Synchro-Phasor Data Conditioning and Validation Project

Phase 1, Task 2 Report

Best Practice Recommendations for Synchrophasor Systems: Administration, Planning and Implementation, and Operation and Maintenance

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EXECUTIVE SUMMARY

This report presents results of Task 2 of the Data Validation and Conditioning project. The report covers best practices for administration, planning and implementation, and operation and maintenance of synchrophasor measurement systems. The best practice recommendations are based on the survey carried out in Task 1 of this project and the experience of Electric Power Group, LLC ("EPG") with synchrophasor systems. The study starts with project administration and carries on through maintenance.

Phasor systems have four essential components:

1. Measurement devices in substations.
2. Communications to bring the measurements from the substation to the Transmission Owner (TO) control center.
3. Data processing in the control center.
4. Accumulation of data in archives or at a higher level such as an Independent System Operator (ISO) control center.

These components are tightly coupled: a failure in one part will cause a failure in the end product and it may be difficult to identify the root cause in a failure situation. It is important to start the phasor system with a plan that covers all aspects. Planning should begin with the applications to assess their requirements. The locations, measurements, and devices should be selected to support these requirements. Consideration of communication, control center, data storage, and application availability need to be factored in and may require some modifications to the original plan.

The best practice recommendations for administration, planning and implementation, and operation and maintenance are summarized below.

Administration starts with assembling a design team and carries through with assuring timely maintenance and support for upgrades. For the initial stages, it is important to bring together a team that can deal with all aspects from measurements in substations to communications and finally to computer-based applications. Phasor systems generate a lot of data that is sent and processed in real-time, which creates more interdependencies than most utility systems in service today. It is important

to deal with these complexities in the early stages. Coordination must continue through the implementation stage to be sure the measurements are correctly identified, characterized, and calibrated. As with any system, problems will occur and updates will be required. Ongoing management needs to coordinate the activities of the responsible groups to maintain the system in good operating order. A good documentation chain is needed to assure calibration is up to date and restoration can be done effectively when there are problems. Best practices for administration include:

1. Multidisciplinary design team covering equipment selection, applications use, power systems, information technology (IT), communications, and operations.
2. Design documentation and change management process.
3. Configuration management – connectivity of new equipment.
4. Performance management – data validity, equipment malfunction detection and restoration.

Planning should start with the applications to be sure the system meets their data requirements. This includes measurement points (PMU locations) and equipment selection. During implementation it is important to validate the measurements, preferably both with basic substation measurements and with comparable measurements reported to the control center such as Supervisory Control and Data Acquisition (SCADA). This step assures signals are correctly identified and calibrations are correctly applied. Data processing in applications and archiving needs to be closely monitored initially to be sure there are no systemic problems causing hidden failures. Best practices for planning and implementation include:

1. **Planning** – phasor measurement unit (PMU) location, data rates, signal selection, application requirements.
2. **System Development** – equipment selection (PMUs, timing equipment, etc.), communications, and control center applications.
3. **Implementation and installation** – substation, control center.
4. **Measurement validation** – comparison with state estimator and SCADA, latency.

Once in operation, tools are needed to provide constant monitoring. Generally these are provided by application vendors, but in some cases utilities develop their own applications to meet their special needs. In both cases, a process for human monitoring is required to act on problems and note when unusual situations occur. A regular maintenance program is advisable and can usually be established along the lines of similar equipment under standard utility programs. Of special note are the high use of data storage space and bandwidth by phasor systems; these particularly need to be monitored. Best practices for operation and maintenance need to address:

1. Operations and Analysis of System Performance – function involves IT (network, communications, data archiving) and power systems metrics.
2. On-Line Data Validation and Monitoring Tools – vendor provided as well as in-house development to integrate with internal processes.
3. Off-line Data Validation and monitoring tools.

4. System Maintenance.
5. Configuration Management.
6. Data analysis – on-going monitoring of events to integrate with planning and operations, including establishing alarm thresholds and operating procedures.

Each of these areas is discussed in the report. In addition, there are two appendices which provide detailed guidelines.

- **Appendix A** provides procedures for validating the installation and measurements. It starts with procedures for the PMU in the substation and continues on through the TO and ISO control centers. It suggests alternative methods depending on what tools the utility has available. It gives a range of accuracies to be expected.
- **Appendix B** is a troubleshooting guide. It details some background information on data quality indications. It describes some common problems and details the analysis and solution. It both provides a reference for the problems and methods for solving similar problems.

CHAPTER 1. INTRODUCTION

This report presents results of Task 2 of the Data Validation and Conditioning project. This report covers best practices for administration, planning and implementation, and operation and maintenance of synchrophasor measurement systems. These best practice recommendations are based on the survey carried out in Task 1 of this project and EPG experience with synchrophasor systems. The Task 1 report detailed the results of a survey of synchrophasor projects at 20 companies in North America. That survey found varying degrees of completion of projects and success with the results. This follow-on report is intended to document the most successful approaches to these projects by way of best practice recommendations. Most of the survey participants have been focused on infrastructure deployment and hence their responses primarily addressed installation, measurement validation, and problem resolution.

The overall project focus is data validation, making sure the data received from phasor systems is valid and accurately represents the measured quantity so that the data can be relied upon in real-time operations. Good project administration and system design are critical to having good and validated data for use in operations. Systems are the product of everything that goes into them. If they are poorly designed, problems will crop up more frequently and be more difficult to resolve. If the governing administration is not effective, identifying problems, addressing them effectively and resolution may be more difficult. Poor documentation can contribute to errors in use and repeated problems. The report covers infrastructure as well as data from the standpoint of project administration, planning and implementation, and operations of synchrophasor systems.

CHAPTER 2. ADMINISTRATION OF PHASOR MEASUREMENT SYSTEMS

This section describes the administration of synchrophasor measurement systems and in particular issues that make it different from administration of other systems. There are 2 principal phases of such administration: first is the design and implementation and second is operation and maintenance. This division is typical of most utility projects, so this is not unique. This chapter is organized with a section on each of these phases. A section on documentation completes the administrative aspects.

2.1 Project development administration

Synchrophasor projects differ from many common utility projects in their high interdependency of components ranging from the remote substation sites to the higher level control or monitoring centers. Some relay projects involve direct high-speed connections but usually between substations. SCADA involves reporting from substations to control centers, but at much slower rates. Special protection schemes (RAS) often serves the wide-area but with intermittent signals. Synchrophasors are thus similar to some existing systems, but require continuous, real-time communications at higher rates with active signals over the entire grid. In addition, synchrophasor systems cover a wide-area involving multiple companies that requires effective coordination and communications.

To be sure the scope of the project is fully considered during the project development phase, it is recommended that a steering team is established for project administration. The team size will depend on the size of project and the number of separate departments involved. For the transmission operator (TO) which builds and operates the substations, the steering team should include representatives from system planning, substation engineering (usually protection group), telecommunications (substations to control center), IT/application support, and operations. For the system operator (ISO, RTO, etc.), the team needs to include communications, IT administration (network, data storage), application support, and operations. Other departments may need to be included if there are some special aspects of the projects, such as added control functions. The makeup of the team is intended to make sure that all aspects of the project are fully considered from the start. It is suggested that the team has co-leaders or the team lead has rotation so that more than one person is familiar with the overall aspects of the project. This helps assure continuity as staff changes, which can be important if the project carries on for a longer period of time than anticipated.

Regular steering team meetings are recommended to deal with problems that come up as well as sharing the progress and issues that have been resolved. This helps uncover issues that may become problematic in the future, as well as keeping the project on track. Meeting records should be kept for tracking problem notifications and resolutions.

2.2 Synchrophasor system administration

Usually each department manages their own equipment including changes in equipment and settings as dictated by failures, upgrades, other installations, etc. This can lead to some difficulty since the measurements can be considerably affected by changes in setting parameters even though the measurements may look the same. In addition the operation of the system is highly dependent on many components in a chain, from the potential transformer/current transformer (PT/CT) through the PMU, communications, routing, phasor data concentrator (PDC), storage, applications, and so on. When there is a data problem at the user end, it could originate anywhere in the measurement chain making it difficult to determine root cause and location of the problem. Synchrophasor systems need to be managed as a SYSTEM and not individual devices, such as relays.

For these reasons, formation of an ongoing coordination team is recommended. This team should include representatives from the following departments:

1. System planning (users).
2. IT – network and data storage (support).
3. Applications (support, configuration management, data analysis).
4. Operations (user).
5. Maintenance (support).

This team should have a clear charter that defines the individual responsibilities and the procedures to be followed by the team members. The project team should have routine meetings for coordination and for sharing issues and problems between different departments, at least in the initial stages. Once the system is operating to its expected performance level, meetings could be reduced to an annual review and special sessions to resolve issues. Duties of the coordination team include:

1. Examination and resolution of problems.
2. Coordination of changes in equipment and settings, both internal & with other organizations.
3. Determination of need for upgrades including added measurements, locations, and application deployment.
4. Data storage and retention policy.
5. Recommendations on data sharing requests (decision rests on utility administration).
6. System security application (such as NERC Critical Infrastructure Protection {CIP}).
7. Documentation of activities & overall system documentation review.

Data users will usually be the first to discover problems or see the need for some changes. Typical users include operators for real-time data and planning and engineering personnel for recorded data. In any case, there should be a procedure to contact an appropriate representative of the coordination team for further action. Standard company procedures for repair, maintenance, and project requests should be sufficient for most cases. However for some issues, the coordination team can pull together a cross discipline team that can solve more complex issues more quickly. In addition, often, problems extend beyond company boundaries and coordination and communications among owners of all components of the synchrophasor network is critical.

Participation on a coordination team will be an added responsibility to the usual duties for most staff. Over time, there will be changes in personnel. Therefore rotation of the team lead is recommended to build a broader knowledge base among the team members and assure continuity. Avoiding dependency on a single person, who may be on leave or may move to another job, is important for good functioning of the whole project.

2.3 Synchrophasor system documentation

Documentation for synchrophasor systems should follow normal company procedures and standards. Supplementary documents are recommended to help understand the following:

1. Overall system diagrams of phasor system.
2. Phasor system data flow & processing details.
3. Documentation of equipment settings (especially PMU).
4. Primer on phasor estimates from a PMU.

The overall system and data flow diagrams should include details on equipment brand, model and version, communication type, intermediary stations of communications, data concentrator and location, database and location, server details, phasor applications and their latest version number. They should distinguish between the existing and planned phasor system. The in-depth details on the equipment source is advocated to be documented with a comprehensive list of PMU settings such as type, number of phasors, filtering and windowing technique, data rate, PT/CT ratios, calibration and communication. The primer on synchrophasors is helpful to anyone who is trying to get started on this technology. It is also helpful if the documentation clearly indicates the group that manages each piece of equipment and software to help work coordination.

In addition to project documentation, record of ongoing maintenance and troubleshooting procedures is recommended. Since system problems are often hard to diagnose and resolve a description of symptoms and problems discovered can be very useful, particularly for a changing staff. Some of this additional documentation should include:

1. Quick methods to solve common issues.
2. Historical records of equipment settings (especially PMU).
3. Records of issues and problem resolution.
4. Procedures for troubleshooting and problem resolution.

A record of problem resolution should include a detailed description of the observed symptoms including the starting date/time and related activity in other parts of the phasor system. Once the issue is tracked down and resolved, the problem details need to be included. Details on the resolution process and the lead group in the work could be helpful too. If the problem is significant or likely to re-occur, the technical team solving the issue should prepare a step-by-step procedure on how to troubleshoot the issue. An index of problem symptoms and resolutions is helpful for expediting the overall process of troubleshooting. An electronic cross reference is a very good approach for this indexing.

CHAPTER 3. PLANNING, DEVELOPMENT, AND IMPLEMENTATION

3.1 System planning

The first step in building a phasor measurement system is a system plan. Planning should start with the applications that will use the data and the requirements for data that serves these applications. Data requirements include but are not limited to:

1. Locations from where measurements are required (PMU location).
2. Signals to be measured at those locations (including phasors, megawatts, MVAR, status or switch indications, controller values, frequency, rate of change of frequency, etc.).
3. Data rate (rate at which measurements are sent from site).
4. Maximum reporting latency (delay in sending data from site).
5. Reporting reliability (allowable data loss).
6. Measurement characteristics (accuracy, resolution, response time).

It is often the case, however, that the applications that will use the data are not clearly defined or fully characterized. Since synchrophasor technology is relatively immature, even current applications with defined requirements are likely to evolve and develop new requirements. Without well-defined requirements, a recommended approach is to get the most comprehensive measurement set the project allows in its given scope and budget. Attention should be given to enable overall grid monitoring and the ability to observe dynamics. Monitoring should include all key transmission inter-connections, major generating sites, and stations with dynamic control capability, such as direct current (DC) terminals and Flexible AC Transmission Systems (FACTS) sites. PMUs should meet established measurement standards. Available communications with sufficient bandwidth is needed and the project should follow established company practices for system implementation. Table 1 summarizes typical requirements for some general application types that are in current use. Any particular system may have different established requirements, so this is only a general guideline.

