North American SynchroPhasor Initiative (NASPI)

Performance and Standard Task Team (PSTT)

A Guide for PMU Installation, Commissioning and Maintenance

Part II

PMU Installation Procedures

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1. Glossary of Terms

BPA/PDCStream – An extension of IEEE 1344, widely used by the BPA PDC and human-machine interface software on the West Coast.

GPS – Global Positioning System. A satellite based system for providing position and time. The accuracy of GPS based clocks can be better than 1 microsecond.

IEEE 1344 [4] **–** A highly efficient protocol for real time SynchroPhasor data. Typically data is streamed in this format over UDP/IP or across a serial link.

IEEE C37.118 [3] **–** Related to IEEE 1344, but adds much needed capability. This protocol and its associated standard are intended to replace IEEE 1344 and the BPA/PDCStream protocols. Typically data is streamed in this format over UDP/IP or across a serial link.

NERC – North American Electricity Reliability Corporation

PDC – Phasor Data Concentrator. A logical unit that collects phasor data, and discrete event data from PMU's and possibly from other PDC's, and transmits data to other applications. PDC's may buffer data for a short time period but do not store the data.

PMU – Phasor Measurement Unit. A device that samples analog voltage and current data in synchronism with a GPS-clock. The samples are used to compute the corresponding phasors. Phasors are computed based on an absolute time reference (UTC), typically derived from a built-in GPS receiver.

SuperPDC – The PDC which is implemented to collect all the phasors of the Eastern Interconnection for the EIPP. It is physically located at TVA.

TCP/IP – TCP/IP is a low-level protocol for use mainly on Ethernet or related networks. Most of the higher-level protocols use TCP/IP to transport the data. TCP/IP provides a highly reliable connection over unreliable networks, using checksums, congestion control, and automatic resending of bad or missing data. TCP/IP requires time to handshake new connections and will block if missing data is being resent.

TVA – Tennessee Valley Authority

UDP/IP – UDP/IP is a low-level IP protocol that provides low-latency communication across Ethernet or related networks. UDP/IP does not provide any error-control or resending of missing or bad data. The Application will need to check data for correctness. UDP/IP however, does not require time for handshaking and will not block, making it ideal for real-time data communications.

UTC – Coordinated Universal Time (initials order based on French). UTC represents the time-of-day at the Earth's prime meridian (0° longitude).

CT – Current Transformer, used to couple an AC current from one circuit to another.

CCVT – Capacitively Coupled Voltage Transformer, used to transform the voltage on a high voltage power line to a lower voltage that is suitable for use inside a substation.

PT – Potential Transformer, used to transform the high voltage on a high voltage power line to a lower voltage that can be used with control and measuring circuits; this type of transformer usually uses magnetic coupling of wound circuits but can be a capacitively coupled unit.

FO – Fiber Optic, a means of transmitting signal values using light conducted on a fiber of optically conducting material.

EIPP – Eastern Interconnect Phasor Project

NASPI – North American SynchroPhasor Initiative

PRTT – Performance Requirements Task Team

PSTT – Performance and Standards Task Team

CRC – Cyclic Redundancy Check, a code affixed to a block of data that is computed from the data using a specific formula that can be used to assure to a high degree of reliability that the data has not been changed in any way since the CRC was computed.

BPS – bits per seconds

SONET – Synchronous Optical NETwork

2. Preface

In this guide are recommendations for PMU installation. This guide is based on general installation requirements for PMUs being manufactured in 2007 and typical (sub) station configurations. Some anecdotal information from utilities is included for informational purposes. Manufacturers' recommendations and specifications, and standard operating procedures of various utilities are ultimately the overriding concern and will require the installers to write their own procedures. A PSTT survey on PMU installation and maintenance shows different situations at specific utilities and substations. The summary of that survey can be found in Appendix I as well as in [6]. This guide should only be considered as a starting point, and will be expanded and modified from time to time based on user feedback.

3. Overview

PMU installation requires access to signals to be measured, a timing signal to synchronize the measurement, data communications to send the measurement, as well as a power supply. Each of these items is discussed in the pre-installation procedures below. A PMU primarily monitors AC voltage and current signals and estimates a phasor equivalent based on a time signal. A typical PMU uses an A/D converter to sample the three single-phase AC waveforms of a three-phase signal. It estimates a phasor equivalent for each single-phase AC signal, using the time reference to establish the phase. These estimates are usually combined to obtain a positive sequence equivalent that is recorded or reported. Single phase monitoring and reporting is a valid option and preferred for some applications (Figure 1).

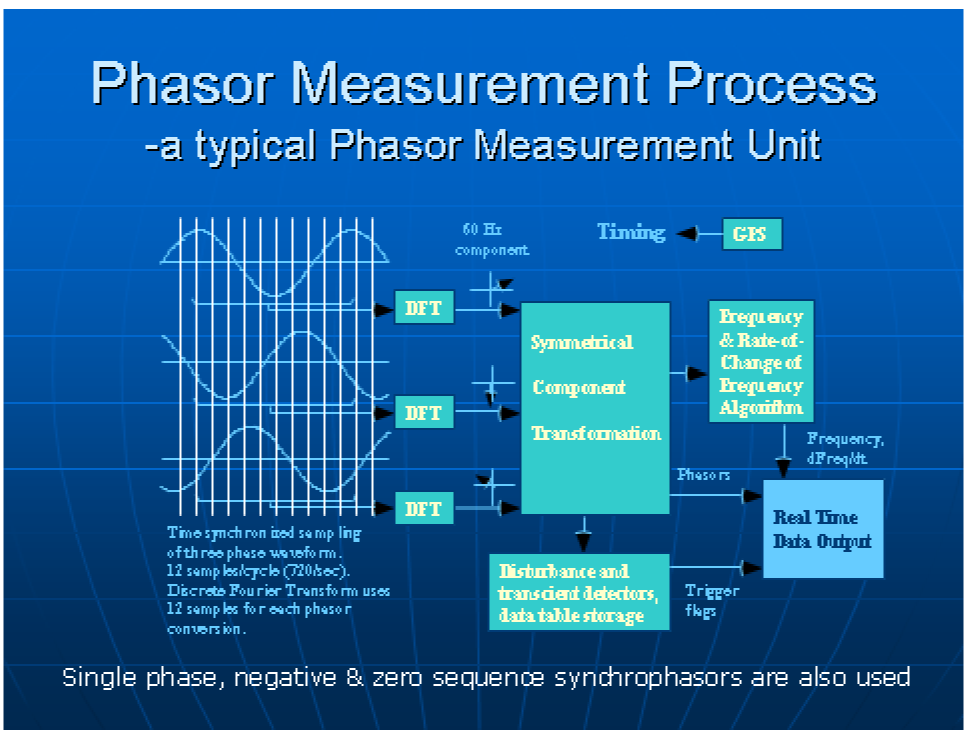


Figure 1. Typical PMU measurement process.

A PMU will typically monitor several three-phase voltages and currents. Data can be recorded locally, sent to a remote location in real time, or both. In this document it is assumed the users will be sending the data to a remote location in real-time whether it is locally recorded or not. If data are only recorded locally, skip the sections concerned with communications. A PMU needs access to a communication system that can transmit data at the PMU reporting rate and one that matches the format and interface. These requirements are detailed below.

In some cases the PMU will have status inputs (Boolean 1 or 0) or other measured value ("analog") inputs. Access to these signals will depend on the situation, but need to be considered at the planning stage.

4. Pre-installation procedures

4.1 Installation design

In most cases, a PMU installation is considered a permanent installation and requires a complete design. Each utility has different procedures for authorizing projects, designing installations, and carrying out construction. Below are only supplementary guidelines to help scoping a project and proceeding with the design.

PMUs need access to signals, time, data communications, and power. Generally power comes from an AC or DC source that is relatively easy to route anywhere. Communication ultimately goes out through some kind of terminal system within the (sub)station which is usually easy to access throughout the substation. Access to time and measured analog signals is usually the most difficult to design, so these issues will be considered first.

<u>Timing input</u>

Many PMUs input time from GPS directly, which requires an antenna open to GPS signals and a cable to the PMU within signal limitations. Antennas ideally have a clear sky view (free from obstructions) above a 15 degree elevation. In most cases this is difficult to achieve, and compromise factors need to be followed.

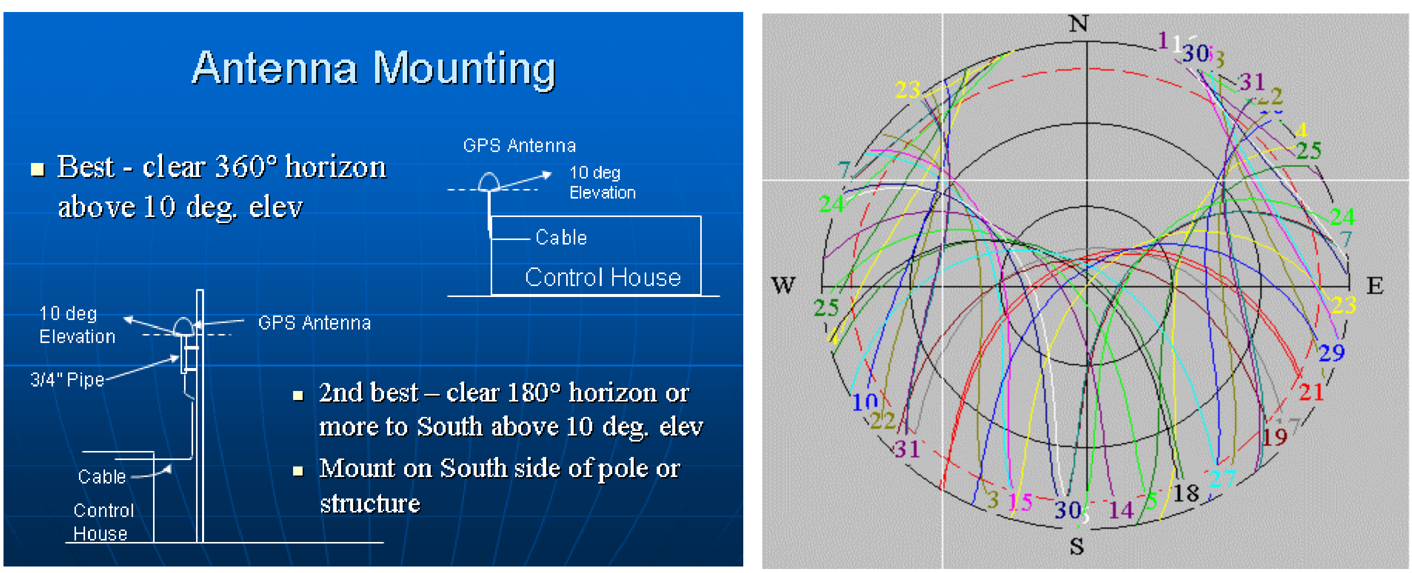


Figure 2. Recommended antenna mounting locations on pole or roof. Plot of GPS satellite trajectories for 45° North latitude shows that best coverage is to the south.

Most of the signals will come from the south (in the Northern hemisphere) from the horizon to about 15 degrees north of vertical (Figure 2). Small obstructions more that 15" away from the antenna should not cause a problem, but a large flat obstruction within a few hundred meters could act as a reflector and cause multi-path problems. The antenna should be mounted with a clear view to the south and as far north as possible. Check around the mounting location for structures—such as a flat metal roof—that is oriented so that it could reflect a satellite signal to the antenna (keeping in mind satellites will traverse most points in the sky). Also check for obstructions that can block the signal, and high power signal sources that could saturate the GPS input. Some GPS receivers have been operated successfully with the antenna mounted inside a building, receiving signals through the roof. In other situations mounting the antenna by a southerly facing window has been successful. Many less than optimal installations will experience some signal outage which degrades the measurement, so the safest option is an open air sky-view installation. The 1.5 GHz signal attenuates rapidly in a cable, and most vendors recommend limiting cable runs to less than 150 ft. There are alternatives for longer cable distances, such as high power antenna or in-line amplifiers and low loss cable. In many substations, roof access for cables is difficult, so a PMU should be located with this in mind. For an externally mounted antenna, it is advisable to incorporate a lightning arrestor into the design.

Some PMUs input time from a local source, such as a GPS receiver, using a local signal type such as IRIG-B [5], 1 PPS, Have-Quick, IEEE 1588, or something similar. Some of these signals degrade rapidly in a cable, and all signals are delayed in cables, so excessive cable runs should be avoided. When using this type of PMU, consult the vendor as to what signals they require and whether the delays are compensated. Use a signal source that will provide the required signals at the accuracy at the PMU required for meeting timing requirements. For example, IRIG-B may be specified and can be used in any of its modulated forms, but the DC level-shift or the Modified-Manchester coding forms will allow the highest accuracy.

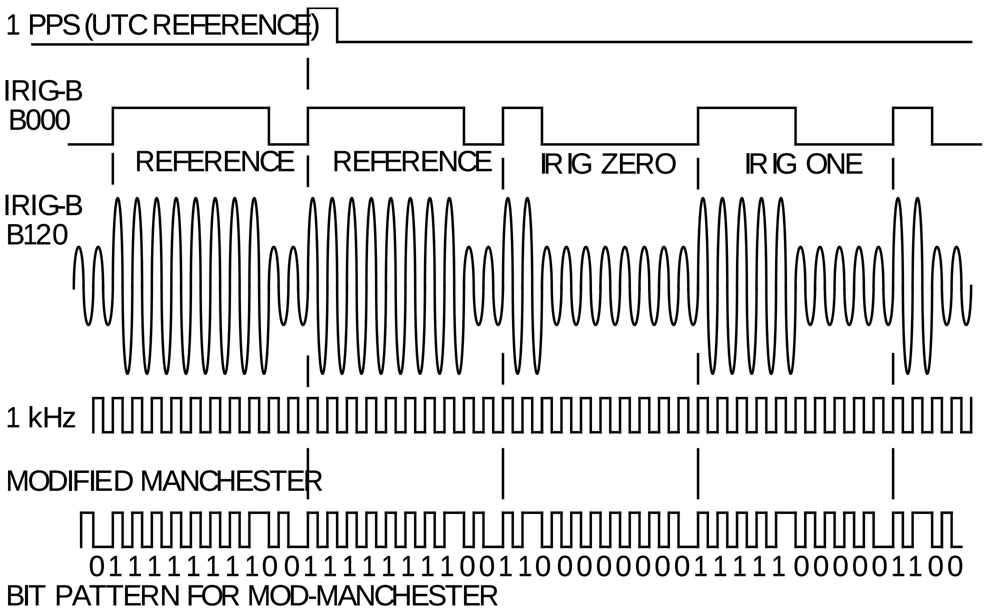


Figure 3. Example showing forms of IRIG-B comparing the un-modulated (level shift) B000, 1 kHz modulated B120, and modified Manchester B200.

Voltage & current input

Most PMUs convert voltage and current signals by sampling them with an A/D converter. This requires an installation that has access to these signals. In many substations, these signals are brought only to certain buildings or cabinets, not all to a single location. In these cases it is probably easier to install a PMU or PMU input unit where the signals are found rather than extend the signal cables (Figure 4). Of course installing multiple PMUs or input units will require installing multiple synchronizing signals (and possibly multiple antennas) and some local data distribution. This consideration may dictate the choice of PMU to accommodate the station configuration. If possible, the PMU should be installed with test access to the PT & CT inputs so test signals can be injected for performance tests and calibration.

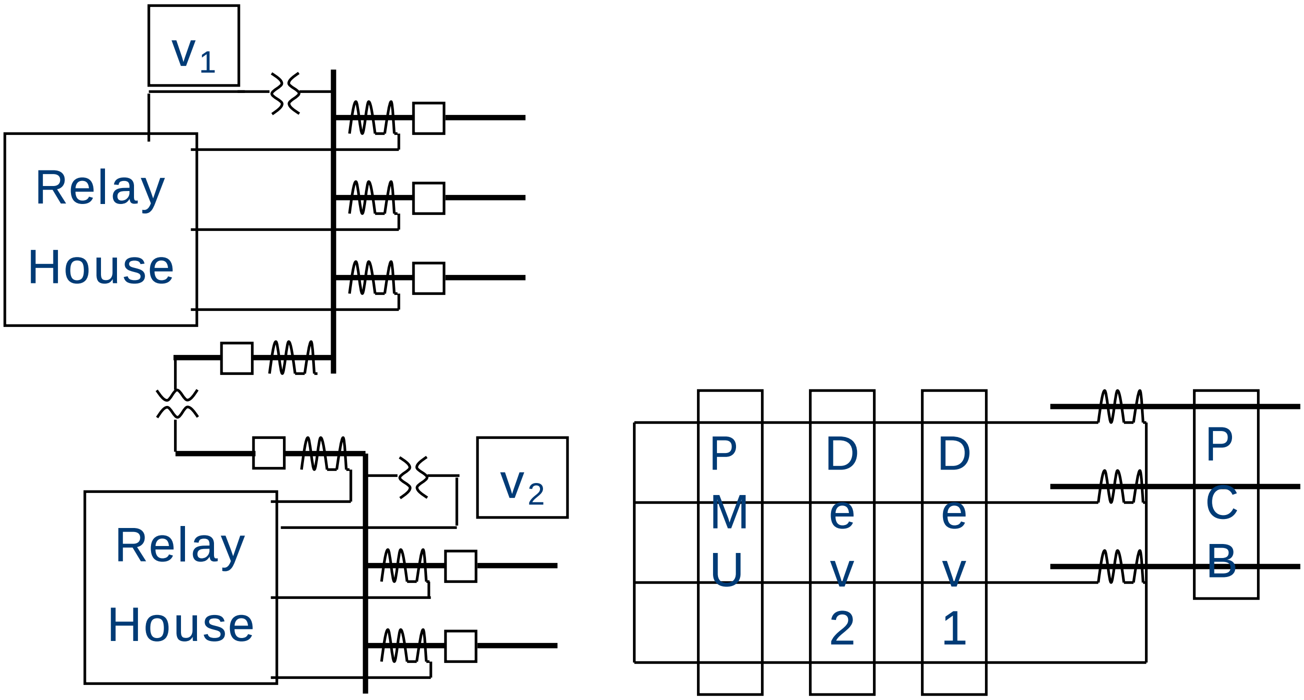


Figure 4. When voltages and currents are brought into different relay houses, it is necessary to use more than one PMU or a PMU that has remote sensing units. A PMU needs each phase current; when sharing with other devices, carry all 3 phases through to the return.

