Energy Research and Development Division
FINAL PROJECT REPORT

RESEARCH, DEVELOP AND DEPLOY PRODUCTION QUALITY ADVANCED SYNCHROPHASOR TECHNOLOGY APPLICATIONS AT CALIFORNIA ISO FOR RENEWABLES INTEGRATION

Prepared for: California Energy Commission
Prepared by: Electric Power Group, LLC

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PREFACE

The California Energy Commission Energy Research and Development Division supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The Energy Research and Development Division conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

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- Energy Innovations Small Grants
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- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Research, Develop and Deploy Production Quality Advanced Synchrophasor Technology Applications at California ISO for Renewables Integration is the final report for the California ISO Synchrophasor Technology Investment & Implementation project (contract number PIR-10-068) conducted by Electric Power Group, LLC. The information from this project contributes to Energy Research and Development Division's Energy Systems Integration Program.

For more information about the Energy Research and Development Division, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

The California Independent System Operator is a leader in advancing electricity grid technologies including synchronphasor technology. This project used high-resolution time-synchronized data at the California Independent System Operator control center to enable operators to monitor grid dynamics over a wide-area and deliver the benefits of improved reliability, renewables integration, and increased use of existing transmission networks. Synchrophasor technology collects data at 30 to 60 samples per second over a wide-area,such as the entire Western Grid, and is several hundred times faster than current state of the art technology currently used in control centers. This research provided the California Independent System Operator with support for applications and technologies that could be used in the control center for wide area monitoring, oscillation detection (fluctuations in the electricity system), identifying pre-cursors for grid stress and taking timely corrective action to prevent blackouts and cascading events. This is consistent with their Five Year Synchrophasor Plan and integrating California Independent System Operator technology with the Western Interconnection Synchrophasor Program.

Using synchrophasor technology is new and continued research and development support is recommended for improving data quality and reliability; data analysis for improved planning and operations using data mining technologies; new applications; technologies and systems for operator training; and addressing cyber security challenges. This project benefits California consumers by providing next generation technology for the California Independent System Operator that will reduce the likelihood of blackouts, prevent cascades, efficiently integrate renewable resources, allow grid dynamic impacts monitoring (such as harmful oscillations and corrective actions), and use existing transmission assets more effectively. The California Independent System Operator is in a better position to take advantage of the growing deployment of phasor technology and can perform wide-area monitoring and situational awareness of the grid.

Figures/diagrams without citations are sources by author.

Keywords: enhanced Phasor data concentrator, phasor measurement unit, phase angle baseline analysis, production grade visualization, integrating phasor data with PI historian and EMS, automatic event analyzer, phasors, situational awareness displays

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Introduction

Major blackouts such as the August 10, 1996 and September 8, 2011 blackout in the Western United States and the August 14, 2003 blackout in North Eastern United States and Canada impose billions of dollars in damage to the economy and disrupt people and businesses in their daily lives. Investigations of these and other major blackouts around the world found some common contributing factors:

- Operators did not have visibility of the power grid beyond their control area such as lack of real-time wide-area visibility and situational awareness.
- Data across different parts of the grid was not time-synchronized data leading to delays in diagnosing grid problems and confusion about root causes over a wide-area.
- Operators could not monitor grid dynamics, such as oscillations, in real-time.
- Models were inaccurate and did not reflect the current system state.
- Traditional technologies did not provide metrics that could be used to detect grid vulnerabilities of wide area grid stress

The California Energy Commission (Energy Commission) has been a leader in providing research support to advance the next generation technologies in California. This research focused on using synchrophasor technology, which collects real-time data at 30 to 60 samples per second (compared to current technology of one sample every 2 to 4 seconds), throughout a power system for example, the entire Western Grid. Building on prior research funded by the Energy Commission, the Electric Power Group, LLC conducted research that addressed shortcomings of existing synchrophasor technologies and delivered tools and technologies to the California Independent System Operator (California ISO) to benefit California consumers. Electric Power Group developed a Real Time Dynamics Monitoring System (RTDMS) that is a robust platform for analytics and visualization designed for control center use to deliver state of the art wide-area visualization and real-time grid monitoring using synchrophasor technology.

Synchrophasor technology holds the promise of improving reliability, increasing transmission asset use, reducing electricity costs, and facilitating integration of intermittent renewable resources and distributed smart grid technologies. Synchrophasor technology has the potential to deliver these public benefits as it offers:

- Time-synchronized high-resolution data at 30 to 60 samples per second compared to one sample every 2 to 4 seconds with current Supervisory Control and Data Acquisition technology.
- Wide-area real-time situational awareness and ability to observe the entire interconnection rather than by utility or California ISO footprint.

- Ability to measure grid dynamics that are indicators of the grid health of the grid such as phase angles, oscillations and damping, frequency coherency, voltage and angle sensitivities that allow power system operators to use measured values in real-time operations, rather than values based on engineering studies or estimated values from models.

Deploying phasor measurement units in the grid provide high-resolution (30 to 60 samples/second) and time-synchronized measurements of important system parameters (voltage and current phase angles, frequency deviation and rate-of-change). This real-time information offers a dynamic visibility into the power system, which helps to identify:

- Grid Stress: identified by higher phase angle of separation between predefined phasor measurement units.
- Grid Robustness: identified by damping status and trends.
- Dangerous Growing Oscillations: identified by oscillations with high energy and low damping.
- Frequency Instability: identified by large frequency variations or incoherency at different measurement points across interconnections.
- Voltage Instability: identified by any sudden drop in voltage magnitude from its normal operating conditions.
- Reliability Margin: identified by a calculation of power voltage and power angle sensitivities that can provide power system operators with an indication of reliability margins.

The Energy Commission has made a significant investment in phasor technology research to maintain and enhance California's technology leadership. As a result of this and earlier Energy Commission-funded synchrophasor research, the California ISO now provides their system operators with accurate wide-area situational grid awareness by the RTDMS platform developed by Electric Power Group.

Project Purpose

The California ISO has been at the forefront of using synchrophasor technology, having implemented the first generation RTDMS developed by Electric Power Group in 2003. The California ISO's management determined that there is value using synchrophasor technology in real-time operations and requested that Electric Power Group develop a plan to transition this technology from the current research and prototype system to a production quality system appropriate for an operational environment.

The key research areas are listed below:

- Procure and install the necessary hardware to ensure the California ISO's synchrophasor network is a production grade quality and can reside on the operating side of their computer network.

- Provide the necessary software interface to allow critical phasor data and information from the RTDMS application to transfer to the California ISO's Data Archiving System.
- Provide real-time operations with an automated event analyzer that will summarize critical grid metrics immediately after detecting an event.
- Transition RTDMS Visualization platform to a production grade quality.
- Perform analysis to establish alarm limits that alert operators of deteriorating grid conditions and to take corrective action.

Project Results

The Energy Commission funded Electric Power Group to address the limitations of existing technologies and deliver tools and technologies to the California ISO to benefit California consumers. Electric Power Group developed a RTDMS that provides state of the art wide-area visualization and real-time grid monitoring using synchrophasor technology. The RTDMS was then tailored for the California ISO to meet their needs for wide-area situational awareness with state of the art high-resolution visualization using sub-second phasor data.

Procure and Install Production Hardware at California ISO's Facilities

The California ISO's management determined there is value in using synchrophasor technology in real-time operations. A plan was developed to transition this technology from the current research and prototype system to a production quality system appropriate for an operational environment as outlined in their Five Year Synchrophasor Plan.

The Energy Commission provided the funding to procure the necessary hardware for Electric Power Group and the California ISO to design and implement a production grade phasor network and allowed the California ISO to use phasor technology in an operational environment. In addition, the California ISO was able to interface with the Western Interconnection Synchrophasor Program project participants exchanging phasor data and information and helping manage the California and interconnected electric grid.

Integrate Phasor Data with California ISO's Performance Index Historian and Energy Management System/Supervisory Control and Data Acquisition

The California ISO wanted the enhanced Phasor Data Concentrator and RTDMS data integrated with their performance index historian system and Energy Management System/Supervisory Control and Data Acquisition.

This project implemented an end-to-end solution that directly integrated raw and processed phasor data from the RTDMS Data Management Server into the Performance Index Historian and Energy Management System/Supervisory Control for the operating staff to access through their normal workstations.

Automatic Event Analyzer

Electric Power Group developed a tool that, after detecting an event on the grid such as a blackout, will automatically retrieve and compile the relevant phasor metric information into a meaningful summary of the event. This automatic event analyzer will describe the condition of the grid immediately before the event and identify the sequence of events (within the limits of the phasor points being monitored) leading up to the event. Having access to this information almost immediately following an event will enable the power system operators to begin system restoration more quickly.

