synchrophasor Feature

These are the steps to take to configure the Nexus® 1500+ Power Quality meter as a PMU. Once configured as a PMU, the meter can operate in a synchrophasor system, reporting synchrophasor data to a PDC. Note that this procedure assumes CommunicatorPQA® 5.0.68 or higher, meter firmware version 20 or higher, and meter V-Switch™ key 4, 5, or 6.

1. Step one - program time synchronization method - either IRIG-B or IEEE 1588 PTPv2.

2. Step two - enable synchrophasors.

3. Step three - program the meter’s nominal frequency.

4. Step four - program the meter’s phasor measurement unit settings.

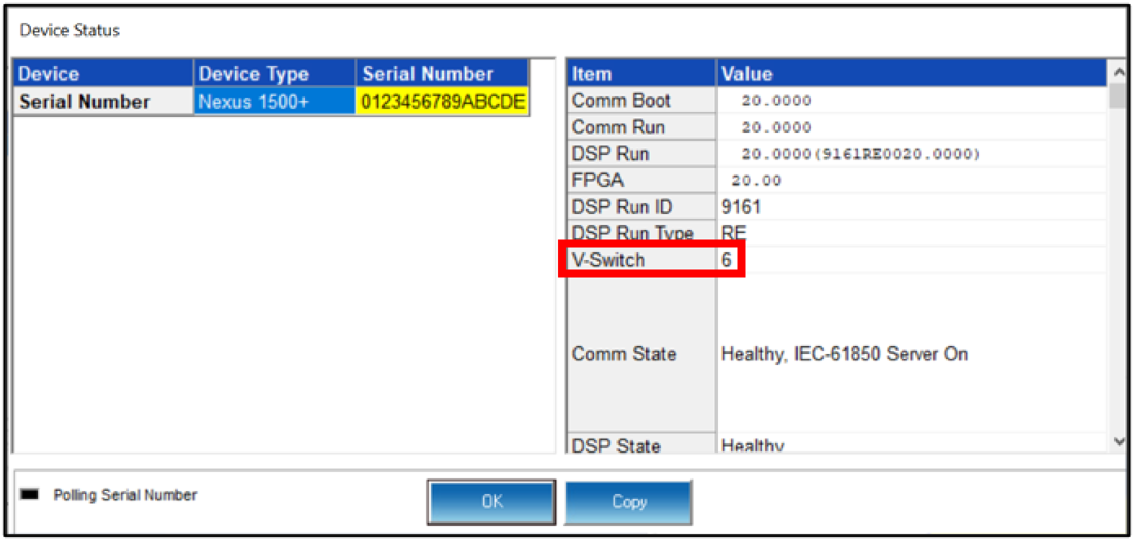
   NOTE: Steps one through three are accomplished through the meter’s programmable settings, which necessitates updating and resetting the meter. Step four uses the Tools>Phasor Measurement Settings screen, which can be changed dynamically, without changing the programmable settings or resetting the meter.

5. The remainder of the programming will take place in your synchrophasor system.

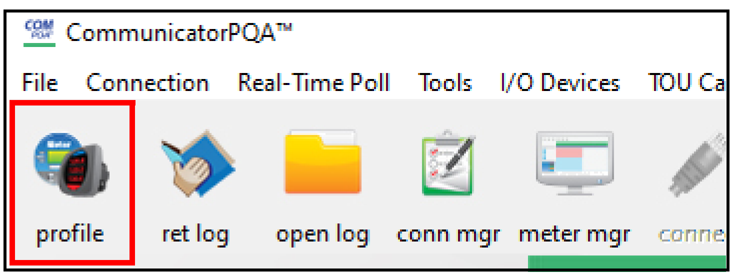
F.2.1: Step One - Select Time Synchronization Method

1. Connect to the meter using CommunicatorPQA® software. If you don’t already have the software, you can download it from https://www.electroind.com/products/communicatorpqa-software-application-5/.

2. In the Device Status screen, make sure the meter's V-Switch is 4, 5, or 6. If it is not, contact EIG sales to upgrade your meter (email sales@electroind.com or call 1-877-346-3837).

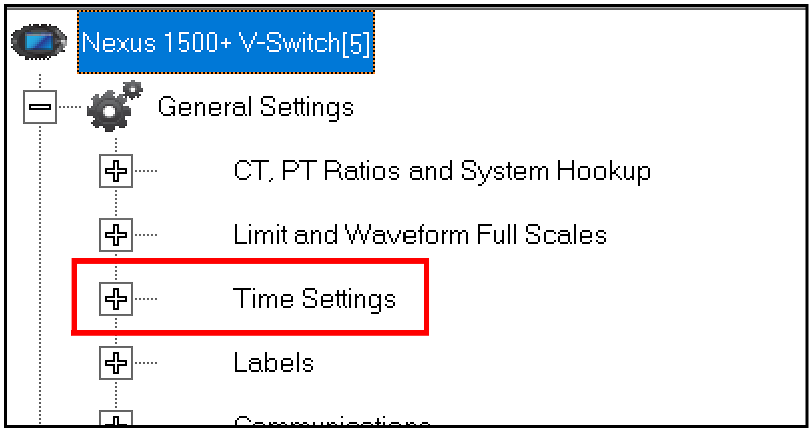


3. Click the Profile icon in the Icon bar.

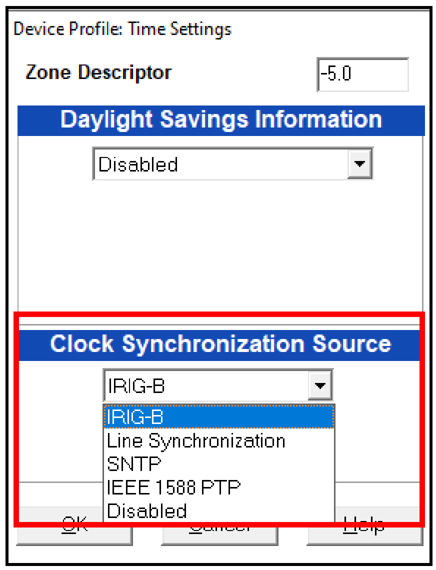


NOTE: Specific instructions for programming synchrophasor functionality are given here. Detailed instructions for programming the Nexus® 1500+ meter are located in Chapter 11 and Chapter 21 of the *CommunicatorPQA®, MeterManagerPQA®, and EnergyPQA.com® Software User Manual*. Download the manual from: https://www.electroind.com/products/communicatorpqa-power-monitoring-software/. Click Downloads>Tech Documents>User Manual from the right side of the webpage.

4. Select the time source for time synchronization by clicking General Settings>Time Settings.

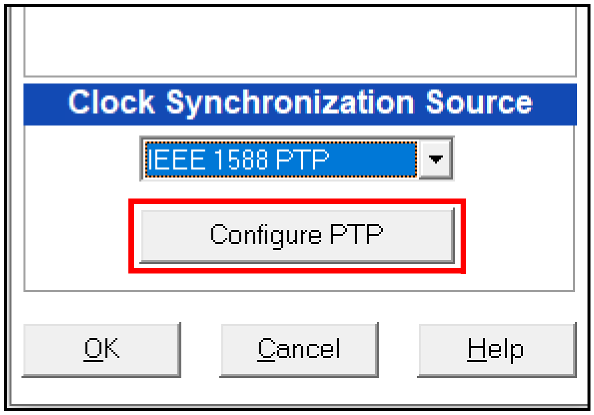


5. Under Clock Synchronization Source, select either IRIG-B or IEEE 1588 PTP.



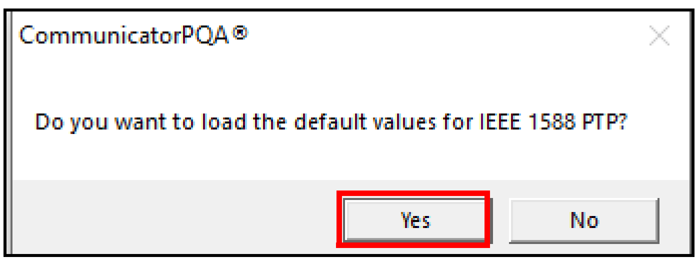
- If you selected IRIG-B, click OK and then proceed to F.2.2: Step Two - Enable Synchrophasors, on page F-8.