Table 1 - Typical measurement requirements for general application types

Parameter	Off-line (studies, operation verification, model validation)	Operator visualization (graphic displays)	Operator alarms	State estimation	Real-time controls (depend on specifications)
PMU location	Key substations, generation & controller sites	Key substations, coverage of grid	Depends on particular alarm	Grid coverage by bus voltage and line currents	Specialized for control
Measured signals	All voltage and current (V & I) at the substation, selected other	All main grid voltages, selected currents	Selected V & I, selected other signals	All V & I in grid	Selected V & I, selected other signals

	signals				
Data rate (min)	20-30/second	10/second	10/second	1/second	10-60/second
Reporting latency (max)	No requirement, set by archiving delay limit	2 seconds	2 seconds	10 seconds	0.05 - 1 second
Accuracy	High, at least per C37.118	1-5%	1-2%	1%	1%
Resolution	High, .01%	Low, 1%	Medium, 0.1%	High, .01%	Medium, 0.1%
Measurement response time	Medium, 50-300 ms	Low, 150-500 ms	Low, 150-500 ms	Low, 150-500 ms	Varies, 16-500 ms

In addition to the application and grid considerations, the overall system constraints need to be factored in. PMUs need to be installed so they have access to the required signals. If the substation is owned by another utility, a special PMU installation agreement may be needed, or observability may be achieved from a nearby substation. It may not be possible to install a measurement on a generator, but the line side of the step-up transformer may be accessible and provide the required information.

Measurements need to be transmitted to the location where they will be used. The first step is from the substation to a control center. The second step may be to a co-located application or to a higher level control center. Since phasor data systems operate with a predictable data rate, it is easy to assess the bandwidth requirements. Some examples are presented in Table 2. Use of a bandwidth calculator based on the actual implementation for an accurate estimate is recommended. Reliability and latency need consideration also, but these will usually be dictated by the system architecture and communications network that is available.

Table 2 – Typical data rate requirements for C37.118.2 format data over TCP in Bits Per Second (BPS)

Transmitted data rate (BPS)	**10/s, integer**	**30/s, integer**	**30/s, floating point**
1 PMU, 2 phasors	8 000	24 000	26 880
1 PMU, 10 phasors	10 560	31 680	38 400
10 PMU, 6 Phasors/PMU average	30 880	92 640	159 840
200 PMU, 6 Phasors/PMU average	486 880	1 460 640	2 804 640

Factors that influence the data rates in Table 2 above:

- Each data report is sent in an individual packet: with a small number of measurements (line 1) the bandwidth is dominated by packet overhead; with a number of measurements (line 4) the packet overhead is insignificant.
- With larger packet sizes (over 1500 bytes) the packets will be fragmented by the Ethernet interface, so the data rate will be greater than shown here (~10%).
- Floating point data is 2x the size of integer data (see line 4 where overhead is small).

- 60/s data is exactly 2x the requirement for 30/s data.

Once the needs for observability (i.e., signals to be measured and their locations) are addressed and consideration is made for PMU installation and data transmission, the next stage is comparing what is implemented versus the planned applications, budget, schedule, and other expectations. There may not be enough budget or time to implement all the expected or desirable parts of the system. Some of the desired measurement points may be inaccessible. Some of the anticipated applications may not be available. It is also wise at this point to make a list of possible future expansions.

Several approaches can address budget constraints to cover all the desirable measurements. One is to use a phased implementation that installs the first PMUs in the most important locations as determined by system dynamics followed by less significant ones. Another approach is to create a matrix of applications to prioritize which installations will serve the most applications and the ones of highest priority. If the focus is on analysis, the system planners can determine the most important locations. If the focus is on operations, the dispatch and operations group can point out the most important locations. If there is an ISO or Regional Transmission Owner (RTO) organization directing the work, they should supply a list that needs the highest priority. Some locations may already have adequate communications and equipment capable of making phasor measurements. These can be included with very little budget, even if of lower priority. The most important thing is to create a workable system within budget that will serve the most important needs of the users.

Various power system monitor, operation, control, and analysis applications are being developed all the time. Many products take full advantage of the capability provided by phasor measurement. If the particular application that the user wishes to use is not readily available, in-house development, perhaps with a university partner, is an option. Another option is to contract with a vendor for modification of an existing product. There are a number of utilities and vendors involved in this industry that are good references for advising on new application development. In any case there is more risk developing a new specialized product than in using well proven existing ones. Synchrophasor technology is relatively new, and not many people have experience with application of this technology.

When a regional group such as an ISO or RTO is involved, their requirements need to be included in the TO system planning. The requirements should include mutual agreed plans on identified PMU locations, measurement characteristics, signal characteristics, communication requirements such as bandwidth and reliability. Parameters such as data rates, measurement characteristics (M/P class, filtering), single-phase/positive-sequence, and other characteristics that can be user chosen need to be discussed and decided. Naming conventions need to be crafted so they satisfy both the TO and regional entity requirements. The communication method and interconnection issues such as bandwidth, reliability (including redundancy), point of interconnection(s), latency through TO equipment, and data flow control need to be agreed. Finally, the longer term issues such as troubleshooting coordination, operational controls, scheduled and unscheduled maintenance, notifications, equipment calibration, and replacement policy should be at least be discussed at the planning stage.

Planning also includes the overall system considerations such as redundancy, archiving, and cyber security. Full redundancy should include the PMU, communications from the substation to the TO control center, all processing within the control center, and communications and systems within the RTO if that stage is included. It could also include the sensing instrument, such as the PT/CT devices. Redundancy can be an expensive requirement, so it is advisable to consider the applications and alternatives. For example, if bus voltages are critical measurements, a particular bus voltage can be backed up with the measurement of a neighboring bus voltage combined with a line current between busses, eliminating the need for two measurements on the same bus and the additional communication requirements. If the application can tolerate short outages, a hot standby or fail-over design could be used instead of a complete dual system. This document will not present an analysis on the subject, but rather point out that there are many options for redundant operation and encourage the designer to consider the requirements of the application and choose an approach that will meet those requirements within the context and budget of the project.

Most phasor data systems include archiving for the data. Usually only a small percentage of the overall budget is needed to build an archiving system, so it certainly makes sense to include one, particularly considering the number of applications that use archived data. A redundant archive system or some kind of backup is highly recommended. This could be in the form of a fully redundant database system or a primary archiver with a file writer. In some cases, archiving at the substation is used to provide back up. The main problem in archiving is failures can happen without much notice and may not be discovered until someone tries to access the data. Then it is too late. Considering the value of the data and low cost of archiving, a backup is recommended.

Cyber security is at the forefront of most networking and computer system considerations. It is a prudent practice and is also in most cases a regulatory requirement. Since phasor systems are heavily dependent on communications networks, cyber security needs consideration from the first system designs and through the whole process. The planner is advised to not postpone these considerations.

3.2 System Development - Equipment Selection

The next step is the equipment selection and detailed system and subsystem design. The detailed design will depend on the particular utility facilities including substation, communication, and control center equipment. This document makes recommendations about equipment characteristics and leaves the required selection to a design engineer who has knowledge of utility requirements and facilities.

3.2.1 Phasor Measurement Unit (PMU) selection

There is a wide variety of PMU equipment available. These range from specialized PMUs that have only a single voltage and a single current input to digital fault recorders (DFR) type equipment that will handle a dozen or more voltage and current (V & I) signals distributed throughout a substation. The main PMU differences considered here are:

1. Number of V & I inputs.
2. Distributable input interface units.
3. Auxiliary inputs for analog or Boolean (status) inputs.
4. Timing input.
5. Communication interface.
6. Phasor algorithm options.
7. Accuracy & performance.
8. Multi-function devices vs. single function PMUs.
9. Cost.

All V & I inputs should be 3-phase and the PMU should offer positive sequence as one of the output options. The number of V & I inputs will vary by the installation and the signal measurement requirements. Generally the principal bus voltages and major line currents should be included in the measurement set. Since the incremental expense to include most line currents is small, most utilities will try to do a complete station measurement. It may be necessary to include several PMUs to cover a large station.

The designer needs to consider which V & I signals are required, how/where the signals are accessed, and the types and number of PMUs required to accomplishing this. In some substations, the currents are only available at distributed relay houses, or even in bay controller boxes. In others, all signals are brought to a single control house. When choosing a PMU, it is necessary to determine how the signals are distributed for access. It may require using a PMU that has distributable input modules that can be located where the input signals are available or using several PMUs distributed where the signals are located. Data may or may not be collected with a local PDC. It is advisable to consider these issues before choosing a PMU and other equipment.

Most PMU focus is on the V & I inputs for phasor calculation. In some cases, the user needs auxiliary information such as breaker or switch status, or control values. For example, dynamics analysis may be significantly improved by including measurements of DC power order, stabilizers, exciters, harmonics with percent values, and similar values. Having all this information in a coherent measurement set can be the key to a forensic analysis or essential to a wide-area control system. Analog and Boolean data is included in the C37.118 measurement set and is supported by some PMU vendors. If these data types are required for the phasor system applications, the designer must select units that support them and with input characteristics that match the installation.

All PMUs require a precise time input. Most will either use a direct Global Positioning System (GPS) input (from an antenna) or an IRIG-B time code. For the former, the PMU must be located within allowable cable length distances from an antenna mounting point (including routing into the building). For substations, this is usually not too difficult if well planned. Fortunately the GPS signal is fairly resistant to interference from substation equipment. IRIG-B must be likewise provided from a high accuracy source, usually GPS. The IRIG signal type needs to match the PMU requirements and should use a high-accuracy modulation (level shift or Modified Manchester). Analog modulated signals do not provide adequate accuracy. The C37.118 (also called 1344) time information profile should be used with IRIG-B so the PMU can determine when a timing error occurs. IEEE 1588 for timing is being introduced and should also work well; however there is not enough current implementation to make specific recommendations.

Most PMUs transfer data over an Ethernet interface and include an Internet Protocol (IP) stack for network communications. Some models only have RS-232 serial output but can be adapted into a network using a serial-Ethernet translator. In some cases, serial communication may be preferred due to cyber security concerns. Both serial communication and Ethernet will handle all communications from a single PMU up to 60/s data rates. Where data from several PMUs is combined, serial communication probably won't have enough bandwidth. Note that the slower clocking rates of serial communication cause longer delay than Ethernet rates. The designer needs to determine the necessary bandwidth and allowable delays and design the system accordingly.

PMU algorithms and performance are difficult to assess without testing and a thorough study of the technology. Generally, a PMU with M-class performance will have more accuracy but more delay in reporting. A PMU using P-class will have faster reporting but will suffer loss of precision in some situations. These performances will vary somewhat between devices. Most PMUs offer both classes of performance. It is recommended that the designer evaluate the intended use of the system and design accordingly. Choose a few PMUs that meet the expected use and have them tested. Choose PMUs that pass IEEE C37.118.1 requirements and other particular tests that are specified, and have the best measurement accuracy. It may be advisable to consult with others through involved technical organizations for more insights.

A commonly cited difference between PMUs is stand-alone vs. multifunction. The stand-alone PMU is a hardware device that is built as a PMU and primarily functions as a PMU. A multifunction device is a device that is built for other functions, such as a relay or a DFR, but includes PMU functionality. An area of concern is whether the multifunction device will fully perform its PMU functions while performing its primary task. There is also a concern as to whether hardware optimized for another function can perform PMU functions as well as hardware designed specifically for PMU functions. Based on performance testing, a multifunction device is not necessarily better or worse than a stand-alone unit. The basic hardware configuration of the two types is the same. Both unit types need to be tested under realistic operating conditions to be sure that internal housekeeping tasks and other functions will not interfere with the critical PMU functions. The multifunction unit needs additional testing for proper PMU operation while the non-PMU function is also operating.

Cost is always a consideration, and is sometimes the main driving factor. Generally the overall cost of installing a PMU with its communication components is 3-10 times that of the PMU itself. Based on this factor, it makes sense to choose a PMU that fits into the installation with the least amount of auxiliary equipment. That will often be the cheapest alternative overall.