Transition Real Time Dynamics Monitoring System Visualization to a Production Grade Quality

As new requirements develop and technologies advance, RTDMS has been re-architected. Power system information must be organized and presented in a manner that allows the user to immediately become aware of any condition requiring urgent attention, to quickly grasp the most significant aspects of a situation, and to have fast access to related data for the investigation of details presented. In addition, the system should adopt simple, fast, and unambiguous operating and navigating procedures to guard against user errors. Where feasible, a single-step procedure is used such as initializing a function by clicking a button for frequently used functions and for critical functions.

Phase Angle Baseline Analysis

The objectives for this task is threefold: (1) review and compare the phasor data being received at the California ISO with the California ISO's state estimator data; (2) to perform an initial phase angle baseline analysis for the California ISO's portion of the Western Electricity Coordinating Council grid; and (3) to document the entire analysis process and

Project Benefits

Previously the California ISO's synchrophasor network was viewed as a research-grade system and not suitable for real-time operations. The funding provided by the Energy Commission for these projects has allowed the California ISO's synchrophasor network to transition to a production grade system with state of the art advanced metrics, such as oscillations detection and damping. The associated network hardware and visualization of the California ISO's synchrophasor network is ready for real-time operations, and in fact, the visualization was rated as an industry leader at a recent North American SynchroPhasor Initiative visualization workshop.

California's expected benefits from the significant upgrades and enhancements to the California ISO's synchrophasor network are four fold:

1. Improved reliability through avoidance of large-scale outages, such as the Pacific Southwest outage on September 8, 2011, as a result of improved situational awareness, early detection, enhanced visualization, and decision support tools.

2. Production grade hardware and visualization that meets operational reliability and performance needs and a secure network.

3. Improved ability to facilitate integrating and using renewable resources.

4. Increased use of existing transmission capacity such as on the California-Oregon Intertie through dynamic graphic calculations that provide a more accurate picture of available capacity compared to current static methods.

This research continues to position the California ISO as an industry leader in harnessing the benefits of synchrophasor technology in operations and planning. This techoloygy also delivers the benefits to California citizens by improving electricity reliability, increasing transmission asset use, reducing electricity costs, and integrating intermittent renewable resources and distributed smart grid technologies.

CHAPTER 1: Procure and Install Production Quality Hardware at California ISO's Facilities

1.1 The Goal

This task transitioned the California Independent System Operator (California ISO) phasor system onto production grade hardware to run synchrophasor software applications.

The California ISO management determined that there is value in using synchrophasor technology in real-time operations, and they developed a plan to transition this technology from the current research and prototype system to a production quality system appropriate for an operational environment. This research provided the California ISO with the necessary support for applications and technologies that could be used in the control center for wide area monitoring, oscillation detection, identifying pre-cursors for grid stress and taking timely corrective action to prevent blackouts and cascading events, consistent with their Five Year Synchrophasor Plan and integrating California ISO technology with the Western Interconnection Synchrophasor Program.

1.2 Approach

The following provides a summary of the work done under this portion of the research project:

- Worked with California ISO to procure and install the production quality hardware to run synchrophasor applications at California ISO.
- Reviewed phasor network architecture design for reliability. The architecture for a production grade network at the California ISO included:
  - Production Environment;
  - Staging Environment; and
  - Testing Environment.
- Faciliated integration with the Western Electricity Coordinating Council (WECC) developing phasor network.
- Prepared and provided a draft and final architectural design diagram of the proposed system.
- Downloaded, tested, and installed Electric Power Group, LLC's (EPG) Real Time Dynamics Monitoring System (RTDMS®) and *enhanced* Phasor Data Concentrator (*e*PDC™) software in use at California ISO on production quality hardware, and assisted in installation of hardware and software at California ISO's primary system, backup system, and test system at Folsom and Alhambra, California.

1.3 Background

Computer hardware architecture is the conceptual design and fundamental operational structure of a computer system and addresses these concerns:

- Maintainability – the ability of the system to undergo changes with a degree of ease when adding or changing the functionality, fixing errors, and meeting requirements.
- Availability –the proportion of time that the system is functional and working.
- Interoperability – the ability of a system or different systems to operate successfully by communicating and exchanging data and information with other external systems.
- Performance – the responsiveness of a system to execute any action within a given time interval. It can be measured in terms of latency or throughput.
- Reliability – the ability of a system to remain operational over time. Reliability is measured as the probability that a system will not fail to perform its intended functions over a specified time interval.
- Scalability – the ability of a system to either handle increases in load without impact on the performance of the system or the ability to be readily enlarged.
- Security – the capability of a system to prevent malicious or accidental actions outside of the designed usage, and to prevent loss of information.
- Testability – the ability to have a test environment to evaluate the performance of software revisions, patches, or new software in a safe environment with no impact on the operational system.
- Usability – how well the performance of the applications residing on the hardware meets the expectations and requirements of the user.

1.4 Phasor Network Architectural Design

Collaboratively, the California ISO and EPG staffs worked closely to define data storage and hardware requirements and then the design for the hardware architecture to address the above concerns. First, EPG provided the California ISO staff with a data storage calculator to help define storage requirements for the hardware.

Figure 1: Phasor Data Storage Calculator

EPG Phasor Data Storage Calculator	
Number Of Days	90
Sampling Rate	30
Number of PMU	150
Number of status per PMU	1
Number of frequency channels per PMU	1
Number of phasor channels per PMU	2
Number of power channels per PMU	2
Number of digitals per PMU	0
Number of analogs per PMU	0
Number of corridor channels	50
Number of angle difference channels	50
Number of system frequency channels	1
Number of alarms/events per second	20
Ratio of event data over raw data	0.2
Estimated Disk Storage for raw data (in Gigabytes)	808.64
Estimated Disk Storage for raw & calculated data (in Gigabytes)	1,210.87

The phasor data storage calculator (Figure 1 above) shows an example of the data storage requirements for 300 phasors (assumed to be comprised of 150 phasor measurement units (PMUs), and each PMU has 2 Phasors (1 voltage, 1 current), 1 Frequency, 1 Status Word, 0 Digitals, 0 Analogs, at 30 Samples/Sec for 30 days, including aggregated channels & alarms: 50 power corridors, 50 angle pairs, 1 system frequency, 20 alarms/events per second, and an event table filling up ratio to raw data is 0.2 (maximum ratio). This calculator stores high-resolution data associated with an event such as frequency transient.

California ISO and EPG agreed on the hardware requirements to meet the data storage requirements including Intelligent Synchrophasor Gateway (ISG), and database (Figure 2).