Good measurements require consideration of the signal. The measurement speed has to be fast enough to capture required frequency contents. The range needs to be high enough to capture required maximums and low enough for resolution. The PMU device should have adequate sample rates and filtering for accurate signal representation. See the PSTT testing guide for those considerations [1]. The PMU will specify the maximum input range and resolution. Power system voltages rarely deviate more than 10%, so the input should be set so the voltage input is 50-75% of the maximum allowed. This gives some overhead for large swings, but good resolution for nominal input. Currents will operate over a much larger range. Fault recording and relaying requires a scale that will accommodate very high currents; phasor measurements are concerned with normal operational and system swing currents which range from somewhat over nominal to light load (10% of nominal). Setting the maximum at about 2X nominal will give good measurements at light load and normally cover swings. However, it may be considered more important to capture all swings and overloads at the expense of lighter loads. Sometimes the PMU is a part of another device, such as a relay or DFR and the calibration will be dictated by another requirement. This is a user consideration where the user needs to be aware of the tradeoffs.

The PMU will also derive frequency from one of the AC input signals. These are fully user selectable in some PMUs and fixed in others. Some PMUs will allow selecting a backup channel when the primary one has a low signal. To assure a good frequency measurement, it is best to select a voltage input channel which has good signal strength, since these don’t vary as much as currents.

<u>Analog & digital input</u>

Some PMUs allow connecting "analog" inputs. What this refers to is a non-sinusoidal signal that represents some other kinds of measurement, such as a MW transducer, transformer temperature, or stability control setting signal. This signal value will be reported along with phasor values in the time synchronized data packet, which opens up the use of phasor data for many real-time and analysis applications. Generally these data signals are easier to route than high-current CT circuits, but they need to be considered. All PMUs should allow digital "status" inputs. These are Boolean 0 or 1, and are represented as a single bit in a digital word. Access to these signals is usually not difficult, but again need consideration.

Power input

Since PMUs need to operate continuously, and particularly without interruption during disturbances, they should run on station DC power. Be sure the PMU will run on whatever uninterruptible power source is available at the station, such as 125 VDC.

Communications

The PMU will need communication access. Communications are usually the most problematic part of phasor measurement systems, so it pays to carefully plan the system and be sure all aspects are addressed. The first part will be cabling from the PMU to some kind of communication interface. Next will be the interface itself. Last, at the PMU end, is the communication system. The overall system including the application end (PDC or other devices) requires complete planning, but that is beyond the scope of this document.

Cabling is required between the PMU and the communication interface (modem, router, etc). Most cabling is small and rather easy to route and install. The principal issues are interference and cable length. Substations are notorious for high interfering signals, particularly during a nearby fault. The best policy is to use fiber optic cable (FO) for all signals that travel outside of a single rack (grounding unit). However, practically speaking, a signal within a building can run in metallic cable as long as the length does not exceed maximum specified distances. If the signal is to run between buildings, it should be run over FO cables. In some cases this requires signal converters at each end, but many vendors have FO I/O built into their equipment.

Metallic cable can be selected to minimize the most likely sources of interference. Coaxial cable has good electrostatic shielding but is subject to electromagnetic interference, particularly where ground differences can occur (conduction through the ground). Shielded twisted pair (Cat5) has good rejection for both electrostatic and electromagnetic interference, but all shielding has limitations. High magnetic fields can penetrate most kinds of shielding, so are best treated by avoidance. It is best to route cables with some thought as to what is in close proximity. Also note that many substation cables are large and heavy, so they may pinch a poorly routed communication cable resulting in loss of shielding and transmission properties. Table 1 below summarizes the signal types, the recommended and practical length, and some comments. Please refer to PSTT's "SynchroPhasor Accuracy Characterization" document for more considerations regarding cable selection [8].

Table 1 Recommended cable lengths for signal transmission

Signal type	Cable type	Recommend max length	Interference/comments
Asynchronous serial (RS-232)	Twisted pairs	15 m @ 20K BPS	Actual length depends on cable & rate.
V.35	Twisted pairs	600 m @ 100K BPS 90 m @ 10M BPS	Standard well specified and followed. Widely used outside of US.
Synchronous serial (RS-422)	Twisted pairs	1200 m @ 100K BPS	Bipolar low level signal has good transmission characteristics

Ethernet thin-net	Co-ax		Good static shielding, use tri-ax where there are grounding issues
Ethernet 10BaseT	Cat4	100 m	Good shielding, move up to Cat5 for better signal
Ethernet 10/100BaseT	Cat5	150 m	Good shielding, use ruggedized version for better mechanical protection **
Ethernet 100BaseFX	FO	2 km	Best for interference rejection & avoiding grounding problems

** Std CAT5 is Unshielded Twisted Pair (UTP). This should be Shielded Twisted Pair (STP)

In addition to the physical installation summarized above, the communication types need to match in type and rates. This is an extensive area and will not be detailed here. The basic consideration is the PMU itself and data rates required by the measurement system. The PMU must be chosen so that it will output measurements at the rate required by the measurement system. If the system runs at 30 samples per second, the PMU needs to measure and output data at 30 samples per second.

PMUs generally will have asynchronous serial (RS-232) or Ethernet communications. Both will handle data at the rate and block size used in most measurement systems. An interface device between the PMU and the communication system is required. This area is not really clear since vendors have used terminology loosely to describe their products. Generally, a modem translates between a digital data system and an analog communication system, and a CSU/DSU or router or bridge translates between a digital data system and a digital communication system. In either case, the PMU output is a digital data type and needs one of these devices to interface to the communication system. The important points are the appropriate sides of the interface have to match the PMU and communication system, and must handle the required data rate. If the PMU output is asynchronous serial, the interface must handle asynchronous serial at the given rate.

Table 2 Examples of required data rates using C37.118 data format & protocol.

30 frames/sec	**All Integer format**	**All floating point format**
5 phasors, no analog/digital	1260 bytes/sec	1980 bytes/sec
10 phasors, no analog/digital	1860 bytes/sec	3180 bytes/sec
5 phasors, 2 analog/ 1 digital	1440 bytes/sec	2280 bytes/sec
10 phasors, 2 analog/ 1 digital	2040 bytes/sec	3480 bytes/sec

Notes:

- Asynchronous serial requires 10 bits/byte, so required BPS rates are 10X the above figures.
- UDP/IP over Ethernet has a fixed size overhead of 54 bytes per packet, so actual required rate is higher than the requirement above. It ranges from 23,040 BPS for phasor/integer to 41,120 BPS for the 10 phasor-2 analog-1 digital/floating point shown above.
- Since data is sent continuously at the rates shown in the table, the communication channel must have a capacity at least that large and should be at least 10% higher than the required data rate to accommodate error correction and short dropouts. The PMU port speed will likewise have to be equal or higher than the actual data rate. In many cases this requires high serial data rates, such as 38.4 or 57.6 KBPS.

Generally speaking, asynchronous serial ports interface better with analog modems than digital type interfaces. Analog modems are also easy to interface with analog communications. The problems with analog modems include limited bandwidth and data loss due to communication impairment. Also, as digital communication becomes more prevalent, there is decreasing availability and support for this equipment.

PMU communications by Ethernet match directly with digital systems and interface well with digital communications, such as SONET. Ethernet based digital systems are well developed and supported, so building these systems is generally very straightforward. Care needs to be exercised when connecting the local Ethernet system through a digital communication system (e.g., SONET), usually called the WAN connection. The WAN needs to support the minimum data rate with some room for overhead and the interface needs to have sufficient buffering to match WAN & Ethernet speed differences. Most of these systems currently use Internet Protocol (IP) for data communication. Building and managing these systems is centered on setting up IP hosts, subnets, and routing.

Summary

The following table summarizes basic design considerations somewhat in the order of importance. Since any factor can impact the whole project, it is important to scope out the whole project before deciding on equipment and making the designs. These are only the installation considerations. For the overall project consideration, spare parts, training, overall cost, and company policies are also important. Use this installation information while keeping the overall project in mind.

Table 3 Summary of design considerations for PMU installation

Question	Answers	Alternate answer
How many phasor inputs are needed?	How many voltages are available or important? Are bus voltages available? If only line voltages are available, it is advisable to use two or use one with a backup in case a line is out of service.	How many feeder currents are needed for important power flow calculations?
Are all measured signals at a single location?	Yes. Choose a single PMU type that supports the number of signals.	No. Choose PMU type that can be networked or install multiple PMUs that will handle all inputs at a single location.
Does PMU require direct GPS input?	Yes. Choose location that will have access to antenna (a single antenna can serve several receivers).	No. IRIG-B/1PPS signals are generally easier to route, but check wiring availability.
Does the PMU output match the communication system interface?	If system is digital and PMU is RS232, be sure interface is available in type and speed	
What type of communications are established within the substation?	If FO, will it match PMU? If not FO, are distances short enough for galvanic? Grounding problems?	

DC power available?	Be sure PMU matches the DC voltage available.	
Need to modify PMU operating characteristics remotely?	Yes, choose PMU that allows changing settings remotely?	
Will the circuit handle the PMU burden?	Yes, no problems.	No, choose a PMU with lower burden, such as isolated instrumentation CT or different circuit.
Does the application have particular filtering needs?	Yes, be sure the PMU has settings that match or use alterable settings.	No, any PMU qualified in other respects will do.

4.2 Pre-installation tests

The extent of pre-installation testing depends on utility policies and resources. This can range from complete performance testing and a mock-up of the entire communication system to no testing at all. At a minimum, some quality assurance testing should be done to be sure units work in the planned system and are reasonably in calibration. If the host utility has relay test sets or an equivalent signal generator, it is relatively easy to put signals into the PMU and check that the output meets specifications for a few magnitude and phase angle checks. If not, this could be done by a contractor.

Overall, a host utility should have a complete set of test data for each PMU type they use. The utility could do their own tests, or have it done at a test lab capable of doing the tests. PMUs sample and process data digitally. Each type will have characteristics that differ from other types, but will produce measurements the same as other PMUs of the same type. It is not necessary to fully characterize each one that is installed. Also, since the A/D inputs tend to be accurate and stay accurate, it usually is not necessary to do a precision calibration on each individual unit (but it doesn’t hurt either). The PSTT PMU test guide or an equivalent test procedure should be followed for PMU characterization and calibration.

If the PMU is going to be installed in a rack that will be shipped to a substation, the verification test should be done on the completed rack to assure the PMU is working and the rack is wired correctly. Bringing the test signals into the host system will confirm that the whole system less the remote communications operates together. All the tests that can be done in a shop where everything is at hand will save time in the long run. It is very difficult to troubleshoot a system a hundred miles away when all you have to go on is data that may not be coming in reliably. Typically the biggest problem is data communications, so minimizing other problems ahead of time is worth the effort.

A risk assessment is needed to investigate worst case problem scenarios which may occur while commissioning the PMU installation. This risk would include information from an equivalent to Transmission Services with respect to power system conditions allowed during commissioning.

Cyber security issues have to be resolved beforehand with information services. Each utility will have its own recommendations, but the use of a VPN form of communication not connected to the internal LAN is one option to provide isolation and security. Communication links should be in place prior to the day of commissioning the PMU.

5. During Installation

Installation is usually done by specialized crews with participation from: Information Services, Plant Engineering, Protection Maintenance, Communication Engineering, Commissioning, and Transmission Services. The project manager can help coordinate these groups with a few meetings to ensure questions are answered in all areas beforehand. Scheduling the project is one of the biggest challenges especially since the priority of the work is often low.

The project manager should be aware of when the commissioning is to be done and be on hand for any questions (preferably with some wiring drawings nearby and verbal communication to the PDC site).

6. After Installation

Depending on the utility, the measurement system user may or may not be involved in the checkout and final calibration. If not, the checkout/calibration data should be supplied to the user who will confirm full system checkout. It is important to assure measurement continuity from instrumentation to the end application.

The checkout at this point is to confirm operation on actual system signals. Full calibration and characterization of the PMU and measurement system should be done in a lab environment where the input values can be precisely controlled. If the PMU installation is equipped with a complete set of test jacks, the inputs can be accurately measured, but since the real system is constantly changing, it is difficult to achieve precision. Test jacks can be used for injection of calibration signals which will be useful for periodic maintenance; this is covered in the PSTT's "A Guide for PMU Installation, Commissioning and Maintenance: Part III – PMU Maintenance Procedures".

The principal points covered here are:

- Is the measured quantity the correct one?
- Are the values reasonably close to correct?
- Are the measured values in reasonable agreement with other measurements?
- Is the phasing relative to other local signals correct?
- Is the signal phasing in agreement with other PMUs?
- Is the PMU locking to the synchronizing signal and staying locked?
- Are the communications performing well?

<u>Correctness of measured value</u>

The most reliable method of checking the measured values is comparison with the input. This is easiest to do if the PMU has a local readout or tool that provides a local readout. Measure the input V & I with a calibrated meter. The positive sequence phasor magnitude is approximately the average RMS of all three phases (Figure 5). Be sure you are measuring at a time that there are not huge value swings. Read all 3 phases with an RMS meter and note the measured phasor value in quick succession. Average the three readings and compare that with the PMU measurement. For voltages, these should be within 2% and currents within 5%. If the currents are very steady and midrange, the comparison should also be within 2%. If phase imbalance is significant (>

5%), it is advisable to use phase angle as well as magnitude readings to come up with the estimated value, since this also affects the positive sequence equivalent.

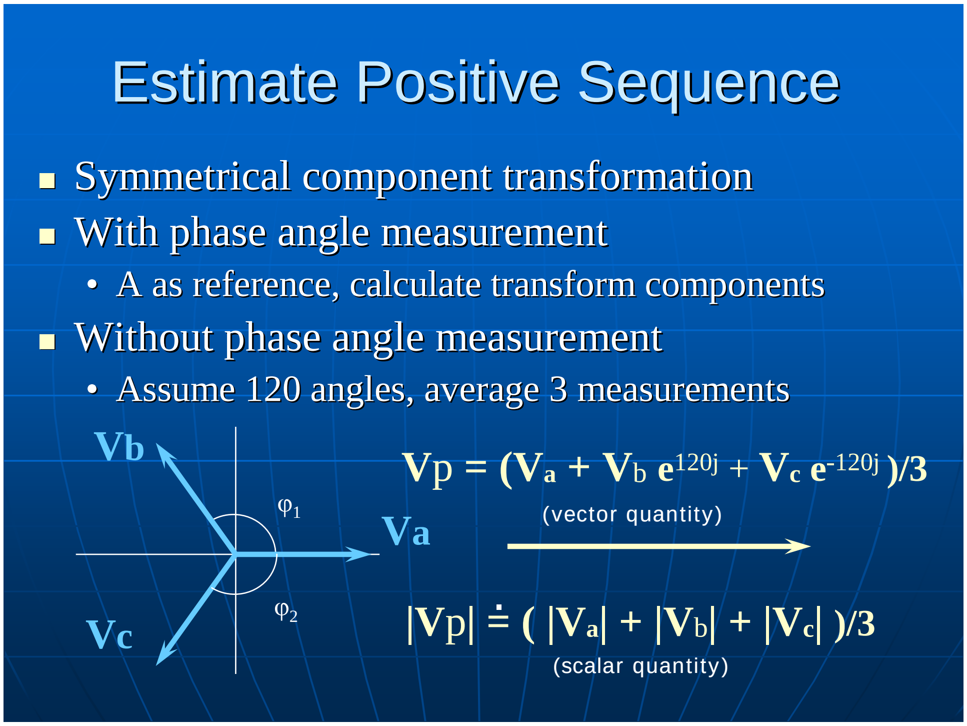


Figure 5. Estimate positive sequence from individual readings if power system is reasonably well phase balanced.

<u>Comparison with other measured values</u>

Checking input with measured value assures the wiring is correct and the PMU channels are working. It does not assure the input is actually from the line or bus that is supposed to be measured. Short of tracing wiring from the PT or CT device, the best way to check this is comparison with existing measurements. Compare with panel meters and transducer measurements such as through the SCADA system. These often don't agree very closely, so don't be alarmed. Most panel meters and transducers are based on analog technology and are not very accurate at low levels. Voltage is fairly constant at a median value so it is easy to get a good comparison. Currents vary greatly, and are often low, so it may be difficult to get a good reading. The important thing is that with proper scaling the voltage should be within a few percent and the current should agree in direction and generally in magnitude.

Issues with using these measurements include those on single phase voltage or current and only power measurements. Use single phase metering just as with 3 phase without averaging; just be aware that it can be further off than you would normally expect. If there are only power measurements, you can either combine the phasor current with the appropriate bus voltage and compare power, or divide the power measurement by (1.732 * voltage) to determine the current. Current in phase with voltage (< +/- 90 degrees) is considered current out of the bus and combined with bus voltage will compute as power out of the bus (Figure 6).

Don't expect the readings to agree closely, even if the PMU is carefully calibrated. The error is often (usually?) in the SCADA measurements. Many SCADA voltage measurements use only single phase transducers. It is common to have 2-3% imbalance in phases which show up as a 10-15 kV difference in measurements. Transducers that are calibrated infrequently can further increase error. Modern digital displays show as many digits as the user wants to see, whether they mean anything or not. Displays frequently use 4-5 digits even though the measurement accuracy is usually limited to 2-3. Consequently the user sees measurement errors where there are none. Phasor measurements are often suspected because they disagree with SCADA, and

SCADA is the reference everything is compared to. It pays to check the phasor measurement well enough to be sure it is defensible if there are perceived differences.