3.2.2 Communication equipment selection

Phasor measurement data is usually sent as packets with phasor, frequency, and other measurements all corresponding to the time stamp that is included in the packet. This packet is referred to as a "data frame" since the measurements are more complex than a sampled waveform. The rate is usually 10/s or greater and the data is pushed from the PMU at the periodic rate rather than polled by command. The data rate and packet contents are generally pre-planned, so it is easy to calculate the required bandwidth. The actual equipment will depend on the communication facilities in the substation and the communication system that connects to other locations. Detailed scenarios are not presented here since there will be a wide variety of actual equipment needs as well as company procedures and regulatory policies to follow. The basic requirements of data rate (bandwidth), latency, and reliability should be presented to communication specialists to design the system and specify the equipment.

3.2.3 Timing equipment selection

The only widely available source of time that is reliable and accurate enough for phasor measurements is GPS (as of 2013). The GPS uses satellites that transmit precisely timed signals that a receiver correlates to triangulate position. The satellite time codes are stable and synchronized to universal time (UTC), so the signals can be used to provide a precise time as well as position. A PMU may have a GPS receiver installed internally inside or may require a timing signal from an external GPS receiver. The basic GPS signal is 1575 MHz so it will travel only a limited distance from the antenna. The designer must consider the PMU location relative to potential antenna locations if the PMU uses an internal GPS receiver. Note also that a single antenna can supply several receivers by using amplifiers and splitters. If the PMU is supplied by an external GPS clock, it will receive timing signals by local time code. The most common local time code is IRIG-B. The level shift and modified Manchester versions have sufficient precision for synchrophasors. There may be some issues with amplitude and impedance matching, but these can be readily solved. The IRIG codes were designed for timing on military test ranges, so they do not have built-in continuous timekeeping capability. In particular, they do not inherently provide indication of synchronization to a universal time source. These added features can be provided in the indication field of the IRIG codes (control bits). The C37.118 standards provide a recommended set of codes tor continuous timekeeping. If the GPS clock can add this code set and the PMU can read it, the PMU can provide the synchronization time and status required by the standards which are necessary for reliable measurement system operation. If the GPS receiver is internal to the PMU, the required time and status can be derived directly. Details for GPS installation and time distribution are left to specific manufacturer instructions.

3.2.4 Control center equipment selection

Synchrophasor measurements are digital signal representations when they reach the control center. The applications that use them are signal processing and display programs. Consequently control center equipment consists of computer processing and display systems, and networking for moving data between systems. The basic requirements are sufficient computing capability and communications to support the applications in a timely manner. A key difference between typical data processing and synchrophasor applications is the real-time aspect. Modern servers are very fast and appear to do things in real-time, but in fact control their own processing priorities according to an internal schedule, usually optimized for efficiency. Processors using standard operating systems generally are more efficient running a single task through to completion than switching rapidly between tasks. The normal preference is to keep efficiency high by minimizing task switching. Synchrophasor data is transferred in frequent short messages, therefore frequent switching is favored to process the data. Synchrophasor applications also often need to run on this same frequency processing cycle. If the delays to process messages are too long, data will be lost. Problems have been encountered using programs not set for real-time operation, and using virtualized servers with parameters not set for this type of application. The designer needs to carefully evaluate the real-time requirements of the applications, as well as data flow since this aspect is different from standard data processing.

Control center applications should include archiving, operation and error logging, system real-time monitoring, and some kind of visualization. As mentioned before, the incremental cost of archiving is small but the value of the data for analysis can be very large. A suitable archive also provides a way to analyze phasor system performance when questions arise. An operation and error log should include all detected errors in measurements and communications as well as statistics on all aspects of the system performance. This is essential for problem analysis as well as detecting performance degradation. Real-time monitoring alerts the operators to failures in a timely manner and emerging problems. Real-time visualization of the data is available in many forms from simple strip charts to complex analytical and geographic displays. Some visualization is recommended at a minimum to maintain awareness of the system's operation and alert users to the data availability. It is well-established that there is a high value in using displays to improve operation situational awareness, and it is recommended that visualization be provided to serve that need.

3.3 System Implementation

System implementation consists of equipment installation, operational checkout, and validation of the measurements. Typical procedures for similar equipment and systems are generally followed. Synchrophasor systems are not substantially different than other systems using similar measurements, communication, and control equipment. A few details are noted here.

3.3.1 Substation equipment installation

A PMU is similar to a relay or DFR in that it needs power to operate, access to V & I signals, and communications. It also must be connected to an accurate timing source, which is not a necessity for most other equipment. Equipment power should be DC backed by the station battery so there are no interruptions during major events. Customary established utility procedures for relays and DFRs should be followed. The PMU may be primarily a relay or DFR anyway.

Substation to control center communication uses standard communication systems with standard provisioning and communication checking procedures. It is important to ensure that the allocated bandwidth is sufficient for the PMU data set. Also, it is important to set communication priority of PMU data relative to other data on the same communications circuit to meet application requirements. Communication equipment should all be DC powered backed by the station battery as well (don't allow an AC modem or Channel Service Unit/ Data Service Unit {CSU/DSU} to sneak in there). Note that NERC cyber security provisions will apply if the system is used in operations. It is best to be aware of this in the design cycle and plan it into the installation rather than trying to add it later.

3.3.2 Control center equipment installation

Control center phasor measurement system equipment is basically computer and networking system components, no different than any other such equipment. It should be installed and configured accordingly. One additional consideration is the operational priority. Synchrophasor systems typically handle a lot of data that continuously flows in real-time. The priority for data forwarding and computer task switching needs to be high enough to prevent losing data. Problems have been observed with multitasking computers, virtualized servers and inadequate disk storage space where data was lost due to servicing other tasks. If the planned computer cannot be controlled tightly enough to prevent data loss, use a separate one. It is much cheaper to buy more hardware than track down data loss problems. Another added consideration is data timing. If the PDC is doing arrival time calculations, it needs connection to an accurate timing source, much better than the typical NTP or SNTP time server. This may require a special GPS module in the server itself or dedicated IEEE 1588 time server. Since a GPS time input into the control center can be difficult to install, try to arrange the time service in advance. Computer and networking equipment is typically AC powered, but consider DC backed or a UPS so there are no interruptions.

3.3.3 Measurement validation

Validation of the measurements is one of the most important parts of the installation procedures. This consists of validating that the measurement correctly represents the expected quantity and is correctly reported to the applications in the control center. Some common problems include reporting an incorrect quantity, reversed signal polarity, incorrect signal scaling or offset, and misidentified signals. Other less common problems surface as well. If validated initially, the signals will usually continue unaltered, though things can change during "operation" so it is advisable to have on-line validation to continuously check for changes.

Phasor measurement initially measures the V & I secondary signals. The relation to primary signals depends on the PT/CT ratios. These ratios must be entered into the PMU. If the PMU outputs the phasor estimates in floating point format, they are scaled to primary values using the PT/CT ratios. If the PMU outputs the phasor estimates in integer format, the ratios are included in the scaling factor included in the configuration message. Older PMUs may require some external scaling. The user needs to apply the right ratios and is responsible to update them if they are changed.

The PMU sends data to the control center equipment in packets where the data is identified by the data type and order in the packet. A configuration message provides signal names and data type, and their mapping to the data. If the configuration is incorrect or decoded in error, the mapping may be wrong and signals may be corrupted. Also, the configuration may change at the sending end, but the change may not be detected at the receiving end, also creating errors. Some errors in decoding are detectable in the data, some are not. Where possible, most phasor system processing equipment (usually a PDC) will detect and keep the configuration synchronized with the data. Where the error is not obvious, the problem will only be found through data examination. Periodic examination of all data is recommended (see maintenance section).

The principal process for initial validation consists of comparing the actual signals with the measurements and at successively higher levels. First, the PMU measurements are compared with values measured in the substation using test instruments or installed meters there. With accurate and full test instrumentation, the measurements can be validated to 1%. Substation validation also requires checking the timing operation.

At the next level, the measurements are validated against SCADA or other reported instrumentation. This level of validation is more for checking the signal reporting, flow magnitude and direction, and overall reporting than precision. Comparisons at higher precision can be made by comparing the reported measurements with a state estimate during steady state conditions (a time when there is little dynamic activity). High precision will not be obtained from every comparison since the power system varies constantly even at steady state, and the dynamic responses of the two measurement systems are different.

The final level of comparison is at an ISO or RTO which receives measurements from many TOs. At this level, comparisons with regional phase differences will be evident. Other than that, it is basically the same as at the TO control center.

Appendix A is a detailed procedure for this validation process from the substation to the control center. It discusses the measurements to be made at each stage as well as the process. Validation can be done at the control center level without doing the substation level, though it is possible some problems may be difficult to resolve without investigation at the substation. The control center validation process is basically the same whether done at the TO or ISO level. Refer to Appendix A for more detail.

CHAPTER 4. OPERATION & MAINTENANCE OF PHASOR SYSTEMS

4.1 Operation and analysis

Most user interactions with phasor measurement systems will be through vendor provided applications. These applications should provide data validation functions including appropriate indications where the measurement may not be reliable. This section provides key points that the user should confirm to be sure the application has the indications it should provide.

Lost data usually requires some kind of recognizable placeholder in the message or data store. It will usually be indicated by NaN, -9999, or a separate flag. The display, analysis, or other package needs to indicate when the data is missing rather than just offering the placeholder as though it is actual data. Some PDCs will repeat old values to fill in missing data. This needs to be flagged and indicated as well. (The standard IEEE C37.118.2 designates bit 9 in the status for this purpose).

Each data sample has a status that indicates if there is a PMU, sync, or time stamp problem, or the data is simply in error. The application should be able to indicate when these problems occur and flag the data appropriately so the data will not give the user false indications.

Phase angle measurement is based on UTC time supplied to the PMU. The measurement Status bit 13 indicates if the PMU time was UTC synchronized when the measurement was made. The state of synchronization cannot be determined from the phasor value itself. The user needs to check the sync flag before using phase angles.

The frequency measurement is usually derived from the phasor values. If the input that is providing the phasor fails, the phasor will not be accurate, and the frequency measurement is likely to be bad as well. The application should be able to link the frequency to a source signal and thereby be able to indicate when the frequency should not be used.

Other data impairments are detectable using other more complex techniques. These will be explored in the next report that includes a validation and conditioning algorithm. At this point, it is recommended that the user examine the validation techniques built into each application and compare them with input processing to be sure they are compatible. Most data problems can be resolved by careful implementation using techniques and flags that have already been established.

4.1.1 On-line data validation

On-line data validation requires building data checks into the processing applications with conversions to displays and operations. There are three essential functions here: indicate data problems to users, provide real-time system problem alarms, and create a record of data problems. There are three areas that need to be addressed:

1. Indication on displays and in alarm functions that are using the data that the data may be impaired. This will prevent users from taking incorrect actions.

2. A separate alarm function to tell users where a problem has been detected, what it is, and whether it is still active.
3. System or process to record data issues to evaluate performance and find problems that are developing. A record of performance is also helpful for analyzing intermittent problems.

Data usually comes into a PDC which aligns it with other data and then distributes the data to other PDCs and applications. It is probably the best place for both real-time alarming and creating a record of data problems. It could create a special flag for downstream applications, but that flag will have to be blended into the data stream and the applications configured to look for them. It is recommended that the PDC build indications into the data itself so special processing is not required, and have the applications do validation indications appropriate to their tasks. This will maintain interoperability of systems and programs.

4.1.2 Off-line data validation

Off-line validation is much easier to do since there are no time constraints. It also does not require alarming or error and performance recording. It is recommended that on-line detection and flagging information be retained in the data set so this does not have to be done again. It also saves time when the user does not have to re-examine all aspects of the data.

Off-line processing may be performed manually or automated. Automated processing such as for baselining studies or anomaly detection requires techniques to detect the parameters under investigation, as well as validate the data that is being used. These special processing applications will often include data patching, down-sampling, and other modification processes specifically to suit the objectives. These applications should also provide flagging to alert the user when a data anomaly is detected that is not expected. No other recommendations are offered here since these specialized applications are too diverse to attempt to cover.

Manual off-line processing is the most common. This includes routine examination of events, determining operating parameters, model validation, and other related work. One of the most common issues is that most manual processing does not automatically alert the user to data problems that are indicated by the status and other flags. Unless the user is educated to look at the status and takes time to do so, invalid data may be displayed as though valid, leading to incorrect conclusions. Analysis programs should be equipped to read data flags and indicate problems to alert the user.

Other than the status flags and other indications embedded in the data, validation should include simply observing unusual traces, patterns that don't make sense, and comparisons with other measurements. Some unusual patterns include:

- **Flat line** – continuous line with no changes at all indicating the variable being reported is not being updated. This could be at the PMU or at a PDC that is replacing lost data.
- **Noisy data** – could be higher frequency oscillations. Expand time scale to see if an oscillatory pattern appears. Measurement could be near 0 so it is just noise on signal input. With no signal input, a phasor angle will be random noise.