6. If you selected IEEE 1588 PTP, a new button - Configure PTP - is displayed.

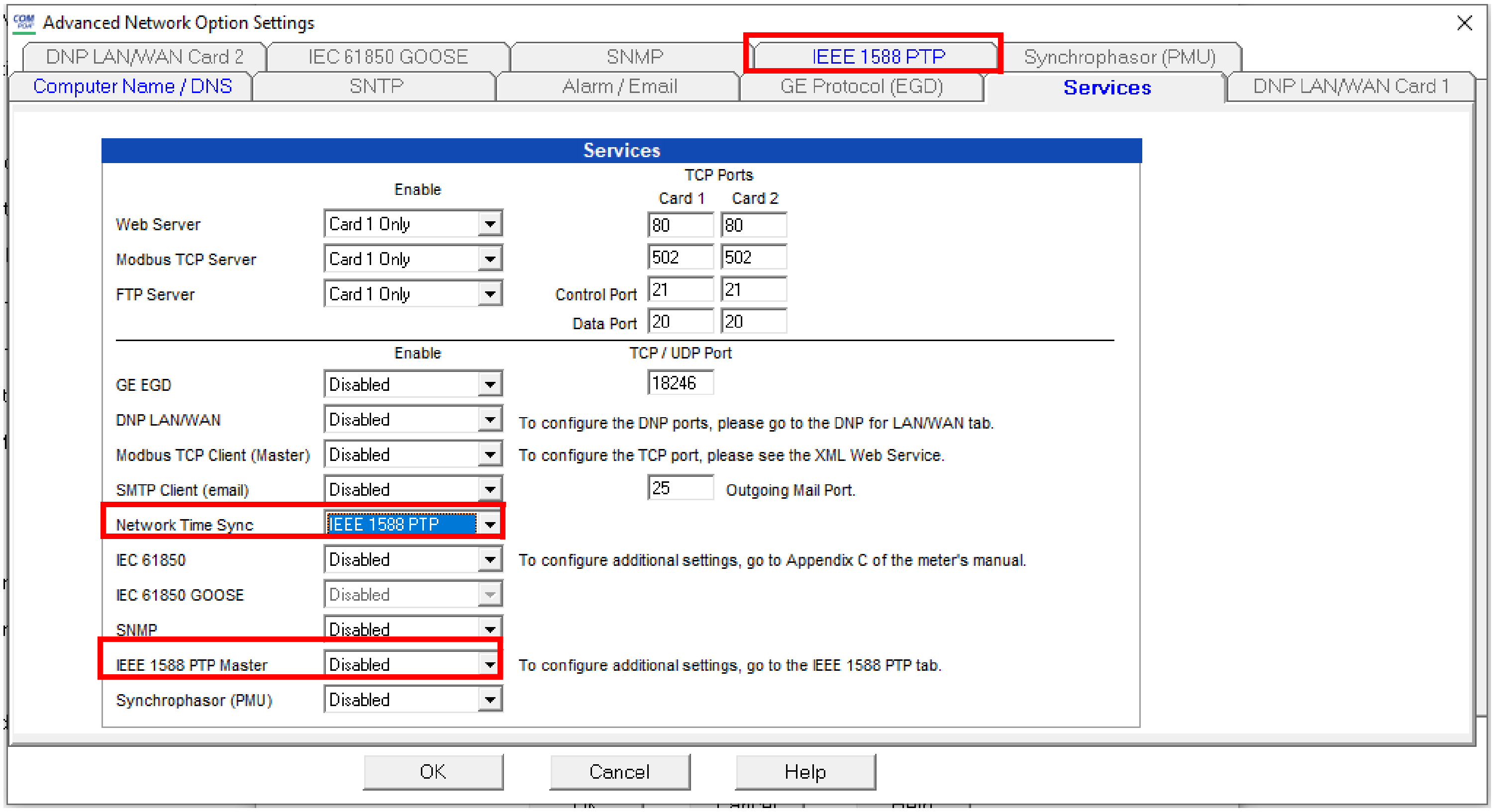


7. Click the Configure PTP button.

- If this is the first time you are setting up IEEE 1588 PTP (or if it was not previously set up correctly), you will see the message shown below. Click Yes to continue.

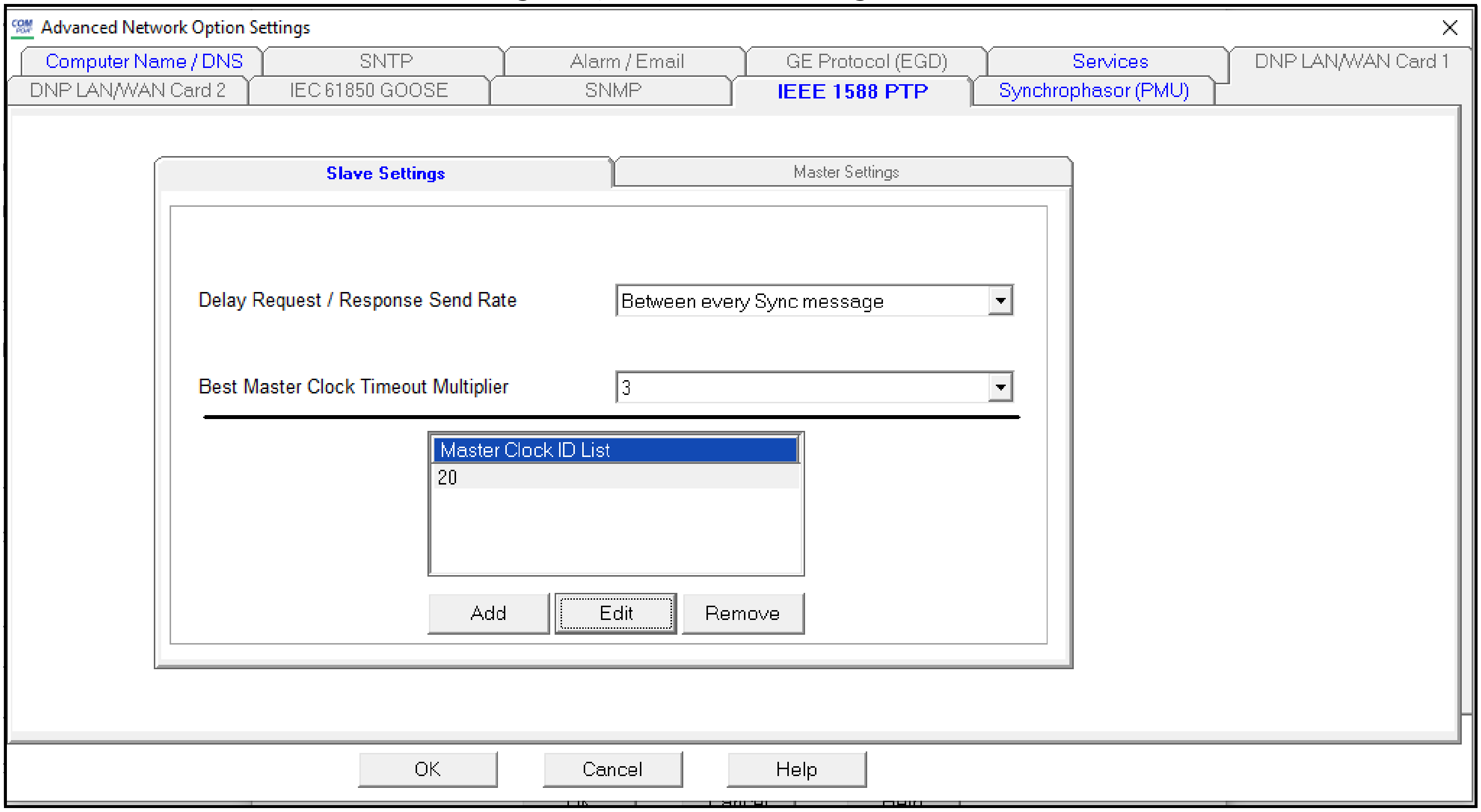


8.The Advanced Network Settings screen opens, displaying the Services tab.



9. Make sure that IEEE 1588 PTP is selected for the Network Time Sync and that Disabled is set for the IEEE 1588 PTP Master. Then click the IEEE 1588 PTP tab.

10. In the Slave settings tab, make these settings:

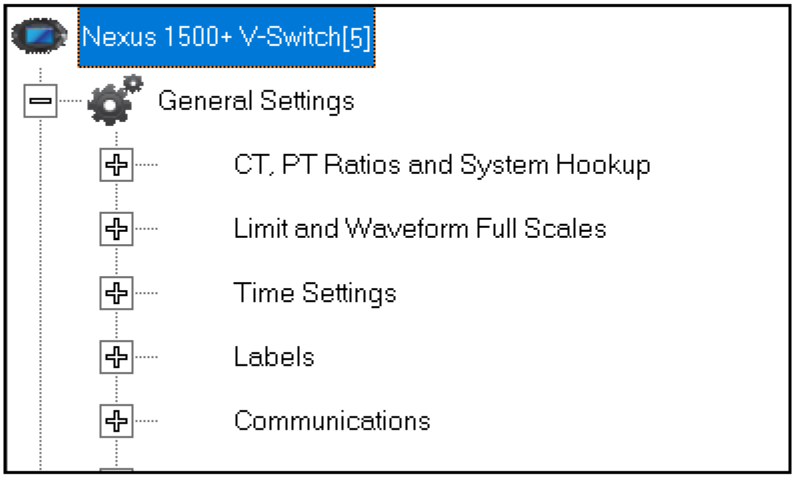


- Delay Request/Response Send Rate: select the time delay you want from the pull-down menu.
- Best Master Clock Timeout Multiplier - select from the pull-down menu the amount to multiply the master clock's timeout by, enabling a longer period before timeout.
- The Master Clock ID list is used when there are multiple master clocks in the system.
  - The clocks are listed in order of priority, e.g., if the first master clock is not accessible, the second will be used, and so on.
  - The order is set when the master clocks are added - the first one added is first, the second added is second, etc.
  - You can Add a new master clock (Add button) or edit an existing master clock's ID (click on the master clock ID and click Edit button). If you want to delete a master clock from the list, click on it and click Remove.