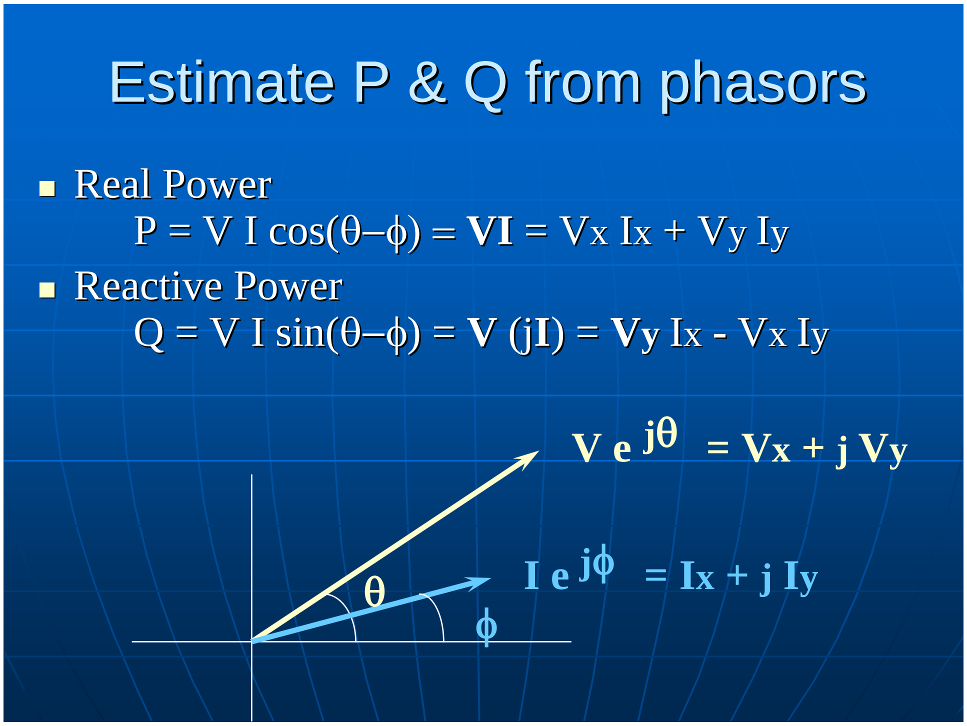


Figure 6. Estimate real and reactive power from complex phasor values. Be sure to use the phasor scaling values as well as PT/CT ratios.

Another valuable comparison is the System State Estimation (SE) value for the measured phasors. SE can provide accurate voltage and current amplitude, and phase angle relative to the reference (swing) bus. Comparing this with another certified PMU can provide a good check of measured phase angle. Be sure the comparisons are made at the same time since loading and angles constantly change.

Phasing of local signals

Once the phasor measurements can be confirmed as correct and defensible, the phasing of the signals relative to each other should be checked. A-phase for each signal must be correctly wired as A-phase for the conversion. If not, signals will be displaced +/- 120 degrees from what they should be. Current inputs should be oriented so that current is approximately in phase with voltage when power is flowing out of the bus. CT circuits can be easily reversed, so be sure to check this. (Some utilities use the opposite orientation, so check with your utility design standards.) Generally current will be within ±20 degrees of the voltage (power leaving the bus) or 160 to -160 degrees of the voltage (power entering the bus). Your utility standard may be the opposite, so check this before reversing the CT wiring. The exceptions are if the current is feeding a reactive device or an open line. If feeding a capacitive device or open line it should be about 90 degrees leading and a reactor about 90 degrees lagging. However, if feeding a synchronous condenser the angle can be either way. In any case, be sure the current directions are properly oriented relative to the voltage. It is usually instructive to convert the phasor values into MW and MVAR and compare with other measurements. At low values, various measurement systems may differ significantly, but anything near full scale should be within a few percent. MVAR is typically difficult to confirm, since it is usually very small in relation to the feeder MVA. Again, comparisons with the System State Estimator are another good way to check the measurement.

System signal phasing

This is the topic of a whole paper written by the PSTT [7]. Generally within a single utility, A-phase is well defined and the same at all substations. The easiest way to determine that A-phase at a new PMU installation agrees with other installations, is to compare the phase angle with the nearest installed PMU. It the two stations are adjacent to each other, the angle between them can be approximately calculated by:

$$\phi = \arcsin(\frac{PX}{V_1 V_2})$$

where P = power flow on the line, X = line reactance, and V_1 and V_2 are the bus voltages. Line resistance and line charging are neglected. Power always flows from a leading angle to a lagging one. The measured angle should be reasonably close to the value calculated from the power flow above. If the stations are not adjacent, or the parameters are not well known, this heuristic approach can be used: power flows from buses with leading angles to those with lagging angles. If there is little power flow, the distance is short, or the impedance is low, the angle will be small. Higher voltage systems have lower impedance. Multiple lines or a meshed grid has lower impedance. Note the power flow in the area between the stations being compared. If it is notably flowing from one to the other, the angle definitely should match in polarity. If the stations are fairly close, say within 200 miles, expect an angle of 30 degrees or less. If they are more distant, it could be higher, even over 90 degrees in a meshed grid. If the power flow between stations is not clearly one direction or the other, the angle could go either way but the total should be smaller, perhaps in the area of 15 degrees. Ultimately, without a number of accurate power flow measurements, it is difficult check the accuracy of phase angle measurements. However, the main objective here is to confirm measurement phasing. A phase selection error results in a 120 degree phase shift, which should be distinguishable from the angles estimated by power flow. Note that it is not possible to determine inter-station phasing errors using only one station. Phase angle measurements are relative to absolute time and do not indicate relative bus measurements. Also note that comparing phase differences across Y-Δ and phase shifting transformers as well as series capacitors can produce results that make phase checking difficult to determine. Generally a 120 degree error is big enough to be obvious, but pay attention to all these factors. Loading at the time of comparison will affect the phase angles seen so a few tests throughout the day at different loadings are needed to confirm the phase angles seen are within a reasonable range. Large errors of 30 degrees can usually be detected if the PMU is assumed to be connected for line-to-neutral measurements but is actually line-to-line (or vice-versa). Large errors of 120 degrees can also be detected if the rotation of the sequences for phase A, B and C, is in a different order than expected. With these large errors removed, comparison to SCADA load flows can be expected to be within 5 degrees.

Time synchronization

Most PMUs have direct indication of time synchronization. This should indicate time synchronization as soon as the power is on and time synchronization is supplied. Since this will be vendor specific, only general observations will be offered here.

If time synchronization is supplied directly from GPS with a built-in decoder, the system should show lock with at least 4 satellites at all times. If fewer than that are indicated after initial lock, the antenna may be impeded or there may be a source of interference. An over-length cable run or damaged cable can also lead to low signal and tracking fewer than optimum satellites. Initial lock may take a while, up to 30 minutes, but re-lock after a reset or power cycle should only take a few minutes. Lock will be indicated in the data. This should be observed closely the first few days to be sure the PMU maintains continuous lock. If it does not, again check the antenna, cable, and overall installation.

If time synchronization is supplied by another system through a signal, such as IRIG-B [5], the PMU should indicate lock shortly after the system is powered on provided the clock sends quality extension bits as specified in IEEE 1344 [4] or C37.118 [3]. The PMU should provide an indication that it is locked to the signal. Monitor this closely for the first few days to be sure it maintains continuous lock. Some time codes include a quality indicator generated by the signal source, and this may be monitored by the PMU; if so, check this as well during the break-in period. A local signal source could be set to local time (daylight or not) as well as UTC. By standard, all phasor measurements are provided in UTC time, so it may be necessary to adjust settings in the time source or the PMU. Check vendor specifications for these issues.

Communications operation

Communications from the PMU to the data concentrator is a critical link and often the most troublesome. Initial checkout details depend on the particular system. A few general observations are offered here.

Data are sent at the selected reporting rate from the PMU in packets that are precisely timetagged and terminated with a CRC or checksum. In many cases, the communication medium provides its own packetizing with a check word. The receiving device (e.g. PDC) should use the check word to detect corrupted data and timetags to keep track of missing data. This information is essential for initial system checkout as well as ongoing maintenance and repair.

After installation, corrupt and missing data should be monitored closely for a few days. A good communication system should not lose more than 3 packets/hour at a data rate of 30 samples per second. At the receiving end, it is not possible to differentiate between data that has been lost in communications and data that was never sent. Pre-installation testing should include enough monitoring to prove that the PMU outputs data reliably (or does not!). Here it is assumed missing data indicates losses in the communication system. Losses greater than 5% are seriously underperforming and need to be fixed. The amount of tolerable loss depends on the application and user. Real-time applications that need to operate within the span of a few packets need very high reliability. If the user is only using the data for trending or translation to SCADA rated, a 5% loss may be tolerable, depending on how it is distributed.

Patterns of data loss indicate different problems depending on the type of communication. RS-232 serial systems using analog or digital communications will have a few check word errors and a few lost packets per hour with a normal communication system. It may show increased loss—particularly longer periods of outage—at certain times of day if affected by fading (temperature related). Occasional to frequent outage blocks can indicate communication system synchronization problems or modem re-synchronization due to low signal levels. Any more than a few lost samples/hour usually indicates a communication problem that can be resolved. Experience has shown this type of system with solid and well maintained communications can run for weeks without a single lost packet.

Network based systems over analog communications will behave somewhat like the RS232 mentioned above. Network over digital communications can be divided into connected types like TCP/IP and non-connected like UDP/IP. TCP provides packet ordering and re-transmission in the case of missing or corrupted packets. With a good communication system, data will be delayed occasionally, but otherwise there will be no data loss apparent to the user. With a degraded or overloaded system, data delay may become significant enough that TCP cannot recover lost packets and there will be longer outages while the system holds data waiting for recovery, and then has to re-synchronize the data stream.

With UDP, data is sent to a destination, but there is no built-in ordering or recovery. Sometimes ordering and re-transmission can be built into the application. UDP is used commonly with phasor measurement systems since it is fast, un-delayed, and simple. A small amount of lost data is tolerable and preferable over delayed data in many applications. With a good communication system, data will rarely be delayed and data loss will be less than 1 packet/hour (in practical experience, these systems have be observed to run weeks without any data loss). Occasional packet loss is expected. If a general purpose network is being used, there may be greater loss during periods of heavy use. Router or switch mis-configuration problems can cause unresolved collisions resulting in high loss. Loss greater than 3 packets/hour warrants investigation, particularly during installation time, since that indicates a configuration error.

Once in service, the user will have to determine by experience what is indicated by different patterns of data loss. A complete outage can indicate PMU failure or communication system failure. Varying degrees of loss can indicate configuration errors, overloads, synchronization issues, and so on. Being able to provide guidance to maintenance staff speeds repair and helps in maintaining the system in top operating condition.

Record keeping

A permanent record of installation details and initial tests is important. The installation will normally have formal drawings that include wiring and physical layout, but not necessarily details of scaling, ratios, and settings. A clear record of settings is essential for checkout, verification, and ongoing maintenance. This record should include all PT/CT scaling, PMU calibration factors, communication settings, triggers, limits, and recording parameters. It should be used and confirmed during the checkout outlined above. Additional information like cable type and length, CT/PT/CCVT details, etc. can help with other efforts ongoing in the NASPI. The record of initial tests can be used as a baseline during ongoing maintenance and provides a baseline for problem resolution. In the past, installation test records have been used on several occasions to see if a particular issue was actually tested initially or was the result of a change in the system, or some kind of component failure.

7. Conclusions

This PMU installation guide has been produced by the PSTT, first under the EIPP project and continuing under the NASPI. It is intended to supplement vendor instructions and utility company guidelines for the installation of PMUs. Details for installation depend on the actual equipment being used. Use this as an overview or as an outline for developing your own company guidelines and policies. Please report any omissions or discrepancies as well as further suggestions to the PSTT. This is intended to be a "living document", subject to continuous update.

8. References

[1] *"PMU System Testing and Calibration Guide"*, Performance and Standards Task Team (PSTT) of the North American SynchroPhasor Initiative, 2007.

[2] *"Implementation of Virtual Bus Angle Reference"*, Performance Requirements Task Team (PRTT), Eastern Interconnection Phasor Project, January 2007.

[3] *"IEEE C37.118-2005, IEEE Standard for Synchrophasors for Power Systems"*. Supersedes and replaces IEEE1344, 2005.

[4] *"IEEE 1344-1995 Standard for Synchrophasors for Power Systems"*. Superseded by C 37.118 above, 1995.

[5] *"IRIG Standard 2004 – IRIG Serial Time Code Formats"*, Timing Committee, Telecommunications and Timing Group, Range Commanders Council, US Army White Sands Missile Range, NM 88002-5110, September 2004.

[6] *"Responses Summary to Questionnaire on PMU Installation and Maintenance"*, Performance Requirements Task Team (PRTT), Eastern Interconnection Phasor Project. May 2006.

[7] *"Performance Requirements: Phase Angle Installation Issues"*, Performance Requirements Task Team (PRTT), Eastern Interconnection Phasor Project. March 2007.

[8] "SynchroPhasor Accuracy Characterization", Performance and Standards Task Team (PSTT) of the North American SynchroPhasor Initiative, 2007.

9. Appendix A: Responses Summary to Questionnaire on PMU Installation and Maintenance

9.1 Section 1: Introduction

The Performance and Standards Task Team (PSTT) of the Eastern Interconnection Phasor Project (EIPP) in the process of creating a guideline for installation and maintenance of phasor measurement units (PMUs) sent a survey to PMU users participating in the EIPP. The intent of the survey was to collect data to reduce some of the possible installation problems, provide some reference for PMU maintenance, and create a general and practical guideline to future users.

Where applicable multiple choice answers were provided but users were encouraged to add any comments, explanations or questions. It is worth mentioning that some responses were received from companies that do not posses PMUs but are planning to install them and/or use them in the near future.

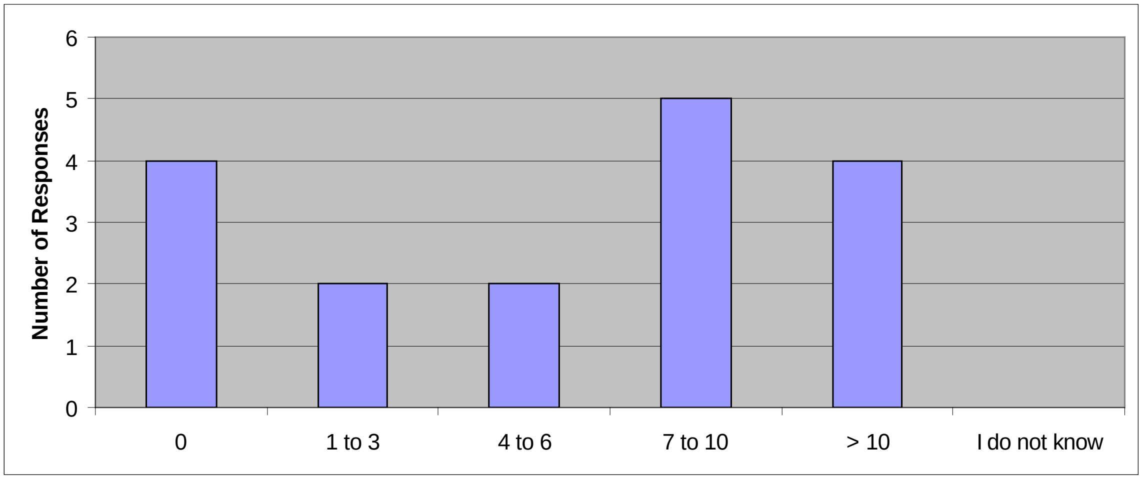
The following sections of this document provide a summary of the responses of the seventeen companies that answer the survey. The comments received from the different companies for some of the question are also listed. After reviewing the responses to the questioner the PSTT realized the limitations of the multiple choice options and recommends that numerical answer be requested in future questioners.

Table 4 List of Responding Companies

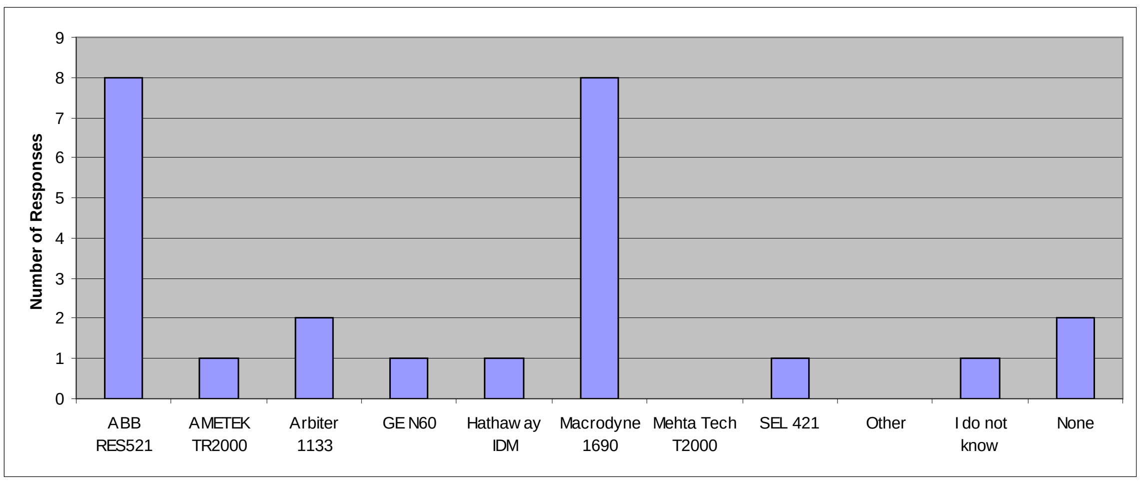
Company	**Contact**
American Electric Power	Sanjoy K Sarawgi
Alberta Electric System Operator	Darren McCrank
Ameren	Rajesh Pudhota
Arizona Public Service Co.	Douglas Selin
BC Hydro	Harry Lee
Bonneville Power Administration	Ken Martin
Entergy	Floyd Galvan
Florida Power and Light	Don Mcinnis
Hydro Quebec	Danielle Mcnabb
Michigan Electric Transmission Company	Paul Myrda
MidAmerican	Mark Albright
New York ISO	Dean Ellis
New York Power Authority	Bruce Fardanesh
PG&E	Fred Henderson
PJM	Jon Ponder
Southern Company	Lee Taylor
Tennessee Valley Authority	Ory Shannon

9.2 Section 2: General Information

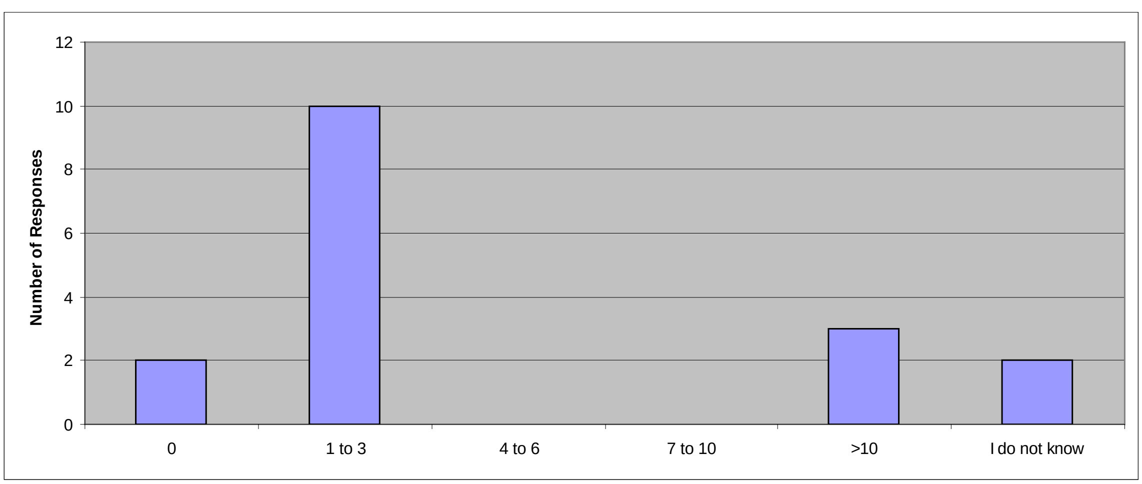
2.1 How many PMUs does your company currently own?