- **Unusual pattern** – signal is following a perceptible pattern that does not look like a simple oscillation. It could be caused by a clock that is resetting on a regular basis, a stuck measurement bit, an algorithm that is failing at a regular place, and so on. Nearly anything is possible, so the only way to resolve these issues is careful examination and comparison with other signals.
- **Measurements that don't make sense** – a voltage way too high or low, an impossible power flow, phase angles that are unlikely, etc. These problems are usually scaling errors, but also include an incorrectly identified measurement (i.e., the wrong signal), a direct measurement error, data patching errors, bad timing input to PMU, and similar issues.

The next level of manual data validation is comparison with other measurements. SCADA is usually the most available. This data is reported at a much slower rate, so it will only confirm readings within that rate. Steady-state measurement levels can be confirmed. Phasor data can be visually estimated at a slower rate, but more precise comparison requires an averaging type of down-sampling. Voltage measurements and power flow computed from phasor data should match reasonably close. Discrepancies need to be investigated and recorded.

State estimation is required for finding bus voltage phase angles from SCADA data. A state estimate with low residual error can be used to confirm phasor values from the same point in time. As long as there are no major system changes occurring at that time, the comparison should be close.

For dynamic measurement validation, DFR recordings are a good source. They have been used in a number of cases to determine whether the PMU data indications are valid. DFRs usually record data at a sample rate ranging from 960 to 6000 samples/second. The file lengths are usually only a few seconds, so validations can only be made for very specific measurement points. Phasors show the envelope of the 60 Hz sinusoid while the DFR shows the entire sinusoid. While some simple comparisons can be made by visual observation, detailed analysis requires some conversion. One approach is to estimate synchrophasor values directly from the DFR samples. If their time stamps are accurate enough, direct comparison can be made. If not, the traces can be lined up manually to correct the time offset after which they can be compared. Another approach is to look at the signal spectrum of each record. The DFR data has a much higher frequency spectrum due to the higher sample rate, and can be used to confirm frequencies detected by the PMU. It will show if a signal detected by a PMU is present, absent, or possibly aliased from a higher frequency. Some DFRs also include event recording inputs. Some utilities use a separate sequence of events (SER) recorder for this purpose. If the PMU also records Boolean information, these devices can be used to validate the PMU data. Note that the time stamp is precise for the phasor and frequency values, but Boolean data may represent a digital signal (change of state) that occurred between time stamps. When a Boolean value changes state, the new value will be reported with the next phasor report so that it appears to occur at the time stamp, even though it actually occurred between time stamps. So the time stamps for events reported by the DFR and the PMU may differ, but no more than the interval between PMU reports.

4.1.3 Data analysis in operation

Regular analysis of events can significantly enhance system operations. Phasor data will show dynamic activity that is not apparent from other measurement sources. It also provides a good check on other system alarms and measurements. In particular it is recommended that:

- Alarms for saving phasor data be set so that event records are easy to locate and not overwritten
- A policy is established to examining system responses to certain events, such as an event that causes a frequency excursion over 100 mHz, voltage sags below 5%, generator trips at > 250 MW, etc.
- Alarms based on synchrophasor data are established to alert operators for unstable conditions such as low voltages, excessive system phase angles, low frequency, etc.
- Operating procedures are established based on synchrophasor system alarms.

These procedures can significantly enhance operations and planning by including full consideration of dynamics as well as wider measurement area in most cases. Regular examination of phasor data also supports monitoring measurement system performance, helping to spot problems before they lead to greater interruptions.

4.2 System maintenance

Synchrophasor systems are relatively new and experience with their maintenance is limited. Most utilities plan to use the same maintenance schedules already established for similar types of equipment. These recommendations are limited to aspects that can be estimated or predicted by common sense.

4.2.1 Hardware maintenance

PMU equipment in the substation and hardware PDCs are the only actual equipment that are specifically for a synchrophasor system. Measurement accuracy depends on the PMU and periodic calibration is needed to assure precision. There are a minimum number of components that will affect accuracy in a PMU. In most PMUS there is an analog input circuit leading to an A/D converter. Once changed into digital form, the value is handled mathematically and will not degrade with time. Only changes made in the analog circuitry and converter can degrade the measurements and cause changes in measurement over time. A well-designed system should maintain calibration for several years. Since the functional application is similar to relays, DFRs, and meters, it is suggested that routine calibration be initially planned on the same interval as that for these devices. In the survey, several utilities planned a 5-year maintenance interval. It is recommended to plan the first calibration interval no longer than this. If the readings are observed to change more than the expected accuracy level (1%) during the planned calibration interval, it should be shortened to maintain the accuracy.

System components such as routers, modems, multiplexers, and computers should be maintained on the company established schedule and policy. No particular recommendations are indicated relating to their use in a phasor measurement system.

Applications and most PDCs operate on standard personal computer (PC) hardware and operating systems (Windows or Linux). Hardware PDCs are uncommon, but operate on some kind of computer type hardware and an Operating System (OS). In all cases, the accuracy does not degrade over time, so no calibration is needed. What is needed, however, are patches and upgrades for the programs and OS. These should be applied in a timely manner and documented.

4.2.2 Performance maintenance

Measurements from the synchrophasor system should be compared regularly against similar measurements from other systems, such as metering, SCADA and state estimation. The best practice would be to do these comparisons continuously; however if that is not possible an annual comparison of most readings is highly recommended. This will detect problems that have come up, such as undocumented signal changes, PT/CT errors, failed A/D units, etc. This kind of change is outside the scope of normal calibration, but happens and is sometimes not noticed until a problem comes up. (It is also a good way to find SCADA failures.) These comparisons should be documented in such a way that slower degradation can be detected as well.

Resource use needs to be checked and documented on a regular basis. This includes communication bandwidth used for the phasor system and disk space for data storage. Changes in the monitoring can add more data and impact the available bandwidth without obvious indications. Also, many communication channels are shared, so growth in other systems would impact the phasor system. On the data storage side, data growth is normally planned with some allowance for changes. However there are often unplanned expansions such as extra events and user analysis records that significantly increase the space requirement. Disk space should be checked regularly to be sure there is sufficient space to avoid loss of data due to disk overflow. Communication bandwidth should be checked at least annually and disc space at least quarterly.

Maintenance procedures and intervals are established by the utility that operates the equipment in accordance with regulatory and other controlling party requirements (e.g., ISO). The recommendations given here are based on observed practices and problems, and should be considered as advisory to establishment of a company plan.

4.2.3 Configuration management

System configuration includes measurement sub-system identification and characteristics, communication sub-system connections and routing, and application sub-system settings. These configurations are done initially as part of the installation and checked in the validation process. As long as the system doesn't change, it should all operate as first planned. However, change is inevitable and a process for configuration management is critically important. Changes in configuration need to be planned by the person or group that manages that particular aspect. For example, an IT department usually manages routing and firewall configurations in the network. They should plan all such changes. After change planning, the other stakeholders need to be notified of the planned changes, as these changes may affect other parts of the system in unexpected ways. For example, the substations group may be adding a few measurement points, but that may increase the packet size enough to require additional communication bandwidth. Finally, after notification and sufficient time for a response, the lead part can proceed with the change. This should assure a smooth transition to the new configuration.

APPENDIX A. PMU AND SYSTEM INSTALLATION AND VALIDATION PROCEDURES

A.1 Introduction

This document provides the requirements for validation and documentation of phasor system installation. It is broken into sections for each level of installation. A.2 describes PMU certification and calibration requirements. A.3 focuses on the PMU installation in the substation. A.4 confirms the data as reported to the control center. It should be followed in order to identify problems where they first occur.

Test equipment and methods may be called for that are beyond the practice of a particular utility or staff function. Signal readings may be indicated that do not exist or are inaccessible. The procedure attempts to offer alternative processes, but in places may not do so. The reader is advised to use alternatives that match the intended process as closely as possible.

A.2 PMU compliance with C37.118.1 and calibration

Compliance with C37.118.1 should be shown. The utility, vendor, or a third party can perform the required tests. The requirements in the standard cover both overall performance and calibration. Compliance needs to be shown for the particular PMU with the specific settings that will be used, since differences in settings can significantly change performance. A complete set of tests would only be needed on a single unit, since most of the processing is a software function and these will not change from unit to unit (unless the actual design is faulty). Differences between units of the same type and the same settings should only be found in input scaling and phase angle measurement. These differences are determined by calibration testing.

The measurement accuracy capability of a typical PMU is in the 0.5% range. Calibration requires signals and measurement devices that have resolution and accuracy in the 0.05 to 0.1 % range. It is difficult to do this in a substation setting, so this type of testing needs to be performed in a laboratory. The basic C37.118.1 performance requirements require accuracy in the 1% range, but the test results can be used to as high accuracy as the test equipment will allow. The C37.118 steady state magnitude and angle tests can be used for calibration.

For best operational accuracy, every PMU should be calibrated in the lab before deployment in the field. The scale factors should be adjusted based on these calibration results to give the best accuracy possible. A test record needs to be kept, and periodic recalibration is required.

Since individual lab calibration may not be practical, a generally acceptable approach is to sample test a batch of PMUs. If they meet the requirements consistently, testing of a subset of deployed PMUs should be sufficient. Examination of the results may show a systematic error in the measurement that can be improved by adjustment of the default scaling. However, in general, calibration adjustments for individual units cannot be made from a sample test.

A third alternative requires manufacturer certification and calibration. This can include calibration with adjusted scale factors. The utility should spot test a few units to be sure calibration is good.

A.3 Substation installation requirements

The phasor system substation installation consists primarily of installing the PMU with its related input and output. It will have V & I inputs for measurement, a time input for synchronization, and a data output. It may have additional measurements of status (Boolean values) and analog values, either input through an A/D or internally calculated. Validation of this installation consists of assuring that the inputs are correctly connected, quantities are correctly identified (labeled), the scaling is correct, and the data I/O is operational. Calibration to the system requires local test instrumentation.

A.3.1 Check that the clock used for synchronization to UTC is on time and locked on time. Check that the PMU correctly indicates when time is locked and that the lock is steady.

- **Method**

The clock may be a GPS receiver internal to the PMU or may be a substation clock that supplies time using IRIG-B or another format. The PMU may provide a display to show the clock time as received by the PMU or allow using a program to look at the data. Alternatively use a data reader to look at data and time. A PDC on a laptop is another way to locally check the data output. UTC time does not change with seasons for daylight. It has a constant offset from local standard times. The offset from Eastern Standard Time (EST) is -5 hours (subtract 5 hours from UTC to get EST).

Lock should be indicated by the receiver, whether internal or external to the PMU. It is required to be indicated by the output data. If there is no user indication on the substation equipment, start output data and observe the indication there using a local device as indicated above.

To determine that the lock indication reports correctly, remove the time synchronization source from the clock. The PMU should report sync is lost within 1 minute. It should likewise report sync is regained when the time is reacquired (the receiver may take a few minutes to re-lock after the antenna is reattached). Note that if GPS is used as the prime source, this exercise will involve disconnecting the GPS input from the clock. If the clock is internal to the PMU, disconnect the GPS input. If the clock is external to the PMU, the GPS must be removed from the clock, not just the time signal (i.e., IRIG-B) from the PMU. The PMU must determine that the time signal is synchronized, not simply that it is receiving a time signal (the PMU may have a valid time signal but the signal may not be synchronized to UTC).

The lock to GPS must be continuous. In reality the receiver may have short unlocks while switching satellites, but the receiver should ride through those with its internal oscillator. If there are any significant reception difficulties, they should show up within a day. Monitor the lock signal for a 24-hour period to be sure that there are no dropouts. Any dropouts require investigation, remediation, and retest. The clock or PMU may have a built in monitor which can be used to confirm lock. Alternatively collect output data using Connection Tester or a PDC to analyze for dropouts. A PDC should provide performance statistics that will show the sync performance.

A.3.2 Confirm that the phasor measurement magnitudes are within 1% of input levels. Also confirm voltages are within 1% + 1kV and currents within 1% + 100A of comparable substation measurements.

Traditional substation measurements are bus voltage and power flow in lines. Some substations will provide metering or other indications of line currents. PMUs measure V & I. The challenges in measurement comparison are that the values vary constantly, so the user has to estimate at a moment where the values are not varying rapidly and input and output can be captured at the same time.

Substation values can be read from test equipment, substation meters, or local SCADA systems. PMU values are often provided by a PMU display. Alternatively the PMU vendor may provide a viewing program for a PC, or Connection Tester or a portable PDC can provide the data.

