PHASOR TECHNOLOGY
AND
REAL-TIME DYNAMICS MONITORING SYSTEM™ (RTDMS)
FREQUENTLY ASKED QUESTIONS (FAQS)

Phasor Technology Overview

1. What is a Phasor?

Phasor is a quantity with magnitude and phase (with respect to a reference) that is used to represent a sinusoidal signal (Figure 1). Here the **phase** or **phase angle** is the distance between the signal's sinusoidal peak and a specified reference and is expressed using an angular measure. Here, the reference is a fixed point in time (such as time = 0). The phasor **magnitude** is related to the amplitude of the sinusoidal signal.

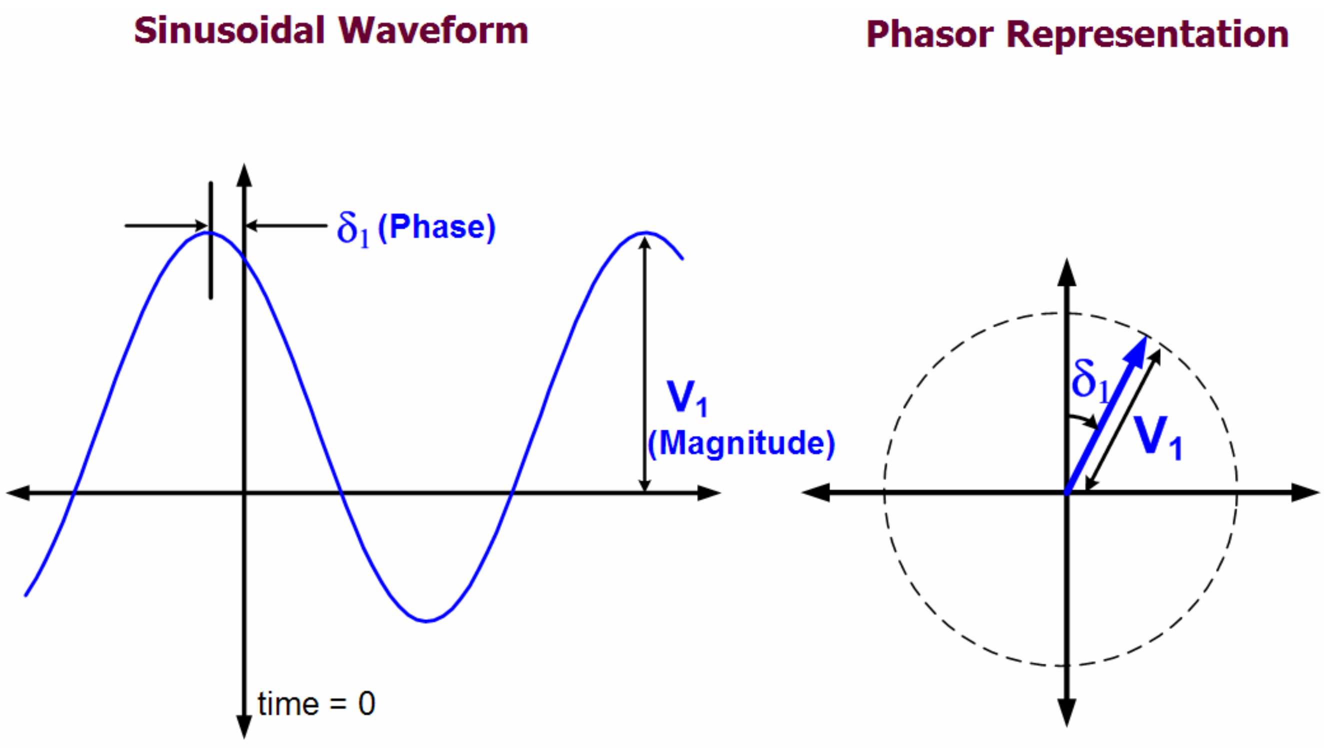

Figure 1: Phasor Representation of a Sinusoidal Waveform

2. What is Phasor Technology?

Phasor technology is considered to be one of the most important measurement technologies in the future of power systems due to its unique ability to sample analog voltage and current waveform data **in synchronism** with a GPS-clock and compute the corresponding 60 Hz phasor component (i.e. complex numbers representing the magnitude and phase angle of a 60 Hz sinusoidal waveform) from widely dispersed locations (Figure 2). This synchronized sampling process of the different waveforms provides a common reference for the phasor calculations at all the different locations.