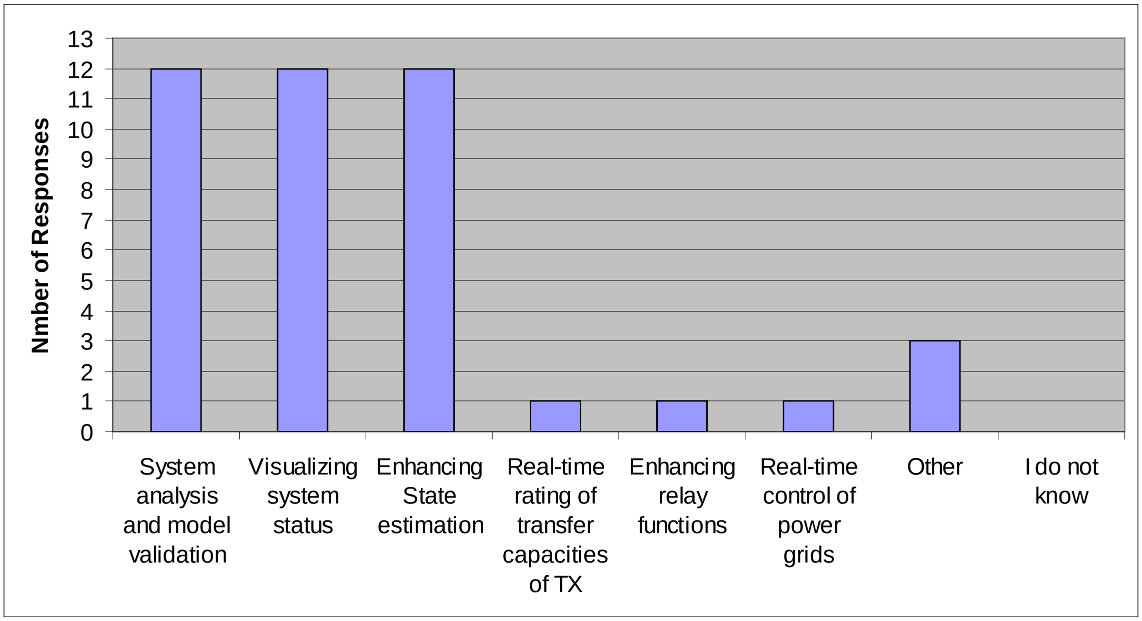
2.2 What are the models of the PMUs your company currently owns?



2.3 How many PMUs is your company planning to install over the next year?



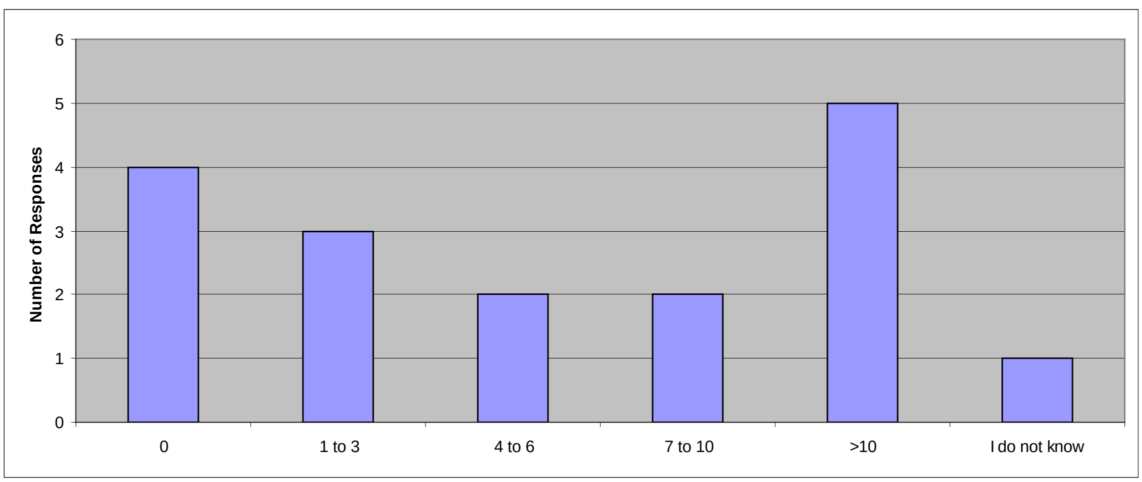
2.4 What applications are you using, or do you plan to use, the PMUs for?



Other:

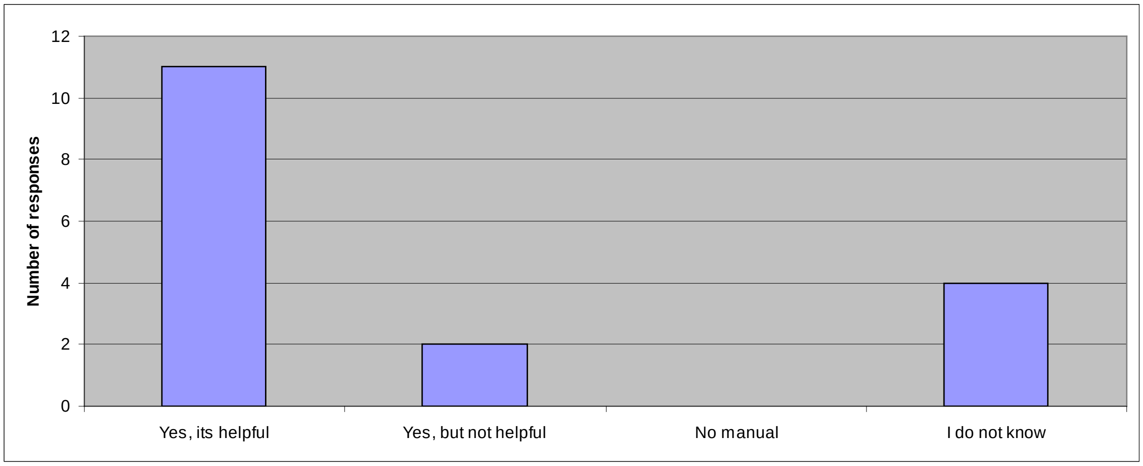
a. Detection of geomagnetic activity. High accuracy frequency monitoring. Accumulated time error monitoring (Hydro Quebec).
b. Potential subsynchronous resonance condition near a critical power plan but suspect that the relay sample rates, processing, and memory are inadequate (MidAmerican)
c. Monitoring the units (Ameren).

2.5 How many years since the first PMU was installed in your company?

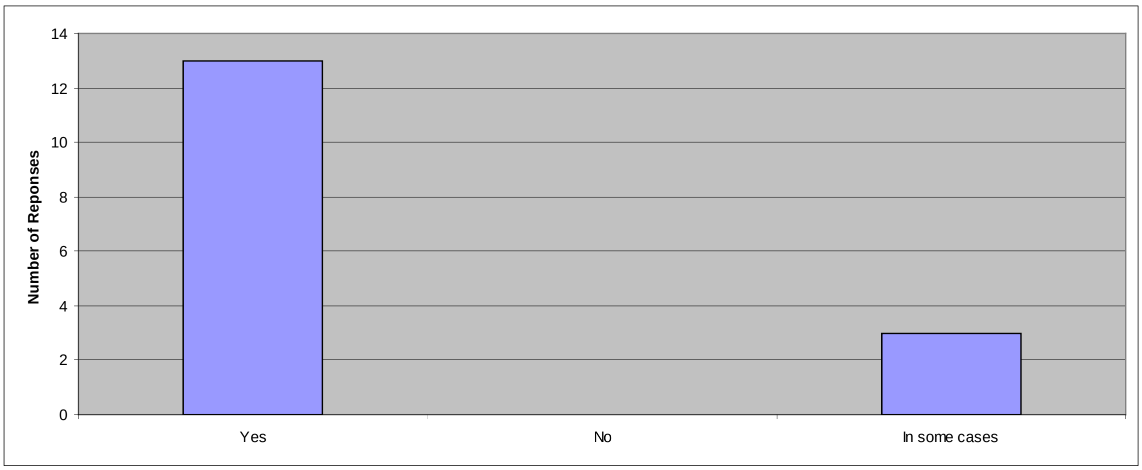


9.3 Section 3: PMU installation

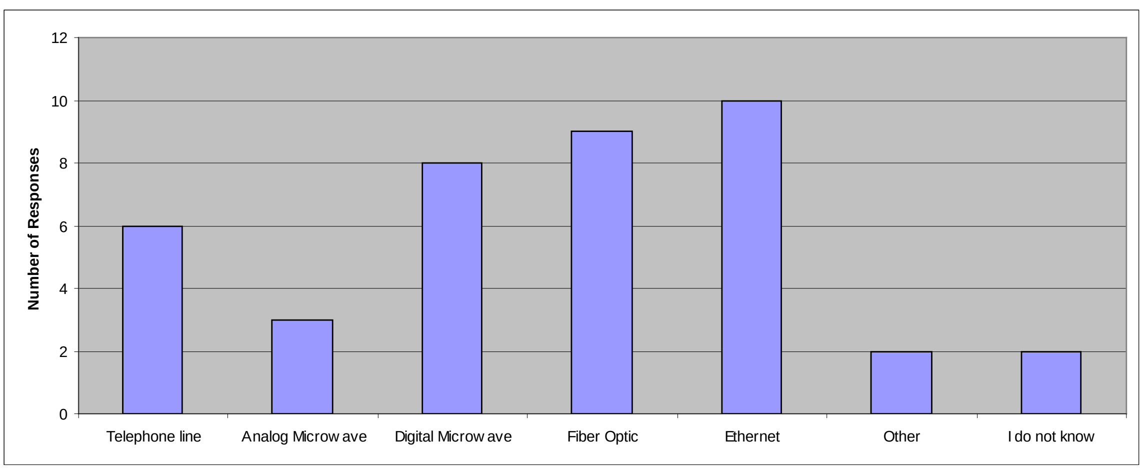
3.1 Is the installation manual coming with your PMU helpful?



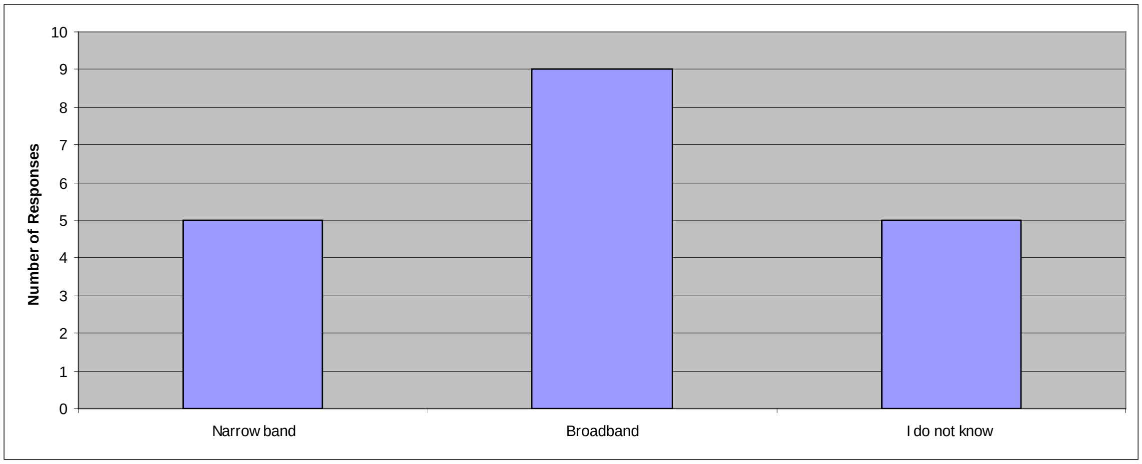
3.2 Were there existing CTs/PTs available for your PMU installation?



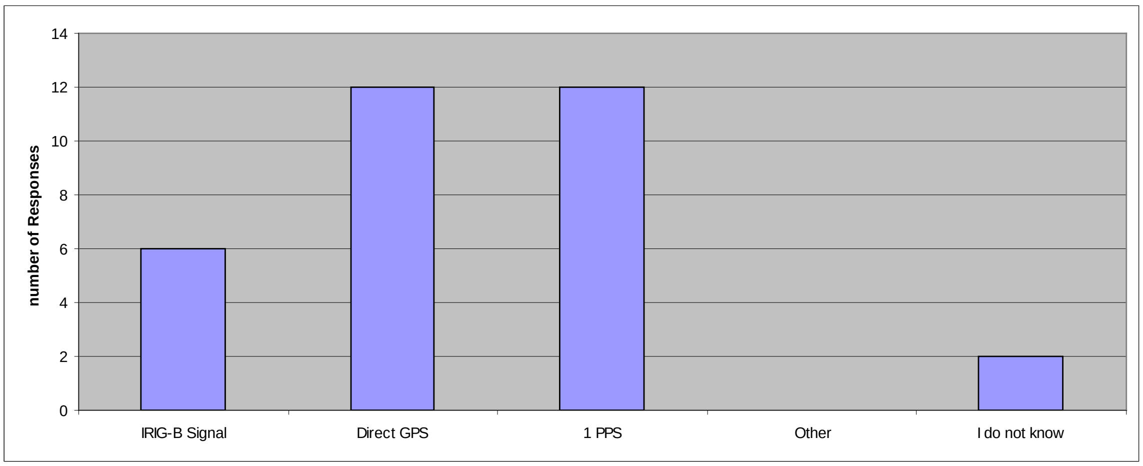
3.3 What type of data networks available for your PMU installation?



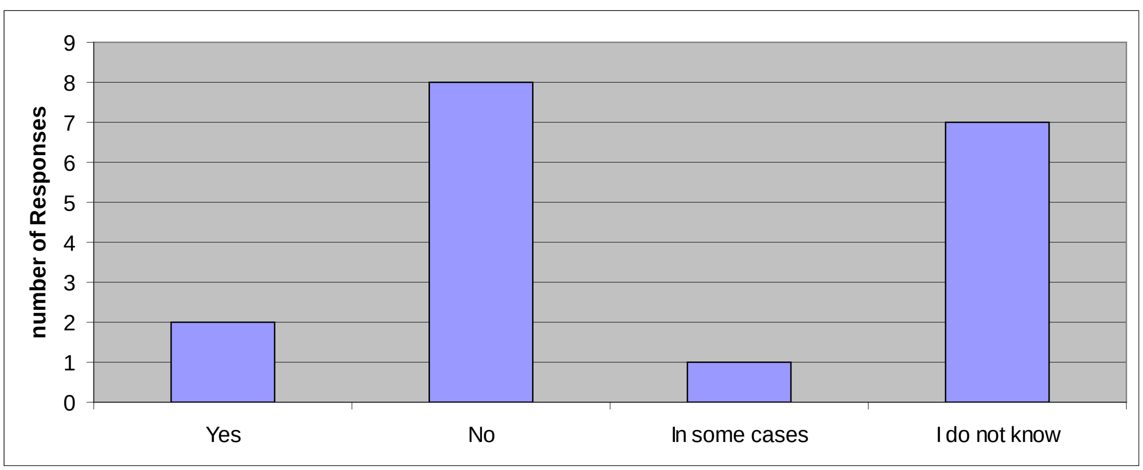
3.4 Are your data networks narrowband channels (voice channels) or broadband channels?



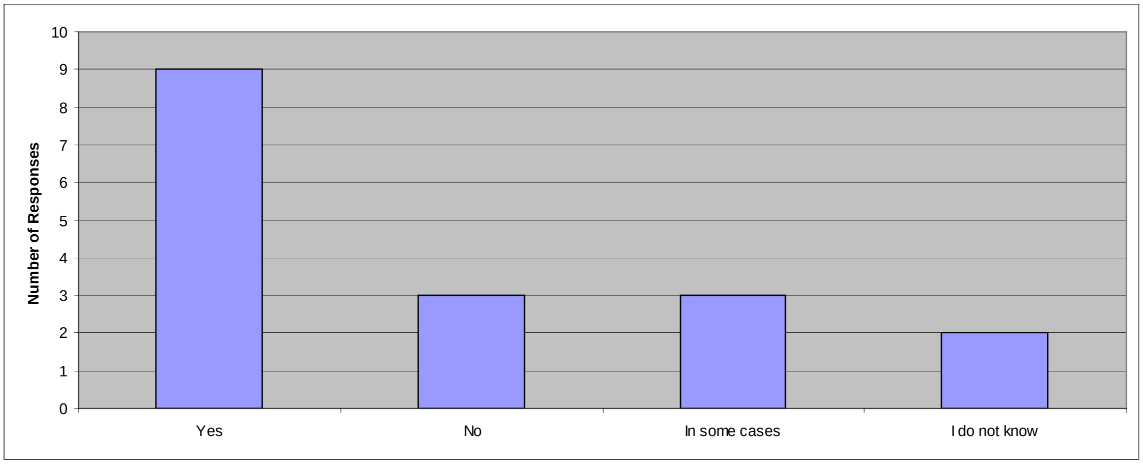
3.5 What time synchronizing signals are available for your PMU installation?