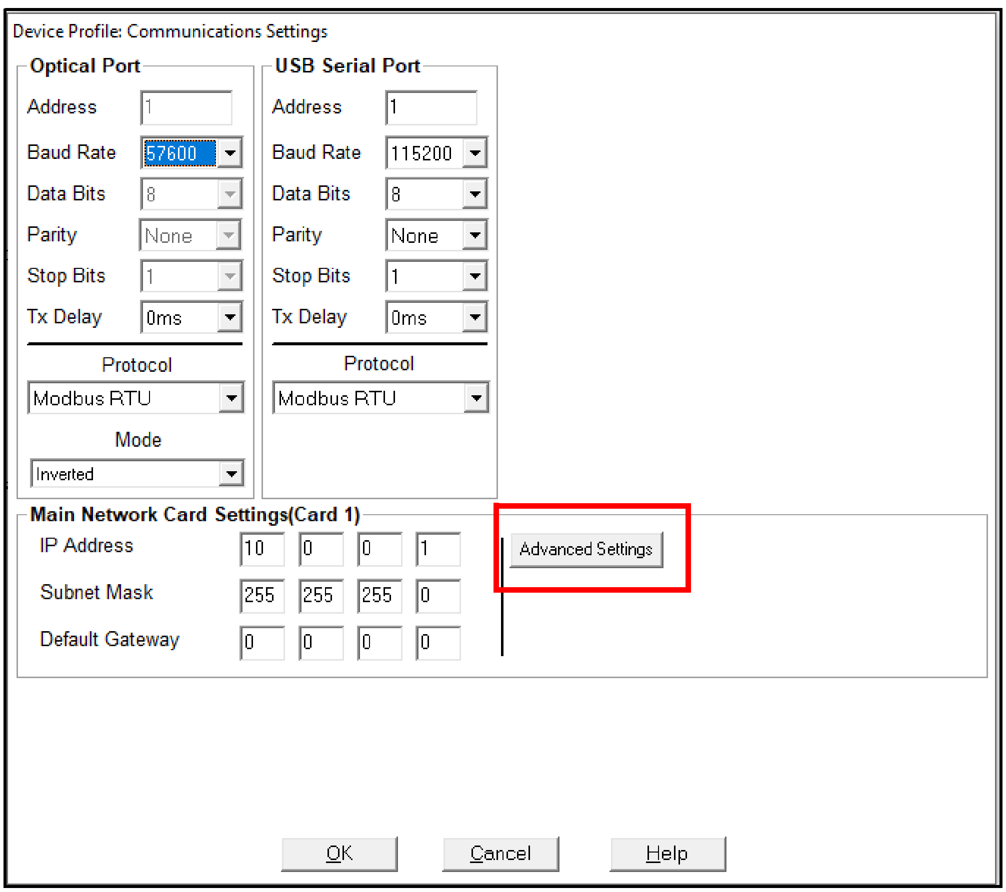
k. Click the Services tab and proceed to step 3 in the next section.

F.2.2: Step Two - Enable Synchrophasors

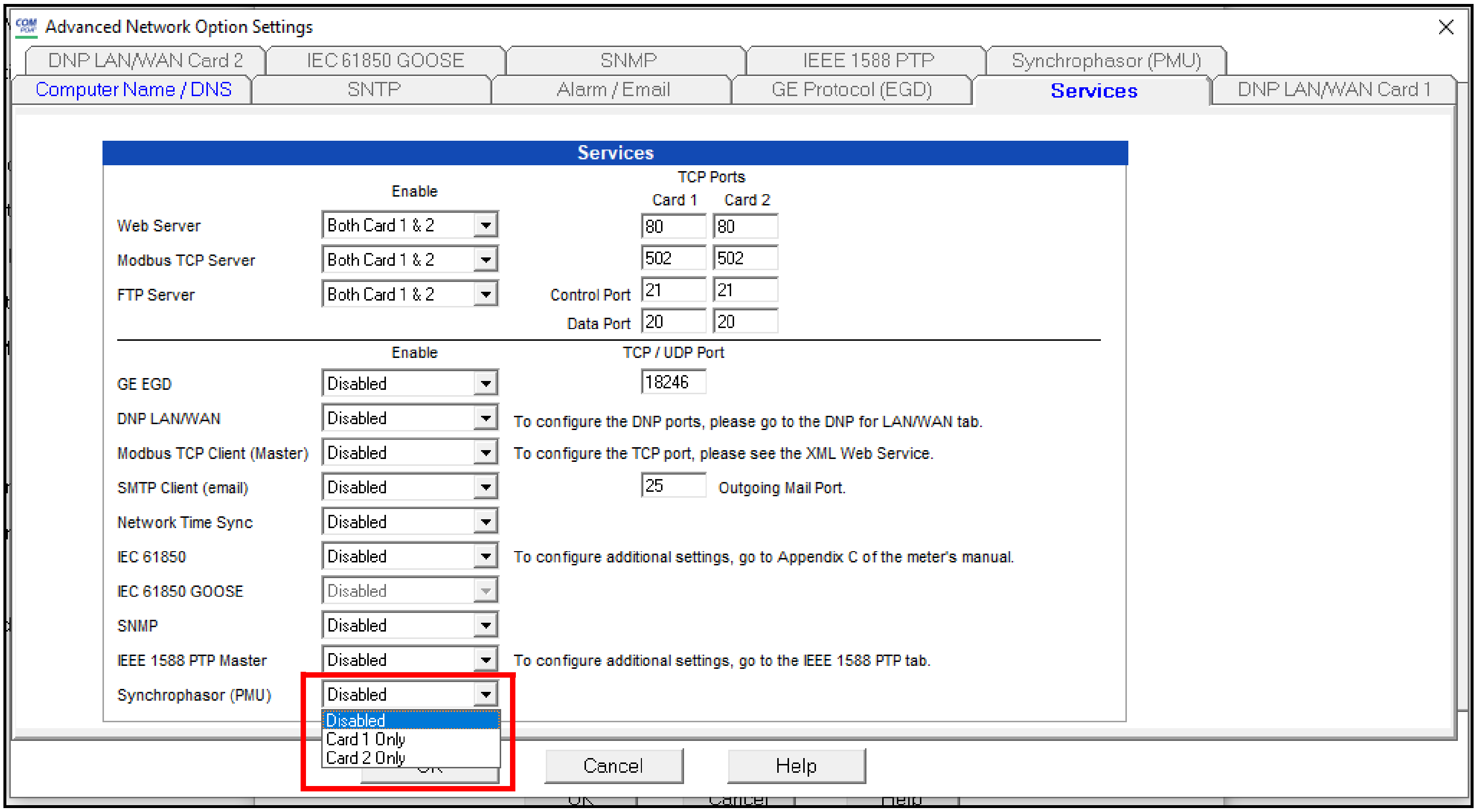
1. Next, you need to enable Synchrophasors (PMU). Click General Settings>Communications.