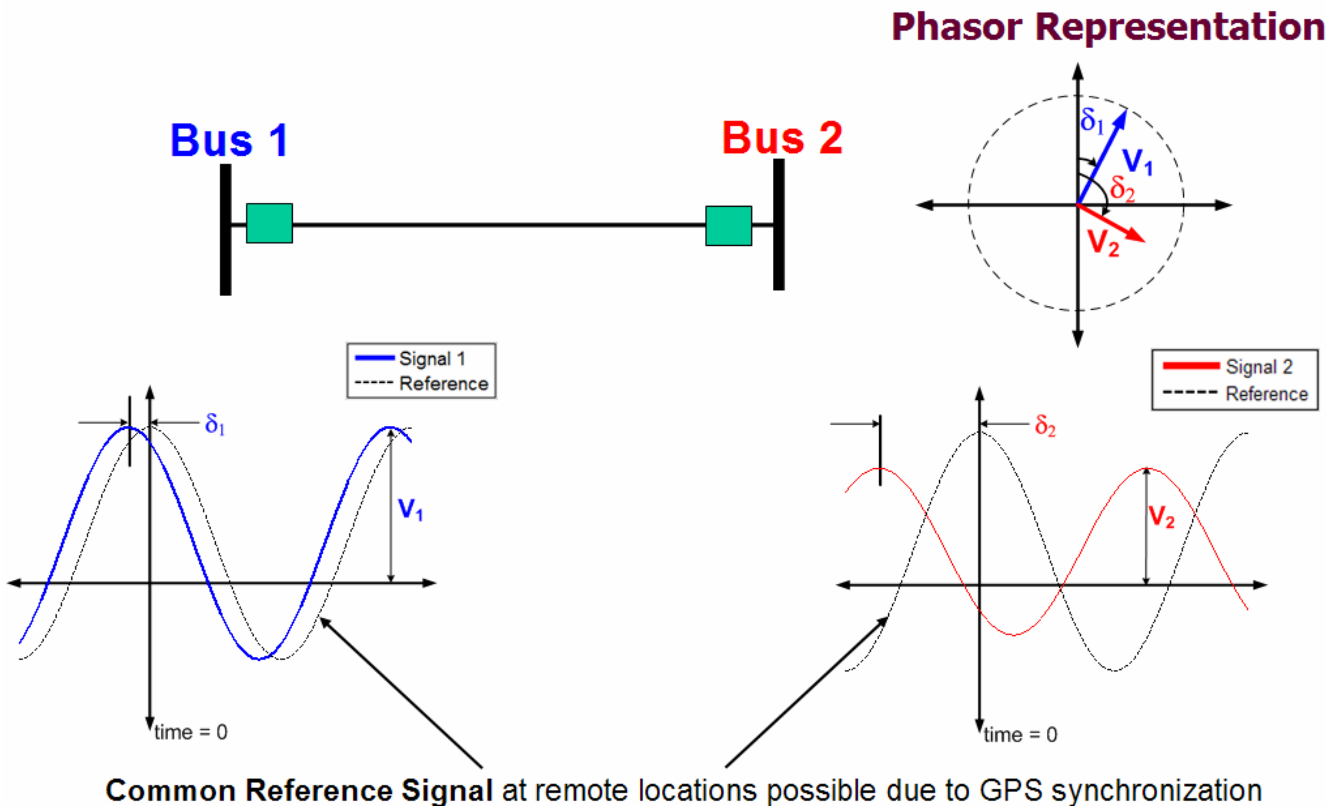

Figure 2: Phasor Measurements at Remote Locations

Note: The phase angle differences between two sets of phasor measurements (i.e. δ_1-δ_2) is independent of the reference. Typically, one of the phasor measurements is chosen as the "reference" and the difference between all the other phase angle measurements (also known as the **absolute phase angle**) and this common "reference" angle is computed and referred to as the **relative phase angles** with respect to the chosen reference (Figure 3).

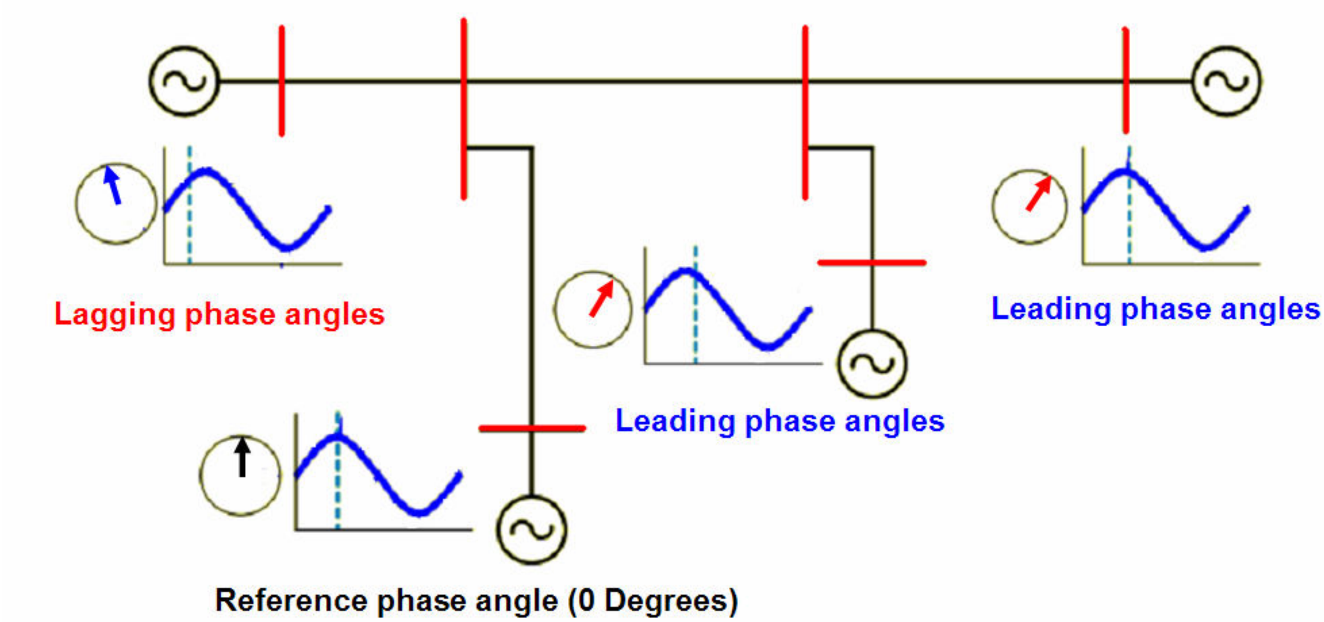

Figure 3: System-Wide Snapshot of Relative Phase Angles with Respect to a Common Reference Angle.

3. Why are phase angle differences important?

Just as in DC circuits, power flows from high voltages to low voltages, in an AC power system, power flows from a higher voltage phase angle to a lower voltage phase angle – the larger the phase angle difference between the source and the sink, the greater the power flow between those points implying larger the static stress being exerted across that interface and closer the proximity to instability. Figure 4 shows the growing phase angle difference between Cleveland and Michigan during the August 14, 2003 blackout in the Eastern Interconnection.