- **Comparison of phasors with actual inputs**

Connect test equipment to the PMU V & I inputs. The test equipment should be within its certification period and have an accuracy rating of 0.1% or better. Compare the input values with the values provided from the PMU. Make the readings for comparison at as close to the same time as possible to eliminate variations. Make the comparisons by phase, i.e., Va input to Va phasor, etc. Be sure to apply sqrt(3) corrections where needed. Note that generally PMU voltage inputs are phase-neutral and current inputs are phase, so Y-Δ scaling is probably not needed. The comparisons should be within 1%, which is the minimum C37.118 requirement. If the error is larger, investigation should be done as there is probably a connection or setup error. If PMU also reports positive sequence, it is worth checking by averaging three single phase readings for comparison (the phase angles should be close enough). Positive sequence thus tested should be within 2%. This additional comparison assures that the phasing is properly connected.

- **Comparison of phasors with substation instrumentation**

This will be less accurate than the first step since installed substation instrumentation is usually less accurate than portable test equipment and is often connected to different PT and CT signals. It does provide local validation that the PMU is correctly connected to the indicated PT and CT signals as designed. There will usually be voltage measurements in the substation and sometimes current measurement. Compare individual voltage and current phases as above. Try to choose voltage readings from the same PT for comparison. If there are single readings, just compare the appropriate phase.

If there are only power measurements on feeders, compare with power computed from V & I phasor values. A tool that will provide these readings on-line is the best approach. If no such tool is available, power can be computed manually $P = I_x V_x + I_y V_y$ using rectangular components or $P = I_m V_m \cos(\emptyset_v - \emptyset_i)$ using polar components.

The main point to these comparisons is to spot wiring, naming, and scaling errors. For example, if the wrong current is wired into the PMU, the computed value will probably differ considerably. The comparison needs to be only to an accuracy that will reveal errors since the accuracy is checked directly in the test above. A comparison of 3-4% is probably sufficient, allowing for 1% in the PMU and 2-3% for the local measurement.

A.3.3 Confirm that the phasor measurement angle differences are within 1-3 degrees of corresponding input signal angle differences. Also confirm the angles with comparable measurements in the substation.

Phasor angle measurements are made relative to UTC time and there is no direct way to validate these values short of using another PMU. However the phase angle between signals can be readily determined by a number of methods. As above, portable instrumentation is prescribed here for calibration and using installed substation equipment for signal validation. The angle should be validated to within 1 degree, but this may not be possible in all test situations. The test staff needs to use judgment as to whether the measured errors correctly represent the PMU errors or whether they are a result of imprecise test equipment and methods.

- **Comparison of phasors with actual inputs**

Choose a reference signal (e.g., the bus voltage) against which all other angles will be measured. Connect phase angle measurement equipment to the reference signal and another input signal (voltage or current). Compare the angle between the same signals measured by the PMU. Make the readings for comparison at as close time wise as possible to eliminate variations. This comparison is easiest with a phasor reading device that allows setting a reference that will be subtracted from the other signals to directly display the angle difference. Alternatively, the process can be done manually. Choose a time when the system frequency is very close to 60 Hz as the phase angles will vary more slowly. Compare measurements of the same signal and phase. The input and PMU measurement should be within 1 degree of each other. PMU qualification based on 1% Total Vector Error (TVE) requires phase angle accuracy 0.57 degrees or better. Testing has shown that most PMUs measure phase angle to accuracy near .02 degrees. Test equipment should be capable of 0.1 degree accuracy, but check the specifications. If the current is low (under 20% of rated current) the measurement may be less accurate.

- **Comparison of phasors with substation instrumentation**

Compare PMU measurements with local installed instrumentation. Traditional measurement equipment does not measure phase angle. Angle between V & I can be determined from real and reactive power measurement. Phase angle is defined as $\phi = \tan^{-1}(Q/P)$ where Q and P are reactive and real power respectively. The phase angle for each current relative to the related voltage can be determined this way. These standard instruments will not give the angle between different bus voltages or currents for which there is no corresponding voltage. As with the specialized instrumentation, when the current is low, the watt, var, and phasor measurement will be less accurate. Allow larger errors for currents less than 20% of rated current, and do not expect to make comparisons with currents less than 10% of full load.

As above, this step is intended to spot wiring and naming errors (scaling errors do not affect phase angle), so compare measurements with this in mind. The level of comparison should be enough to confirm that the correct signal with the correct phasing has been selected.

A.3.4. Confirm that analog measurements are within 5% of other measuring devices in the substation

Synchrophasor data communication can include samples of analog signals that are not phasors. The C37.118 protocol includes this data type as "analog" data. It can be represented in integer or floating point values. The standard does not specify what these analog signals are, so they can be any continuously varying signals such as power (watt and var), control signals, local readings (pressure, temperature) or any other continuously varying signal. They can be sampled from an external source or produced internally in the PMU from other inputs. The standard also does not specify how the measurement is to be made, scaled, recorded, or any other measurement parameter. The data type was added to include measurements in the synchronously sampled data set that are important to using phasor system data and adding understanding of power system operation. Some of these values may have local reporting in the substation and some may not. Since there is no standard specification for making these measurements and what they represent, this confirmation test is simply a best effort to be sure that the reported data reasonably represents the signal it is supposed to.

- **<u>Method</u>**

In cases where there is no means to locally observe the measured quantity, this test can be ignored. Where it is observable, find a suitable means to read the values as sent from the PMU. These values are often provided by a PMU display. Alternatively, the PMU vendor may provide a viewing program for a PC, or Connection Tester or a portable PDC can provide the means to read the data. Locate a measurement display for the quantity in the substation. In some cases portable test instrumentation may be required. If computed internally, the user can compare PMU input values or even use the PMU phasor values. Compare the two values. The values generally should be within 5% of each other, however, in some cases it can be much closer and in some other cases not as close. It is left to the user's discretion to determine an appropriate level of correspondence and validate the measurement to this level. Deviation of accuracy acceptance from the given 5% minimum needs to be documented.

A.3.5. Confirm that digital status measurements report the correct Boolean state

Synchrophasor data communication can include digital status indications. The C37.118 protocol includes this data type as "digital" data. Digital status is represented as a Boolean 0 or 1 binary value. The standard carries Boolean values in blocks of 16 as 16-bit words. The standard includes the ability to specify which bits in each word are valid representations (that is, in use) and what is the normal state (as opposed to an alarm state). These status can be used for any binary signal (i.e., on or off) such as alarms, switch position, position, etc. The user must assign suitable identification and determine how the indication will be used. The data type is included so the user can include indications in the synchronously sampled data set that are important to using phasor system data and adding understanding of power system operation. Some of these values may have local reporting in the substation and some may not, however it should be possible to determine the local state of all such indications.

- **Method**

Find a suitable means to read the values as sent from the PMU. These values are often provided by a PMU display. Alternatively the PMU vendor may provide a viewing program for a PC, or Connection Tester or a portable PDC can provide the means to read the data. Locate the source of the signal and if possible, a display or indicator in the substation. The goal is to determine whether the input state is correctly indicated by the phasor data. Observe that the output correctly indicates the input. Change the state of the input and observe that the indication changes. In cases where the source cannot be changed, such as breaker position on a critical line (that cannot be taken out of service), operate the input in a test mode to be sure the indication changes. It is important to actually change the input to the PMU (e.g., voltage on the PMU input) to be sure that the actual PMU input is working, it is mapped to the correct data, and voltage or current input thresholds are satisfied. Do this for all digital inputs that are sent as digital status.

A.3.6 Substation installation confirmation documentation

Documentation in the form of notes and test results needs to be provided to show each test was successfully completed. It should include a description of the test methods, equipment used for tests, raw measured results from the instruments and the PMU, calculated values, calculation methods and formulas, and the comparison results. Anything that was observed which could be of interest should be noted as well, whether it is relevant to the given test or not. Any repairs or changes made as a result of these tests should also be noted.

A.4 Control center installation requirements

The control center installation includes the PDC, communication systems, and various applications. This checkout is primarily to confirm that the communication to the PMUs is operating correctly, the data is correctly identified and scaled, and interstation phasing is correct. It also provides an initial comparison with state estimation to confirm if the overall measurement schemes compare.

A.4.1 Confirm that received data match the setup and the time stamps are within 3-seconds of the local time

There will generally be a number of remote devices (PMUs and PDCs) reporting to the control center. The data received from each device needs to be validated that it matches the data description. At this stage only the message reports need to be validated; data content will be validated in A.4.3. If the time stamps do not match the actual time, the data will not match and cannot be combined. These issues need to be resolved before the data itself can be validated.

- **Method**

Data is mapped as binary values into a frame (message) that is sent from the PMU to the control center. These frames will vary in size and content from station to station. The receiving device, usually a PDC, will make the connection to the remote and request a configuration message. This message will provide the data description including names, scale factors, data type, and the location in the data frame. The PDC uses this information to decode and scale the data to usable values. The PDC should do this automatically, but it is highly recommended that the test engineers examine the values. In particular, compare the signal names and scaling with a listing from the design documents. The names should match, all data items should be accounted, and scale factors should seem reasonable. Data values will be more closely examined in A.4.3, but a review at this stage can reveal problems that are more difficult to diagnose later.

A timestamp is included with all data frames. It indicates the time of measurement. Data frames should be sent with minimal delay, so they should be received with a time stamp that is no more than a few seconds earlier than the current time. The data time stamp is in UTC time which will be offset from the local time and does not change for daylight seasons. If a local time is used, determine what the current offset from local to UTC time is. The offset from Eastern Standard Time (EST) is -5 hours (subtract 5 hours from UTC to get EST), and Eastern Daylight Time during the summer season -4 hours. Use an accurate computer time reference and visually compare the received data time with the computer time. This can be done with some PDCs or alternatively a data viewing program for a PC, or Connection Tester. A visual comparison can determine if the times are within one second of each other. If the received data time appears to be more than one second ahead or more than 3 seconds behind local time, there is likely a clock error at the PMU or some other setting problem that needs to be resolved.

A.4.2 Catalog communication errors and show that the overall data loss is less than 0.1% over a 24-hour period

Each remote device reporting to the control center has a communication channel which may include a number of links, translations, carrier systems, and so on. Each element of the communication chain can cause impairments of one type or another. This test simply observes and documents these impairments over a 24-hour period, as well as assures that the overall data loss is less than 0.1%. Phasor data systems should operate at loss rates much less than 0.1% (which is approximately loss of 2 data samples/min at 30/s data rate), which will generally provide sufficient data availability for most applications. A well-designed and implemented system can be expected to have a loss rate <0.001% (1 frame/hour) during normal operation.

- **Method**

For each remote measurement input to the control center, monitor the reception of data over a 24-hour period and record all data loss. The inputs will usually be from a single PMU at a substation, but can be from a substation PDC or possibly from another PDC that collects data from other PMUs. The record of data loss should include separate tallies of data that is received but corrupted, data that is not received but expected, and any unexpected changes in data format. The receiving device needs to have a long enough wait that it includes all data received up to a reasonable delay of at least 10-seconds (i.e., it should count data that is up to 10-seconds delayed as successfully received). Data that is received with a time stamp more than 10-seconds from the current time should be counted as lost with a time error. The tally should also include data received but flagged as an error. These flags are data invalid, PMU error, PMU sync lost, or sort-by-arrival. For data loss that is significant (> 0.001%), the record should include sufficient information to determine the pattern of data loss, such as all data loss in one long dropout, data loss of 1-2 frames at a time spread over the time period, a regular repetition for dropped frames, etc. For this requirement, the received data itself should be saved so that a more detailed analysis can be performed.

- **Special documentation**

Documentation for this test should demonstrate that the data loss for each input channel is < 0.1% over the 24-hour test period. It should include a list showing the number of times and overall percent of each category of data loss including:

1. Data not received.
2. Data received but corrupted (Cyclic Redundancy Check {CRC} error or similar).
3. Data received with time stamp error.
4. Data received with error flag set
    a. Data invalid
    b. PMU error
    c. Sync lost
    d. Sort-by-arrival

In cases where data loss is significant (> 0.001%), the store of data captured during the test should be further examined for the pattern of loss; this will be included in the report. Describe the method for performing these tests and list of the equipment used.

A.4.3 Compare received signals with SCADA measurements and confirm they report the same values within the following limits:

1. Voltages – 1% + 1kV magnitude.
2. Currents – 3% + 1% full-load current magnitude & same direction.
3. MW & MVAR – 5% magnitude & same direction.
4. Frequency – 0.003 Hz.

SCADA provides fairly complete power system measurement capability for most utilities. This step confirms that the phasor system reporting is consistent with that provided by SCADA. Since SCADA is the established system, it will generally be used as the benchmark or reference that other measurements will be compared with; if they are reasonably close to the SCADA measurement, they will be accepted as correct. This comparison will first help to locate measurement quantities that are mislabeled or otherwise incorrectly identified. Secondly, it will enable finding scaling or wiring errors. Lastly, it may result in correction of SCADA measurements. Some measurements from phasors will not have a SCADA equivalent, so can be skipped in this procedure. These measurement comparisons are intended to be taken once and reported; if taken several times over different operating conditions, the results will be more accurate and useful, but this is not required.