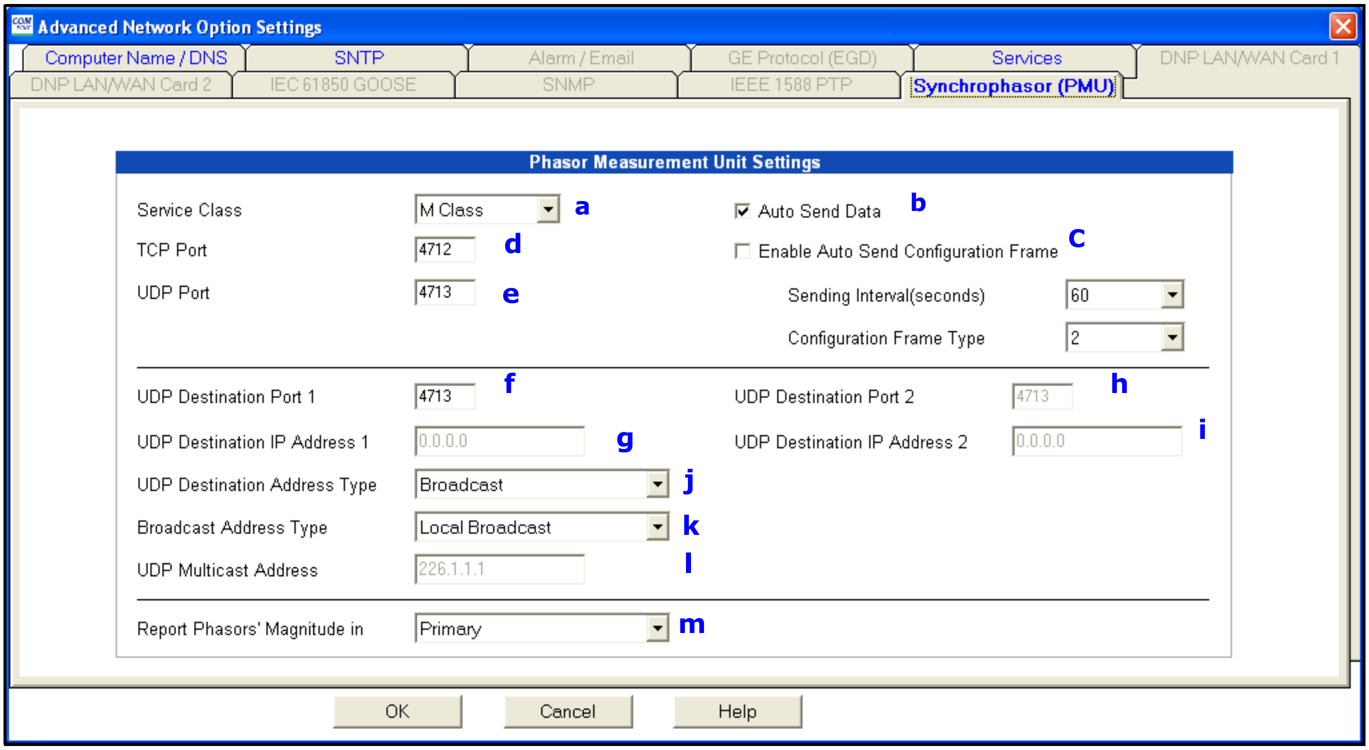
2. If there are two Ethernet cards in the meter you will see two Advanced Settings buttons - otherwise, there will just be one. Click an Advanced Settings button.



3. In the Services tab (the first tab that opens in the Advanced Settings screen), select either Card 1 only or Card 2 only in the Synchrophasor (PMU) setting, to specify which card will handle Synchrophasor traffic in the meter. You can use either card, but only one card at a time can be set for Synchrophasors.



4. Click the Synchrophasor (PMU) tab. This screen lets you make communication settings for the meter/PMU and the client/PDC.



5. Make these settings:

- For Service Class (a), select either M Class or P Class. Your selection depends on your synchrophasor system - the meter supports both classes (see E.3.1.2: PMU Software Requirements, on page E-4, for a detailed explanation of classes). This field is required.

- Check the Auto Send Data box (b) to have the PMU send data automatically on startup. This setting depends on your system requirements. If you do not select auto send, the meter will wait for a request for data from the client/PDC on startup.

- Check the Enable Auto Send Configuration Frame (c) to have the PMU send the configuration frame data automatically on startup, in the same channel as the Auto Send of data; then select the sending interval in seconds (1-3600, the default is 60) and the configuration frame type (1 or 2, the default is 2)from the drop-down menus.

- In TCP Port (d), enter the TCP port used by the meter to receive synchrophasor commands. This field is required.

- In UDP Port (e), enter the UDP port used by the meter to send synchrophasor data. This field is required.

- In UDP Destination Port 1 (f), enter the client's/PDC's UDP port used to receive synchrophasor data from the meter. This field is required.

- In UDP Destination IP Address 1 (g), enter the client's/PDC's IP address. This option is only available in Unicast mode.

- In Unicast mode only, you can also set a second UDP Destination Port (h) and Destination IP Address (i), to be used by a second client/PDC. In other modes, these fields cannot be used.

- In UDP Destination Address (j), select from Broadcast, Multicast, and Unicast.

  - If you select Broadcast, then select either Local Broadcast or Global (255.255.255.255) from the Broadcast Address Type field (k).

  - If you select Multicast, enter the UDP Multicast Address in its field (l).

  - If you select Unicast, enter the UDP destination IP address 1 in its field. You also have the option to enter a second UDP destination address in Unicast mode - use the UDP destination port 2 (h) and IP address field 2 (i) to set up a second client that can communicate with the meter/PMU.

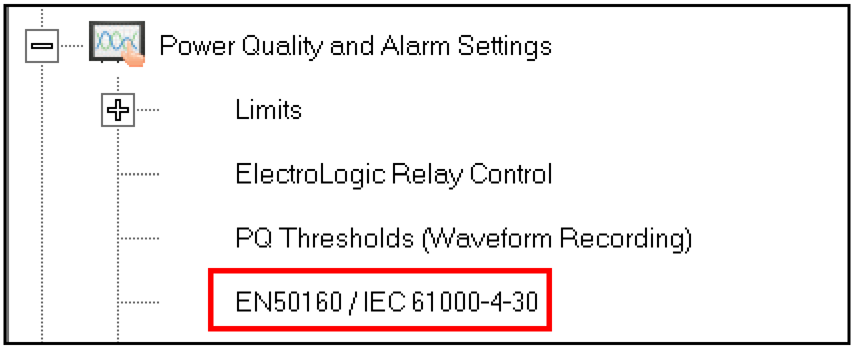
- Select Primary or Secondary from the Report Phasor's Magnitude in field's (m) drop-down menu, to select primary or secondary readings for the phasor's magnitude in data reporting. The default is primary.

6. Click OK to save your settings and close the Advanced Network Option Settings screen.

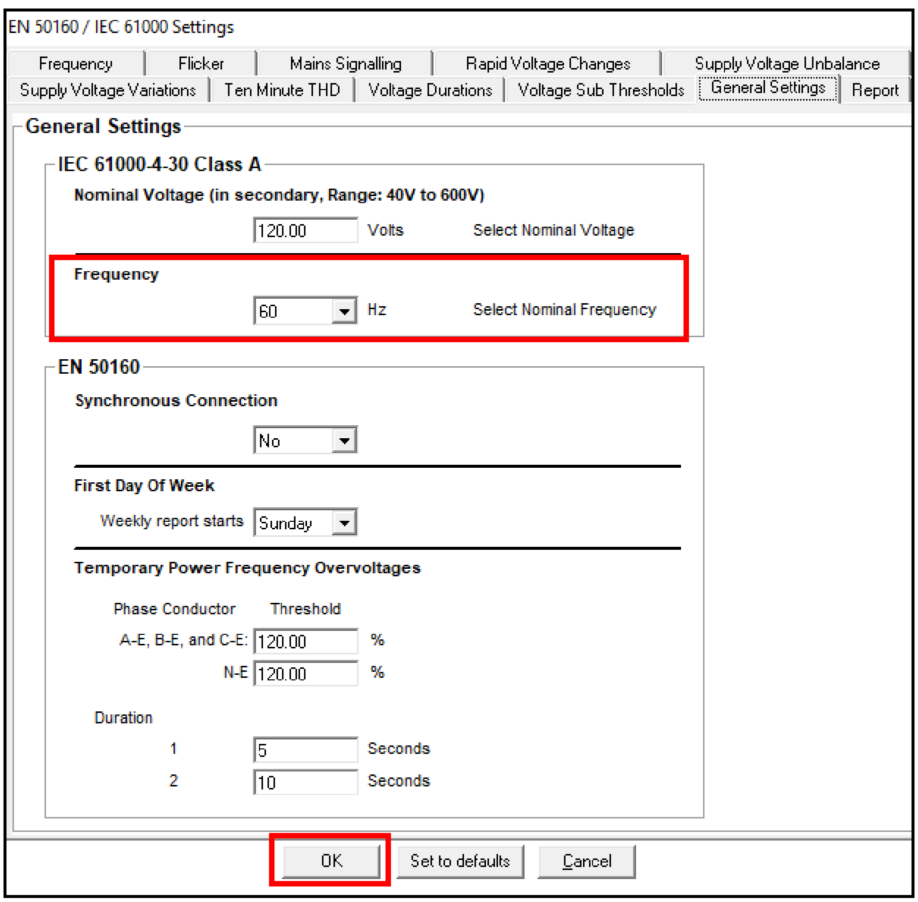
F.2.3: Step 3: Program the Meter's Nominal Frequency

The next step is programming the frequency for the meter.

1.From the meter's Device Profile menu, click Power Quality and Alarms>EN50160/ IEC 61000-4-30.