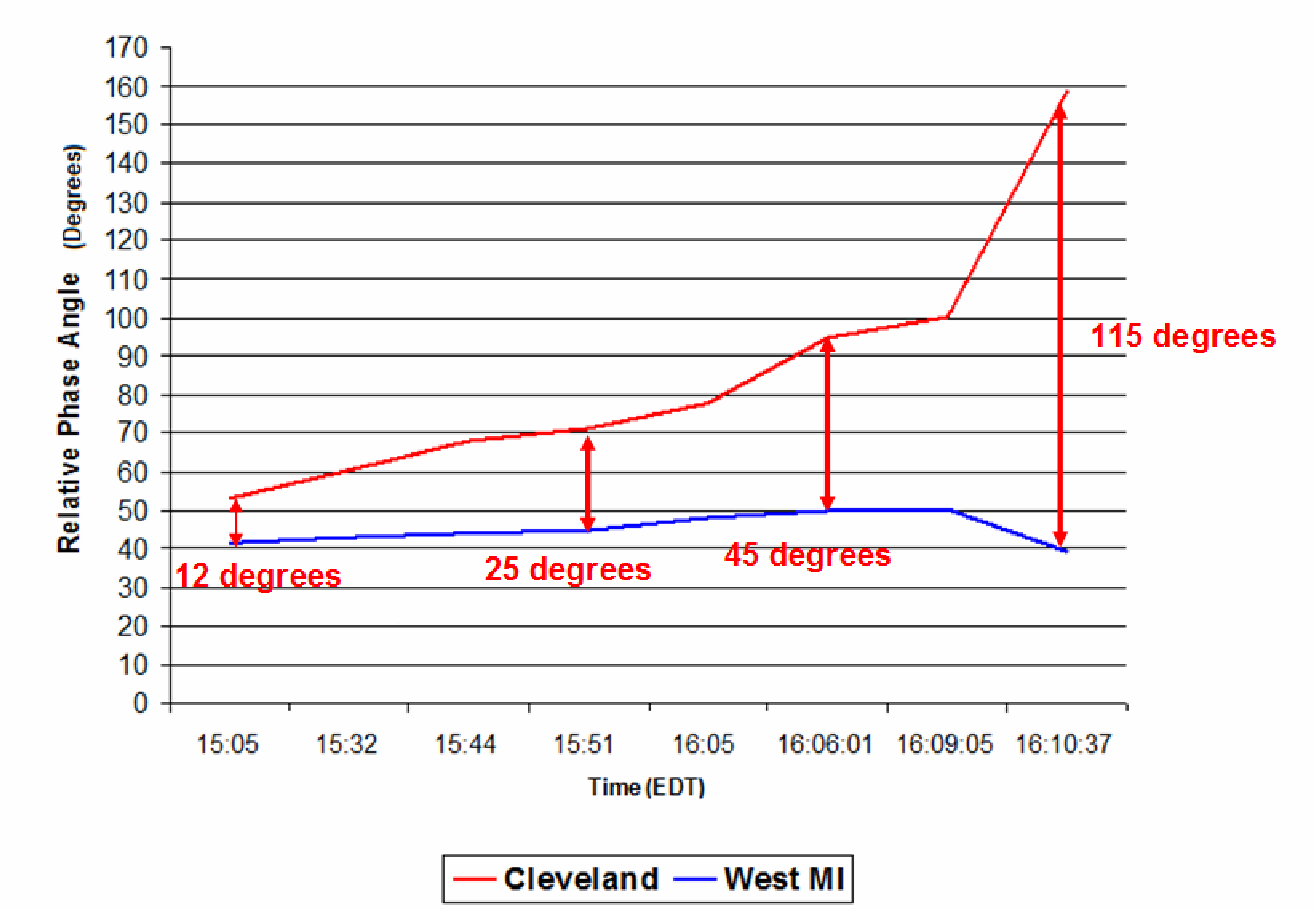

Figure 5: Increasing Phase Angle Difference between Ohio & Michigan during August 14, 2003 Blackout.

4. What are some of the unique properties of this technology?

- Phasor technology provides **time synchronized sub-second data** (typically 20, 30 or 60 samples/second) which is applicable for wide area monitoring; real time dynamics and stability monitoring; dynamic system ratings to operating power system closer to the margin to reduce congestion costs and increasing asset utilization; and improvements in state estimation, protection, and controls.
- Traditional SCADA/EMS systems are based on steady state power flow analysis, and therefore cannot observe the dynamic characteristics of the power system – phasor technology is the "MRI of the power system" industry providing the high sub-second visibility required for **observing dynamic behavior** and, therefore, overcoming the limitations of the old "x-ray" quality visibility that traditional SCADA-based systems offer.

- The precise timing of phasor data makes it useful beyond the local bus where the measurement was taken, i.e. the technology offers **wide area visibility**. This, in turn, facilitates the capability for distributed sensing and coordinated control action.
- Phasor measurements **directly provide the phase angles** at the high sub-second rate. These phase angles have traditionally been obtained from state estimators which are inherently slow (typically every 5 minutes) and susceptible to errors due to outdated or inaccurate models required by the state estimation process.
- Phasor measurements **improve post disturbance assessment** capability using high-resolution time-synchronized data.
- The **high data rates and low latency** associated with phasor acquisition systems provide the desired agility to respond to abnormal conditions.

5. Why is time synchronization important?

Through the use of integral GPS receiver-clocks, PMUs sample synchronously at selected locations throughout the power system. This provides a system-wide snapshot of the electrical system. The GPS not only provides time tagging for all the measurements but also ensures that all phase angle measurements are synchronized to the same time as well.

Figure 6 shows how time skews in the measurement and analysis process can induce errors in the phase angle difference computations. Here, the phase angle difference between two sets of measurements was approximately 10 degrees. However, when one of these two phase angle signals was skewed by 1 second and then the phase angle difference was computed, then the resulting answer incorrectly indicated a phase angle difference of approximately 5 degrees between those two data sets. Phasor calculations demand greater than 1 millisecond accuracy.

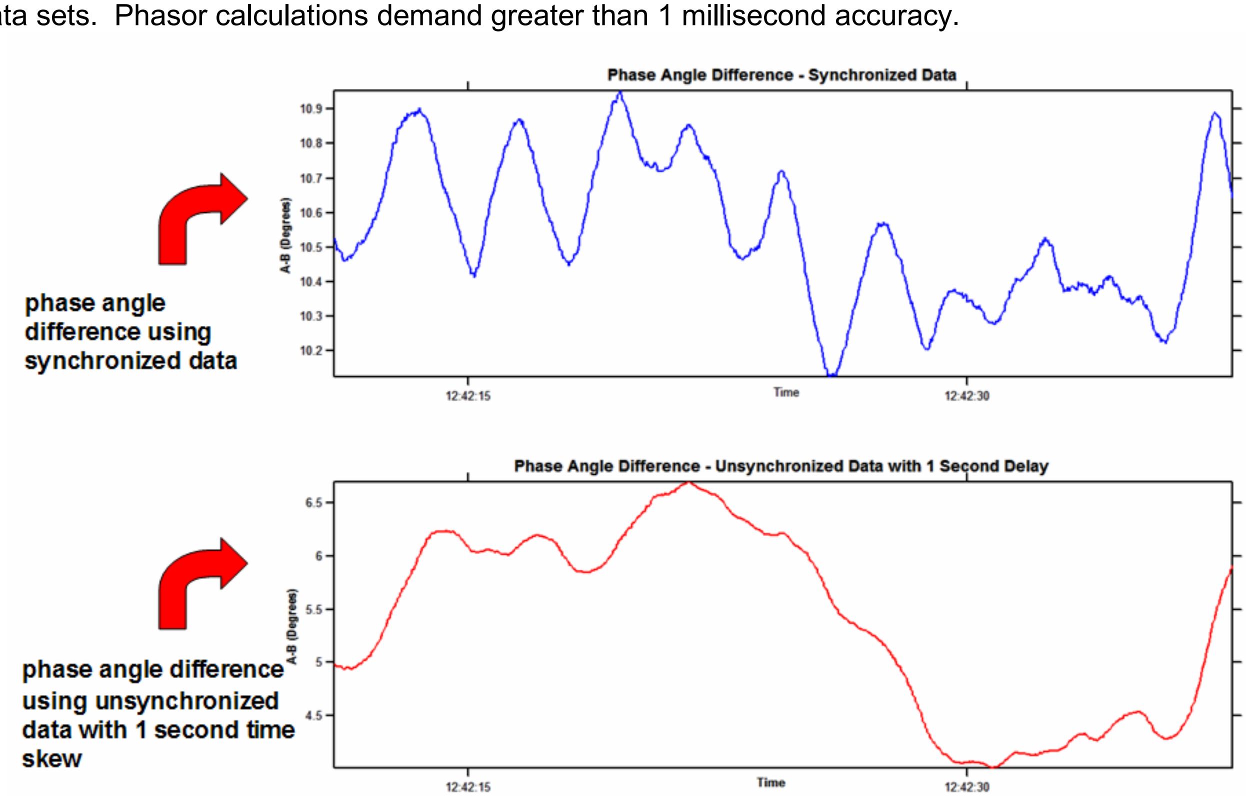

Figure 6: Illustration of How Time Skews in Phasor Measurements Induce Errors in the Phase Angle Difference Computations.