- **<u>Method</u>**

Comparisons can be done with live displays side by side, or snapshot data samples. The important point is that data from each will need to be compared at the same time.

Both systems provide voltage measurements. As long as the comparisons are from line or busses that are connected, the voltages will be essentially the same. In many cases the SCADA measurement is a single phase. If the phasor single phase measurements are provided, the same phase can be used for comparison. The positive sequence is generally close enough. Phasors generally report line-neutral, so use appropriate conversions.

SCADA systems often do not report currents. If they are available, make phase by phase comparison where possible. Note that the current direction is arbitrary and can be wired with either direction representing positive. Most systems designate the current as positive when it is out of the bus as indicated by being approximately in phase with the voltage. For consistency, it is recommended that the current direction be designated the same as in the SCADA system.

SCADA systems usually report MW and MVAR. Phasor systems usually do not, but they are easily calculated from the V & I measurements. An additional application may be required to make these conversions, or the user can manually calculate them from phasor V & I values. Once calculated, compare SCADA and phasor system MW and MVAR values. They should be within 5% of each other. The direction indications follow the current direction choices. If the directions do not match, the problem is probably the designated current direction.

An important point to consider for current, MW and MVAR calculations is the reduced precision at low current levels. If current is less than 20% of the indicated full scale, the measurement accuracy is likely to be less than the rated accuracy, and the resulting comparisons will be degraded. The error is usually greater for the angle, so computing MW or MVAR is likely to have high error. For example, a line scaled for 2000 amps but with only 100 amps of load (5% rated) might show a VAR reading of 20 MVAR when it really only has 3 MVAR. The point here is not to expect to get good comparisons with this kind of reading. It is recommended to perform comparisons when the line has higher loading, at least 30% of capacity. However it is good to record results at different levels for comparison. The flow direction will usually be ok even if the reading is low. Lines out of service will often provide measurements, but they tend to be very random. Be careful to limit comparisons to lines in service.

Frequency varies constantly but generally in a limited range during normal steady-state operation. Choose a time when frequency is changing slowly to make the frequency comparisons between PMUs and SCADA. It is best to compare the frequency from several PMUs against each other to spot any that are in error. Pick a few PMUs that are in close agreement, average their readings over 1-3 seconds, and compare with that from SCADA. Keep in mind that the SCADA measurement probably averages frequency over a second or more. If the phasor measured frequencies are close to each other but different from SCADA, then the SCADA measurement is probably in error.

A.4.4 Validate data status indications

Every frame of data includes a 4-bit data quality status indication. These 4-bits are *data valid, PMU error, sync valid*, and *sort by arrival*. The "good" or normal state is cleared to 0; when set to 1, the bit indicates the alarm or abnormal state. These bits are set by the measurement device (PMU) or other processing devices (PDC) based on measurement conditions or errors detected in further data processing. Appendix B describes these bits and their use. This step is to validate that these quality indications are being properly received and handled by the control center equipment.

- **Method**

For each incoming data stream, observe the status indications with a device that receives the incoming data. Confirm that all bits are cleared (to a 0) indicating that all incoming status indications are good. If any are set to 1 indicating a trouble condition, confirm that the impaired state is actually valid. No further testing is required for this requirement.

While not required, further testing of system operation is recommended. First, set up a data output from the control center PDC. Observe that the input under test is included in the output. Disconnect or disable that input only. Observe that the output data for that input is marked as invalid data. Secondly, if the PDC allows manually setting the input to sort by arrival, set it that way. Observe that the output data stream indicates the data is timed using sort by arrival. Thirdly, if assistance is available at the substation, have the timing synchronization removed from the clock (remove GPS antenna) so the clock will go to an unsynchronized status. Observe that the sync bit is set in both the input and the output data.

A.4.5 Compare received signals with EMS state estimation results and confirm that the phasor system reports the same values within the following limits:

1. Voltages – 2% magnitude, 1° phase angle.
2. MW & MVAR – 5% magnitude and same direction.

State Estimation (SE) uses primarily watt and var measurements along with bus voltages to estimate the complex system voltages (magnitude and phase angle) across the grid. By using over-determined equations and complex processes to reduce errors, the techniques can provide highly accurate results, including location and reduction of actual measurement errors. SE solutions are used to set operation guidelines as well as system security assessment, so they become a critical element in system operation.

Phasor system measurements should compare accurately with SE, and differences need to be resolved. SE is also the only method other than phasor measurement that can provide system phase angles, which is the basis for power flow in the grid.

- **Method**

SE is usually performed automatically on a scheduled basis, with the repetition interval ranging from one to several minutes. It uses measurements gathered primarily with a SCADA system. The comparison for this test needs to be done using a snapshot of phasor data corresponding to the same time as the SE. Data for the SE will usually span several seconds to several minutes. The best approach is to use phasor data with a time stamp close to the middle of the time span used for the SE. It is also important to use a time when the system is as quiescent as possible. If one can observe the frequency signals, choose a time when all the phasor frequency signals are near nominal and changing very little. At these times the phase angles and consequently power flows are undergoing minimum change.

Use a single phasor data snapshot for the comparison, using only valid, synchronized data. Use the positive sequence voltages and currents for the calculations and comparisons. Use the voltage phase angle to calculate phase angle between busses. Compare the SE solution at as many points as possible, making at least one magnitude and angle comparison at every station where there are phasor voltage measurements. This process is an important step in the validation of phase angle measurement in each station.

The MW and MVAR comparisons are not as important at this step since they are also covered in A.4.3. If the SE provides MW and MVAR estimates that are corrected from those supplied by SCADA, compare these with the phasor provided values as described in section A.4.3. The same observations provided in A.4.3 about limited accuracy due to low currents apply here as well.

Problems in SE solutions are well documented. The phasor solutions are likely to be better than those from the SE in boundary areas and where there are limited measurements. This step has also proven to locate errors in SE configuration. Differences in excess of the given comparison limits should be investigated to determine the cause, which could be in either measurement system.

A.4.6 Control center installation confirmation documentation

The documentation requirement is the same as for substations confirmation described in section A.3.6.

APPENDIX B: TROUBLE RESOLUTION FOR INSTALLATION AND MAINTENANCE

B.1 Introduction

This appendix provides troubleshooting guidance for both the installation and maintenance phases. The installation section focuses on the PMU since that is the most unique part of the system installation. There are often difficulties with communication installation as well, but this is most often with the PMU communication interface or the networking rather than the communication system itself. Since these problems are very system specific, they are not addressed here.

Once the PMU is correctly installed and the system is operating, problems are usually detected by the end user. Often it is difficult to determine where the problem originates since there are many elements in the system. This appendix provides some guidance for locating and resolving common problems.

B.2 Installation problem solving

B.2.1 PMU installation

The magnitude of voltage and current signals is determined from the sinusoidal AC signal itself; the time reference does not affect the measurement. The value should be the Root Mean Squared (RMS) value for the signal. All three phases of a three phase signal and positive sequence should be about the same magnitude. Phasing can affect positive sequence, so if it is significantly different, check the phasing.

The PMU may require the phases for a specific 3-phase input to attach to specific terminals or may allow the user to select the phases in software. Errors in phasing can be determined and corrected as follows:

1. **Phase order** - If A-B-C phases are not in the correct order, the positive sequence will be small, close to zero. Swapping any two phases will correct the order. A-phase should be the about same phase angle as positive sequence which can give a guideline for the overall designation.
2. **Missing phase** - If there is a missing phase, the positive sequence will be 2/3 its normal value. Single phase phasors should tell which phasor input is missing. Note that a missing input can be from a connection problem or a failed input channel.
3. **Reversed phases** – Most PMUs use Y connected voltages so the connection is unlikely to be reversed. With current, the CTs are line current which can be connected with either polarity. While there is no absolute designation, the most common orientation is positive power (**V** x **I***) is power flowing out of the bus. Thus, if using the convention of positive power is power flowing out of the bus, the current will be approximately in phase with the voltage. Conversely if power is flowing into the bus, the current angle will be approximately 180 degrees from the voltage. All currents on lines with the same power flow should have similar phase angles.
4. **Designated A-phase** – Since measurements cover a wide area, it is necessary to have the same A-phase designation for all substations over the area where the measurements will be compared. There is no fixed reference that can be used at a single substation for checking the system phasing

relative to other stations; it must be checked with other time-synchronized measurements. This is most easily done at the control center where all signals are available.

5. **Y-Delta** – phasor measurements are usually referenced to a Y connection for voltage. Currents are usually phase currents. If some connections are Y and some Delta, there will be 30 degree offsets and magnitudes to correct. It is best to make all measurements the same. In some cases it is not possible to access phase currents or Y voltages. In these cases it will be necessary to correct the angle measurements with a +/- 30 degree correction and the magnitude with the correct sqrt(3) factor.
6. **Incomplete connection** – if a 3-phase connection is not accessible, the measurement may be made with one or two phases. Without all three phases the measurement will not be as good quality, but this would make a minor difference in most cases. As long as the inputs are connected to their designated phases, the reported angles will be correct. The amplitude of the sequence quantities will be 1/3 (one phase connected) or 2/3 (2 phases connected) of the normal value. Correct this with a PT/CT ratio adjustment.

Frequency is generally derived from rate of change of phase angle. It can, however, be derived in a more traditional way, such as the period between zero crossings. It can be derived from any AC signal, but a voltage signal usually one of the individual phases or the positive sequence. The particular source signal is usually assigned by the PMU vendor. Some PMUs allow the user to select the signal. There may or may not be a fail over signal designation. If the signal fails, the frequency measurement will be lost. Some PMUs lock the frequency output to a nominal value if the source is too low; others will continue to estimate frequency from whatever signal is present, which usually presents a rather poor measurement. If the frequency measurement appears incorrect or noisy, check that the signal source is properly selected and active.

Rate of change of frequency (ROCOF) tends to be a very noisy measurement since it is the second derivative of the phase angle, the usual measured quantity. It is not widely used due to the noise content. The new standard, C37.118.1 imposes new limits on this measurement and makes some recommendations for its measurement, so it is expected to improve. It has been observed that when the PMU is near a device that distorts the waveform such as a Static VAR Compensator (SVC), frequency and ROCOF are very noisy. If the measurement seems excessively noisy, check the input levels and the frequency. However the user needs to understand that a ROCOF measurement with high noise may be inherent with a particular PMU.

The synchrophasor standard, C37.118.2, includes an analog signal type which is not phasors. This is intended to cover scalar measurements such as exciter values, controller settings, or air pressure. By sampling these values and including them in the data stream, auxiliary equipment operation can be analyzed right with the power system. These values can be supplied in many different ways ranging from sampling by an Analog to digital (A/D) input in the PMU to digital data transfer from other devices. The measurement characteristics depend on many external factors and therefore are not specified by the standard. It is left to the user to provide and define scaling, operation, and meaning for these signals as well as troubleshooting.

The C37.118.2 synchrophasor standard also includes a digital data type which is in Boolean format. These values normally represent switch, alarm, or other indications that are represented as a 0 or 1. They are packed into 16-bit digital words for transmission to the control center. In most cases, the PMU samples the digital input when it sends a report. If the input changes state twice (e.g., 0 to 1 and back to 0) in the same sampling interval, the change will be missed since the value is reported at the sampling time. In some cases, the PMU may latch the change so it will catch momentary transitions. That leads to another problem where the reported value is not the current state. These details of performance and operation need to be examined by the user so that measurement reports can be correctly understood. If the digital indications seem to be incorrect, troubleshooting consists of checking the input compared to the output indication. Check that the input voltage matches the threshold for the PMU. In some cases, the PMU requires an active voltage that exceeds a threshold, perhaps 24 V or 60 V for a 48Vdc or 120Vdc system respectively. In other cases, the input requires contact closure.

B.3 OPERATION PROBLEM SOLVING

These procedures are oriented to solving problems in operational systems. These same methods can be used for solving problems during system development as needed.

B.3.1 Overview of synchrophasor data using C37.118 transmission

When using C37.118 format, data is sent in packets called frames. Frames are sent at timed intervals based on a reporting rate that is a sub-multiple of the system frequency. The most common rate used in North America is 30/s, so a frame is sent every 33.33 ms. Every frame contains a sync word, a time stamp, a block of data, and a CRC check word at the end. If the frame is from a PMU, the data consists of a status word, phasors, analogs, digitals, and frequency. If the frame is from a PDC, it may have data from several PMUs. Data from each PMU is included as a block in the message, each of which has the aforementioned elements. The timestamp in the frame applies to all the data in the frame, so if data is combined from several PMUs, it needs to be time aligned. Each PMU block retains its status word, which validates that particular measurement information. See figure B.1.