2. The EN50160/IEC 61000 screen is displayed. Click the General Settings tab to see the screen below.



3. Select your meter's frequency - 50 or 60 from the pull-down menu.

4. Click OK.

5. The Device Profile part of the PMU configuration is complete. You can either:

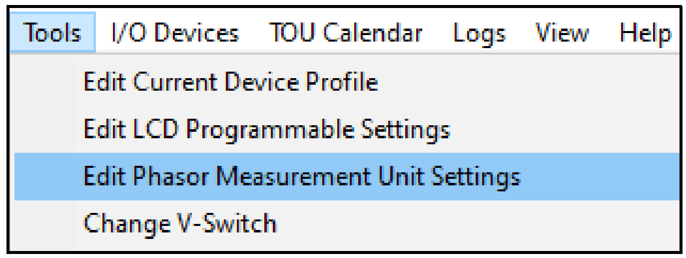
- Click the Update Device button at the bottom of the Device Profile screen and wait until the meter is back online.

- Click the Save button at the bottom of the Device Profile screen and save the settings you have made. Then when you are ready to update your device, click the Load button in the Device Profile screen and select the saved Device Profile. You can then update the meter with the new device profile settings.

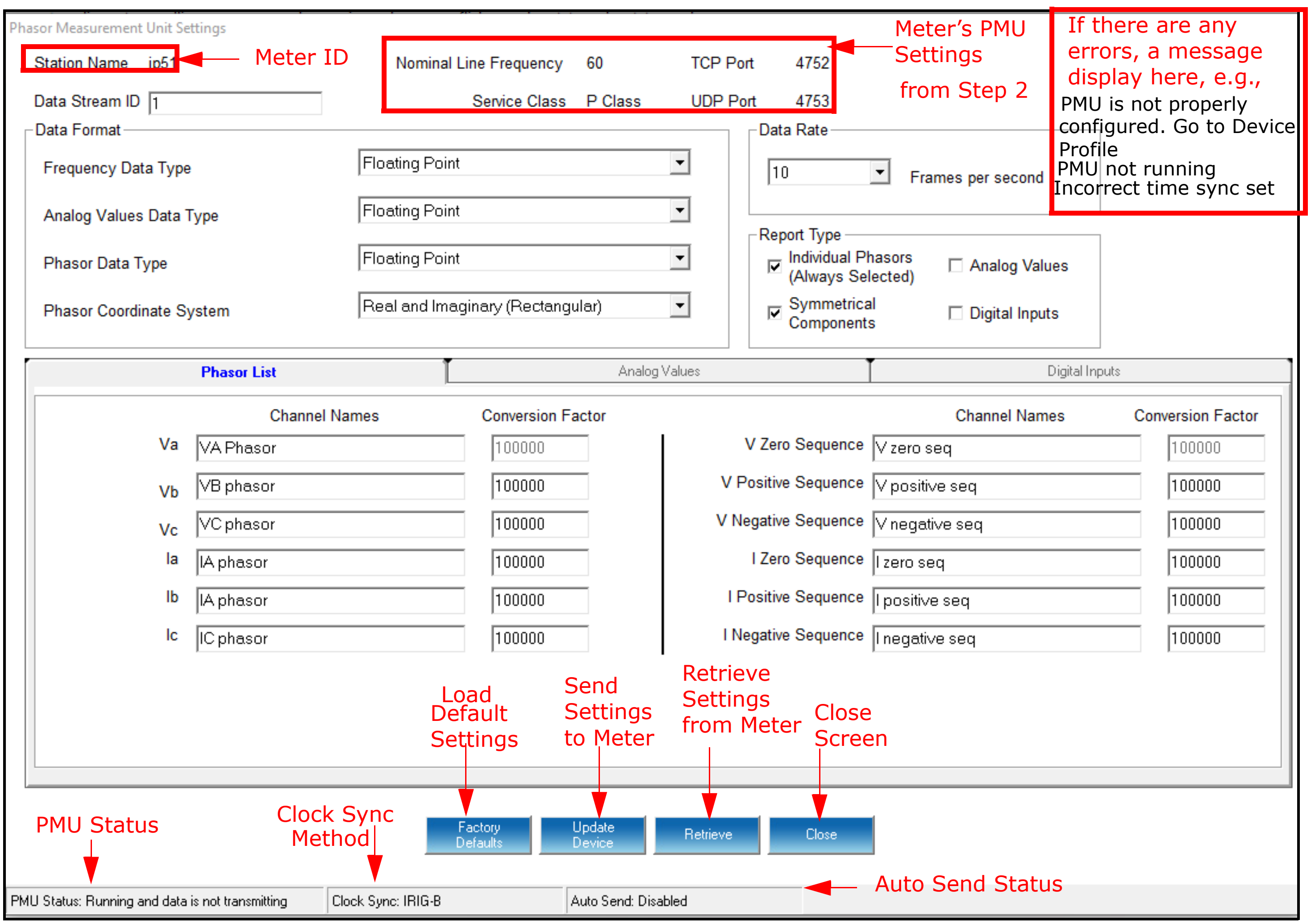
F.2.4: Step 4: Program the Meter's PMU Settings

Once the meter has been updated with the PMU settings made in steps one through three and the meter is running, you will configure additional settings for the Nexus® 1500+ Power Quality meter acting as a PMU.

1. From the top of the Main screen, click Tools>Edit Phasor Measurement Unit Settings.



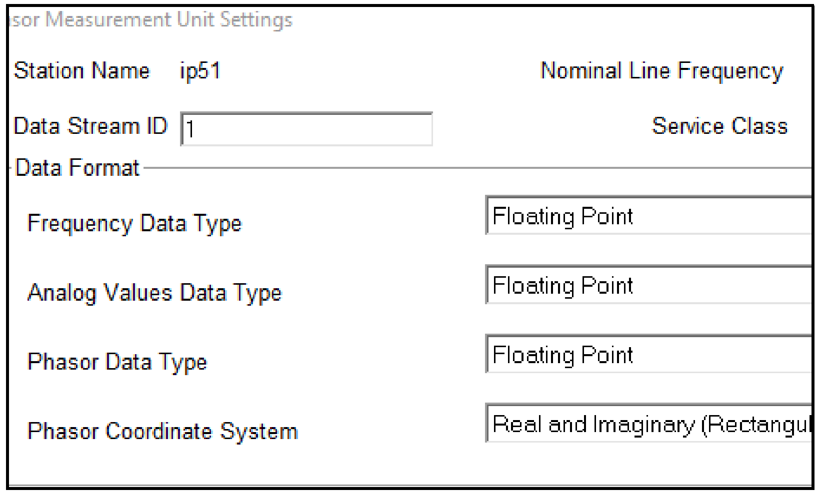
2. You will see the screen shown below.



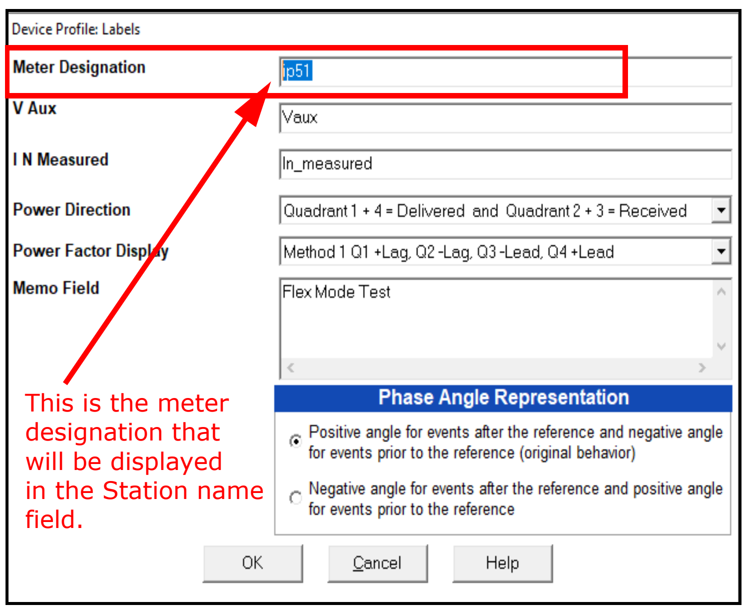
IMPORTANT! If you have updated your meter's firmware from V15 to V20, click Factory Defaults and then make any of the following settings you need.

3. The Phasor Unit Measurement Settings screen has a top portion and three tabs. With the exception of the service class field, the settings on this screen are transmitted via the configuration and header in the meter's PMU communications. These settings enable a client, such as a PDC, to distinguish between and interpret the synchrophasor data from different PMUs.