Phasor Network and Data Management

6. What are the fundamental elements that constitute a phasor network?

The simplest form of phasor network consists of TWO nodes; one Phasor Measurement Unit (PMU) at node 1 that communicates with one Phasor Data Concentrator (PDC) at node 2. Typically, many PMUs located at various key substations gather data in real-time and they are connected to a PDC at the utility center where the data is aggregated. A personal computer, connected to the output of the PDC provides the users with software, such as RTDMS that calculates and displays locally measured frequencies, primary voltages, currents, MWs and MVARs for system operators (Figure 7). Additionally, many PDCs belonging to different utilities can also be connected to a common central PDC (a.k.a., SuperPDC) to aggregate data across the utilities to provide an Interconnection-wide snapshot.

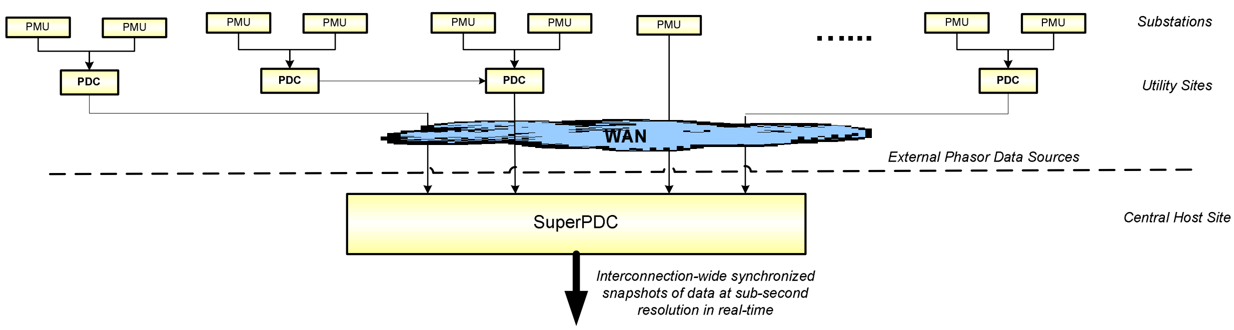

Figure 7: Typical Phasor Point-to-Point Network.

7. What is a Phasor Measurement Unit (PMU)?

A PMU is an electronic device that uses state-of-the-art digital signal processors that can measure 50/60Hz AC waveforms (voltages and currents) typically at a rate of 48 samples per cycle (2880 samples per second). The analog AC waveforms are digitized by an Analog to Digital converter for each phase. A phase-lock oscillator along with a Global Positioning System (GPS) reference source provides the needed high-speed synchronized sampling with 1 microsecond accuracy. Additionally, digital signal processing techniques are used to compute the voltage and current phasors (
Figure 8). Line frequencies are also calculated by the PMU at each site. This method of phasor measurement yields a high degree of resolution and accuracy. The resultant time tagged phasors can be transmitted to a local or remote receiver at rates up to 60 samples per second.

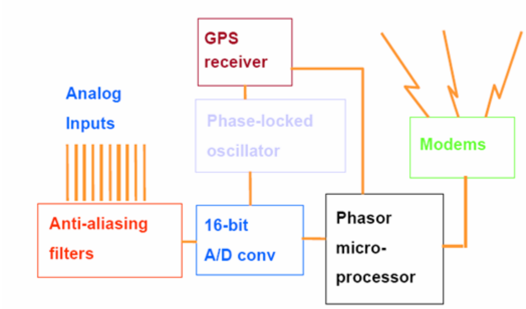

Figure 8: Phasor Measurement Unit Block Diagram[1]

[1] R.F. Nuqui, "State Estimation and Voltage Security Monitoring Using Synchronized Phasor Measurements", Doctorate Dissertation, Virginia Polytechnic Institute, Blacksburg, VA, July 2, 2001.

PMUs come in different sizes. Some of the larger ones can measure up to 10 phasors plus frequency while others only measure from one to three phasors plus frequency. The approximate cost of the larger PMUs can range in the $30 to $40 thousand of dollars while the smaller ones cost considerably less.

Figure 9: Vendor PMU Offerings (Arbiter and Macrodyne)

8. What is typically involved in a PMU installation and connection?

Installation of a typical 10 Phasor PMU is a simple process. A phasor will be either a 3 phase voltage or a 3 phase current. Each phasor will, therefore, require 3 separate electrical connections (one for each phase). We are talking about 6 wires per phasor – 2 for each phase of either voltage or current. The PMU will also measure the line frequency from a specific voltage phasor (typically a major bus assigned by the user).

Typically an electrical engineer designs the installation and interconnection of a PMU at a substation or at a generation plant. Substation personnel will bolt equipment rack to the floor of the substation following established seismic mounting requirements. Then the PMU along with a modem and other support equipment will be mounted on the equipment rack. They will also install the Global Positioning Satellite (GPS) antenna on the roof of the substation per manufacturer instructions. The antenna signal cable will be connected to the antenna and brought directly to the PMU. Substation personnel will also install “shunts” in all Current Transformer (CT) secondary circuits that are to be measured. Potential Transformer (PT) connections will not require the installation of any additional equipment other than terminal blocks and fuses. They will have to run wires from the CT shunts and the PTs to either an interface cabinet or directly to the input connections of the PMU (Figure 10). Note: Each phasor (either Voltage or Current) will require three connections – one for each phase.

In addition to the CT and PT connections the PMU will also require the following connections:

- Power connection – typically from station batteries.
- Station ground connection.
- Global Positioning Satellite (GPS) antenna connection.
- Communication circuit connection (Modem if using 4-wire connection or Ethernet for network connection).

After all the connections are made, the PMU is configured and tested. This task is typically performed by a substation Test Technician.