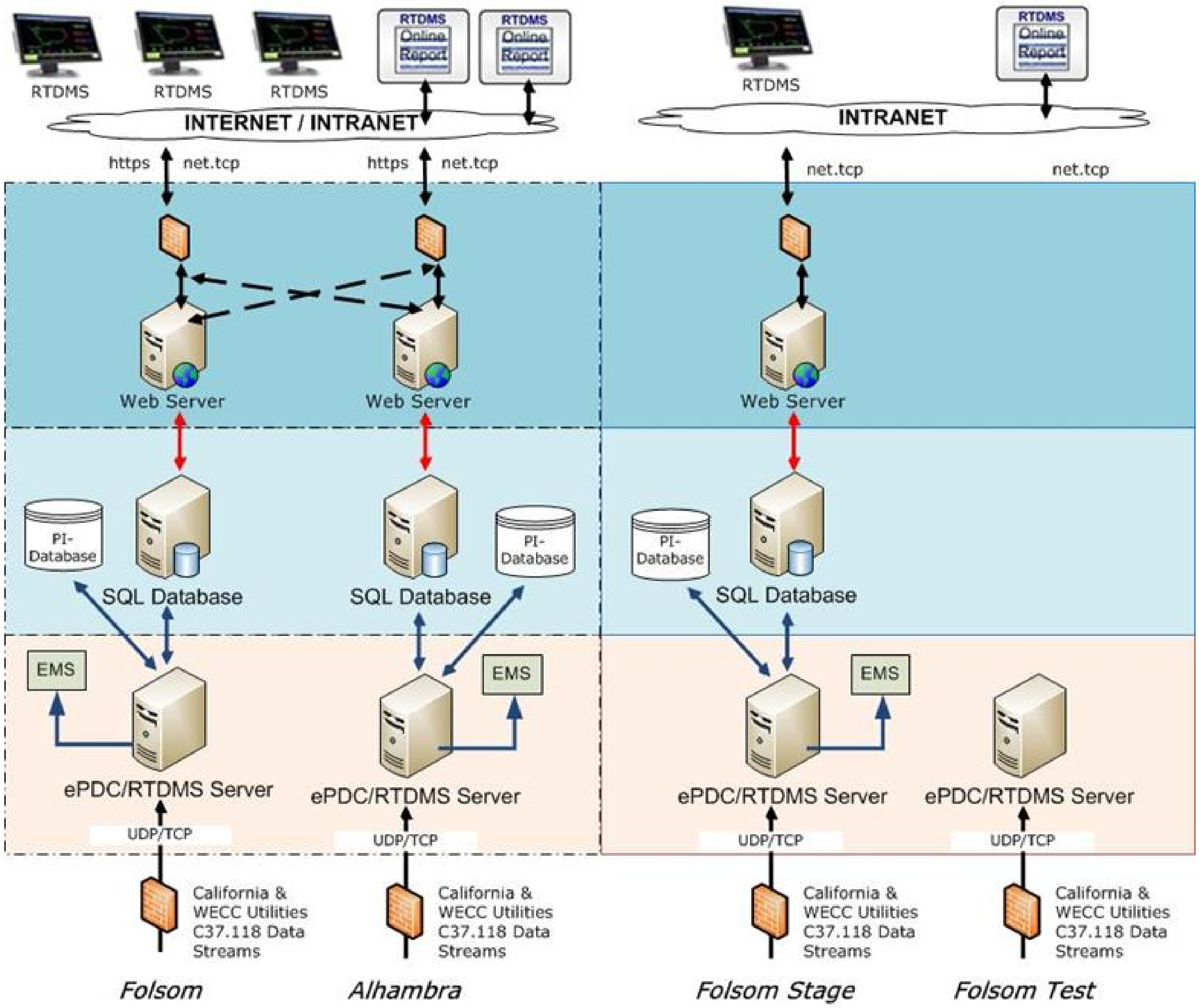
Figure 2: Hardware Requirements

Server 1 Hardware Requirements Will run EPG's ePDC and RTDMS Server software	
Operating System	Microsoft Windows 2008 R2
Processor Speed	2.5GHz
Processors- Cores/CPU	2 Physical Processors
Memory	8 Gigabytes Minimum
I/O ports	1 Network Interface Card (NIC) supporting 1GbPS
Hard Disk Storage	100 Gigiabytes
Server 2 Hardware Requirements Will run Intelligent Synchrophasor Gateway (ISG) hosted on IIS	
Operating System	Microsoft Windows 2008 R2
Processor Speed	2.5GHz
Processors- Cores/CPU	2 Physical Processors
Memory	8 Gigabytes Minimum (Suggested 16 GB)
I/O ports	1 Network Interface Card (NIC) supporting 1GbPS
Hard Disk Storage	100 Gigiabytes
Server 3 Hardware Requirements - Real Time Data Storage Will run EPG's RTDMS Database hosted in Microsoft SQL Server	
Operating System	Microsoft Windows 2008 R2
Database System	Microsoft SQL Server 2008 R2
Processor Speed	2.5GHz
Processors- Cores/CPU	2 Physical Processors (each with quad-core)
Memory	24 Gigabytes Minimum
I/O ports	1 Network Interface Card (NIC) supporting 1GbPS
Hard Disk Storage	2.5 TB Disk Storage (200 PMUs for 30 Days RAW phasor data, calculated data, alarms, and events)

Individual PC Hardware Requirements Will run EPG's RTDMS Client	
Operating System	Microsoft Windows 7, 64-bit.
Processor Speed	2.5GHz
Processor Type	Intel Core2 Quad or i7 processor
Memory	8 Gigabytes Minimum
I/O ports	1 Network Interface Card (NIC) 1 GBPS

The final design and architecture for the California ISO's production grade phasor network describes how each system is interconnected (Figure 3).

Figure 3: Architecture for a Production Grade Phasor Network



1.5 Procurement of Hardware

In January 2012, the California ISO staff provided EPG with the final number of machines required at both Folsom and Alhambra, specifications for the machines, and a cost quote from their preferred vendor. On January 24, 2012, EPG sent a purchase order to Applied Computer Solutions (California ISO's hardware vendor) to purchase the desired equipment. The itemized equipment purchased for the California ISO at both Folsom and Alhambra was delivered to Folsom and Alhambra in March 2012 (Figure 4 and Figure 5).

Figure 4: Hardware Purchased for California ISO Folsom, California Facility

Production Quality Hardware for CAISO Folsom Facility

			HP DL380G7					
1)	8	583914-B21	HP DL380G7 SFF CTO CHASSIS	$1,622.00	$12,976.00	20.63%	$1,287.36	$10,298.88
2)	8	583914-B21 ABA	U.S. - ENGLISH LOCALIZATION	$0.00	$0.00	0.00%	$0.00	$0.00
3)	8	587493-L21	HP X5670 DL380G7 FIO KIT	$1,999.00	$15,992.00	23.24%	$1,534.49	$12,275.92
4)	8	587493-B21	HP X5670 DL380G7 KIT	$1,999.00	$15,992.00	23.24%	$1,534.49	$12,275.92
5)	8	587493-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
6)	48	500662-B21	HP 8GB 2RX4 PC3-10600R-9 KIT	$199.00	$9,552.00	23.24%	$152.76	$7,332.48
7)	48	500662-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
8)	16	512547-B21	HP 146GB 6G SAS 15K 2.5IN DP ENT HDD	$389.00	$6,224.00	23.24%	$298.61	$4,777.76
9)	16	512547-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
10)	8	481041-B21	HP SLIM 12.7MM SATA DVD OPTICAL KIT	$90.00	$720.00	23.23%	$69.09	$552.72
11)	8	481041-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
12)	16	503296-B21	HP 460W CS GOLD HT PLG PWR SUPPLY KIT	$229.00	$3,664.00	23.24%	$175.79	$2,812.64
13)	16	503296-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
14)	1	HG925A3	HP 3 YR NEXT DAY W/DMR HW SUPPORT	$0.00	$0.00	0.00%	$0.00	$0.00
15)	8	HG925A3 7G3	PROLIANT SERVERDL38X HWSUPPORT	$98.00	$784.00	100.00%	$0.00	$0.00
16)	8	TC278AAE	HP IC ML/DL/BL BUNDLE E-LTU 24X7 SW	$449.00	$3,592.00	26.00%	$332.25	$2,658.00
17)	16	LPE11000-E	Emulex 4Gb PCIe 2.5Ghz x4 Single Channel Fibre Channel HBA-EMC	$1,175.00	$18,800.00	28.00%	$846.00	$13,536.00
18)	1	ACS-DISC	ACS Discount				($570.00)	($570.00)
				Total List:	$88,296.00		Sub-Total:	$65,950.32
							Sales Tax:	$5,111.15
							Shipping:	$1,538.66
							TOTAL:	**$72,600.13**

Figure 5: Hardware Purchased for CALIFORNIA ISO Alhambra, California Facility

Production Quality Hardware for CAISO Alhambra Facility

			HP DL380G7					
1)	3	583914-B21	HP DL380G7 SFF CTO CHASSIS	$1,622.00	$4,866.00	20.63%	$1,287.36	$3,862.08
2)	3	583914-B21 ABA	U.S. - ENGLISH LOCALIZATION	$0.00	$0.00	0.00%	$0.00	$0.00
3)	3	587493-L21	HP X5670 DL380G7 FIO KIT	$1,999.00	$5,997.00	23.24%	$1,534.49	$4,603.47
4)	3	587493-B21	HP X5670 DL380G7 KIT	$1,999.00	$5,997.00	23.24%	$1,534.49	$4,603.47
5)	3	587493-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
6)	18	500662-B21	HP 8GB 2RX4 PC3-10600R-9 KIT	$199.00	$3,582.00	23.24%	$152.76	$2,749.68
7)	18	500662-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
8)	6	512547-B21	HP 146GB 6G SAS 15K 2.5IN DP ENT HDD	$389.00	$2,334.00	23.24%	$298.61	$1,791.66
9)	6	512547-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
10)	3	481041-B21	HP SLIM 12.7MM SATA DVD OPTICAL KIT	$90.00	$270.00	23.23%	$69.09	$207.27
11)	3	481041-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
12)	6	503296-B21	HP 460W CS GOLD HT PLG PWR SUPPLY KIT	$229.00	$1,374.00	23.24%	$175.79	$1,054.74
13)	6	503296-B21 0D1	FACTORY INTEGRATED	$0.00	$0.00	0.00%	$0.00	$0.00
14)	1	HG925A3	HP 3 YR NEXT DAY W/DMR HW SUPPORT	$0.00	$0.00	0.00%	$0.00	$0.00
15)	3	HG925A3 7G3	PROLIANT SERVERDL38X HWSUPPORT	$98.00	$294.00	100.00%	$0.00	$0.00
16)	3	TC278AAE	HP IC ML/DL/BL BUNDLE E-LTU 24X7 SW	$449.00	$1,347.00	26.00%	$332.25	$996.75
17)	6	LPE11000-E	Emulex 4Gb PCIe 2.5Ghz x4 Single Channel Fibre Channel HBA-EMC	$1,175.00	$7,050.00	28.00%	$846.00	$5,076.00
18)	1	ACS-DISC	ACS Discount				($350.00)	($350.00)
				Total List:	$33,111.00		Sub-Total:	$24,595.12
							Sales Tax:	$2,152.07
							Shipping:	$643.43
							TOTAL:	**$27,390.62**