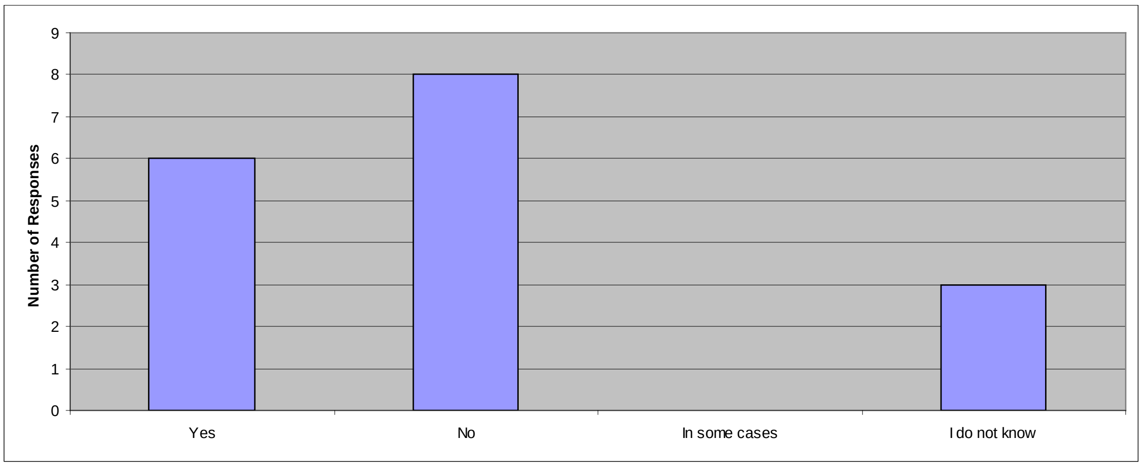
3.6 Does the engineer or technician installing the PMU have remote angle information from the utility selected reference phasor?



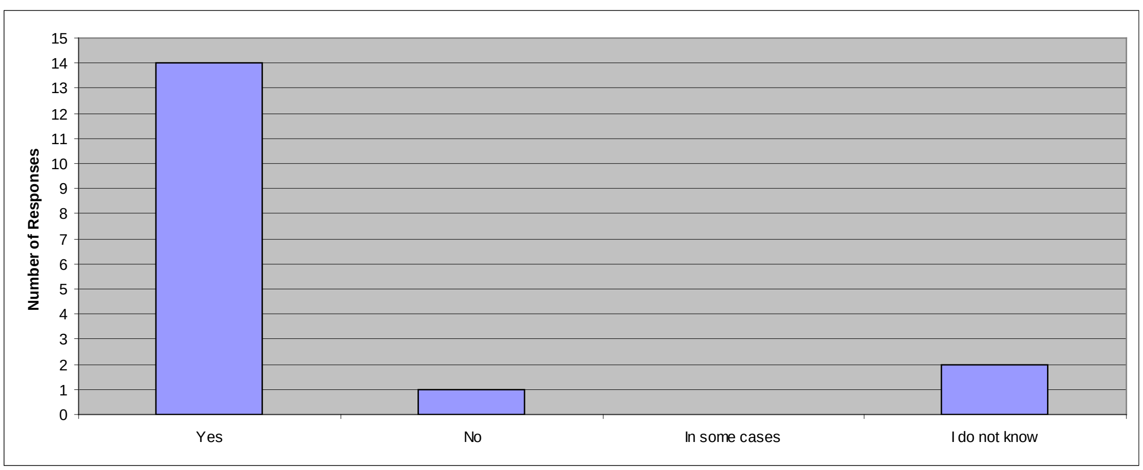
3.7 Does the engineer or technician installing the PMU have access to real and reactive power flow information from a separate device?



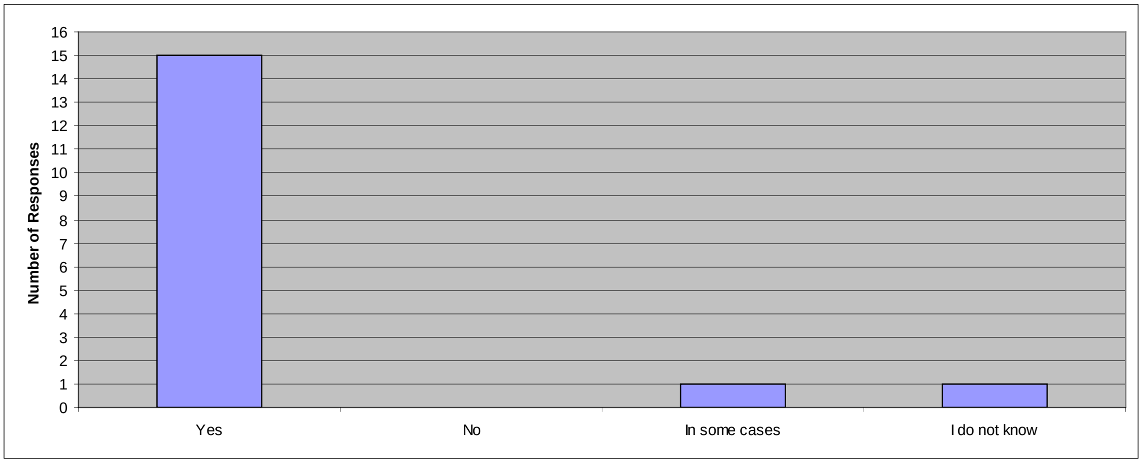
3.8 Does the engineer or technician installing the PMU have access to phasor data concentrator (PDC) information?



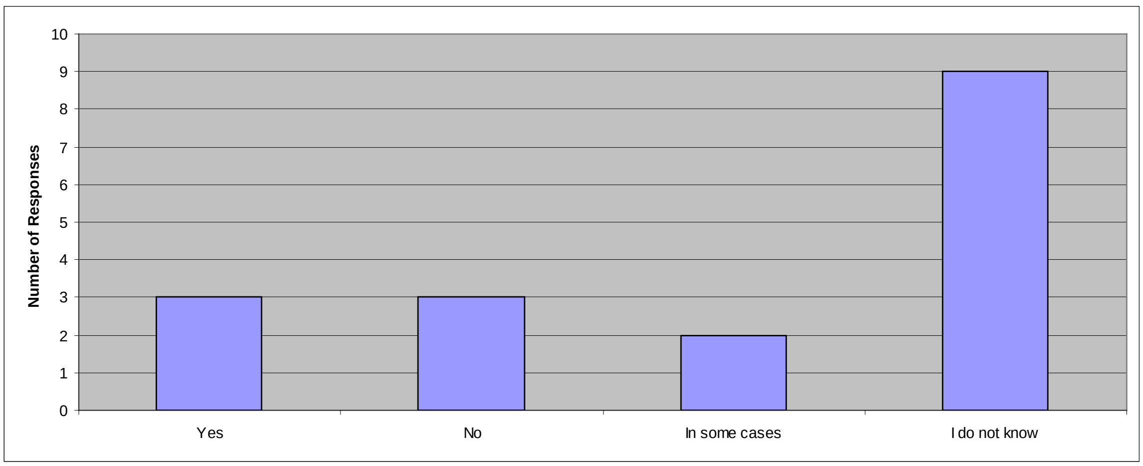
3.9 Does the engineer or technician installing the PMU have communication with the control center that collects PMU information?



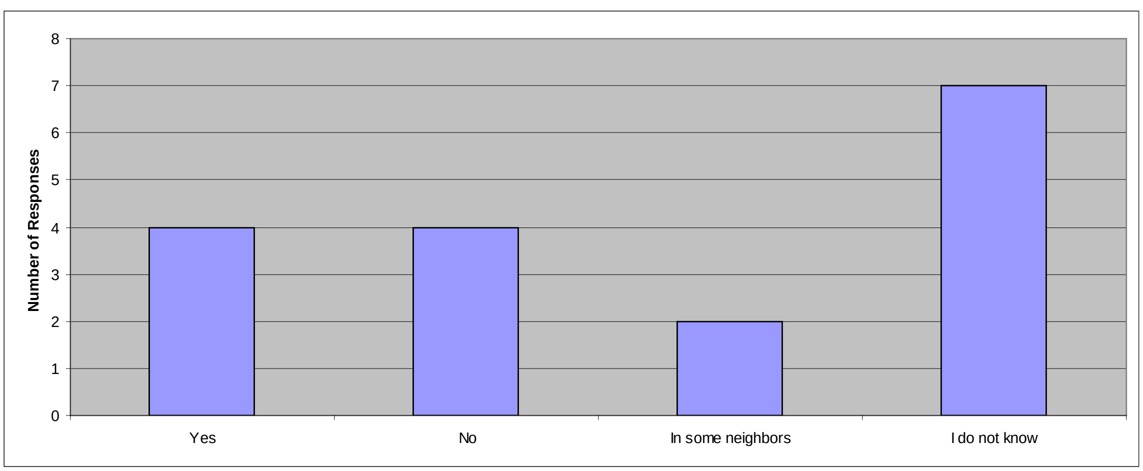
3.10 Is it generally assumed that utilities can consistently identify phases ‘a’, ‘b’, and ‘c’ voltage and current signals at their substations?



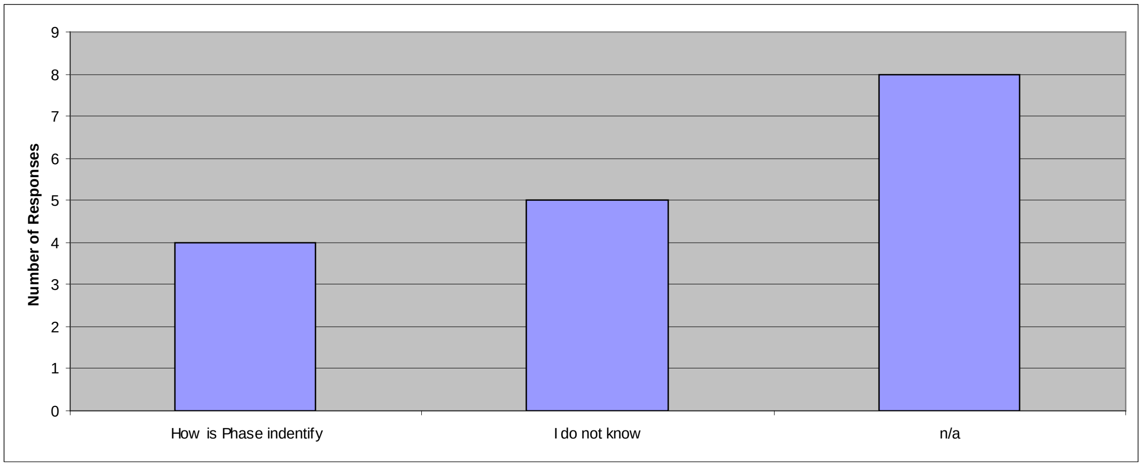
3.11 To your knowledge, is there any agreement among utilities on which phase is called phase 'a'?



3.12 Do you know the phase 'a' convention of your neighboring utility companies?

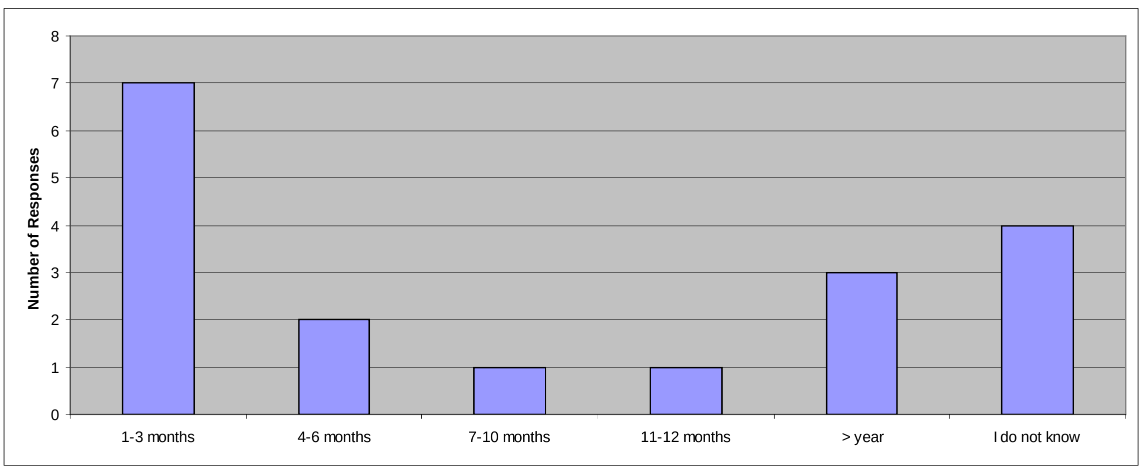


3.13 How is the phase 'a' identified when you install your PMUs?

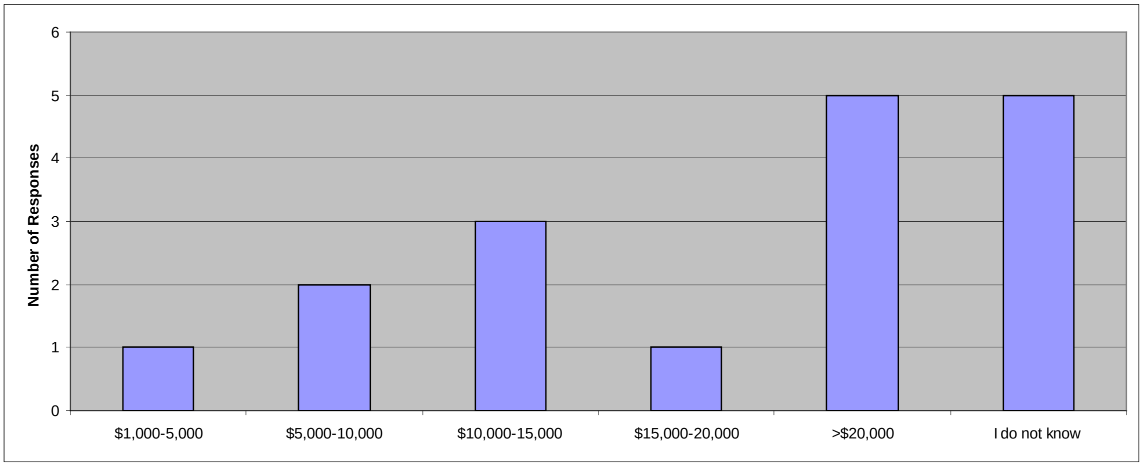


a. Phase A is always identified within the substation. It is originally identified when hooking up with other substations, but by convention is the N. or S. or E. or W. bus in the stustaiton. That is, it is the bus on the same side relating to direction in every station, but I don't know which it is (BPA).
b. By looking at the detailed protection wiring schematics of the substation where each PMU is installed (Hydro QB)
c. From the prints, markings, and labels (NYPA).
d. Phase ID's are labeled on substation structures and represented on 3-line diagrams (TVA).

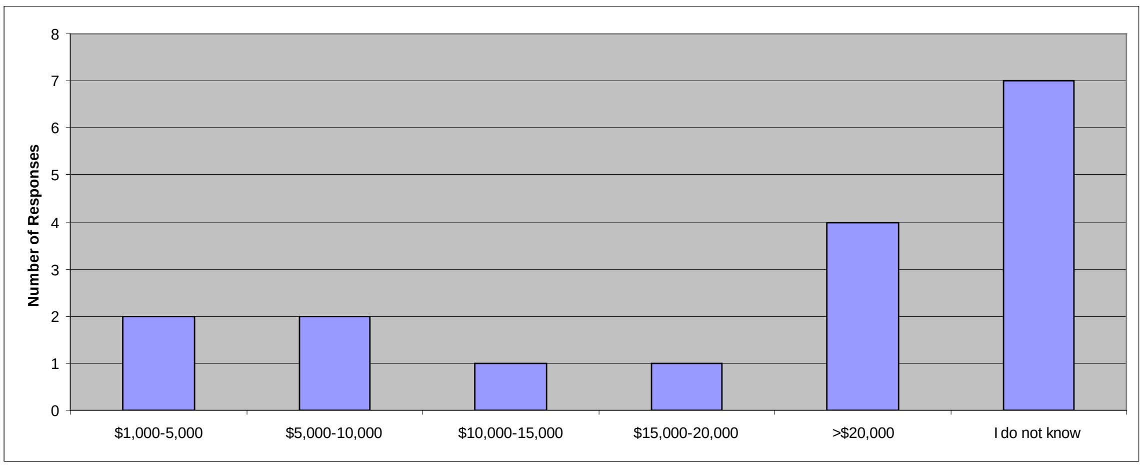
3.14 How long did it take you to complete the installation of one PMU?



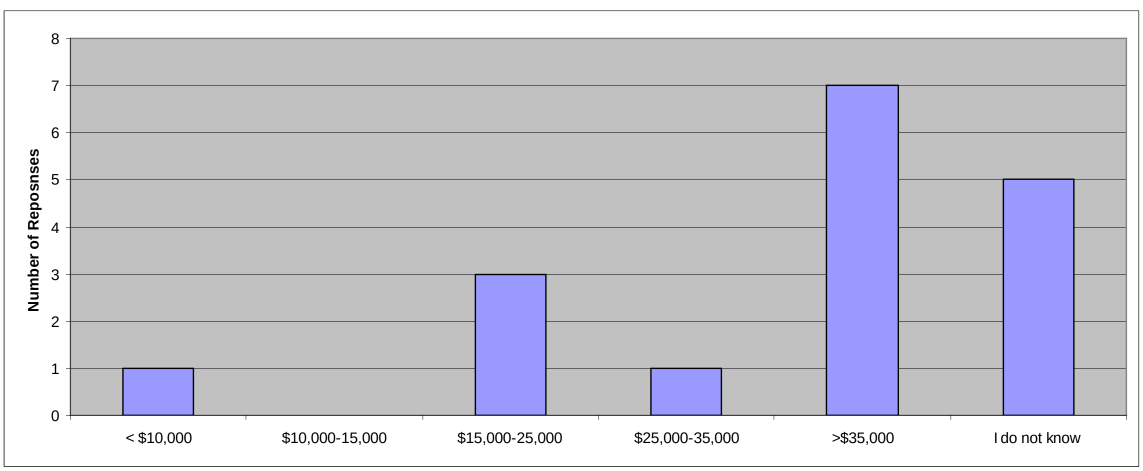
3.15.a. What is the average cost of hardware, including PMU, for one installation?