The utility’s IT department will play a key role will the phasor data connections phase of the PMU installation. After the entire input channel configuration and testing is completed, the PMU is connected to the utility’s Phasor Data Concentrator (PDC) via 4-wire Modem or Ethernet connection depending on the bandwidth needs. They will also need to evaluate the need to install additional communication equipment in order to provide the necessary circuit connections between the PDC at the master site and the PC workstations at the client sites.

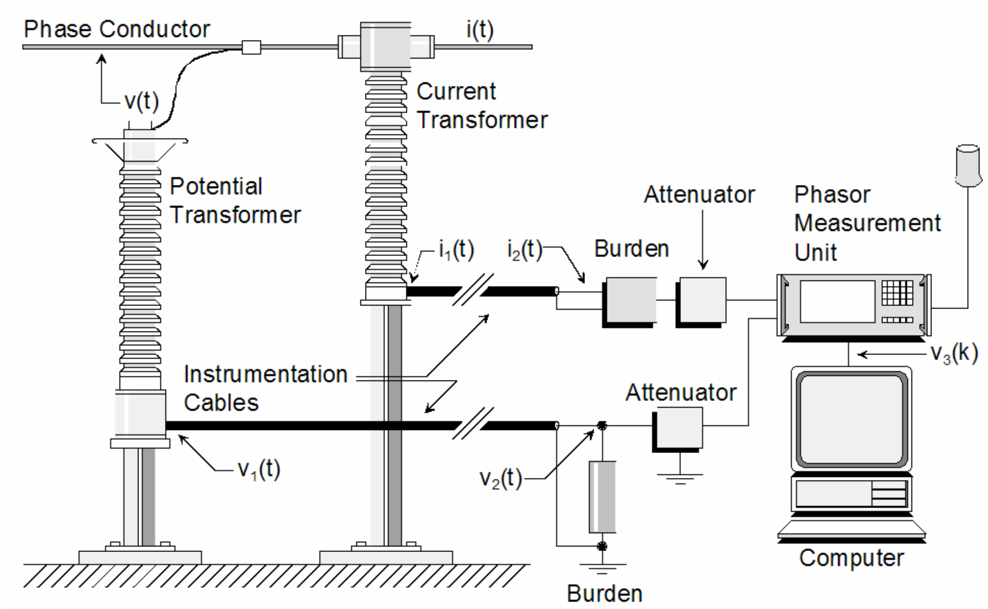

Figure 10: Typical PMU Installation at a Substation

9. What is a Phasor Data Concentrator (PDC)?

A PDC forms a node in a system where phasor data from a number of PMUs or PDCs is correlated and fed out as a single stream to other applications. The PDC correlates phasor data by time-tag to create a **system wide measurement set**. The PDC provides additional functions as well. It performs various quality checks on the phasor data and inserts appropriate flags into the correlated data stream. It checks disturbance flags and records files of data for analysis. It also monitors the overall measurement system and provides a display and record of performance. It can provide a number of specialized outputs, such as a direct interface to a SCADA or EMS system. (From BPA PDC Manual Chapter 1 Intro and Overview page 1-1)

10. What is a Super Phasor Data Concentrator (SuperPDC)?

Within a point-to-point phasor network architecture, the SuperPDC is simply a central PDC that collects and correlates phasor data from all remote PDCs and PMUs and makes it available to a visualization software package as described above (Figure 11). Typically, the SuperPDC is also connected to a central database for long-term archiving of the collected data.

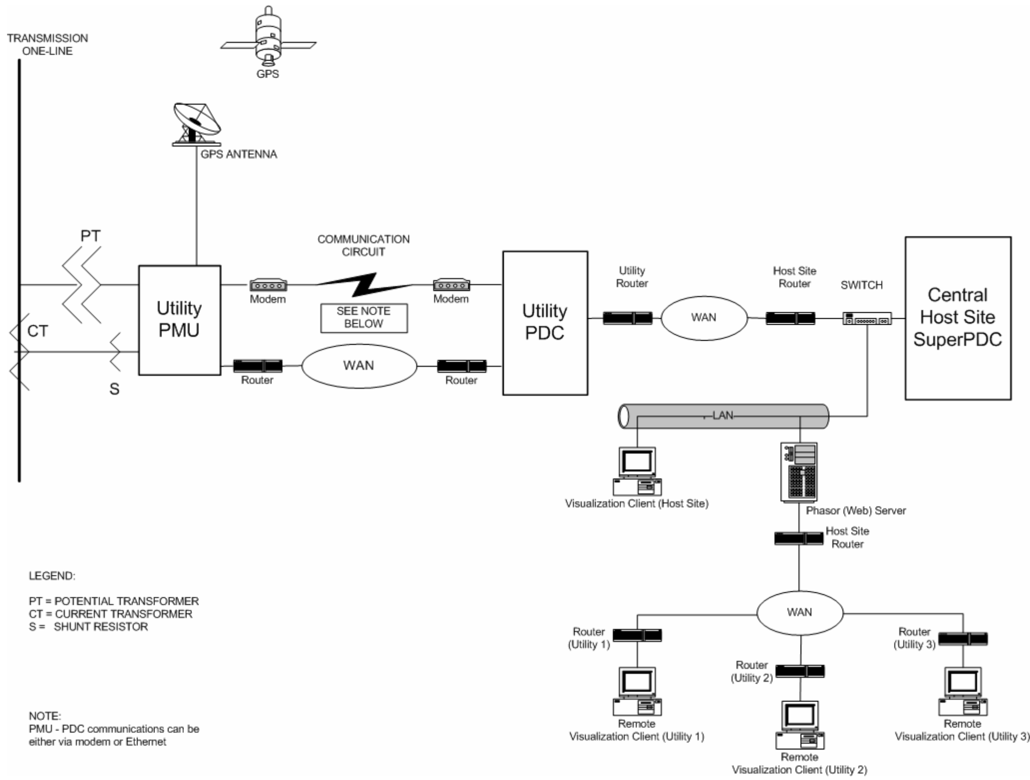

Figure 11: Typical Wide-Area Phasor Measurement System Infrastructure

11. Will the SuperPDC be expected to archive the data or just concentrate it and forward to the several destinations?

A SuperPDC should have the capability to do both if it is fast enough. The obvious problem of locally storing ALL the data would be the need to employ large disk drives and have a system in place to regularly transfer full disk phasor data to DVD for permanent storage. A rate of 30 or 60 samples per second fills up a disk drive very quickly.