1.6 Transfer of Hardware Ownership

Under the grant contract between the Energy Commission and EPG, the hardware procured under this project became the property of EPG. The California ISO, however, requested that ownership of the hardware reside with the California ISO for control of system operations and support. On May 30, 2013, EPG transferred ownership of the hardware to the California ISO.

1.7 Conclusions

The Energy Commission provided the funding to procure the necessary hardware for EPG and the California ISO to design and implement a production grade phasor network. Production grade network and the production grade RTDMS software application allows the California ISO to use phasor technology in an operational environment. In addition, it allows the California ISO to interface with the WISP project participants in the exchange of phasor data and information in support of their overall management of the California and interconnected electric grid.

CHAPTER 2:
Integrate Phasor Data with California ISO Performance Index Historian/Energy Management System

2.1 The Goal

End-to-end solutions were implemented that directly integrates EPG's software applications that are used at California ISO (RTDMS and the offline Phasor Grid Dynamics Analyzer (PGDA)), with the California ISO's Performance Index (PI) Historian to support the following objectives:

- RTDMS Data Management Server archived raw and processed phasor data into the Performance Index (PI Historian), which the operating staff had access to through their normal workstations.
- Allowed the PGDA to directly access historical raw and processed data from the PI Historian for offline engineering analysis within PGDA.

As part of the ongoing synchrophasor technology research for the California ISO, EPG waived the license cost for the RTDMS application, but that was not the case for the PGDA application. EPG provided the California ISO staff with a trial version of the PGDA application, but at this time, the staff elected not to purchase the full license. Therefore, EPG was unable to integrate their PI historian with the PGDA application.

In EPG's discussions with the California ISO staff, it was determined there was a desire to have the RTDMS application integrated with both their PI system and their Energy Management System/Supervisory Control and Data Acquisition (EMS/SCADA) as opposed to either one or the other. It was determined that EPG could take on this additional effort with no negative impact on the project and as a result the requirements were modified to accommodate this change.

2.2 Approach

The following items were required as part of this effort:

- Integrated phasor data performance assessment to either:
  - Connect directly into PI.
  - Use a redundant link to EMS such as the ABB PCU 400 platform.
- Prepared Functional Specifications and Database Schematic Specification documents for integration of the RTDMS application with PI Historian/EMS.
- Reviewed Specification documents with California ISO staff.
- Prepared Test Cases and Test Procedures for testing interfaces.

- Implemented RTDMS-PI/EMS interfaces and conducted factory and field testing at California ISO.
- Conducted a demonstration at California ISO of EPG's software integrated with the PI Historian and EMS.

2.3 Background

The California ISO used the RTDMS from EPG to provide the wide-area monitoring through phasor functions under the project 'Phasor Development, Analysis, and Research for Implementing Various Aspects of Phasor Technology at the California ISO Network, Grant Award Number PIR-10-068.' To meet the requirements of the contract task "Integrate Phasor Data with California ISO PI Historian", the following was completed: (i) development of the PI interface that allowed for tag management and data archiving into PI; and (ii) the use of California ISO's PI Application Programming Interface license for implementation on the California ISO PI system. EPG licensed the PI Software Development Kit and completed the development of the PI interface that allows for tag management and data archiving into PI.

In addition, California ISO was using the *e*PDC from EPG to provide the wide-area monitoring through phasor functions for Energy Commission PIR-10-068 Project. To meet the goals of "Integrate Phasor Data with California ISO PI Historian and EMS," in addition to the design and functional specification of RTDMS to PI interface to California ISO, EPG submitted the functional and design requirements to integrate phasor data into California ISO's EMS/SCADA.

2.4 Functional Specifications

2.4.1 Functional Specifications and Database Schematic Specification for integration of the RTDMS Application with PI Historian

2.4.1.1 Functionalities of the RTDMS to PI Historian Interface

RTDMS to PI Historian Add-on (RTDMS to PI interface) was an optional RTDMS output adaptor. The output adaptor was designed to enable easy storage of phasor data into PI Historian. Like other RTDMS output adaptors, the RTDMS to PI add-on allowed users to select PMUs/channels, sample rate, and maximum cut-off latency options. The add-on performed the following functionalities:

- Configurable to enable/disable automatically create PI tags with configurable default tag attributes.
- Automatically detected input PMU/PDC configuration change and automatically resynchronized tags with PI server when automatically creating PI tags was enabled.
- Automatically generated I/O rate tag and periodically populated I/O data rate value.
- Map data quality flags to RTDMS status digital set.
- Archived all raw measurements including status, analog, digital, voltage phasor, current phasor, frequency, and df/dt, and calculated values including power, angle difference, power flow gate, mode, sensitivity, and oscillation along with PMU's date/time.

- Allowed selection of PMUs/signals for archiving.
- Configurable archiving sample rate.
- High performance, no compression, and supported PI Application Programming Interface Buffering.
- PI Collective aware.
- Fully integrated with RTDMS so that there was no additional service to manage and failover.
- In auto PI point generation mode, point mapping through extended description and point source instead of tag name so that tag were are allowed to be changed.
- In manual PI point mapping mode, RTDMS supported reusing existing points in PI historian.
- Supported PI Software Development Kit (SDK) v1.4.x.

2.4.1.2 Functional Specifications

The Functional specifications for the RTDMS – PI Historian interface is included in Appendix A, "Integrate Phasor Data into PHI Historian through RTDMS, Functional and Design Specification for RTDMS Output Adaptor for California ISO PI Historian." Topics covered in the specifications are:

- RTDMS to PI Tag Matching & Generation;
- RTDMS to PI Historian Output Configuration;
- PI Collective; and
- RTDMS to PI Historian High Availability through PI API Node Buffering.

For detailed description of these components of the interface, please refer to the corresponding Functional Specifications provided as Appendix A.

2.4.1.3 Activities Completed by EPG

EPG performed the following activities:

- Reviewed specification documents with California ISO staff.
- Prepared test cases and test procedures for testing interfaces.
- Implemented RTDMS-PI interface and conduct factory and field testing at California ISO.
- Conducted a demonstration at California ISO of EPG's software integrated with the PI Historian.

2.4.2 Functional Specifications and Database Schematic Specification for Integration of the RTDMS Applications with EMS

2.4.2.1 Functional Requirements of the RTDMS to EMS Interface

RTDMS archives raw data and calculated values of grid metrics, alarms and events in the RTDMS data base. The goal of this task was to establish a data link from RTDMS to the CAISO EMS. This was accomplished by building an adaptor for Distributed Network Protocol (DNP) that takes output from the RTDMS Server to integrate with the California ISO EMS. This was designed to be responsive (referred to as a slave) to requests from EMS, whether from CAISO servers at Folsom or Alhambra locations. For this purpose, EPG used DNP version 3.0 (DNP3) operating on Transmission Control Protocol/Internet Protocol transport {DNP/Internet Protocol (IPCalifornia ISO DNP Clients were configured for exception polling (Class 1 - Object 60, variation 2) for analogs and statuses. Default response was Object 32, variation 2 for analogs and Object 2, variation 2 for statuses. Master station address was 100, remote addresses was 1. IP address and specific IP port numbers for each slave was provided at time of implementation.

2.4.2.2 Functional Specifications

The functional specifications for the RTDMS – EMS interface are included in Appendix B, 'RTDMS Functional & Design Specification of RTDMS & EMS Integration through Distributed Network Protocol version 3.0 (DNP3)'. The topics covered in the specifications are:

- RTDMS DNP3 Protocol Compliance;
- Signal Processing and Input/Output Features; and
- RTDMS Configuration Graphical User Interface (GUI) Design.