3.15.b. What is the average cost of labor for one PMU installation?

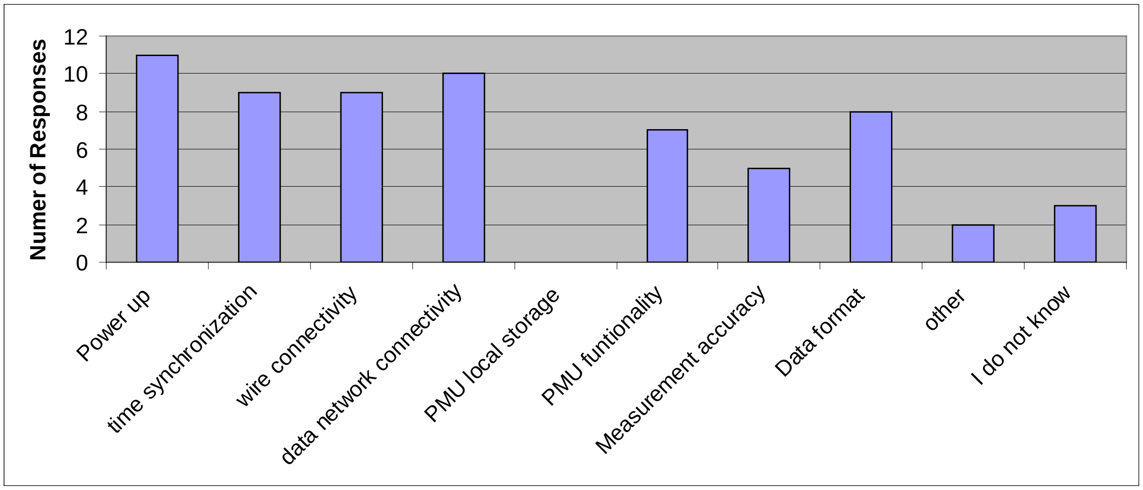


3.15.c What is the average Total cost for one PMU installation?



9.4 Section 4: PMU Commissioning

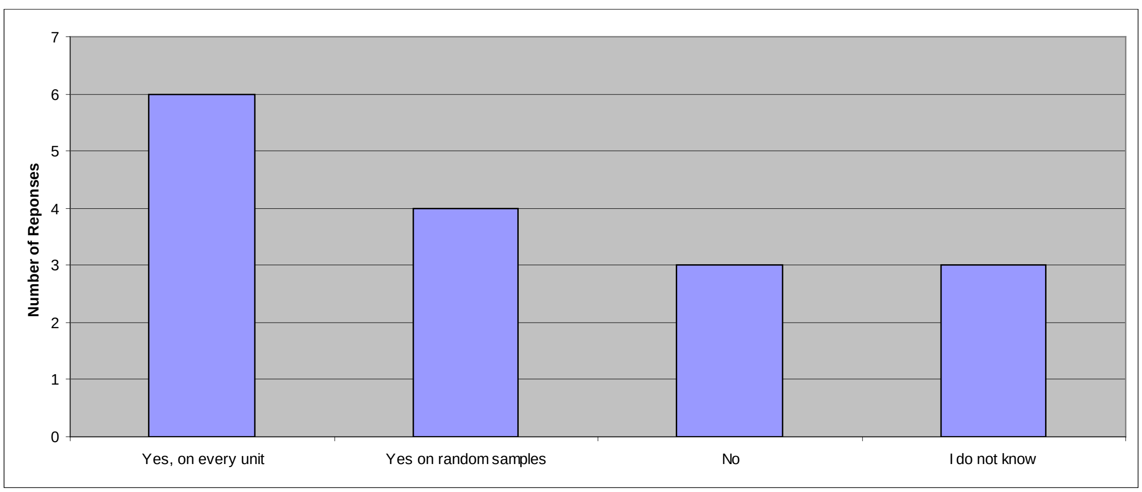
4.1 What test did you perform before commissioning the installed PMUs?



Other

a. It varies depending on who does the installation (BPA).
b. We plan to perform the above tests when the first single test PMU installation is completed (MidAmerican).

4.2 Do you check PMU accuracy on every unit? On random Measurement samples, None?



4.3 What else do you do to initially calibrate PMU measurements?

a. Verify PT and CT ratios with System Protection (PG&E)
b. We have no way to calibrating the unit as we have no other PMU to compare it with (PJM).
c. Compare to SCADA (Alberta Electric)
d. No calibration is done on the PMUs (AEP).
e. Meter is calibrated by manufacturer and they deliver a calibrated meter (Entergy).

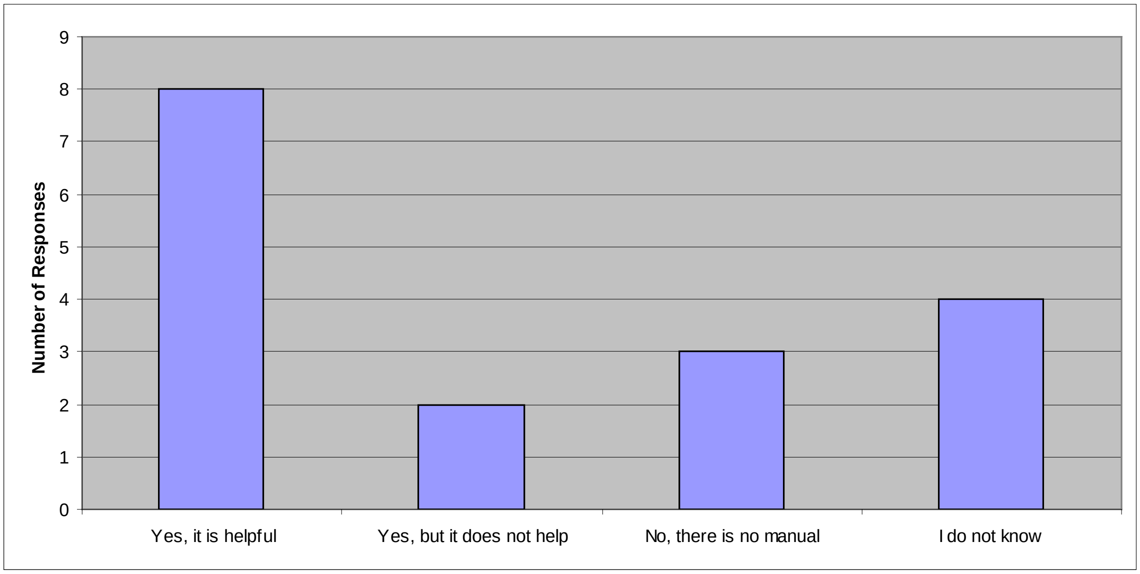
f. Each unit is calibrated in the lab, all the settings are entered and tested except final PT/CT ratios, and the operation is confirmed. Calibration is done using accurate test instruments and meters calibrated against traceable standards (BPA).

g. Each PMU has been tested for accuracy in lab before installation. Once installed, the measured voltage phase angle is checked to make sure that the phasing is correct (Hydro QB).

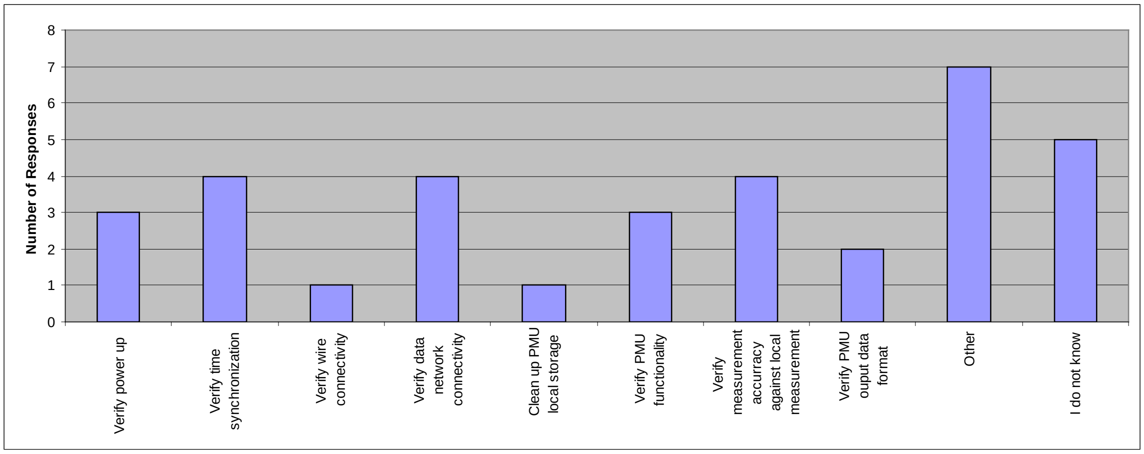
h. Look at data from the state estimator in the EMS and local meters.

9.5 Section 5. PMU Maintenance

5.1 Is there a maintenance manual coming with your PMU products? If yes, is it helpful?



5.2 What kind of maintenance is performed on your PMUs?



Other:

a. Cleaning fans. Replace backup batteries (Hydro QB)

b. The Maintenance program has not been specified (MidAmerican).

c. Meter is pulled and send back to manufacturer for calibration (Entergy).

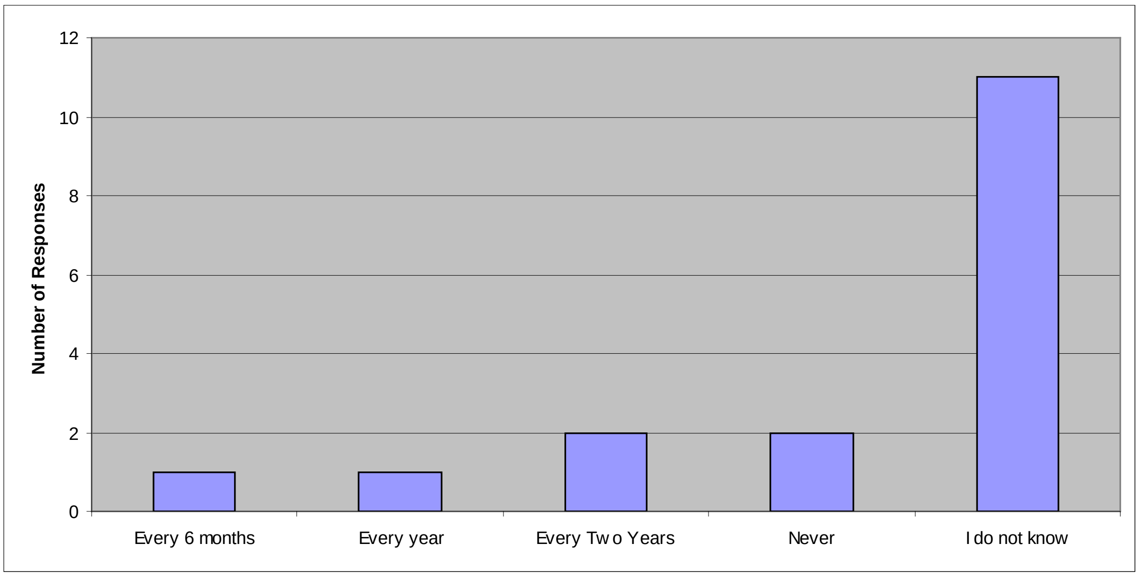
d. Not yet determined (METC).

e. No online monitoring of PDC anyway (BC Hydro).

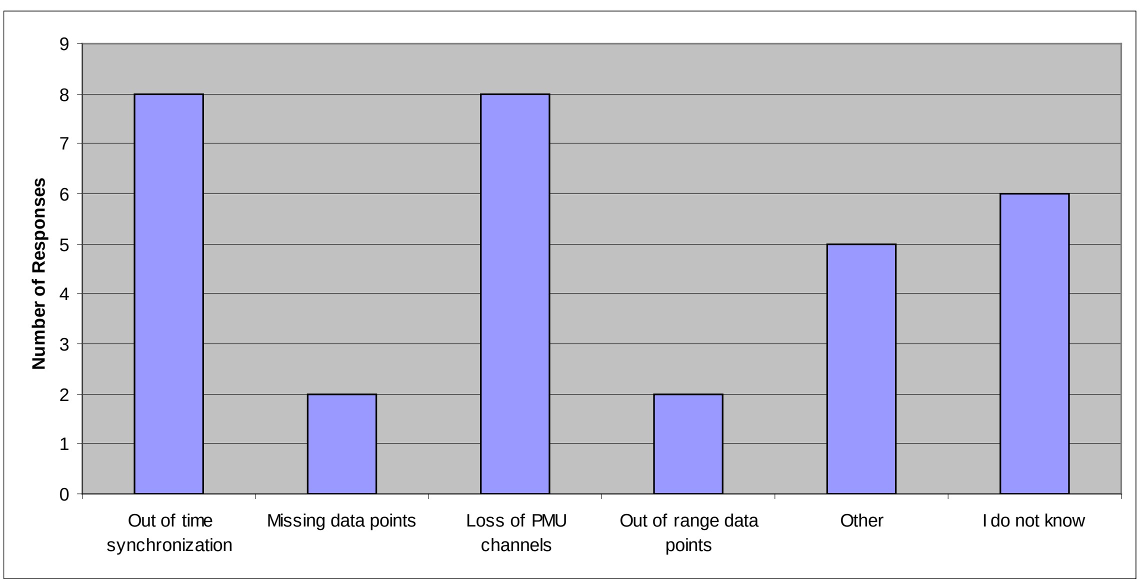
f. Will do whatever is required. Maintenance is expected to be minimal (PJM).

g. Maintenance is an on-line operation, and re-calibration and repair when there is an obvious problem or failure. We have no routine maintenance (BPA).

5.3 How often do you perform maintenance on your PMUs?



5.4 What alarms do you have to alert you to problems?



Other:

a. Our PMUs are on-line all the time. Synchronication & outage problems are tracked and reported by the concentrator. Calibration problems must be reported by users. If reported, we will investigate and resolve the issue (BPA).

b. Email indicating loss of communication (Alerta Electric SO).

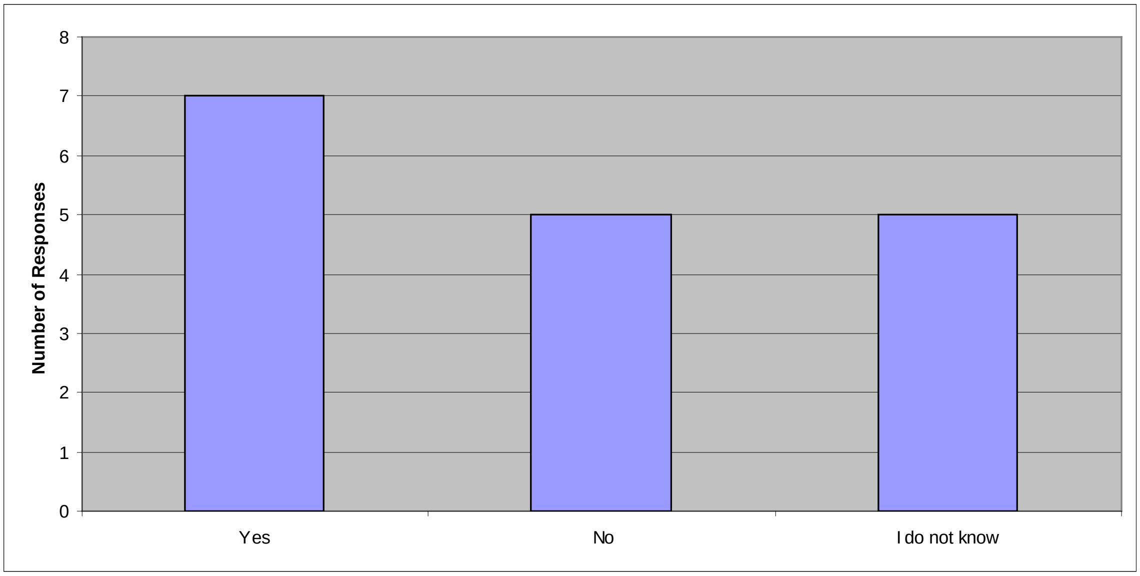
c. No planning on using alarms (PJM).

d. There are other indications on the PDC but there are no alarms (PG&E).