12. What are some of the standard protocols used for phasor data transfer?

The latest PMU/PDC protocol is the IEEE C37.118 that was developed in the last few years and approved late 2005. It will replace the IEEE 1344 synchrophasor protocol which has been in use as the PMU standard since its development in 1998. Before these standards were developed, the defacto standard for PMU to PDC communication has been the Macrodyne type 1 and type 2 protocols developed by Macrodyne Corporation. Some of the PDC to PDC protocols include the PDC data exchange format, the PDC stream, second level PDC using NTP time and the PDC stream, second level PDC using native time. These standards address issues like synchronization of data sampling, data to phasor conversions, and formats for timing input and phasor data output.

13. What kind of delays can one expect in the real-time stream?

A PDC receives data streams from PMUs and other PDCs and correlates it in real-time into a single data stream that is transmitted to a PC via an Ethernet port. They propagation delays associated with communication links from a PMU and PDC depend on the medium and the physical distance separating these components. For a typical PMU with 10-12 phasors, the associated delays for various communication mediums are summarized in Table 1.

Table 1: Associated Delays with Various Communication Links[2]

Communication Link	Associated Delay – one way (milliseconds)
Fiber-optic cables (50 Mbps – 1 Gbps)	≈ 100-150
Digital microwave links	≈ 100-150
Power line (PLC) (upto 4 Mbps)	≈ 150-350
Telephone lines (upto 56 kbps)	≈ 200-300
Satellite link	≈ 500-700

In addition, the fixed delay associated with processing, concentrating, multiplexing, and transducers, and is independent of the communication is 75 ms.

Finally, PDCs also have a maximum wait-time, typically of 1-4 seconds, to allow for all the PMU data to come in before aggregated data is outputted by the PDC. If the data from all the PMUs reach the PDC within this wait-time, it outputs the aggregated data right away. However, in the extreme case that the data from one of the PMUs is indefinitely delayed, then the PDC will wait upto its pre-defined wait-time (i.e., 1-4 seconds) before the data is outputted by the PDC. Hence, the PDC can also introduce an additional delay equal to its wait-time if one of the PMU channels stops transmitting data to the PDC. In such circumstances, if there are additional PDCs downstream in the point-to-point phasor network architecture (such as the SuperPDC), then they too will introduce a secondary delay equal to their wait-time.

Phasor applications such as Real-Time Dynamics Monitoring System™ (RTDMS) are designed to directly integrate with the PDCs over the utility's high speed Local Area Network (100 Mbps) and display the data and calculated individual engineering units such as MW, MVAR, etc. within 1 second of receiving the data from the PDC (Note: The Web based versions of the RTDMS Clients, such as those deployed across the Eastern Interconnection as part of the EIPP project, integrate over secure internet connections rather than Local Area Networks and can longer to display the information within its visualization screens).

<u>Bottom Line</u>: The total delay from when the data is captured by the PMU to it being visualized within the RTDMS screens is typically a few seconds.

14. What type of data quality problems does one typically encounter with such a system?

There are two main types of problems associated with data validation: First, there is a data loss problem associated with network problems such as bandwidth limitations, collisions, misrouting, maintenance outages, and equipment breakdown to name a few. There is not much one can do about this other than to report it to IT for review and repair. The other problem is measurement data validation which has to do with obtaining inaccurate information such as incorrect resistor shunts as well as incorrect CT and PT rations. This also includes larger inaccuracies, such as ±120°, due to incorrect wiring errors or labeling inconsistencies in what is called 'Phase A', 'Phase B' and 'Phase C' across utilities. The latter type will take time to correct and may have to involve station technicians at a particular site and even sometimes the engineering department. If this data is also available through the SCADA system the two values should be compared in order to achieve some degree of validation.

[2] B. Naduvathuparambil, M. C. Valenti, A. Feliachi, "Communication Delays in Wide Area Measurement Systems", Proceedings of the Thirty-Fourth Southeastern Symposium on System Theory, 18-19 March 2002, pp. 118-122.

Finally, each PMU vendor utilizes their own proprietary phasor computation algorithms as well as pre and post processing filters, each with their own unique design characteristics. These and other factors can result in adding constant offsets to the phase angle measurements which may be more significant at off-nominal operating frequencies. Figure 12 compares the phase angle offsets of different PMUs over a wide frequency range about the normal 60Hz operating frequency. As long as all the PMUs within the phasor network are provided by the same vendor, this is not an issue; otherwise these offset errors should be corrected.

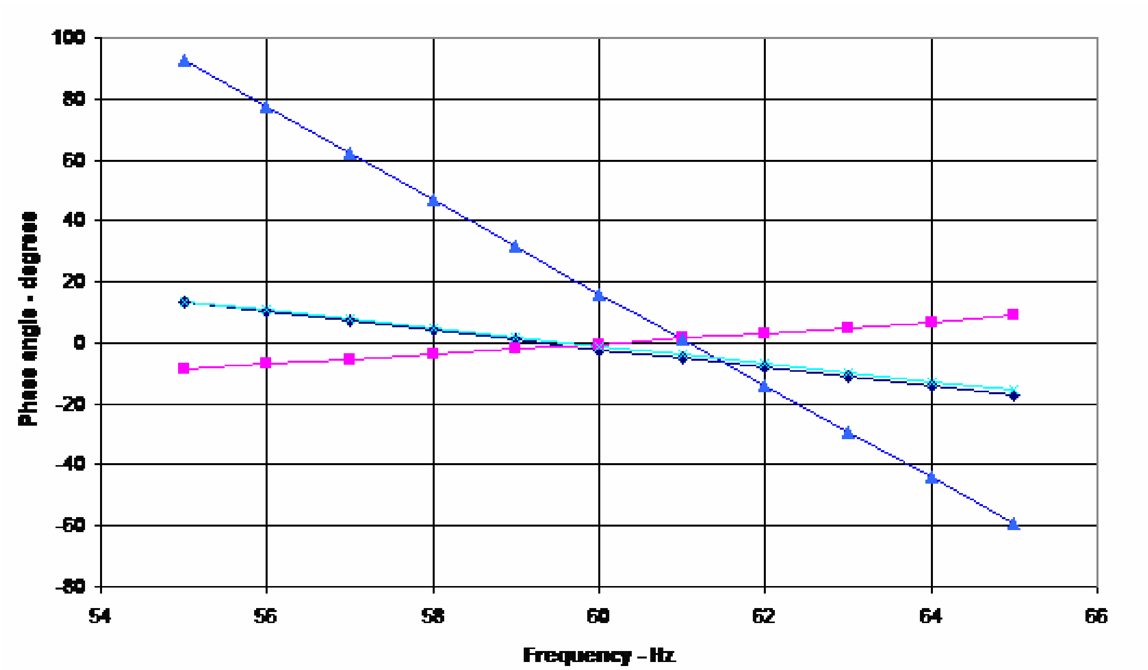

Figure 12: PMU Phase Angle Measurement Error for Different Vendor PMUs[3]

[3] Figure courtesy of Ken Martin, Bonneville Power Administration.