For detailed description of these components of the interface, please refer to the corresponding Functional Specifications provided as Appendix B.

2.4.2.3 Activities Completed by EPG

EPG performed the following activities:

- Reviewed specification documents with California ISO staff.
- Prepare test cases and test procedures for testing interfaces.
- Implemented RTDMS-EMS interface and conduct factory and field testing at California ISO.
- Conducted a demonstration at California ISO of EPG's software integrated with the EMS/SCADA.

2.5 Conclusions - RTDMS Integration with California ISO's PI and EMS/SCADA

- EPG licensed the PI SDK and completed the development of the PI interface that allowed for tag management and data archiving into PI.

- EPG developed the functional specifications for the RTDMS with the California ISO PI Historian and EMS/SCADA interfaces. The functional specifications are included in Appendix A and Appendix B respectively.
- EPG sent these specifications to California ISO on May 15, 2013 for their review and comment and were accepted by California ISO.
- During September of 2013, the California ISO implemented the EPG provided PI and EMS interface software that allows them to transfer phasor data and information to their PI historian and EMS/SCADA.

CHAPTER 3: Event Analyzer Integration

3.1 Goals

The goal of this task was to develop a tool that automatically retrieved and compileds the relevant phasor information into a meaningful summary of an event. This automatic event analyzer described the condition of the grid immediately prior to the sudden event and identified the sequence of events (within the limits of the phasor points being monitored) leading up to the sudden event. Having access to this information almost immediately following a sudden event enabled the operators to begin system restoration more quickly.

3.2 Approach

The following items were required as part of this task:

- Conducted an assessment of the types of automatic analysis that can be performed using available data from the California ISO phasor measurement system.
- Prepared draft and final functional specifications and an analysis framework for integration of an automatic event analyzer into the California ISO phasor measurement system.
- Met with California ISO staff to review specification document.
- Integrated automatic event analyzer with RTDMS visualization display system.
- Reviewed prototype system with California ISO staff.
- Conducted a demonstration at California ISO of a prototype automatic event analyzer system integrated with RTDMS.

3.3 Background

The Automated Event Analyzer (AEA) application of RTDMS runs in real-time and utilizes PMU data to provide grid operators with information immediately following a system event, to enhance the corrective actions of the operators and to improve the stability and reliability of the electric grid.

The AEA application continuously performs event detection, classification, location estimation, and analysis in real-time, including oscillations, islanding, generation trip, load shedding and line outage events. AEA then presents to operators a summary of results of all the relevant information via 'yellow pop ups.' Also, a "more" button immediately brings up more detailed diagnostics and shows grid operators all of the relevant metrics at a glance.

This application consists of the following modules:

- Oscillation Detection Module;
- Mode Meter Module;

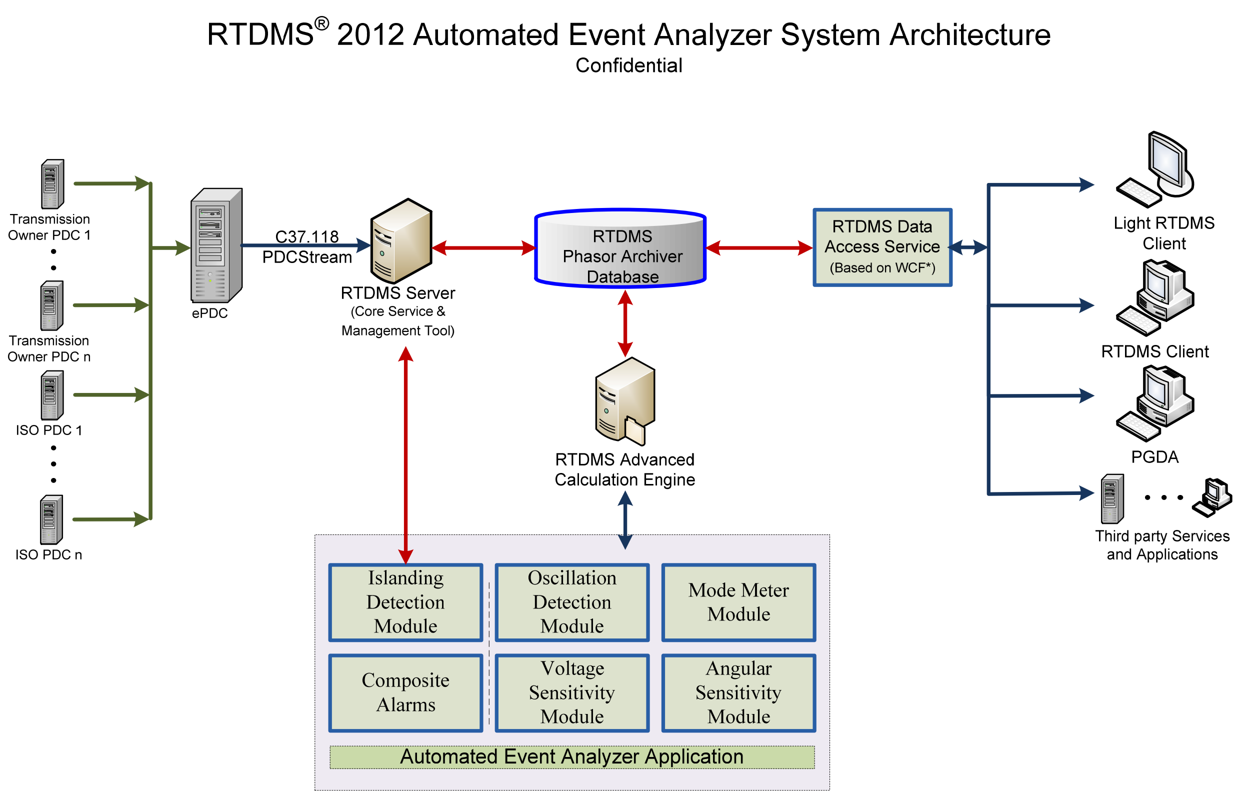
- Voltage Sensitivity Module;
- Angular Sensitivity Module;
- Islanding Detection Module;
- Generator Trip Detection Module;
- Load Shedding Detection Module; and
- Line Outage Detection Module.

One or more synchrophasor signals are independently input into each module via an input data block and each module operates independently, which can be turned on and off individually. A simplified AEA system architecture diagram is shown in Figure 6. Each module exchanges data with RTDMS Phasor Archiver Database, i.e., fetching input signals from database and saving analysis results back to database. Downstream applications then pick up the results and present to the users.

3.4 System Architecture

The automatic event analyzer system architecture is shown in the figure below.

Figure 6: Automatic Event Analyzer System Architecture



3.5 Functional Specifications

The topics covered in the functional specifications are briefly described below. For more details please refer to the Automatic Event Analyzer Functional Specifications included in Appendix C, 'RTDMS Automated Event Analyzer Functional Specifications.'

3.5.1 Oscillation Detection Module

The Oscillation Detection Module (ODM) is designed for rapid identification of system conditions at the time of a disturbance. It automatically detects electromechanical frequency oscillations and damping levels immediately following system disturbances, and it is intended to complement detection methods traditionally used in steady state conditions. The AEA application will detect oscillations that may be unexpected or unknown to operators.

3.5.2 Mode Meter Module

The Mode Meter Module (MMM) utilizes phasor measurement data to identify poor damping and wide-area oscillations on the grid by identifying the dominant oscillatory mode frequencies, magnitudes, and damping.

3.5.3 Voltage Sensitivity Module

The Voltage Sensitivity Module (VSM) provides the users with a current real-time assessment of the slope of the PV or QV curve and alarms them when the sensitivities exceed a user predefined threshold. The voltage sensitivity can be defined as change in voltage as a function of power flow on a transmission line given in kV per 100 MWs change or kilovolts (kV) per megawatt (MW) change. By monitoring the rate of change or slope, the margin from the nose point can be approximated.

3.5.4 Angular Sensitivity Module

The Angular Sensitivity Module (ASM) provides the users with a current real-time assessment of the slope of the δ-PV curve and alarms them when the slope exceeds a user predefined threshold. The angular sensitivity can be defined as change in angle as a function of power flow on a transmission line, and it can be measured in degrees per 100 MWs or degree per MW. A user will be able to select critical corridors or load pockets to monitor for potential angular stability problems in the system.

3.5.5 Islanding Detection Module

The Islanding Detection Module (IDM) is a very efficient tool for detecting islanding conditions in the power system. IDM utilizes the frequency signals and/or voltage angle signals as input to the module, i.e., the frequency difference method and the change of angle difference method. The users can select either of these two implementation methods or use both simultaneously.