4. The top of the screen displays the PMU settings you already made for Nominal Line Frequency, Service Class, TCP Port, and UDP Port (see screen on the previous page). The new settings on the top of the screen are shown the right and explained below and on the following pages.



a. Station name - this field is read only. It is the meter designation that was configured in the meter's device profile Labels screen (General Settings>Labels). See the example screen, on the right.



b. Data Stream ID - enter any number from 1 to 65534. This number is used to identify the synchrophasor data stream coming from the meter. It enables the PDC to know which meter/PMU is sending the data. The number you enter depends on the other devices in your synchrophasor system, e.g., if you already have devices with data stream IDs of 1-20, then you can enter anything between 21 and 65534. Just make sure to enter a unique number, i.e., don't use a number already assigned to a device in the synchrophasor system.

c. Frequency Data Type - select between Integer and Floating Point from the pull-down menu. Integer does not have decimal points, floating point does. Decimals give a reading more precision, if that is what your synchrophasor application requires. You can also use conversion factors or multipliers for greater resolution - see the instructions for the Phasor List and Analog Values tabs, on the next page.

d. Analog Data Type - select between Integer and Floating Point from the pull-down menu. See step c for data type information.

e. Phasor Data Type - select between Integer and Floating Point from the pull-down menu. See step c for data type information.

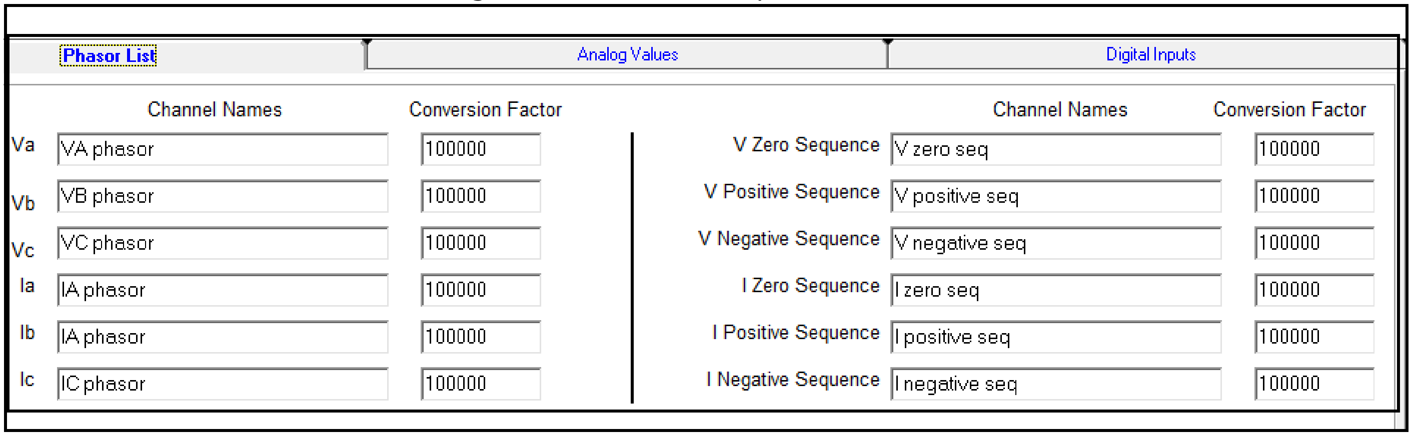
f. Phasor Coordinate System - select between rectangular and polar. Rectangular will provide horizontal and vertical dimensions; polar will provide magnitude and angle dimensions. Note that most users will select polar, but the standard and the Nexus® 1500+ meter support either.

g. Data Rate - choose the data rate from the pull-down menu. The choices you have are determined by your frequency rate (50 Hz or 60 Hz).The data rate is the reporting rate in frames per second.

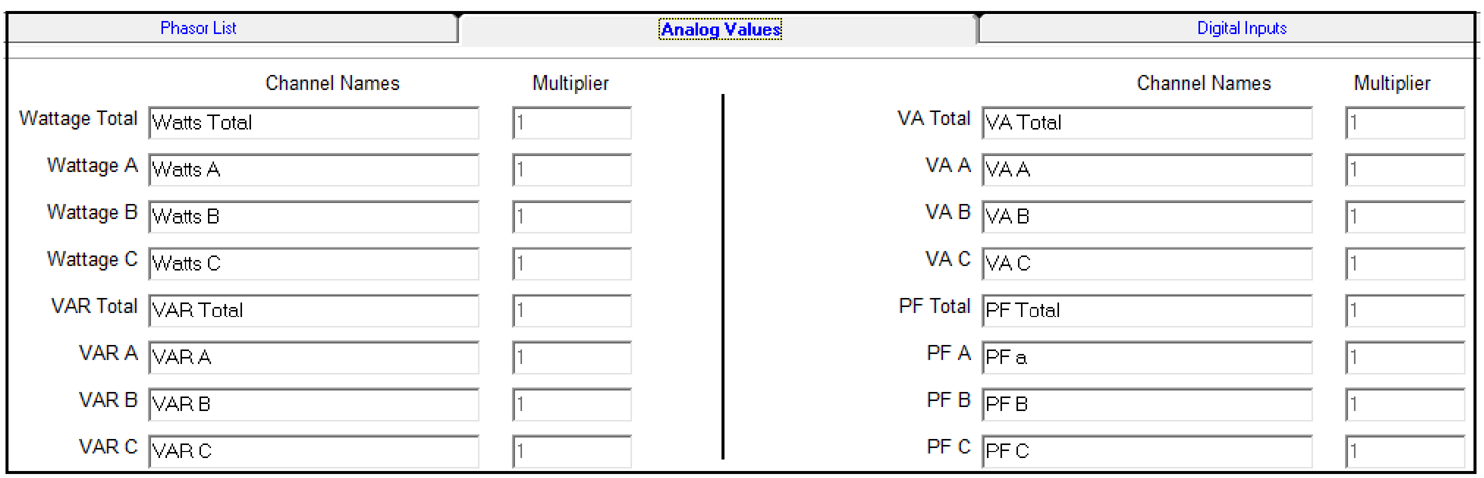
h. Report Type - check the box(es) for the PMU data you wish to transmit. Note that Individual Phasors is always selected. The other choices are:

- Analog (Watt, VAR, VA, PF)
- Symmetrical Components (V0, V1, V2, I0, I1, I2) zero/positive/negative
- Digital Inputs (the meter's high-speed digital inputs)

4. You will use the tabs to enter channel names and other settings for the phasors, and if selected for reporting, the analog outputs and digital inputs. You will only be able to make settings for the selected reports.

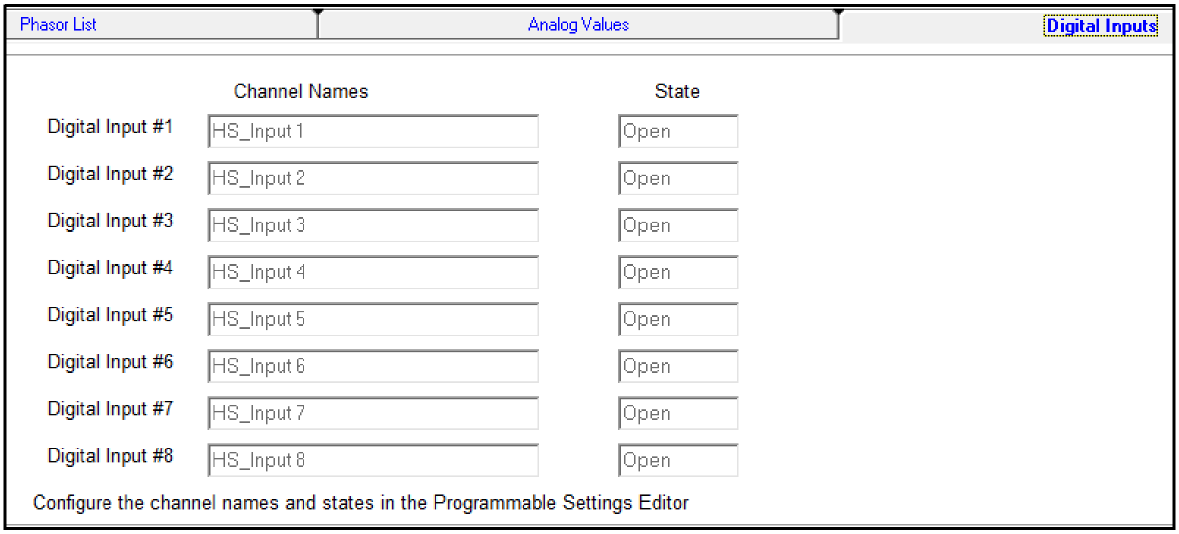


a. Phasor List tab: displays the phasor channel names and, if applicable, the conversion factor.
  - You can change channel names.
  - If you selected 16-bit integer for the phasor data type, you can use the Multiplier field to create a reading with greater resolution. The reading value will be divided by the conversion factor you enter. You will not be able to change this field if the phasor data type is floating point.