Real-Time Dynamics Monitoring System (RTDMS)

15. Who can use RTDMS?

Utility operators and reliability coordinators with reliability monitoring functions with access to data from phasor measurement devices.

16. What are some of existing capabilities of RTDMS?

RTDMS is a phasor based monitoring application that offers real-time wide-area visibility, as well as monitoring and alarming functions on high resolution sub-second phasor data. The system supports a centralized RTDMS Server performing key data management functions such as data reading, cleansing, computing and archiving. Multiple RTDMS Client applications may simultaneously access the information from the central RTDMS Server and, thru various geographic and graphic displays, provide operators and dispatchers both real-time information and alarms on:

Voltage Magnitude and Relative Angles
- comprehensive profile of voltage angles and magnitudes
- identify the high and low voltage regions within the grid
- monitor angles relative to a specific reference

Angle Differences across Identified Transmission Flowgates
- provides a birds-eye view of the sources and sinks of power
- monitor phase angle differences across key flowgates

System and Local Frequencies
- assess system coherency and dynamic stress under normal operating conditions
- identify approximate point of acceleration or deceleration (loss or load or generation)

Real and Reactive Power Flows Across Monitored Lines
- monitor actual MW and MVAR flows at key flowgates
- track flows with respect to predefined thresholds

In addition to the real-time monitoring capabilities, the event detection logic of the application automatically detects transients and stores them as event files, which may be loaded into the application at a later time for offline analysis. Some of the key features of the system include:

- Server and multi-client system architecture
- Synchronized sub-second phasor data read in real-time PDCStream format
- Data access and visualization capability across Local Area Network
- Real-time data cached in memory for fast access
- Real-time monitoring of voltage magnitudes, phase angles, frequencies, and MW/MVAR flows within dedicated displays
- Visualization configuration utility for user defined customization through friendly Graphic User Interface (GUI)
- Data quality filters (user enabled/disabled)
- Replay capability of archived data
- Real-time alarming and event detection capability
- Event archiving and playback
- Built on the Grid-3P™ visualization platform that supports multi-panel displays, graphic-geographic and textual visuals, navigational tools including zooming and panning capabilities, and color coded visual alarms

At the CASIO, the RTDMS application provides wide-area visibility from approximately 45 PMUs belonging to BPA, SCE, WAPA, and PG&E. Within the Eastern Interconnection, it provides wide-area visibility from approximately 35 PMUs belonging to TVA, Ameren, AEP, NYISO, ConEdison, ATC, and Entergy.

17. What hardware is required to utilize RTDMS?

The Real-Time Dynamics Monitoring System adheres to a server-client architecture where a central RTDMS Server running on a PC, connected to the PDC, reads data from the PDC and manages it in memory for fast data access. Multiple RTDMS Clients running on separate PC Workstations at remote locations can simultaneously connect to the RTDMS Server and access real-time data (or cached data) over a local area network, and present it within its various displays (Figure 13).

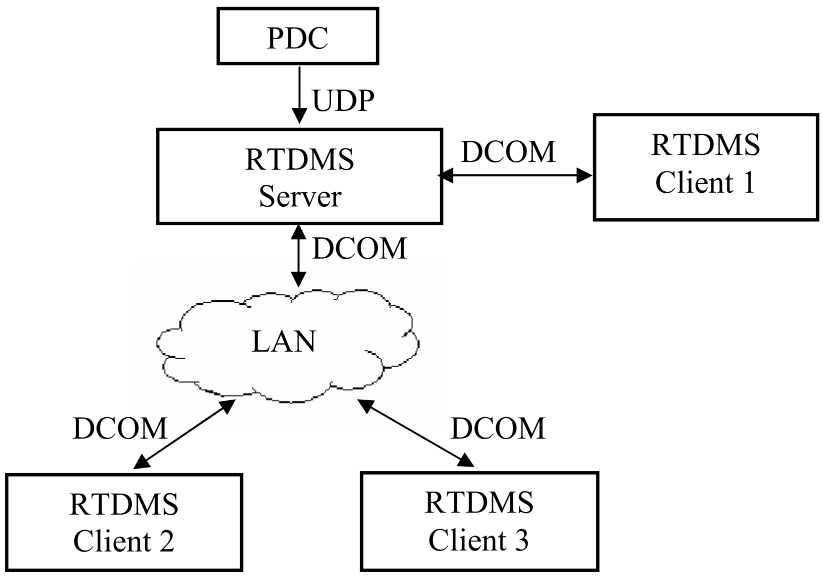

Figure 13: RTDMS Setup Diagram

RTDMS Server Requirements: The main requirement here is adequate memory as the real-time data is cached in memory for replay – the more memory one has on the machine, the more data can be temporarily cached for playback.

Table 2: RTDMS Server PC Requirements

Memory	1GB or greater
CPU	Pentium 4 processor or up (2.0 G Hz or higher)
Hard Disk	40 GB or higher
Operating System	Windows 2000, Windows XP Professional

RTDMS Client Requirements: The main requirement here is display resolution (1280 by 1024 or better is recommended).

Table 3: RTDMS Client PC Requirements

Memory	512 MB or greater
CPU	Pentium III processor or up (1.0 G Hz or higher)
Operating System	Windows 2000, Windows XP Professional
Display	1280 by 1024 Pixels or better

18. What are the main components of RTDMS?

The RTDMS system architecture as it presently exists is shown in Figure 14. As mentioned above, the two main components of the system are a centralized **RTDMS Server** and multiple **RTDMS Client** applications at remote locations. These RTDMS Clients are designed to access the central Server over a Local Area Network or over the Web.