3.6 Conclusion – Automatic Event Analyzer

A major objective for the deployment of synchrophasor technology in real-time operations was to provide power system operators with a tool that detects and alarms when excessive grid stress is indicated. Having this capability provides power system operators with greater situational awareness of the grid, but sudden unanticipated events can occur, and this technology can be used to support real-time operations when they occur. The research and development of the automatic event analyzer supports real-time operations by immediately providing the operator with information, as opposed to more data and alarms, which recaps what the various metrics detected. Below is a sample of the pop-up window that is presented to the power system operator with event information, and by clicking the "More" button (top right) the detailed event analyzer display will come up.

Figure 7: Sample Automatic Event Analyzer Pop-up

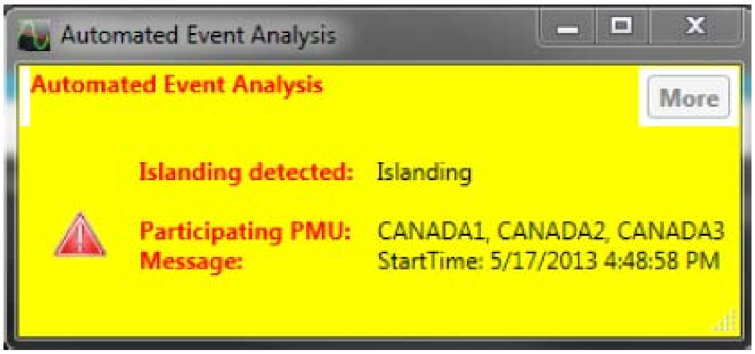


Figure 8: Sample Detailed Automated Event Analyzer Display

The automated event analyzer is an integrated module of the RTDMS application and with this enhancement, the application has become an industry leader in synchrophasor visualization. The module was be integrated into the California ISO's RTDMS in December of 2013.

CHAPTER 4: Transition RTDMS to Production Quality Grade

4.1 Goal

The goal of this task was to improve the situational awareness displays for the California ISO system operators.

4.2 Approach

- Coordinated with California ISO users to determine operational and engineering display needs and preferences.
- Conducted a literature search to determine the best display technologies available and which are compatible with the California ISO user needs.
- Prepared and developed a functional specification for the proposed display improvement and review it with California ISO staff.
- Implemented and evaluated changes in a test environment.
- Transitioned to display improvements to the operational system.
- Conducted a demonstration at California ISO of an improved display capability

4.3 Background

The California ISO had been using the RTDMS to perform wide-area monitoring of the system through phasor functions. To meet the requirements of the contract task "Transition RTDMS to Production Quality Grade,", EPG was required to submit the design and functional specification of RTDMS 2012 to California ISO. These specifications include a new set of displays that best fit current needs of the California ISO operators.

4.4 RTDMS 2012 Design and Functionality

Power system information needs to be organized and presented to the user in a manner that allows the user to immediately become aware of any condition requiring urgent attention, to quickly grasp the most significant aspects of a situation, and to have fast access to related data for the investigation of details of the information presented. In addition, the system should adopt simple, fast, and unambiguous operating and navigating procedures to guard against user errors. Whenever feasible, single-step procedures should be used, such as initialization a function by clicking a button, for frequently used functions and for critical functions. Common and frequently employed actions shall be initiated from toolbars.

In the design of displays there was a thoughtful use of borders or frames to visually group information that logically belongs together. Colors were used sparingly for only the following purposes: to distinguish different dynamic states, for clarification purposes, and to highlight important information.

In designing the system, EPG provided the necessary functionality to address the above needs, as listed below RTDMS:

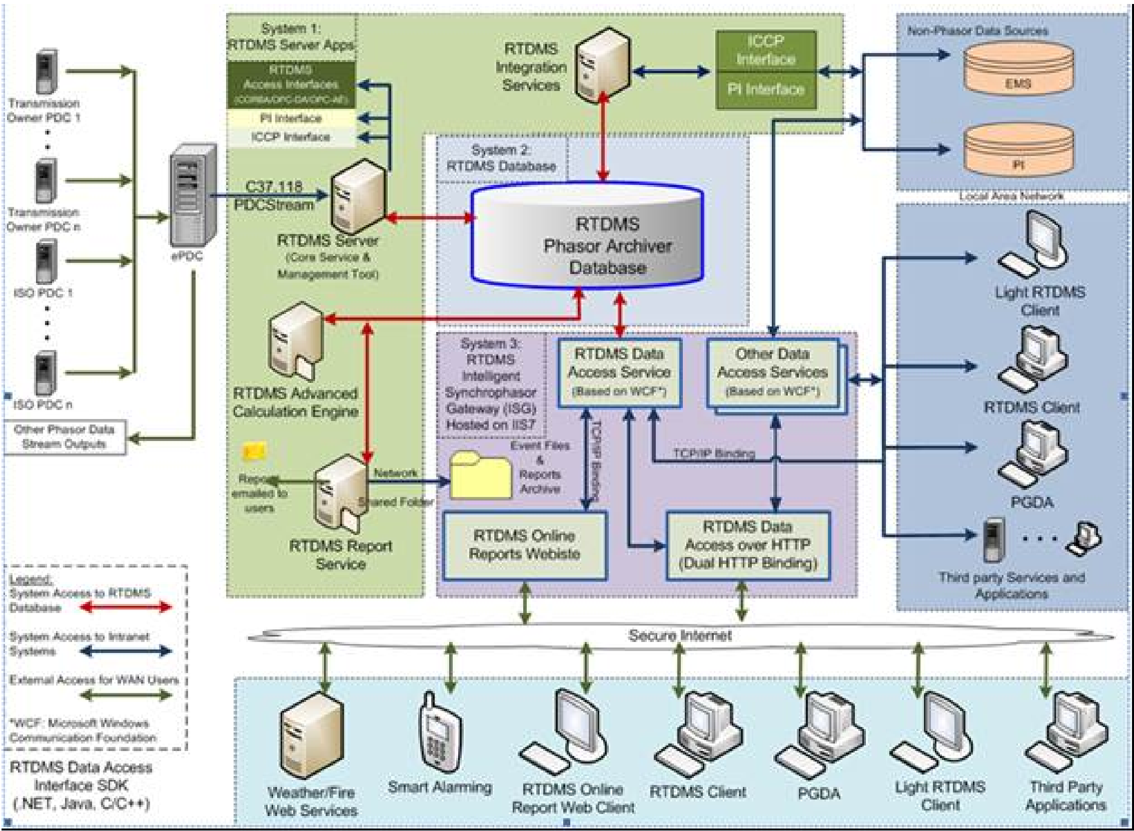
- Provides a global view of key metrics.
- Allows users to define metric alarms and threshold values.
- Alerts users visually via color-coded traffic lights.
- Provides drill-down architecture that enables the users to:
  - Identify which metric is being violated.
  - Identify the location of the problem.
  - Assess the current system vulnerability.
  - Reach conclusions on what actions should be taken.
- Metrics include the traditional as well as advanced metrics, such as:
  - Angle differences;
  - Oscillations;
  - Damping;
  - Sensitivity (MW and angle); and
  - Ability to develop composite alarms.

On September 15, 2011, EPG met with California ISO operating staff to review and get their comments on EPG's proposed production grade displays associated with RTDMS 2012.

4.5 RTDMS 2012 System Architecture

The architecture of RTDMS 2012 is shown in the figure below.

Figure 9: RTDMS 2012 Architecture



4.6 Functional Specifications - Main Items

The functional specifications developed by EPG are extensive and cover a wid- range of areas of interest to the California ISO operators. Below is a list of the items addressed in these specifications.

- Functional Requirements;
- Design Goal and Overall Architecture;
- User Interface Design;
- Geospatial View Design;
- Chart View Design;
- Alarm View Design;
- Location Indicator View Design;
- Annotations;
- Data Service, Logging Service, and other Utility Services;

- Administrator Web App;
- COMTRADE File Replay;
- User-determined refresh rates for map/contour;
- User Preferences;
- Class Diagrams and Package Diagrams; and
- Interaction Diagrams.

Each of these 15 items are extensible explained in the "Real Time Dynamic Monitoring System (RTDMS) 2012 Visualization Wizard Design Specifications (Final)" attached as Appendix D.