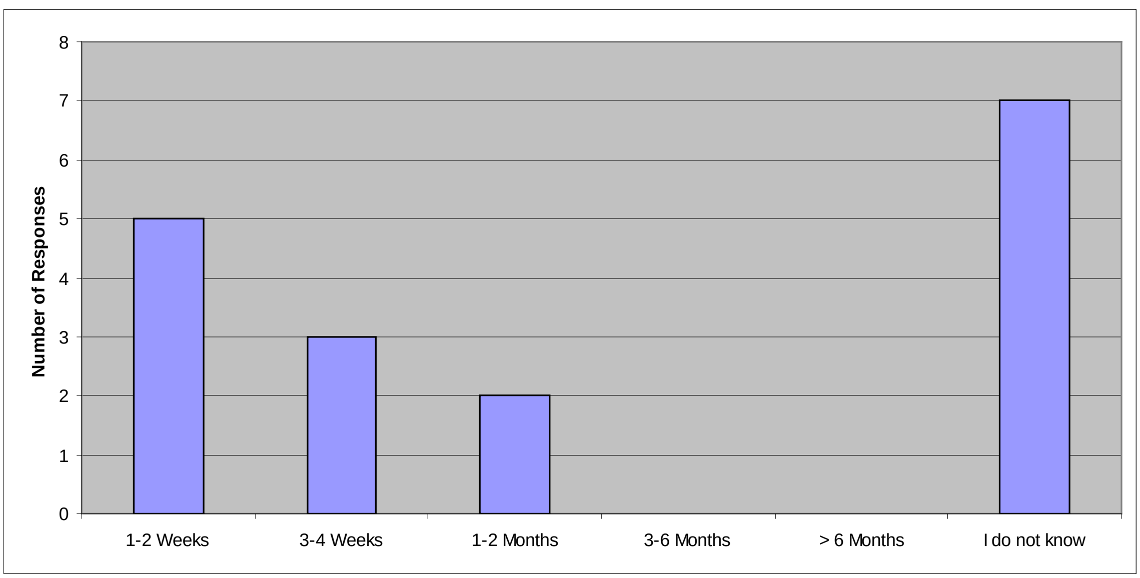
e. Alarm capability exist in PMUs but it is not used (AEP).

f. Utility to talk to the PMU (NYPA)

5.5 Do you monitor the performance of your overall measurement system other than just PMUs?

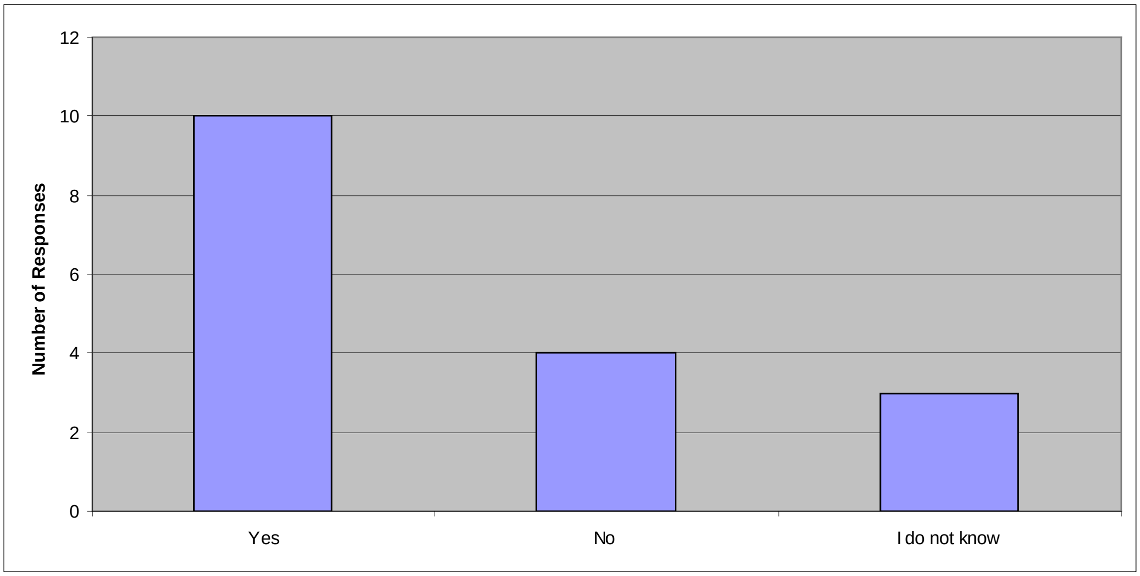


5.6 What is the average time from problem appearance to correction?



9.6 Section 6: Other information

6.1 Do you think an installation/commissioning /maintenance guide would help your job?



6.2 Did you have any other problems during PMU installation/commissioning/ maintenance?

a. The field needs to be educated in these new instruments. We plan on hosting a two day meter workshop for our field personnel. (ENTERGY)
b. The biggest problems seem to be getting the data communications to work right with the PMU and data concentrator. This is when there is a mismatch, such as synchronous to asynchronous or network to channel. Standard interfacing is sometimes difficult to specify and install (BPA).
c. Sometimes there is an issue with the GPS antenna where the cable is pinched or broken. In one case the antenna was close to a UHV line and induced voltage zapped it. Since then if there is any possibility of that, I have instructions for grounding during installation and hook-up (BPA).
d. The biggest maintenance problem is getting people to notice sync or data promptly, and notify the right personnel to fix the problem. It is often difficult to diagnose the root cause from the symptom, so a lot of issues go un-resolved for a long time (BPA).
e. Firmware did not comply to specifications (took about one year to correct, Hydro QB).
f. Early hardware failure on one unit after installation (Hydro QB).
g. Inability to get up to date communication front ends for the PMU. Slow upgrade of the vendor.

10. Appendix B: Example of commissioning tests – Manitoba Hydro

10.1 Section 1: Introduction

Manitoba Hydro performed field tests on its Dorsey PMU on March 9 2007. The results are shown here. The test set up used for the PMU Performance tests is shown in figure 1 below.

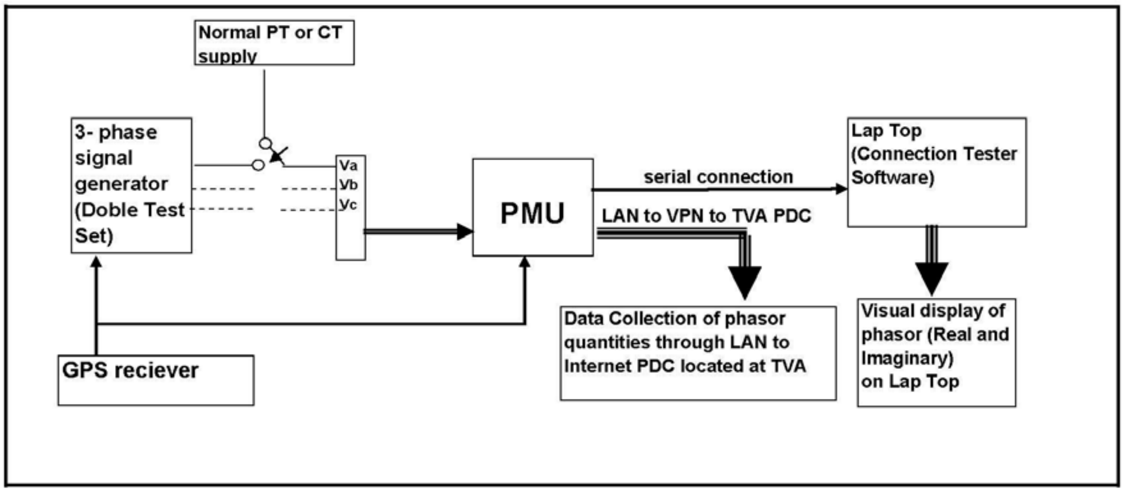


Figure B.1 – Test Set up shown uses 1 PPS signal from GPS to synchronize Doble Test Set software and produce -90 positive sequence angle when the positive zero crossing of A-phase is aligned with this 1 PPS. At nominal frequency of 60 Hz this zero crossing does not change (nor does it change for exact integer off-nominal frequencies of 61 Hz or 59 Hz etc.)

The connection tester software shown acted like a local PDC and was used to confirm correct expected magnitudes and angles. Final results were taken from the PDC located at TVA (Tennessee Valley Authority) in order to include all delays including any delays within the network.

10.2 Steady-State Tests

The results are for the MBHydro PMU located at the Dorsey station on their 230 KV voltage and the positive sequence angle is taken for various initial angles of Va.

For Va = 0 degrees the pos sequence angle is -90.36782837 (expected -90 degrees according to the defined phasor in C37.118) as shown in Fig 2. The error is 0.36782837 degrees.

Similarly for Va= 120 degrees the angle is +29.63899994 degrees (expected 30) and for Va=240 degrees the angle is 149.6264954 degrees (expected 150). A close up of the angle for Va=0 is shown in Fig 3.

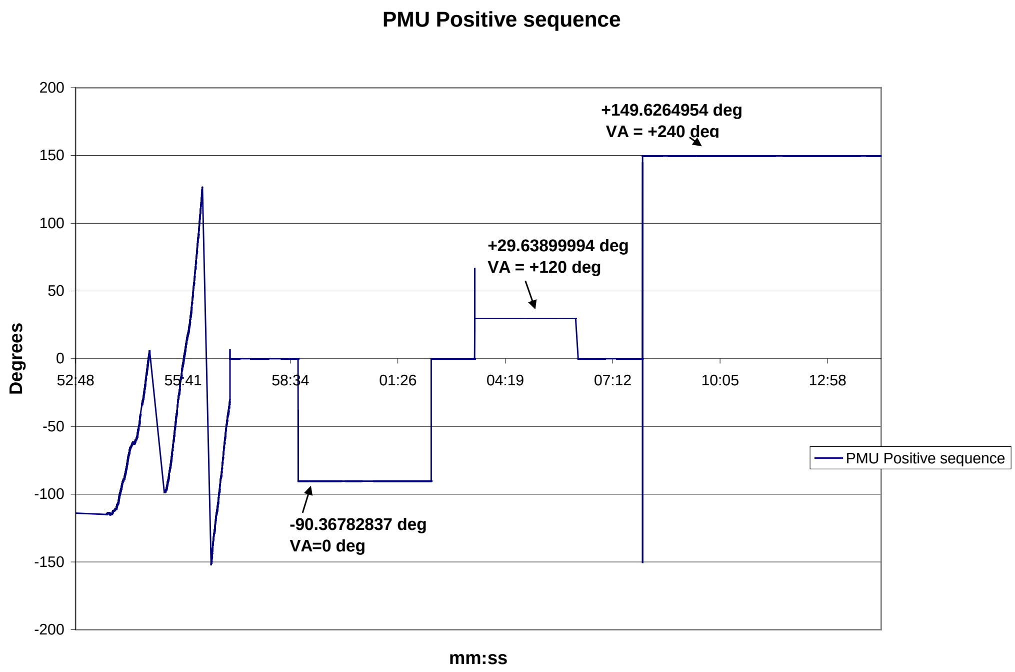


Figure B.2 – Phasor Outputs Positive Sequence Angle as Va is rotated

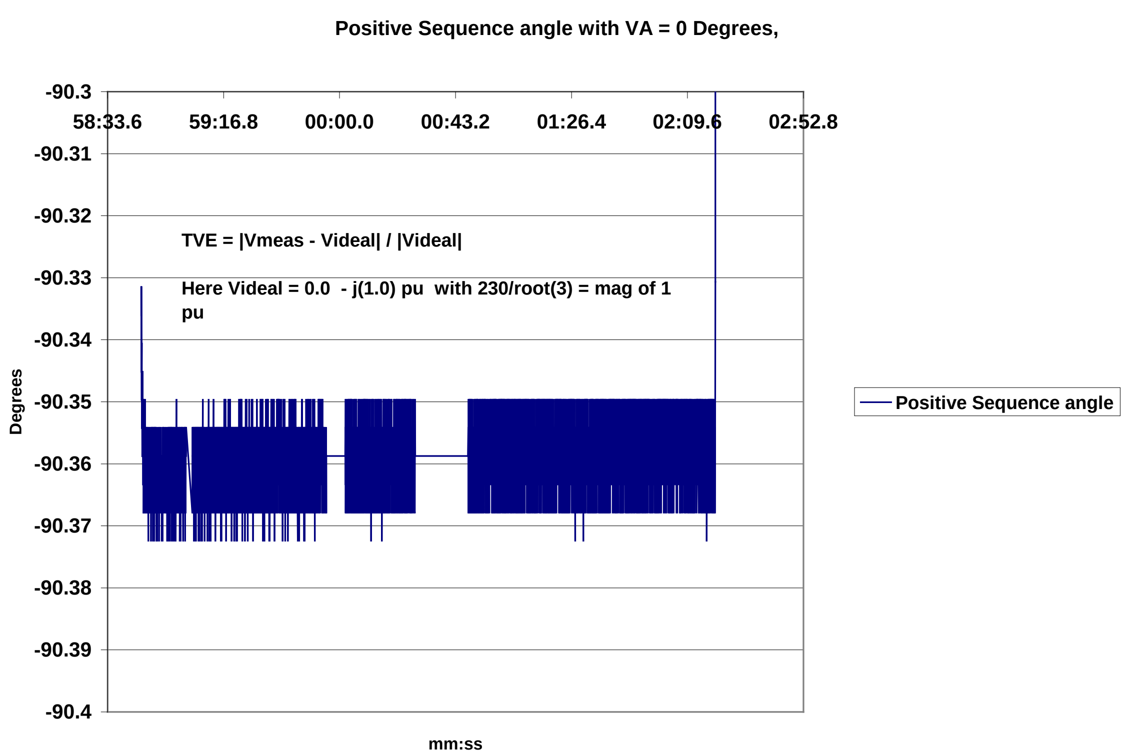


Figure B.3 – Phasor Output Angle Close up for Va=0 degrees

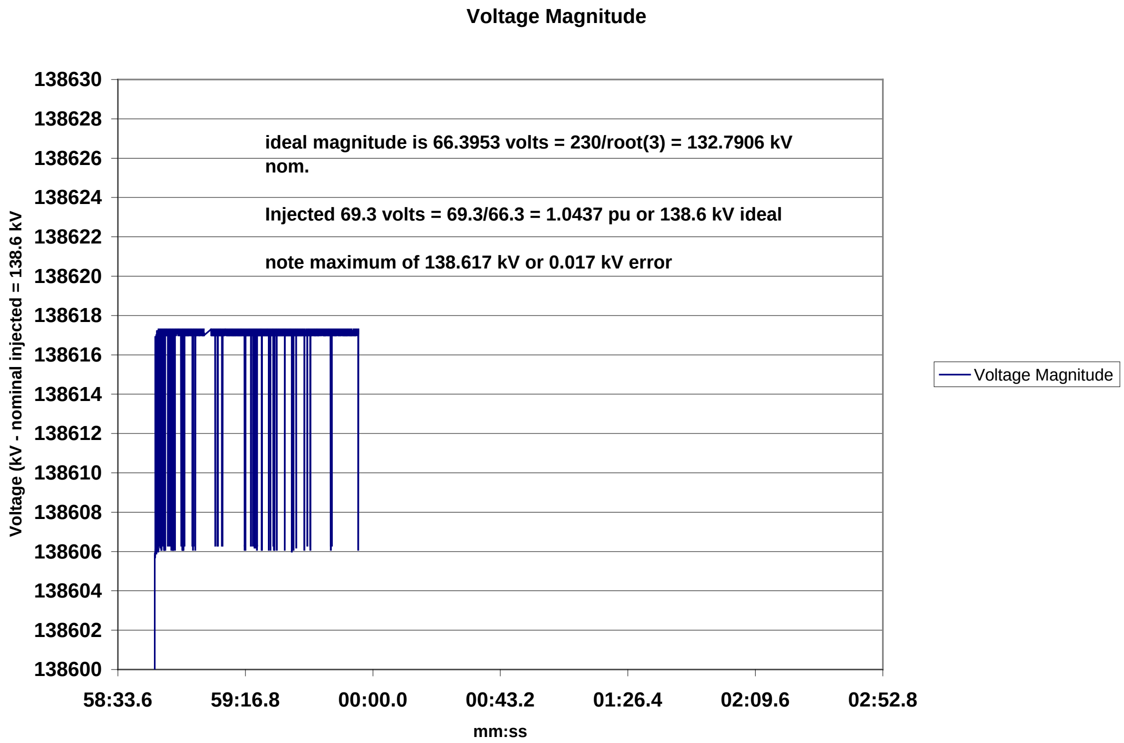


Figure B.4 – Phasor Output Magnitude Close up

The voltage magnitude for the injected voltage of 69.3 V was expected to be 138.6 kV and was found to be a maximum of 138.617 or an error of 0.017kV.

The maximum error in the vector for positive sequence is 138.617 kV and an angle of -90.37 degrees or 0.006486545700177 – 1.004450070277750j compared to an ideal = 0.00-1.00j or 138.6 kV and an angle of -90.0 degrees.

This compares well to the C37.118 standard (note, the standard does not include errors in the field which are outside of PMU device itself - ie. these field result errors are what is termed full-scale tests that do not separate the time tagging error and the angle accuracy) which sets a maximum error on angle of 0.57 degrees and a voltage error of less than 1.0%.

$$TVE = \sqrt{\left[\left((Xr(n) - Xr\right)^2 + \left((Xi)(n) - Xi)\right)^2 / \left(Xr^2 + Xi^2\right)\right]} = \text{ 0.007866282514468 or 0.8\%}$$

This measurement can be averaged over the number of times the test was performed by:

$$TVE = (1/N)\sum_n \left[\left((Xr(n) - Xr\right)^2 + \left((Xi)(n) - Xi)\right)^2 / \left(Xr^2 + Xi^2\right)\right], n = 1,2,....N$$

Here TVE based on the three measurements of positive sequence voltage and angle as in (ie. Va=0 deg., Va=120 deg., and Va=240 deg. from in Figure 2 and Figure 4) is 1/3(0.7866%+0.772300%+0.7866%) = 0.781852% or approx. 0.8%

10.3 Dynamic Tests

The same set up as in Figure 1 was used for dynamic tests but synchronizing the start of the test was more difficult. We attempted to record the GPS time in an effort to retrieve the data for the start of the step changes. By examining the frequency and magnitude test results we could see when the tests occurred but there time values did not exactly match our recorded GPS times. We were still able to align the tests and get valuable information shown below.