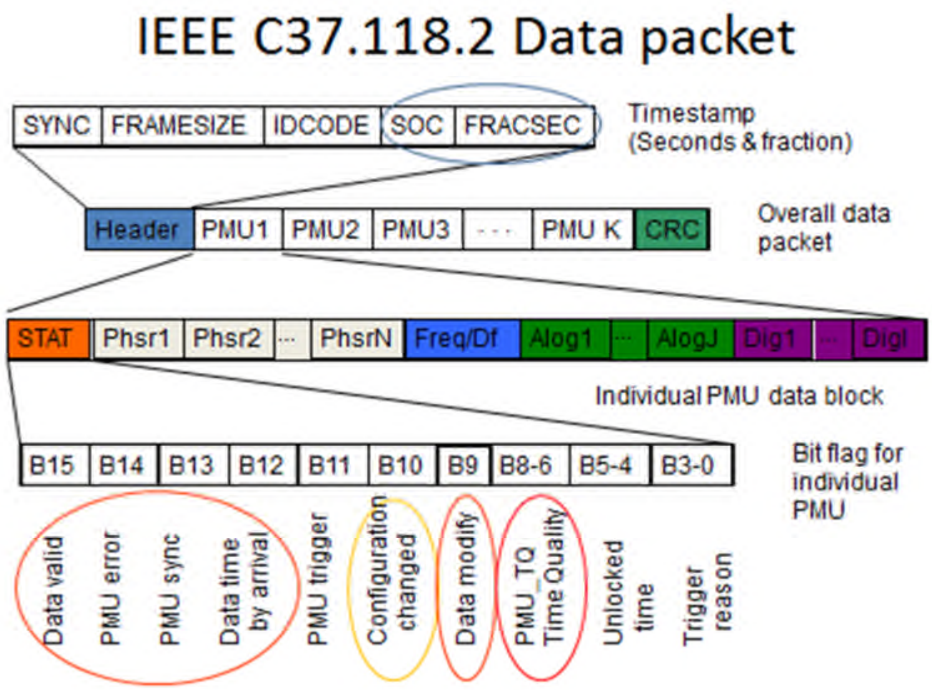

Figure B.1. C37.118.2 format data packet showing status indications

The status word contains six basic quality indications. These are *data valid, PMU error*, *sync valid*, *sort-by-arrival*, *data modified*, and *time quality*. The data user has to check these indications to know if the data item is indeed valid data and if there are restrictions for its use. This quality flag is originally set by the PMU but may be updated by other devices such as a PDC as the data is streamed.

The ***data valid*** bit indicates if the data in the given PMU block is valid or invalid. If the bit is set to 1 indicating the data is invalid, the user should not use the data for anything. At best, the data may be used but only with a prior knowledge of why the bit is set to invalid. The bit is usually set to invalid by a PDC to indicate that no data was received from the data source for this particular data frame. In that case, the data that is in the PMU block consists of random values used as a placeholder. Other reasons for setting the bit to invalid are a PMU in test mode, receipt of a CRC error, and PMU transmission problem. Missing or errored data is (supposed to be) set to a NaN (not a number) state to differentiate non-data from errored data, but this is not done consistently and there is some variability in how NaN is actually indicated.

The ***PMU error*** bit is reserved for the PMU to indicate there is a measurement or operation problem. The exact meaning of this bit is left to the particular vendor since there are many problems it could be used to indicate. These can include A/D problem, computation overflow, memory failure, input failure, configuration error, etc., but are not limited to these issues. The PMU error may be fatal and invalidate some measurements or may be an advisory. In any case, when this error is detected, the user should investigate and determine the cause of the indication before using the data. Note that some vendors have used this flag for other things relating to data processing as well. The user needs to follow the data chain to find the source of the flag and take action accordingly.

The ***sync valid*** bit indicates whether the measurement is accurately synchronized to UTC time. It is set to 1 when the time is not synchronized to UTC. The time source must provide an indication to the PMU when it is not in sync. If the time source is a GPS receiver, the PMU can read a message indicating if the receiver is locked to UTC. If the receiver is external and supplies time to the PMU using a time code such as IRIG-B, it needs to include an indication which could be part of the code or supplied by another signal. Once the bit is set to 1 (not in sync), it should never be set to 0 by other processing in the chain since no device can re-synchronize it. If the PMU reports that the measurement is in sync (bit cleared to 0), succeeding devices will normally pass on the flag without changes. However, it is possible that the PMU incorrectly indicates that the measurement is in sync; if a succeeding PDC determines the measurement is not in sync, it may set the bit to indicate not in sync. Note that if the measurement is not in sync, the phase angle will not be dependable, but the magnitude measurements should be intact. Generally, the frequency and ROCOF will be within usable limits as well. Also note that in most cases, when all measurements from a single PMU use the same internal time reference, the angles between phasors from the same PMU are accurate even though the external sync is bad and the angles with phasors from other PMUs are invalid.

The ***sort-by-arrival*** bit indicates that the data has been assigned a local timetag by the receiving device. In the case that a PDC receives data with a time stamp that is not reasonably close to the current time, the PDC can detect this as a timetag failure and assign a time stamp locally. In this case it must set the *sort-by-arrival* bit to indicate the timetag is artificial so it will not be misinterpreted by subsequent systems. It is also recommended that the *sync valid* bit should be set to indicate the synchronization is invalid, since the phase angles will not be reliable with any timetag change.

The rationale and process for *sort-by-arrival* is as follows: Phasor data systems send data in real-time with minimal delays. Generally the time delay from the measurement until it is received by the first PDC is a fraction of a second. The timetag applied to the data by the PMU is derived from a clock which should be very precise, but could be in error, even a very large error. If data is received by a PDC has a timetag that is clearly incorrect, the time that the data is received at the PDC is closer to the actual measurement time than the timetag supplied in the data frame. In this case, PDC assigns a timetag based on the time that it receives the data. This new timetag, based on when the data arrives, will likely be within a fraction of a second of the actual measurement time. This process was executed by placing the data in a frame with other data corresponding to the most current time (i.e., "sorted into the most current data based on when it arrived").

Sort-by-arrival (SBA) or local timetag processing is used when there is no synchronizing clock or when the PMU has a known bad clock. It is also occasionally used when there are long delays, such as playing back old data for test purposes. The process can be used at higher level communication, such as PDC to PDC communication, not just directly from a PMU. Some PDCs will automatically revert to SBA from timetag alignment when the time offset exceeds a certain value or when the sync bit is set, and may also recover to time alignment when the problem clears. These parameters may be user settable. Having a SBA or local timetag option allows maximum data utilization even when the measurement system is impaired. The ***data modify*** bit indicates that the data has been modified by another device such as a PDC. This should be set whenever any data has been modified such as the magnitude rescaled or the angle rotated. It should also be used if the data was inserted by and interpolation program. Unfortunately with a single bit for the whole data packet it is impossible to clearly indicate exactly what was modified. This bit simply warns the user that they are not seeing data as originally sent and if there is a concern, they will have to investigate.

The ***time quality*** bits provide the accuracy of the timing source used by the PMU at the time the measurement was made. Originally only the sync bit was available to determine that the timing was locked to the reference within a usable range. The range was not specified, but most vendors used a 1-5 microsecond range to determine the time was locked. This 3-bit time quality indicates the actual time quality range since range of locked can vary. The 7 ranges indicate 0.1 to 10,000 microseconds, a good match to phasor measurement.

B.3.2 Operational problem troubleshooting

This section discusses a variety of aspects that may be observed in the data that are the result of installation, setting, and communication decisions as well as the result of errors or failures in the measurement system. Each section describes the cause, observable effect, and a variety of changes that will remedy a deficient situation.

B.3.2.1 Phase Loss

Normally each input will be three phases in approximate balance. Loss of a single phase will result in a large imbalance. The amplitude of positive sequence will drop by 1/3, negative and zero sequences will increase by the same amount, and the lost phase will go to 0. Note that the positive sequence phase angle will not change noticeably. Single phase reporting is the best way to detect this kind of problem, but reading 2/3 of normal in positive sequence is also a good indication. Unless there are complimentary measurements nearby, it is not possible to determine from measurement alone if the problem is primary system failure or something in the measurement chain. However, this primary system failure would likely be detected quickly by protection equipment, so usually this type of failure can be analysed as a measurement system problem and resolved by on-site investigation.

B.3.2.2 Resolution & Accuracy

Two of the primary aspects in a measurement system are accuracy and resolution. Accuracy refers to how closely the measurement compares to an accepted, standardized value. That is, if the values indicated by a measurement system will report the same value that a calibrated measurement instrument would report. Resolution refers to how finely a measurement is made. In digital terms, it is the number of bits of resolution. It should be noted that a measurement can have high resolution but poor accuracy. Conversely it can have high accuracy but poor resolution so it is difficult to determine if it is accurate.

For example, a VOM with 1% accuracy may report a reading of 1.20564 V. In this case, 1% of the reading is .012, so the .00064 is not usable for determining the actual voltage. However, if it can make consistent readings at that level (that is, if reading the same voltage several times will result in the same number), it is clear that reading a different voltage and with a measurement of 1.20521 is a lower voltage. Here the resolution is good, but comparison with a calibrated standard is limited to 1%.

For a converse example, a meter with 0.1% accuracy may report a measurement of 1.2 V. In this case, the accuracy is good to .0012 but since the meter only reports to .1, all digits should be accurate and true, but the meter cannot be used to its full capability.

Phasors are computed from sample values. Sample values have a fixed resolution, usually 16-bits, but since phasors are computed they can have a much higher resolution. If transmitted as integer values, the resolution is limited to 16-bits (C37.118 protocol). Here the scaling will make a big difference in the apparent resolution. If the transmitted value is nearly full scale, then the value will have full 16-bit resolution. If the value is near 0, then there may be just a few bits of resolution.

As an example, if the phasor represents a 230 kV voltage, the transmitted value will be the phase to neutral voltage which is about 132,800 V. The maximum 16-bit signed number is 32767. If the value is scaled to read 132,800 when the integer value is 32767, each bit of the integer value represents 4.05 V. If the voltage went up to 132900, the integer value would overflow and it could not be transmitted. Consequently a scale factor is required so that a voltage as high as could be reasonably encountered can be represented by the integer value, but no larger so that the resolution is as good as possible. If a scaling of 8 V/bit was applied, then we could represent 32767 x 8 = 262 136 Vp-n (454 kV p-p for the 230 kV voltage) which should be adequate. The resolution is 8V for a nominal 132,800 V signal which is .006% of the reading. Put in a different context, if viewing a plot of one minute where the steady-state voltage varies 500 V, the trace would look like a nearly smooth line.

Contrast that with a scale factor of 1000 V/bit. Then 132,800 V would be represented by a phasor value of 1328 which has a resolution of .0075 or .75%. A phasor value as high as 3,276,700 V could be reported which is much higher than necessary. If viewing a plot where the steady-state voltage varied 500 V, the trace would look like a straight line unless the value crossed a bit threshold where there would be a 1 bit step. It would be difficult to make meaningful comparisons of voltages scaled this way in any except large voltage swings. Low resolution also limits the ability to do small signal analysis since the signals are lost in truncation.

Most PMUs internally compute phasor, frequency, and ROCOF values using 32-bit integer or floating point math. This gives a high resolution for internal computation and representation. Transmitting these values using floating point format will maximize the available resolution. This will provide the greatest ability to compare signals and derive low level information from them. Transmission in integer format limits the resolution to 16 bits and depending on the scaling, can considerably reduce the derived resolution. However it probably will not have much effect on accuracy since accuracy is generally 0.1% to 1 % which can be represented with only 10 bits of resolution. The down side of using floating point representation is that the numbers are twice as large requiring about double the bandwidth and data storage. Properly scaled integer values can provide the same accuracy in most cases with minimal loss of resolution. The pros and cons need consideration when choosing the data type for data reporting.