4.7 Research Findings

Currently, synchrophasor technology is being deployed throughout North America and more specifically it is being deployed in the west in an on-going effort to improve grid reliability for both California and the entire WECC interconnected grid. Synchrophasor technology is the most significant control center data improvement tool introduced in the last decade. Collecting phasor data and efficiently delivering it to operators in a structured fashion enhances the quality, speed, and effectiveness of operator actions.

Advanced visualization software, such as RTDMS, allows control room operators to see what is happening on the grid within fractions of a second, rather than the industry standard practice of every four seconds. This technology provides operators with precise snapshots of current conditions, provides clear, timely information on unfolding events, and helps operator analyze the situation and take informed mitigation actions to protect and enhance grid reliability.

In July 18, 2012, EPG sent the California ISO a draft version of the functional specifications for their review and comments and on May 15, 2013, a copy of the final functional specifications was sent for their review and comments.

4.8 Conclusions

EPG and the California ISO are very active participants in the NASPI and on February 28, 2012, EPG provided a demonstration of RTDMS 2012 visualization at a NASPI visualization workshop. The goal of the workshop was to look at how the visualization tools display specific grid events and to give control room operators the chance to comment on the clarity, effectiveness, and intuitiveness of differing displays. EPG's visualization demonstration received very high ratings from the review panel.

On June 14, 2012, EPG installed the beta version of RTDMS 2012 on the California ISO's test system and, on June 11, 2013, EPG installed the production grade version of RTDMS 2012 on the California ISO's test system. In September of 2013, the California ISO staff transitioned the application to both the stage and production systems. In December of 2013, EPG coordinated with the California ISO and had the latest version of the RTDMS application installed.

CHAPTER 5: California ISO Phase Angle Baseline Analysis

5.1 Goal

The goal of this task was threefold: (1) to review and compare the phasor data being received at the California ISO with the California ISO's state estimator data; discrepancies discussed with the appropriate Transmission Owner (TO) for their resolution; (2) to perform an initial phase angle baseline analysis for the California ISO's portion of the WECC grid; and, (3) to document the entire analysis process and determine the feasibility of developing an annual automated process. The sections of this report discuss EPG's findings relative to data quality of the phasor data being received from the California ISO. Appendices F, "Data Quality Report Phasor-State Estimation Comparison for July 28, 2012," and G, "Data Quality Report Phasor-State Estimator Comparison for August 9, 2012," of this report show examples of the data quality issues.

5.2 Background

One of the goals of the Energy Commission contract award PIR-10-068 was to review and compare the phasor data being received at the California ISO with the California ISO's state estimator data and discuss discrepancies with the California ISO and the appropriate TO for their resolution. To accomplish this goal, EPG determined one year's worth of phasor data and state estimator data would allow making a comparison that captures the different condition of the cycle. Previously, as part of another Energy Commission project (Contract #500-08-048), EPG received archived synchrophasor data recorded by the California ISO for the period of February 2, 2011 to July 30, 2011. Initial processing of the data showed that the majority of the synchrophasor measurements received were unreadable. EPG spent a significant amount of time identifying data recording errors and developing a software tool to recover the faulty dataset. After recovering the files and while analyzing the phasor data, EPG encountered a number of data quality issues. These data quality issues were documented and presented to California ISO staff in a meeting in Folsom, California on May 10, 2012.

Subsequently, EPG and California ISO agreed to collect a new set of data free of errors. To this effect, California ISO saved phasor data for the May 24, 2012 to December 31, 2012 period using COMTRADE format and provided it to EPG for analysis. The angle difference data was useable for the second goal of this project, which was to perform an initial phase angle baselining analysis for the California ISO's portion of the WECC grid.

5.3 Approach Methodology

5.3.1 Step 1, Comparison of the phasor data being received at the California ISO with the California ISO's state estimator data (data quality analysis)

EPG conducted a data quality analysis by comparing the phasor data based results with the state estimator data-based results. The phasor data received consisted of voltage phase angles for 22 substations. The state estimator cases received from the California ISO were solved and the resulting solved cases used as sources of information to calculate phase angle differences.

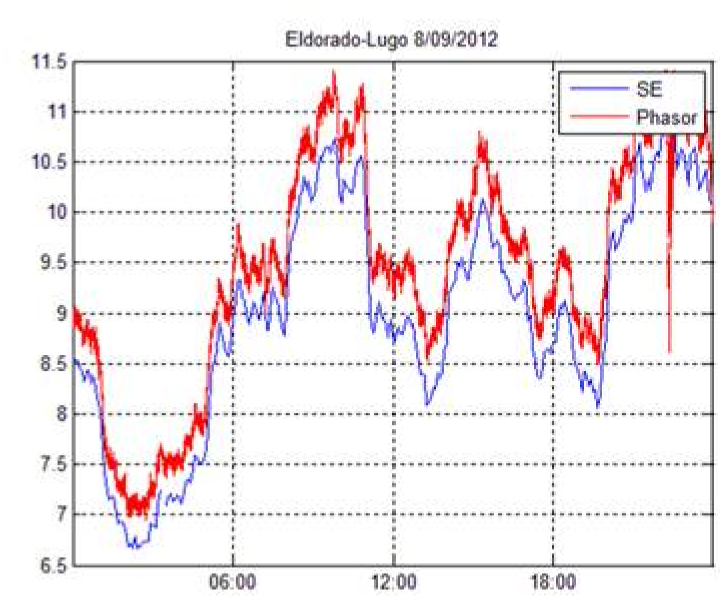
EPG developed computer programs to calculate phase angle differences from the phasor data and from the state estimator solved cases. Angle differences were obtained for 18 pairs of substations equipped with phasor measurement units. The list of 18 pairs developed based on current availability of phasor measurement units is shown below.

Table 1: Angle Pairs for Phasor-based Analysis

1. John Day-Malin
2. Malin-Tesla
3. Tesla-Los Banos
4. Los Banos-Midway
5. Midway-Vincent
6. Vincent-Lugo
7. Eldorado-Lugo
8. Mohave-Lugo
9. Lugo-Mira Loma
10. Lugo-Serrano
11. Devers-Valley
12. Valley-Serrano
13. Vincent-SONGS 230 kV
14. Serrano-SONGS 230 kV
15. Mira Loma-SONGS 230 kV
16. Big Creek-Magunden 230 kV
17. Magunden-Vincent 230 kV
18. Kramer-Lugo 230 kV

For purpose of comparison EPG selected two days: July 28 and August 9, 2012. Phasor data was extracted and processed to develop curves for each of the listed pairs. Similarly, angle differences data was extracted from the state estimator solved cases and data extracted to produce angle difference curves for each of the 18 pairs listed above. The two curves, one from phasor data and the other from state estimator data, were plotted on the same graph for comparison. The attached Appendix F, "Data Quality Report Phasor-State Estimation Comparison" of the California ISO Phase Angle Baseline Analysis report shows phasor vs. state estimator comparison plots for the 18 pairs for July 28, 2012, and the attached Appendix G of the California ISO Phase Angle Baseline Analysis report shows phasor vs. state estimator comparison plots for the 18 pairs for August 9, 2012. Below is a sample of the comparison of SE versus phasor angle difference data.

Figure 10: Sample, Angle Difference Comparison of SE and Phasor Data



5.3.1.1 Research Findings

- Of the 18 angle pairs analyzed, EPG found that phasor data from 19 PMUs appeared to be adequate.
- Phasor data from three PMUs, Tesla, Los Banos and Midway, in the PG&E area were unusable invalidating phasor-based results for four pairs.
- Southern California Edison's Mohave substation no longer had an operable phasor measurement unit, negating results for the Mohave-Lugo pair.
- For the John Day-Malin pair, California ISO phasor data results did not match California ISO SE data results. EPG obtained phasor data for July 28, 2012 and August 9, 2012 from Bonneville Power Administration (BPA). BPA and California ISO phasor data results matched, however BPA and California ISO data results did not match California ISO SE results. See Appendix D of the California ISO Phase Angle Baseline Analysis report. Jim Hiebert for California ISO worked with Nick Leitschuh and Greg Stults from BPA to resolve this issue.
- Phasor data was missing for Big Creek for July 28, 2012 and August 9, 2012 but upon review of all the phasor data received from California ISO, EPG found that overall phasor data for Big Creek was available for 75% of the time. EPG included the Big Creek-Magunden pair for baselining analysis.
- Four pairs in the PG&E area were not included in the baselining analysis due to bad data; the Mohave-Lugo pair were not included in the baselining analysis due to the

PMU at Mohave not being available. EPG did have reasonable data to conduct phasor-based baselining for 13 pairs.

- State estimator based data was adequate to conduct baselining analysis for the 18 pairs.