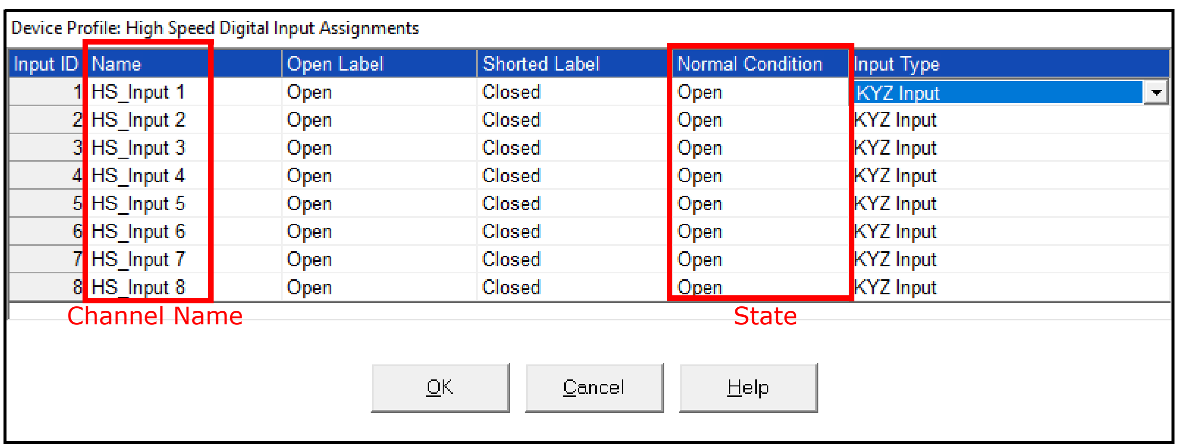


b. Analog Values tab: displays the analog value channel names and, if applicable, the multiplier.
  - You can change channel names.
  - If you selected 16-bit integer for the analog values data type, you can use the Multiplier field to create a reading with greater resolution. The reading

value will be multiplied by the number you enter, e.g., .001. You will not be able to change this field if the analog values data type is floating point.



c. Digital Inputs tab: displays the programmed channel names and state. The fields in this tab are not editable. You make the channel name and state assignments in the meter's device profile high-speed inputs setting (Power Quality and Alarm Settings>High Speed Inputs). See the example screen below.

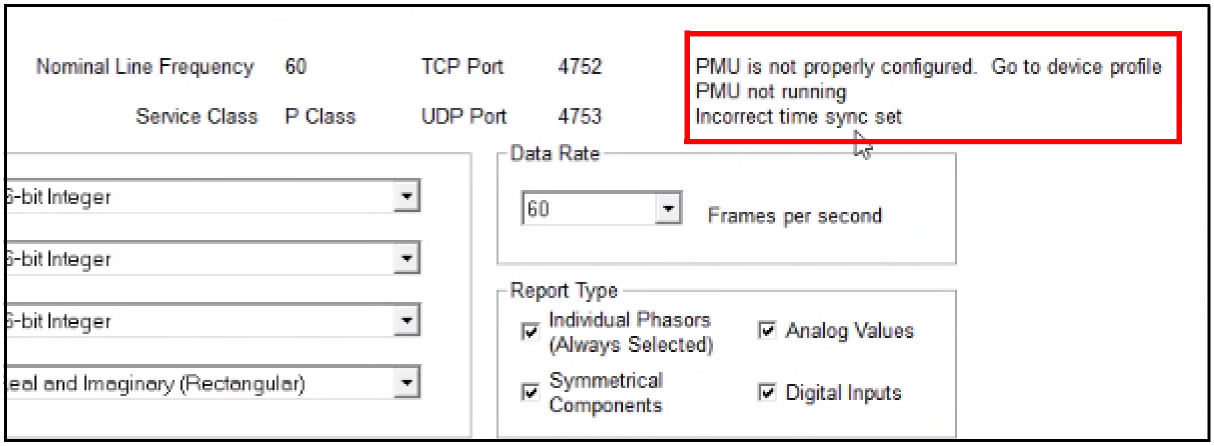


5. The bottom of the screen displays status information:

- PMU Status: whether or not PMU is running in the meter, i.e., enabled and configured properly, and whether or not data is transmitting.
- Clock Sync Status - IRIG-B or IEEE PTP, determined by the setting you made (F.2.1: Step One - Select Time Synchronization Method, on page F-2).

- Auto Send Status - Enabled or disabled, depending on the selection you made (F.2.2: Step Two - Enable Synchrophasors, on page F-8).

6. If there are errors in the PMU settings, e.g., if Time sync is not set, error messages will be shown at the top right of the screen. See the example below.



7. The buttons at the bottom are used as follows:

- Factory Defaults - load the factory default settings for all the screen fields.
  NOTE: When the meter's firmware has been updated from V15 to V20, EIG recommends that you click Factory Defaults to load the correct default settings and then make any settings changes you need. Even if you do not change the default settings, click Update Device before you close this screen.

- Update Device - upload the new settings to the meter. The meter will use these settings when it is acting as a PMU. After you select Update Device you will see a message screen with a countdown timer as the meter settings are being uploaded. The update process will take 60 seconds.

- Retrieve - retrieve the settings that are currently in the meter.

- Close - close this screen.

8. You have now finished programming the meter as a PMU. EIG recommends that you use your PDC to poll the meter/PMU to get the PMU configuration details. You will need these in order to correctly interpret the data that the meter-PMU transmits.

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Glossary

0.2 Second Values:	These values are the RMS values of the indicated quantity as calculated after approximately 200 milliseconds (3 cycles) of sampling.
1 Second Values:	These values are the RMS values of the indicated quantity as calculated after one second (60 cycles) of sampling.
Alarm:	An event or condition in a meter that can cause a trigger or call-back to occur.
Annunciator:	A short label that identifies particular quantities or values displayed, for example kWh.
Average (Current):	When applied to current values (amps) the average is a calculated value that corresponds to the thermal average over a specified time interval. The interval is specified by the user in the meter profile. The interval is typically 15 minutes. So, average amps is the thermal average of amps over the previous 15-minute interval. The thermal average rises to 90% of the actual value in each time interval. For example, if a constant 100 amp load is applied, the thermal average will indicate 90 amps after one time interval, 99 amps after two time intervals and 99.9 amps after three time intervals.
Average (Input Pulse) Accumulations:	When applied to Input Pulse Accumulations, the "Average" refers to the block (fixed) window average value of the input pulses.

Average (Power):	When applied to power values (Watts, VARs, VA), the average is a calculated value that corresponds to the thermal average over a specified time interval. The interval is specified by the user in the meter profile. The interval is typically 15 minutes. So, the Average Watts is the thermal average of Watts over the previous 15-minute interval. The thermal average rises to 90% of the actual value in each time interval. For example, if a constant 100kW load is applied, the thermal average will indicate 90kW after one time interval, 99kW after two time intervals and 99.9kW after three time intervals.
Bit:	A unit of computer information equivalent to the result of a choice between two alternatives (Yes/No, On/Off, for example). Or, the physical representation of a bit by an electrical pulse whose presence or absence indicates data.
Binary:	Relating to a system of numbers having 2 as its base (digits 0 and 1).
Block Window Avg (Power):	The Block (Fixed) Window Average is the average power calculated over a user-set time interval, typically 15 minutes. This calculated average corresponds to the demand calculations performed by most electric utilities in monitoring user power demand. (See Rolling Window Average.)