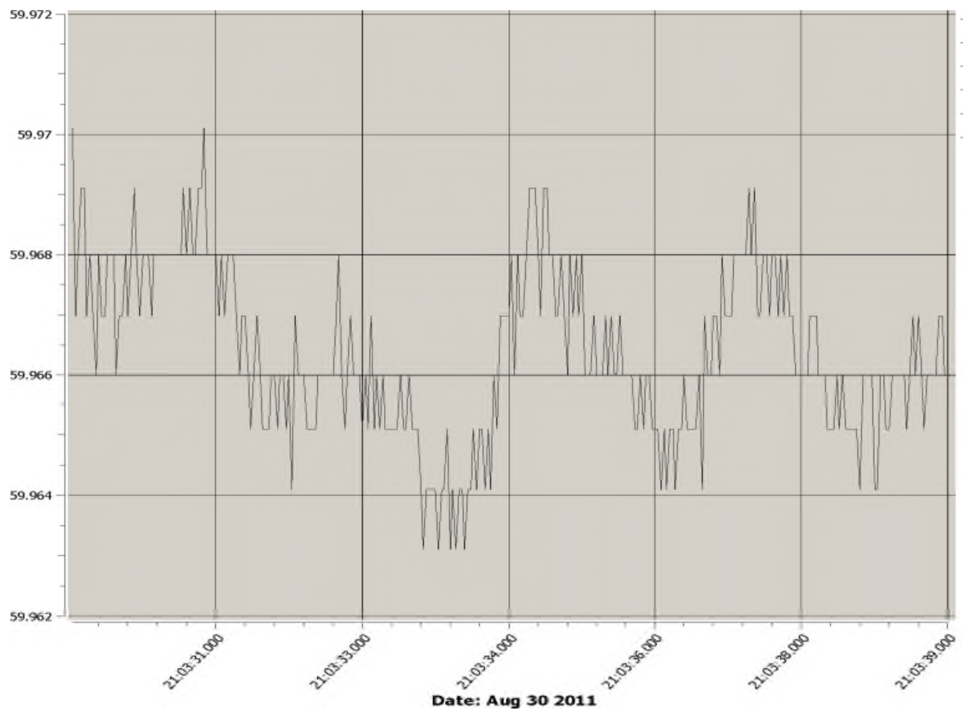

Figure B.2 Frequency reported in integer values

This plot shows frequency reported in integer values. The C37.118 standard requires frequency reporting in mHz, so the resolution is .001 Hz. In this plot where the frequency is very steady, the discrete .001 Hz steps are clearly evident. The frequency is probably computed to a much higher resolution but rounded off for reporting. Since .001 Hz is a very small part of the nominal 60 Hz value, this loss of resolution is likely to be insignificant, but in this case it looks rather coarse. Frequency measurement accuracies are typically .001 to .004 Hz.

B.3.2.3 Input Scaling

Voltage and current inputs need to be scaled so that the input is not saturated with the highest amplitude of interest. Conversely, it should be set so that there is as much resolution as possible for low input values. In the case of voltage, it probably should be set so that the maximum input is 1.5x to 2x the nominal value. This should cover voltage swings and still give good resolution at nominal and depressed voltages. Current is more difficult to set. For most phasor monitoring uses, setting the current input for the current that will be seen with 2x the rated power for the line will capture most swings and give good resolution at light load (0.1 of nominal), though it is probably better to set it a little higher to be sure to capture swings. However in some cases, more resolution may be needed at low levels and in other cases more range for overloads may be required. Scaling should be adjusted according to the typical operation of the line.

The consequence of input scaling errors is noisy or inaccurate readings. If the input exceeds the A/D input range a small amount, the phasor should be derivable with a good phase angle and acceptable magnitude even though the AC waveform will be clipped. If the waveform significantly exceeds the input capability the phasor magnitude will be reduced and at some point the angle will be inaccurate. If the input is very low compared with the A/D range, there will be few bits of resolution and the measurement will become noisy and inaccurate. Handling over-range and under-range conditions and is highly dependent on the particular phasor algorithm.

B.3.2.4 Output Scaling

The PMU calculates phasor values from input waveforms. Internally it uses floating point or integers of 32-bit or greater resolution, so the phasor values are generally derived with high resolution. When the PMU outputs data, it converts the internal numbers to either IEEE 32-bit floating point or 16-bit integer values (±32,767). With floating point, the resolution should be as good as the internal derivation and certainly much better than the accuracy limit. With integer values, the value appears as an integer, so a scale factor must be applied to keep the value within the integer range. The nominal C37.118 scale factor is an (integer) $\times 10^{-5}$. This scale factor should be chosen so that at the maximum phasor value times the scale factor is the maximum value that should be reported. This gives the maximum resolution for lower values and the widest range of reporting. For example, we may want to allow for a 100% overload for a 230 kV voltage. That is, we want to be able to see a voltage up to 460 kV. Voltages are transmitted as phase to neutral voltage, so here we want to report up to 265,600V (nominal 132,800V p-n). This gives the scale factor PHUNIT = (265,600/32767) $\times 10^{-5}$= 810571. Each phasor value will be multiplied by 8.10571 to display the line value. The resolution is thus 8.1 V/bit (14 V/bit l-l), which is very good for a 230 kV system. A larger scale factor will give more maximum range but less resolution for small values.

As a general recommendation, scaling for synchrophasor reporting should be set to report systems voltages up to 1.5 to 2 times the nominal line voltage. This allows observing the overloads and swings that may be encountered in almost all situations and still gives good resolution of the signal. While higher voltages may occur during some extreme events, these are rare and usually only of an interest in protection type analysis. Scaling for currents is normally best served with a maximum value 2x-4x the rated load. Most lines carry considerably less than rated capacity most of the time, and often have light loading. At 2x rated load, the resolution at 10% load is still 1/1600 or about .05%. In some cases scaling at greater than 2x rated load is needed, so the scaling needs to be adjusted accordingly.

Not all PMUs allow the user to scale the outputs to their own specifications. In these cases the scaling should be reasonably set for resolution and maximum range, but the user should check to be sure the settings meet their needs. Analog data, as defined in C37.118, is used for data types other than phasors, such as MW and MVAR measurements. These data types are not specifically identified and consequently their scaling is not discussed here. Frequency data in C37.118 is always scaled in mHz (0.001 Hz) and rate of change of frequency (ROCOF) is 0.01 Hz/s. In all cases, using floating point representation provides the best solution for limitations in maximum range versus resolution.

B.3.2.4 Sync Loss at a PMU

The phase angle measurement is determined in reference to time. Angles can be used together only if they are made with the same time reference. There are two important considerations here. First, all measurements that use a common time reference have phase angles that can be compared with each other. For example, if several measurements are made by a single PMU these should be synchronized to each other so the phase angles are comparable with each other. Likewise a group of PMUs served by a single clock will have comparable angles even if that clock loses UTC sync. This is useful in computing power from one or more PMUs in a substation. Second, the time reference (GPS clock or PMU with a GPS receiver) will have a local clock “flywheel” which will dictate how the time-angle reference will vary. A highly stable clock can remain synchronized to UTC within a few microseconds (µs) for hours or even days, while an undisciplined crystal oscillator can be off by several milliseconds in just a few minutes. At 60 Hz, one degree of phase angle is about 46 µs. A 5 µs error is only about 0.1 degree of error which is generally very acceptable. At 100 µs of error, the phase angle measurement is not very usable. The C37.118 standard requires the PMU to set a bit indicating external UTC synchronization has been lost within 1-minute of the actual loss. This warns the users that the angle is not a reliable measurement as long as that bit is set. However with C37.118.2 there is also a time quality measurement. If this feature is properly implemented, it could be used to determine if the time accuracy is good enough to continue marking the data as synchronized rather than simply concluding that lock is lost. Thus the PMU can use this for controlling the sync bit.

A measurement with sync loss may not be evident quickly, since it takes some time for the phase angle to drift away from an accurate value. Typically the time drift is one direction, positive or negative, and appears as a drifting phase angle. Since system noise and normal angles are generally larger than the drift, it may be hard to determine quickly, but will be observable over time. In the case that the sync loss is not detected or properly flagged, the user needs to be on the lookout for phase angles that have changed or do not match expected values.

B.3.2.5 Intermittent Sync

Intermittent sync is sometimes more difficult to detect than a complete loss. Occasional short loss of lock to GPS is a normal occurrence and should be transparent to the user. These can be the result of switching synchronization between satellites, a short burst of noise, antenna shading, or other effects. These should be short—up to a few seconds—and random. They are generally short enough that they are not even reported by the clock or PMU. However, outages may occur that are significant enough that the clock cannot carry through the outages. Intermittent sync can also be caused by bad connections or signal mismatch. In either case, the sync loss bit should indicate there is a problem. The signal measurements may only show very small drifts followed by a drift back to accuracy or can show a snap back to correction when the clock re-syncs. The particular behaviour depends on the clock implementation. The main points are to monitor the sync loss bit to detect developing problems and keep in mind the effect of synch loss when troubleshooting.

B.3.2.6 Derived Signals

Frequency is usually calculated as the derivative of the phase angle measurement. ROCOF is the derivative of the frequency. The derivative emphasizes changes, so if the base measurement is noisy the derived signal will be very noisy. However, these signals are also good indicators of change. A fault may cause a sudden change in phase angle which in turn causes a jump in frequency. Any sudden change in frequency will cause a spike in ROCOF. Because ROCOF is a double derivative, it tends to be too noisy for useful analysis, but it serves as a good indicator of a disturbance. The new standard, C37.118.1, sets requirements for both Frequency and ROCOF, so the newer PMUs should have more usable and steady reading for these measurements.

B.3.2.7 Delays in signals received at the Control Center

Delays are usually small, but can be up to several seconds. This is highly dependent on the communication system. Since data is sent on a continuous and timed basis, it is possible to confirm the output delay from the PMU itself. If the PMU meets C37.118.1 requirements, it is required to output data within a few reporting periods (see standard). Using that as a baseline, a receiving device can be used to timetag when the data is received at the control center, thereby testing the communication delays. While an accurate measurement is not necessarily easy to perform, an approximate value that compares delay with other data inputs is quite achievable. The important part of this procedure is to make sure that delays from all remote units are similar. It is best to do this test in over a 24-hour (or longer) interval to be sure that there are not some periodic events that adversely affect one or more inputs. If this or other continuous monitoring is not feasible, 1-5 minute snapshots throughout a 24-hour period are advisable.

Differences in delay between signals should be less than 100 ms. unless very special circumstances apply, such as separate back-to-back connected communication systems or very big distance variations. Differences over the 24-hour period should show smaller changes, perhaps 50 ms. or less. In either case, results that are significantly different than these general time durations should be investigated. There could be perfectly acceptable reasons for different numbers, but generally larger deviations are because of a problem in the configuration.

B.3.2.8 Data loss in signals received at the Control Center

Data loss is the most common problem in data transmission from the PMU to the control center. The cause can range from faulty equipment to overloaded communication channels. Some data loss is acceptable as there always are random error effects. Generally the data loss should be less than 0.1% in all cases. Loss < 0.001% is very achievable.

When significant ongoing data loss occurs, there may be a pattern that will help determine the cause. Patterns could include a single sample at regular intervals, blocks of samples that are the same size but randomly spaced, or something else periodic. Random single samples at rates < 0.01% (1 sample/10,000 equivalent to 1 sample/6 min at 30/sec) is not worth pursuing. 0.1% (2 samples/min at 30/sec) may be acceptable in overall performance, but it shows communication problems if it occurs continuously. At this rate of loss, overloaded network segments or faulty equipment are likely to be the problem. If it happens on a regular interval, look for a correlation between the time and the data loss. Greater amounts of data loss are likely due to communication overload or even network mismatches (such as half vs. full duplex). It is often easier to diagnose problems with larger amounts of data loss. In all cases, look for regular patterns of loss and correlation between time and operation of other systems. The problem could be at (or in) the PMU, so it may be necessary to intercept and check the data loss at the PMU output as well as at points in the data transmission system.

B.3.2.9 Data errors in signals received at the Control Center

Data errors are here defined as receiving packets of data as expected, but with an error such as incorrect packet size, incomplete packet, packet run-on with another packet, and packet with CRC error. Errors in data transmission are usually masked by the receiving systems as data loss. Most phasor systems now use a network communication system which protects data integrity at the data link layer with a CRC or other means. When that layer receives data with an error, it discards the packet and the user only observes a missing packet.

If a packet is received that is the wrong size but otherwise complete, it indicates the sending PMU has changed configuration but the PDC has not detected it and reconfigured. This is a mismatch and is easily resolvable, the method depending on the PDC technology. If the packet is incomplete or is run-on with other packets, it indicates the system is fragmenting the data and it is not being reconstructed correctly. This will usually only be seen where the packets are large and an intermediate link needs to fragment packets. Then if pieces of fragments are lost, the whole message will be unusable. Consider improving the intermediate links or reconfiguring to send smaller packets. When using network communications, packet CRC errors will be rarely observed because of the data link layer CRC.

Systems that still use serial communication have direct access to the RS232 interface and detect errors through the packet CRC. These can be observed by the users. Generally such errors are only caused by data collisions or interrupted channels. If data errors of this nature happen more than a few times/day, the complete communication channel needs end to end testing to find the problem. Alternatively there could be a modem problem. It is possible that there is a problem in the PMU or receiving device itself, requiring more thorough testing to determine.