Some of the key functional components within the **RTDMS Server** are:
- PDCStream Data Driver to read sub-second streaming phasor data from the PDC in real-time.
- Data Quality filters to clean the data in real-time
- Server GUI for viewing and configuring centralized data management attributes at the Server
- Alarm and event detection logic on real-time data stream
- Short-term data cache in memory for quick data access
- Long-term data archive into database
- Web services interface for data access over secure internet connections

Some of the key functional components within the **RTDMS Client** are:
- Graphic and geographic displays for visualization of phasor based information
- Configuration GUI for customizing displays to reflect changes within the phasor network (e.g. addition, deletion of PMU devices)
- Real-time alarm notification and acknowledgement within the RTDMS Client applications
- Real-time monitoring on streaming data or offline analysis of archived event files
- Replay capability

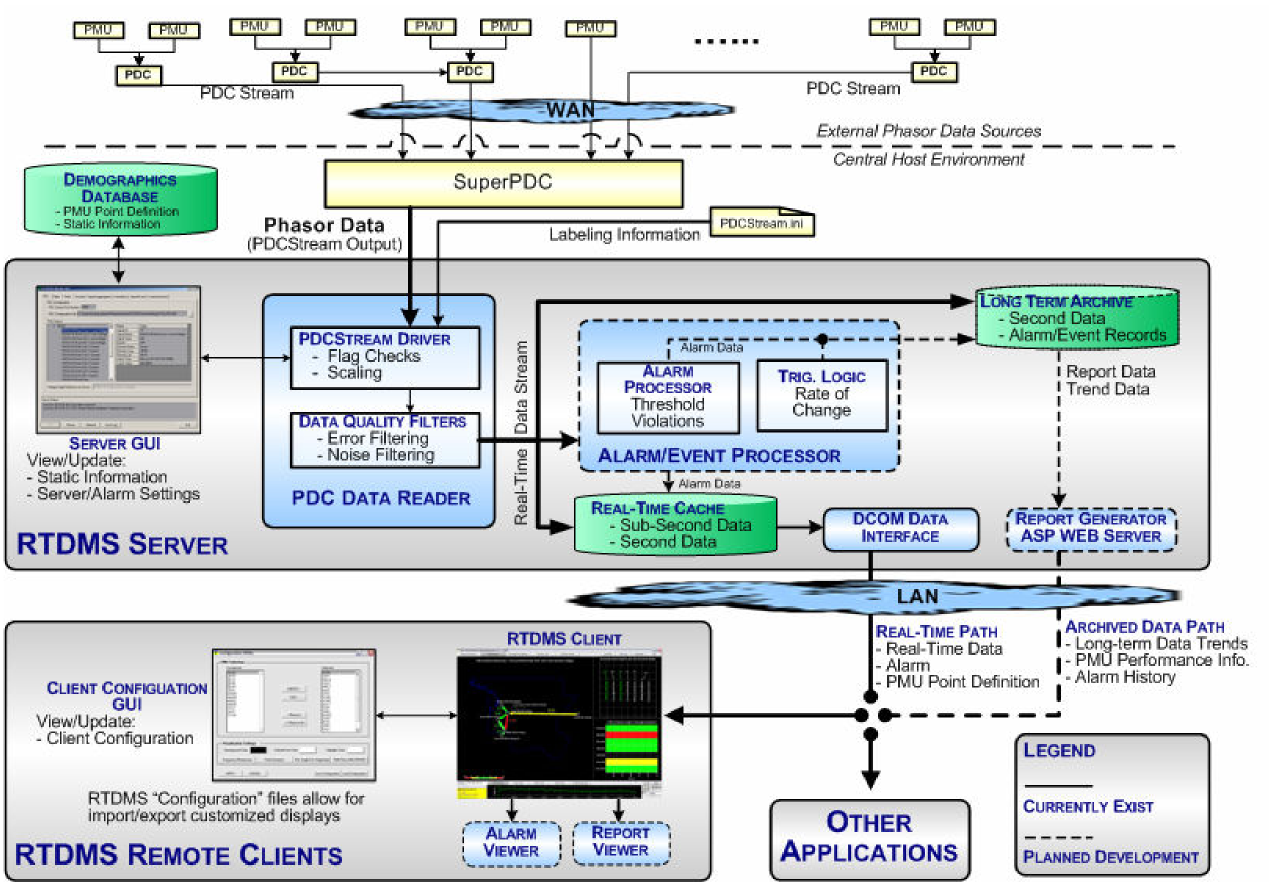

Figure 14: RTDMS System Architecture

19. What is involved in installing RTDMS?

The RTDMS installation process is straightforward and is outlined in the 'Installation and Support Guide'. This process involves

- installing the RTDMS Server application on a PC that the PDC is broadcasting its data. To install, insert the Installation CD and follow the prompts on the screen.
- installing the RTDMS Client application on PCs that are connected to the RTDMS Server machine and would like to have monitoring capabilities. Again, prompts on the screen guide the user through the installation process (Note: the Server and Client use DCOM to communicate between each other – after the Client installation process, the Operating System's 'dcomcnfg' utility should be used to configure the DCOM client properties and direct it to RTDMS Server machine).
- when the Server application is launched, its user friendly Graphic User Interface (GUI) will prompt the user to enter demographic information about the monitoring devices required for visualization.
- with the Server application running, the users may now launch their individual Client applications and utilize the configuration capabilities to customize the displays.

20. Who is using RTDMS?

Within the Eastern Interconnection, this application is currently the system in place for viewing phasor data in the Eastern Interconnection Phasor Project (EIPP). It has been deployed to the 7 operations centers and 11 reliability coordinators within the Eastern Interconnection. In the Western Interconnection, it is being used by California ISO Reliability coordinators, and has been shared with Bonneville Power Administration (BPA) and Pacific Gas and Electric (PG&E).

21. What are some of the planned RTDMS enhancements?

Within the short-term, some of the planned developments for RTDMS include:

- Develop "Summary Dashboard Display" to provide integrated information in a centralized display
- Develop set of standardized tiered displays with drill down capability to:
  - maintain consistent user displays throughout the CAISO
  - effectively manage the data and information by geographic regions and avoid clutter (i.e., Interconnection, Reliability Coordinator regions and Local systems)
    1. Tier 1: Summary Dashboard Display (Default)
    2. Tier 2: Interconnection Displays (Standardized/Centrally Configured)
    3. Tier 3: Reliability Coordinator Displays (Standardized/Centrally Configured)
    4. Tier 4: Local Displays (Customized/Locally Configured)
- PMU performance monitoring providing real-time and historical status information on:
  - Data transmission errors, dropouts, and synchronization errors
  - Non-reporting PMUs
- Online reports with trends showing:
  - Long term trends and statistics on voltage magnitude & angles, and local frequency profiles
  - Daily and hourly reports available

In the long-term, some of the other capabilities that shall be incorporated into the RTDMS include:

- Real-time monitoring and update on dominating oscillatory modes and damping present in the system, and identify the different coherent groups that are observable in the system (i.e. the geographical information on system oscillations).
- Sensitivity computations such as voltage sensitivities at load buses or angle sensitivities at generator buses.

Other

22. How do I obtain more information and get involved?

Additional information on Phasor Technology and some of the ongoing efforts in this area can be found at the following links:

EIPP Project General Information –http://phasors.pnl.gov

WECC WAMS Effort – ftp://ftp.bpa.gov/pub/WAMS_Information/

DOE Website – http://electricity.doe.gov

CERTS Website – http://certs.lbl.gov

Electric Power Group (RTDMS Application) – www.electricpowergroup.com

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