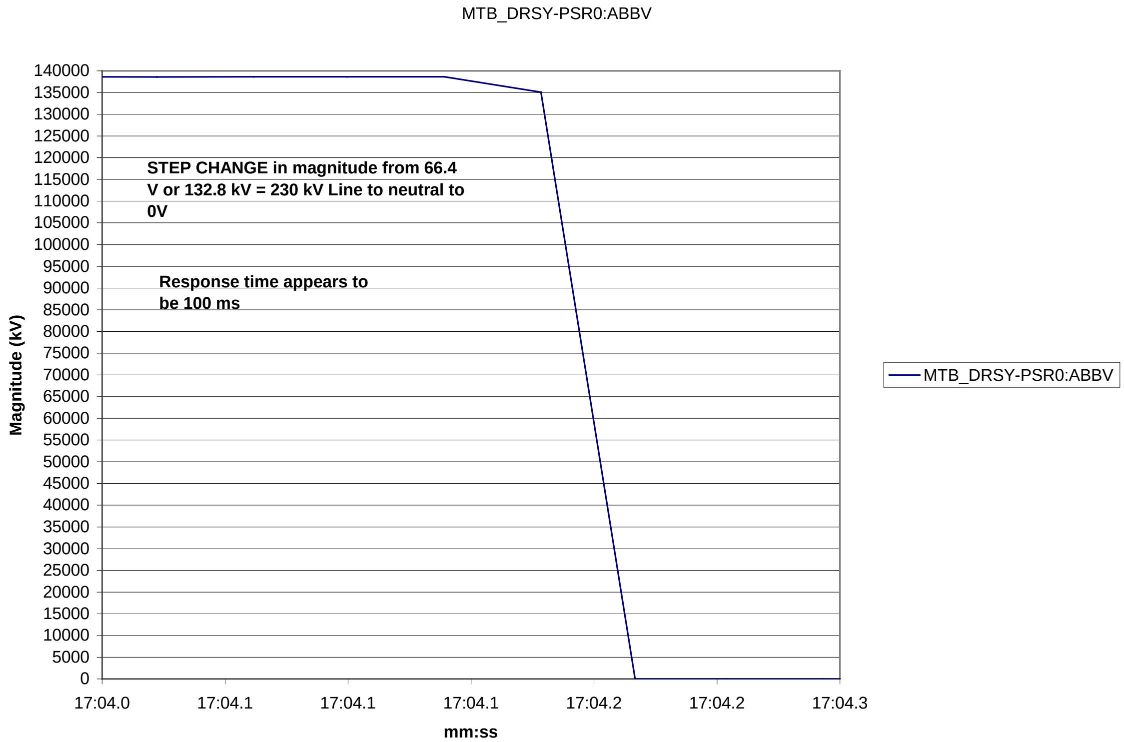


Figure B.5 – Step Change in Magnitude on all three phases from 230 kV L-L nominal (66.4 V L-N injected) to 0kV (0V injected). The response time appears to be about 100 ms. The recorded GPS time of the test was 15:17:15 and the chart shows the test at 15:17:04 so it is not clear why the mismatch and there could be an additional delay before the signal begins to ramp down (inherent to network). Once the signal begins to ramp though we can definitely say the response time is 100 ms. A positive step exhibited a similar response.

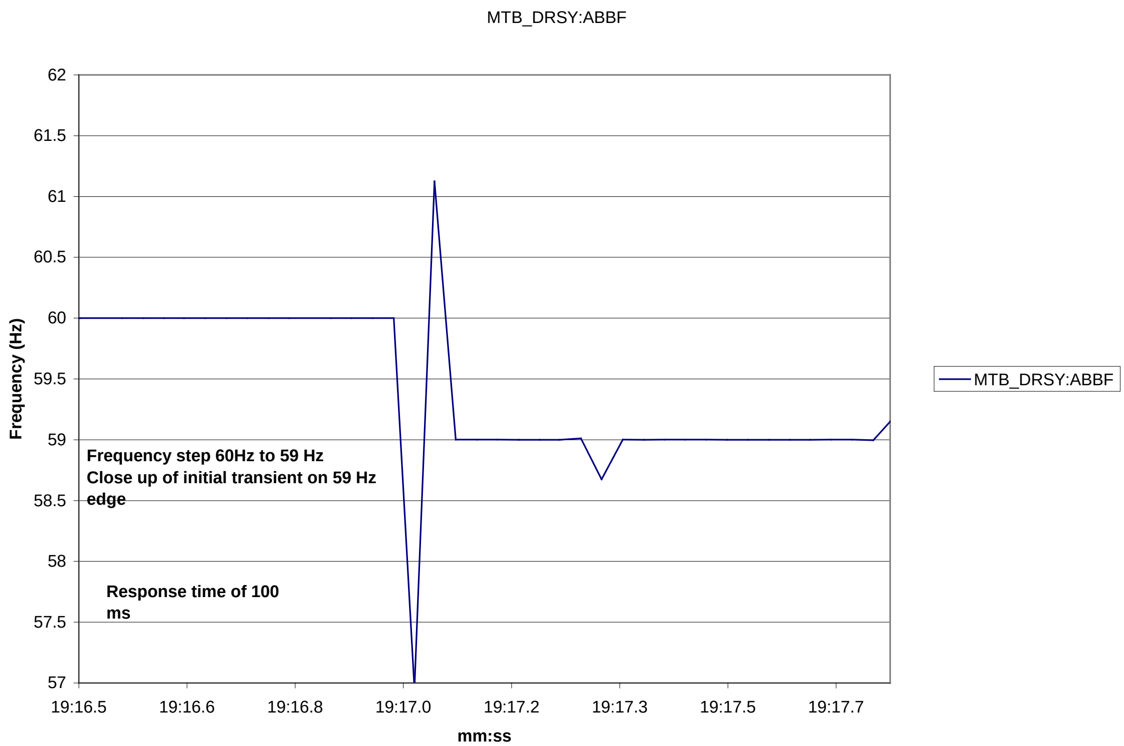


Figure B.6 – A step change if frequency on all 3 phases from 60 Hz to 59 Hz. It is evident that there is some overshoot initially and then a quickly damped oscillation to the final value of 59 Hz. The response time to get to with 99% of 59 Hz is about 100 ms.

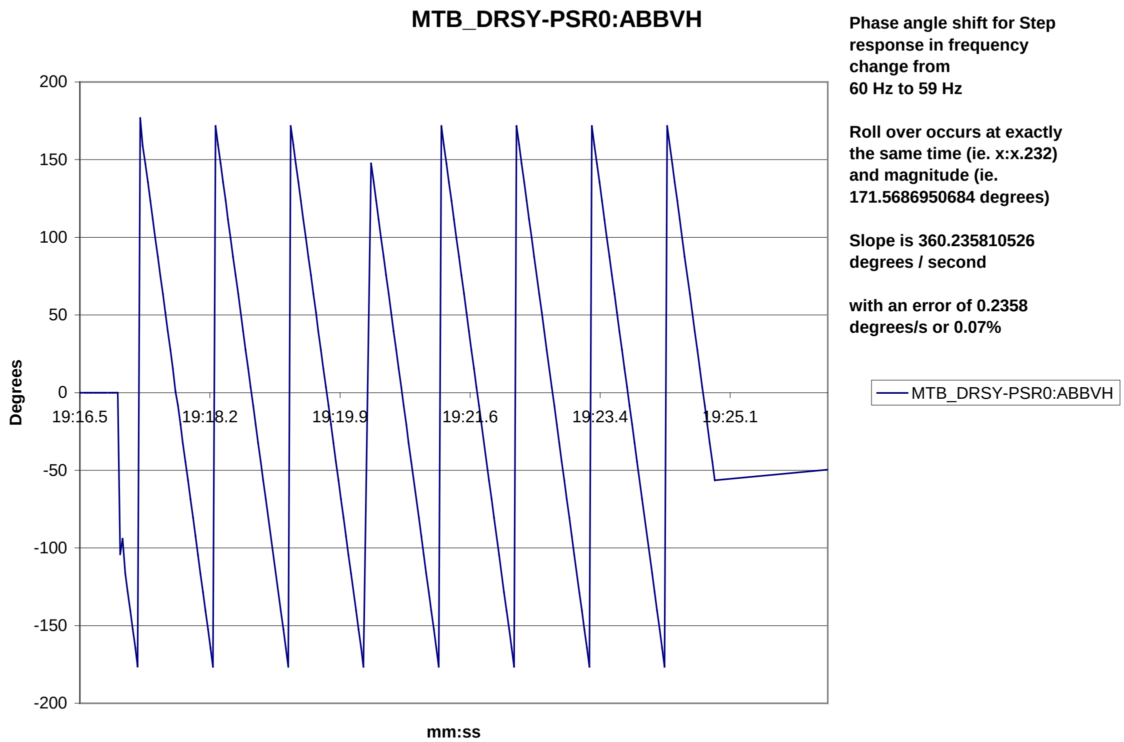


Figure B.7 – Absolute Phase Angle in degrees is plotting while at 59 Hz. The roll over can be seen to occur at exactly the same time xx:xx:x.232 seconds and the magnitude of the phase angle after each roll over is the same at 171.5686950684 degrees. This shows good accuracy of the PMU. Also the slope is 360 .235810526 degrees/second with an error of only 0.07%.

10.4 Conclusion:

The PMU installed is meets the criteria of C37.118 even with any extra delays inherent from network or field. The TVE is about 0.8% and the dynamic response appears to be within 100 ms. PT and CT error would add to the error shown here and has not been evaluated.

11. Appendix C: Example of commissioning tests – Bonneville Power Administration

11.1 Section 1: Introduction

This commissioning test example is from a PMU installed at the Big Eddy substation in Jan 1998. This was long before the standard C37.118 was available, so there was no criteria for comparison. The focus of this test was to establish that the PMU was properly installed, measured the correct signals, and compared reasonably accurately with other measurements.

11.2 In Service Readings for the Big Eddy 230 Phaser Measurement Unit

All quantities are referenced to "A" phase Bus section #3 1V-0V. Measurements made on 1/6/98 from 1 to 2:30 pm. Board Meters and board meter racks where read on all lines, then Rack 67 was read for all lines. After that Scada reading where entered. Due to the time lag, magnitudes may be off some. The power house lines where fluctuating a lot due to some generator control problems.

	Rack 67			***PTR /***	***Board Meter Racks***				
Quantity	***Mag.***	***Angle***	***Primary***	***CTR***	***Mag.***	***Angle***	***Primary***	***BoardMeters***	***Scada***
Bus Sect. 3 VA	69.3	ref.	240.1	2000/1	69.4	ref.	240.4	240 kv	240.2 kv
Bus Sect. 3 VB	69.1	-120	239.4		69.6	-120	241.1		
Bus Sect. 3 VC	69.0	120	239.0		69.1	120	239.4		
Bus Sect. 1 VA	69.1	ref.	239.4	2000/1	69.6	ref.	241.1	240 kv	239.9 kv
Bus Sect. 1 VB	69.0	-120	239.0		69.7	-121	241.4		
Bus Sect. 1 VC	68.9	120	238.7		69.5	120	240.8		
Celilo #3 IA	1.07	48	642	3000/5	1.06	48	636	180 mw out	177 mw out
Celilo #3 IB	1.08	-71	648		1.06	-71	636	190 mv in	196 mv in
Celilo #3 IC	1.07	167	642		1.05	167	630	550 amps	634 amps
Celilo #4 IA	1.19	48	714	3000/5	1.20	47	720	200 mw out	197 mw out
Celilo #4 IB	1.19	-72	714		1.21	-72	726	220 mv in	225 mv in
Celilo #4 IC	1.23	169	738		1.24	168	744	700 amps	719 amps
Power Hs #3 IA	2.57	-149	771	1500/5	1.82	-150	546	200 mw in	239 mw in
Power Hs #3 IB	2.60	91	780		1.83	90	549	110 mv out	171 mv out
Power Hs #3 IC	2.60	-31	780		1.83	-31	549	550 amps	815 amps
Power Hs #4 IA	2.46	-148	590	1200/5	2.51	-154	602	220 mw in	221 mw in
Power Hs #4 IB	2.46	92	590		2.52	86	605	110 mv out	124 mv out
Power Hs #4 IC	2.46	-30	590		2.52	-35	605	600 amps	609 amps
Power Hs #5 IA	3.49	-148	838	1200/5	3.67	-148	881	320 mw in	307 mw in
Power Hs #5 IB	3.55	92	852		3.73	92	895	190 mv out	180 mv out
Power Hs #5 IC	3.53	-28	847		3.69	-28	886	880 amps	854 amps

Power Hs #6 IA	1.52	-149	608	2000/5	1.67	-149	668	240 mw in	246 mw in
Power Hs #6 IB	1.60	90	640		1.75	90	700	150 mv out	134 mv out
Power Hs #6 IC	1.58	-29	632		1.74	-29	696	700 amps	673 amps
XFMR #2 IA	0.52	5	312	3000/5	0.54	6	324	120 mw out	120 mw out
XFMR #2 IB	0.55	-117	330		0.55	-117	330	10 mv in	15 mv in
XFMR #2 IC	0.53	122	318		0.54	122	324	300 amps	
XFMR #5 IA	0.49	0	392	4000/5	0.49	1	392	180 mw out	189 mw out
XFMR #5 IB	0.51	-122	408	See Note	0.52	-121	416	10 mv in	6 mv in
XFMR #5 IC	0.51	116	408	Below	0.51	118	408	400 amps	
XFMR 2&5 IA	XFMR 5 CTR was later changed to 3000/5 so that XFMR 2&5 could be one PMU channel.								
XFMR 2&5 IB									
XFMR 2&5 IC									
	Rack 67			***PTR /***	***Board Meter Racks***				
Quantity	***Mag.***	***Angle***	***Primary***	***CTR***	***Mag.***	***Angle***	***Primary***	***BoardMeters***	***Scada***
XFMR #1 IA	1.16	-120	232	1000/5	1.24	-107	248	40 mw in	54 mw in
XFMR #1 IB	1.21	134	242		1.28	130	256	40 mv out	122 mv out
XFMR #1 IC	1.11	10	222		1.19	9	238	280 amps	
Bus Tie #1 IA	0.33	90	99	1500/5	0.33	90	99	0	1 mw in
Bus Tie #1 IB	0.33	-30	99		0.33	-30	99	40 mv in	81 mv in
Bus Tie #1 IC	0.33	-150	99		0.32	-150	96	100 amps	195 amps
Bus Tie #2 IA				1500/5					
Bus Tie #2 IB									
Bus Tie #2 IC									
Bus Tie #3 IA	0.00	92	0	1500/5					
Bus Tie #3 IB	0.00	-29	0						

Bus Tie #3 IC	0.00	-152	0						
Midway IA	1.31	-175	314	1200/5	1.33	-175	319	140 mw in	119 mw in
Midway IB	1.31	66	314		1.33	67	319	10 mv in	4 mv out
Midway IC	1.27	-56	305		1.29	-56	310	320 amps	286 amps
Troutdale IA	1.53	3	367	1200/5	1.47	3	353	150 mw out	151 mw out
Troutdale IB	1.56	-114	374		1.51	-113	362	10 mv in	8 mv in
Troutdale IC	1.52	122	365		1.47	122	353	370 amps	365 amps
Redmond IA	1.35	7	324	1200/5	1.36	7	326	140 mw out	141 mw out
Redmond IB	1.38	-112	331		1.38	-112	331	20 mv in	17 mv in
Redmond IC	1.38	127	331		1.38	127	331	340 amps	340 amps
Chemawa IA	out			800/5					
Chemawa IB	of								
Chemawa IC	service								
Mcloughlin IA	1.69	4	507	1500/5	1.68	3	504	220 mw out	217 mw out
Mcloughlin IB	1.81	-118	543		1.80	-118	540	5 mv in	12 mv in
Mcloughlin IC	1.76	121	528		1.74	120	522	530 amps	521 amps
Harvalum IA	1.03	-11	247	1200/5	1.07	-15	257	100 mw out	105 mw out
Harvalum IB	1.01	-127	242		1.05	-131	252	50 mv out	14 mv out
Harvalum IC	1.07	113	257		1.10	109	264	260 amps	254 amps

PMU Accuracy Check

All quantities are referenced to "A" phase Bus section #3 1V-0V. Measurements made on 1/7/98 from 7:30 to 8:30 am

Channel & Quantity	Rack 67 Input (Secondary)	Rack 67 Input Angle	Phaser Quantity (As Read in Labview)	Phaser Angle (As Read in Labview)	Error (%)
1 - Bus Sect. #3 VA	68.817	ref.			
1 - Bus Sect. #3 VB	69.101	-120.10			
1 - Bus Sect. #3 VC	68.749	119.78			
1 - Positive Sequence	68.889	ref.	68.62	ref.	0.39
2 - Celilo #3 IA	1.7913	ref.			
2 - Celilo #3 IB	1.7933	-120.10			
2 - Celilo #3 IC	1.7675	119.80			
2 - Positive Sequence	1.7840	10.93	0.1807	11.12	1.29
3 - Celilo #4 IA	1.9895	9.80			
3 - Celilo #4 IB	1.9920	-110.59			
3 - Celilo #4 IC	2.0198	130.42			
3 - Positive Sequence	2.0004	9.88	0.2013	9.78	0.63
4 - Power House #3 IA	1.5096	-162.31			
4 - Power House #3 IB	1.5239	78-07			
4 - Power House #3 IC	1.5447	-43.44			
4 - Positive Sequence	1.5260	-162.56	0.1532	-162.56	0.39
5 - Power House #4 IA	1.1888	-163.96			
5 - Power House #4 IB	1.1851	76.82			
5 - Power House #4 IC	1.2023	-45.21			
5 - Positive Sequence	1.1920	-164.12	0.1202	-164.02	0.84
6 - Power House #5 IA	2.1375	-162.09			
6 - Power House #5 IB	2.1794	78.39			

6 - Power House #5 IC	2.1877	-42.32			
6 - Positive Sequence	2.1682	-162.00	0.2187	-161.52	0.87
7 - Power House #6 IA	1.2933	-164.01			
7 - Power House #6 IB	1.3590	76.19			
7 - Power House #6 IC	1.3511	-42.66			
7 - Positive Sequence	1.3344	-163.48	0.1344	-163.72	0.72
8 - XFMR #2 IA	0.7961	-168.11			
8 - XFMR #2 IB	0.7859	72.39			
8 - XFMR #2 IC	0.7812	-48.47			
8 - Positive Sequence	0.7877	-168.06	0.0797	-167.96	1.18
9 - Midway IA	2.2009	-169.55			
9 - Midway IB	2.2099	72.31			
9 - Midway IC	2.1572	-49.61			
9 - Positive Sequence	2.1891	-168.95	0.2157	-168.46	1.47
10 - Troutdale IA	1.0949	2.14			
10 - Troutdale IB	1.1366	-114.00			
10 - Troutdale IC	1.0987	121.29			
10 - Positive Sequence	1.1094	3.18	0.1128	3.33	1.68