Byte:	A group of 8 binary digits processed as a unit by a computer (or device) and used especially to represent an alphanumeric character.
CBEMA Curve:	A voltage quality curve established originally by the Computer Business Equipment Manufacturers Association. The CBEMA Curve defines voltage disturbances that could cause malfunction or damage in microprocessor devices. The curve is characterized by voltage magnitude and the duration which the voltage is outside of tolerance. (See ITIC Curve.)
Channel:	The storage of a single value in each interval in a load profile.
Cold Load Pickup	This value is the delay from the time control power is restored to the time when the user wants to resume demand accumulation.
CRC Field:	Cyclic Redundancy Check Field (Modbus communication) is an error checksum calculation that enables a Slave device to determine if a request packet from a Master device has been corrupted during transmission. If the calculated value does not match the value in the request packet, the Slave ignores the request.
CT (Current) Ratio:	A Current Transformer Ratio is used to scale the value of the current from a secondary value up to the primary side of an instrument transformer.
Cumulative Demand:	The sum of the previous billing period maximum demand readings at the time of billing period reset. The maximum demand for the most recent billing period is added to the previously

	accumulated total of the maximum demands.
Demand:	The average value of power or a similar quantity over a specified period of time.
Demand Interval:	A specified time over which demand is calculated.
Display:	User-configurable visual indication of data in a meter.
DNP3:	A robust, non-proprietary protocol based on existing open standards. DNP3 is used to operate between various systems in electric and other utility industries and SCADA networks.
EEPROM:	Nonvolatile memory; Electrically Erasable Programmable Read Only Memory that retains its data during a power outage without need for a battery. Also refers to meter's FLASH memory.
Energy Register:	Programmable record that monitors any energy quantity. Example: Watt-hours, VAR-hours, VA-hours.
Ethernet:	A type of LAN network connection that connects two or more devices on a common communications backbone. An Ethernet LAN consists of at least one hub device (the network backbone) with multiple devices connected to it in a star configuration. The most common versions of Ethernet in use are 10BaseT and 100BaseT as defined in IEEE 802.3 standards. However, several other versions of Ethernet are also available.
Flicker:	Flicker is the sensation that is experienced by the human visual system when it is subjected to

	changes occurring in the illumination intensity of light sources. IEC 61000-4-15 and former IEC 868 describe the methods used to determine Flicker severity.
Harmonics:	Measuring values of the fundamental current and voltage and percent of the fundamental.
I2T Threshold:	Data will not accumulate until current reaches programmed level.
Integer:	Any of the natural numbers, the negatives of those numbers, or zero.
Invalid Register:	In the Nexus® meter's Modbus Map there are gaps between Registers. For example, the next Register after 08320 is 34817. Any unmapped Register stores no information and is said to be invalid.
ITIC Curve:	An updated version of the CBEMA Curve that reflects further study into the performance of microprocessor devices. The curve consists of a series of steps but still defines combinations of voltage magnitude and duration that will cause malfunction or damage.
Ke:	kWh per pulse; i.e. the energy.
kWh:	Kilowatt hours; kW x demand interval in hours.
KYZ Output:	Output where the rate of changes between 1 and 0 reflects the magnitude of a metered quantity.
LCD:	Liquid Crystal Display.

LED:	Light Emitting Diode.
Maximum Demand:	The largest demand calculated during any interval over a billing period.
Modbus ASCII:	Alternate version of the Modbus protocol that utilizes a different data transfer format. This version is not dependent upon strict timing, as is the RTU version. This is the best choice for telecommunications applications (via modems).
Modbus RTU:	The most common form of Modbus protocol. Modbus RTU is an open protocol spoken by many field devices to enable devices from multiple vendors to communicate in a common language. Data is transmitted in a timed binary format, providing increased throughput and therefore, increased performance.
Network:	A communications connection between two or more devices to enable those devices to send to and receive data from one another. In most applications, the network is either a serial type or a LAN type.
NVRAM:	Nonvolatile Random Access Memory: able to keep the stored values in memory even during the loss of circuit or control power. High speed NVRAM is used in the Nexus® meter to gather measured information and to insure that no information is lost.
Optical Port:	A port that facilitates infrared communication with a meter. Using an ANSI C12.13 Type II magnetic optical communications coupler and an RS232 cable from the coupler to a PC, the meter can be

programmed with CommunicatorPQA® software.

Packet:	A short fixed-length section of data that is transmitted as a unit. Example: a serial string of 8-bit bytes.
Percent (%) THD:	Percent Total Harmonic Distortion. (See THD.)
Protocol:	A language that is spoken between two or more devices connected on a network.
PT Ratio:	Potential Transformer Ratio used to scale the value of the voltage to the primary side of an instrument transformer. Also referred to as VT Ratio.
Pulse:	The closing and opening of the circuit of a two-wire pulse system or the alternate closing and opening of one side and then the other of a three-wire system (which is equal to two pulses).
Q Readings:	Q is the quantity obtained by lagging the applied voltage to a wattmeter by 60 degrees. Values are displayed on the Uncompensated Power and Q Readings screen.

Quadrant (Programmable Values and Factors on the Nexus® meter:)	Watt and VAR flow is typically represented using an X-Y coordinate system. The four corners of the X-Y plane are referred to as quadrants. Most power applications label the right hand corner as the first quadrant and number the remaining quadrants in a counter-clockwise rotation. Following are the positions of the quadrants: 1st - upper right, 2nd - upper left, 3rd - lower left and 4th - lower right. Power flow is generally positive in quadrants 1 and 4. VAR flow is positive in quadrants 1 and 2. The most common load conditions are: Quadrant 1 - power flow positive, VAR flow positive, inductive load, lagging or positive power factor; Quadrant 2 - power flow negative, VAR flow positive, capacitive load, leading or negative power factor.
Register:	An entry or record that stores a small amount of data.
Register Rollover:	A point at which a Register reaches its maximum value and rolls over to zero.
Reset:	Logs are cleared or new (or default) values are sent to counters or timers.
Rolling Window Average (Power):	The Rolling (Sliding) Window Average is the average power calculated over a user-set time interval that is derived from a specified number of sub-intervals, each of a specified time. For

example, the average is calculated over a 15-minute interval by calculating the sum of the average of three consecutive 5-minute intervals. This demand calculation methodology has been adopted by several utilities to prevent customer manipulation of kW demand by simply spreading peak demand across two intervals.

RS232: A type of serial network connection that connects two devices to enable communication between the devices. An RS232 connection connects only two points. Distance between devices is typically limited to fairly short runs.
Current standards recommend a maximum of 50 feet but some users have had success with runs up to 100 feet.
Communications speed is typically in the range of 1200 bits per second to 57,600 bits per second.
RS232 connection can be accomplished using Port 1 of the Nexus® 1250/1252 meter.

RS485: A type of serial network connection that connects two or more devices to enable communication between the devices. An RS485 connection allows multi-drop communication from one to many points.
Distance between devices is typically limited to around 2,000 to 3,000 wire feet.
Communications speed is typically in the range of 120 bits per second to 115,000 bits per second.

Sag: A voltage quality event during which the RMS voltage is lower than normal for a period of time, typically from 1/2 cycle to 1 minute.

Secondary Rated:	Any Register or pulse output that does not use any CT or PT(VT) Ratio.
Serial Port:	The type of port used to directly interface with a device using the RS232 standard.
Swell:	A voltage quality event during which the RMS voltage is higher than normal for a period of time, typically from 1/2 cycle to 1 minute.
TDD:	The Total Demand Distortion of the current waveform. The ratio of the root-sum-square value of the harmonic current to the maximum demand load current. (See equation below.) **NOTE**: The TDD displayed in the Harmonics screen is calculated by CommunicatorPQA® software, using the Max Average Demand.

$$TDD_I = \frac{\sqrt{I_2^2 + I_3^2 + I_4^2 + I_5^2 + \ldots}}{I_L} \times 100\%$$

THD:	Total Harmonic Distortion is the combined effect of all harmonics measured in a voltage or current. The THD number is expressed as a percent of the fundamental. For example, a 3% THD indicates that the magnitude of all harmonic distortion measured equals 3% of the magnitude of the fundamental 60Hz quantity. The %THD displayed is calculated by your Nexus® meter.

$$THD_I = \frac{\sqrt{I_2^2 + I_3^2 + I_4^2 + I_5^2 + \ldots}}{I_1} \times 100\%$$

Time Stamp:	A stored representation of the time of an event. Time Stamp can include year, month, day, hour, minute, second and Daylight Savings Time indication.

TOU:	Time of Use.
Uncompensated Power:	VA, Watt and VAR readings not adjusted by Transformer Loss Compensation.
V2T Threshold:	Data will stop accumulating when voltage falls below programmed level.
Voltage, Vab:	Vab, Vbc, Vca are all Phase-to-Phase voltage measurements. These voltages are measured between the three phase voltage inputs to the meter.
Voltage, Van:	Van, Vbn, Vcn are all Phase-to-Neutral voltages applied to the monitor. These voltages are measured between the phase voltage inputs and Vn input to the meter. Technologically, these voltages can be “measured” even when the meter is in a Delta configuration and there is no connection to the Vn input. However, in this configuration, these voltages have limited meaning and are typically not reported.
Voltage Imbalance/Unbalance:	As defined by National Equipment Manufacturer’s Association (NEMA), the formula for voltage unbalance is:

$$VoltageUnbalance = \frac{\text{Maximum deviation from the mean of Vab, Vbc, Vca}}{\text{Mean of Vab, Vbc, Vca}}$$

Voltage Quality Event:	An instance of abnormal voltage on a phase. The events the meter tracks include sags, swells, interruptions and imbalances.

VT Ratio: The voltage transformer Ratio is used to scale the value of the voltage to the primary side of an instrument transformer. Also referred to as PT Ratio.

Voltage, Vaux: This is the fourth voltage input measured from between the Vaux and Vref inputs. This input can be scaled to any value. However, the actual input voltage to the meter should be of the same magnitude as the voltages applied to the Va, Vb and Vc terminals.