5.3.1.2 Recommendations

- Obtain usable phasor data from phasor measurement units in the PG&E area; California-Oregon intertie, Path 15 and Midway-Vincent paths are important transmission paths to monitor in this area.
- Develop a computer tool to convert IEC 61850 format PG&E phasor data to IEEE C37-118 format used by everyone else.
- Resolve phasor-SE discrepancies for the John Day-Malin pair; California ISO to work with BPA to resolve discrepancy.
- Continue saving phasor and state estimator data for 2013 to complete one year worth of data.
- Ensure phasor data saved is accurate; periodically compare it with SE data.

5.3.2 Step 2, Phase Angle Baseline Analysis

5.3.2.1 Project Scope

- Developed and utilized software to process California ISO-provided SE data and extracted key metric information (i.e., angles and angle differences).
- Analyzed extracted data and develop baseline understanding of voltage phase angle patterns at key monitoring paths (pairs), and developed patterns and statistics in the form of box-whisker plots and load duration curves. EPG and California ISO agreed to use angle pairs shown in Table 2 below for this project.
- Prepared baselining analysis results as Excel spreadsheet and charts, including:
    - Voltage phase angle difference statistics (mean, maximum and minimum); and
    - Voltage phase angle distribution functions.
- Prepared system performance analysis results as Excel spreadsheets and charts using 2012 phasor and SE data:
    - Summary of Angle – Power sensitivities across major paths.
- Prepared a report of correlation analysis between power and angle differences on major transmission paths.
- Prepared baselining analysis summary for discussion with California ISO.

5.3.2.2 Research Outcomes

- Prepared report and presented findings to California ISO.
- Prepared a functional specification document (draft) when automation of the analysis processes was deemed feasible and data became available.

5.3.2.3 Data Sources

As mentioned earlier, two sources of data were utilized to perform the analysis of angle differences in the California ISO network: phasor data and state estimator cases. Upon performing a data quality analysis as documented in the April 30, 2013 data quality report, EPG concluded that phasor data for the PG&E area was not usable negating four pairs in that area. In addition, in discussions with SCE, EPG learned that the PMU at Mohave was no longer operable, negating the Mohave-Lugo pair. As a result of the data quality analysis, the total number of angle pairs used in the baselining study was 13, as shown in below in Table 2 and in Figure 11, which displays the angle pairs on a map of the California grid.

Table 2: Angle Pairs Used in the Baseline Study

1. John Day-Malin 2. Vincent-Lugo 3. Eldorado-Lugo 4. Lugo-Mira Loma 5. Lugo-Serrano 6. Devers-Valley 7. Valley-Serrano	8. Vincent-SONGS 230 kV 9. Serrano-SONGS 230 kV 10. Mira Loma-SONGS 230kV 11. Big Creek-Magunden 230 kV 12. Magunden-Vincent 230 kV 13. Kramer-Lugo 230 kV

Figure 11: Map of the California Grid

5.3.2.4 Methodology and Study Approach for Phase Angle Baselining Analysis

For the pairs selected for study, the following work was performed:

- Analyzed phasor data and state estimator data and identify maximum, minimum and average values.
- Developed weekly box-whisker graphs and time duration curves for angle differences.
- Where appropriate, developed power flows curves and compared with the corresponding angle differences.
- Identified limits corresponding to normal operation, excluding values corresponding to outliers and to events.
- Analyzed results, identified limits, and reported results for each pair selected.

5.3.2.5 Analysis of Phase Angle Difference Data and Results

The goal for the angle difference analysis was to identify limits experienced during the study period for the list of 13 pairs (Table 2). The detailed baselining report includes two types of results: the first type shows the limits found using all data during the study period including event data, and, the second type in Table 3 shows the limits deemed to have occurred during normal (non-event) conditions. Table 3 shows results side by side from phasor data and from SE data. The results from phasor data are limited to the pairs listed above in Table 2.

Box-whisker and time duration curves were developed for each of the pairs analyzed. Angle differences that may be the result of contingencies were excluded by reviewing points of inflection, that is, points that significantly deviated from the normal operation trend observed in the box-whisker plots. The value of angle difference at the point of inflection was considered to be the maximum angle during normal conditions. If no outlier points were identified, then the angle corresponding to the 0% or 100% time points represent the maximum and minimum angles reached during normal operations in either direction of flow.

5.3.2.6 Proposed Alarm Limits For Angle Differences

Table 3 below shows the values of angle pair differences for the pairs analyzed that EPG proposed for use in monitoring the angle pairs analyzed. This table includes only those pairs associated with PMUs that are installed or will soon be installed. Note that some of the angle differences are all positive, meaning the flow is always in one direction. For these pairs EPG proposed only two alarms, one alert and one alarm. For all others, EPG proposed two pairs of alarms, one for the From-To direction and the other for the To-From direction. Note that the highest angle suggested for alarming is 28.7 degrees for the Palo Verde–Devers 500 kV line, followed by 22.4 degrees for the John Day-Malin 500 kV pair and 21.5 degrees for the Vincent-SONGS pair. In the other direction, the highest recommended value is -18.7 degrees for the Magunden-Vincent pair.

Table 3: Baselining Analysis – Proposed Alarm Limits for Angle Differences for Normal Conditions

			DATA RESULTS											PROPOSED ALARM LIMITS			
			ıasor Data			State								TO - FROM		FROM - TO	
No	Angle Pair FROM - TO	Base kV	Min Angle	Max Angle	Percent Positive	Min Angle at POI or 100%	Percent (POI or 100%)	Min Angle at 99% or POI - 1%	Percent (99% or POI - 1%)	Max Angle at 1% or POI +1%	Percent (1% or POI +1%)	Max Angle at POI or 0%	Percent (POI or 0%)	Alarm	Alert	Alert	Alarm
1	John Day-Malin*	500kV	6.13	22.41	100.00	6.13	99.74	7.31	98.74	21.48	1.09	22.41	0.09	N/A	N/A	21.48	22.41
2	Malin-Round Mt**	500kV	No phasor data		99.94	0.16	99.93	1.71	98.93	8.5	1.0	9.4	0.02	N/A	N/A	8.5	9.4
3	Round Mt-Table Mt**	500kV	No phasor data		65.68	-3.86	99.93	-3.19	98.93	8.0	1.0	8.8	0.01	-3.86	-3.19	8.0	8.8
4	Table Mt-Tesla**	500kV	No phasor data		99.83	0.14	99.82	0.46	98.82	13.5	1.0	16.0	0.00	N/A	N/A	13.5	16.0
5	Tesla-Los Banos**	500kV	No phasor data		42.94	-5.53	99.99	-4.20	98.99	4.1	1.1	5.7	0.05	-5.53	-4.20	4.1	5.7
6	Los Banos-Midway**	500kV	No phasor data		21.4	-11.3	100.00	-9.0	99.0	3.6	1.0	6.2	0.00	-11.3	-9.0	3.6	6.2
7	Midway-Vincent**	500kV	No phasor data		93.7	-2.6	100.00	-0.9	99.0	6.0	1.0	7.1	0.02	-2.6	-0.9	6.0	7.1
8	Tehachapi (WH)-Vincent	500kV	No phasor data		90.6	-2.4	100.00	-0.9	99.0	5.7	1.0	17.9	0.00	-2.4	-0.9	5.7	17.9
9	Vincent-Lugo	500kV	-5.50	4.34	29.6	-6.3	100.00	-4.3	99.0	3.3	1.0	4.9	0.00	-6.3	-4.3	3.3	4.9
10	Eldorado-Lugo	500kV	4.15	17.24	100.0	1.8	100.00	4.9	99.0	16.3	1.0	18.0	0.00	N/A	N/A	16.3	18.0
11	Lugo-Mira Loma	500kV	1.27	6.74	100.0	1.0	100.00	1.7	99.0	6.3	1.0	7.5	0.02	N/A	N/A	6.3	7.5
12	Lugo-Serrano	500kV	2.15	10.00	100.0	1.1	100.00	2.4	99.0	8.9	1.0	10.6	0.00	N/A	N/A	8.9	10.6
13	Palo Verde-Devers	500kV	No phasor data		100.0	8.8	100.00	11.9	99.0	27.8	5.5	28.7	4.50	N/A	N/A	27.8	28.7
14	Devers-Valley	500kV	2.35	6.52	97.1	1.6	100.00	2.7	99.0	6.0	1.0	6.9	0.00	N/A	N/A	6.0	6.9
15	Valley-Serrano	500kV	-0.49	5.76	95.0	-2.3	100.00	-0.2	99.0	5.5	1.0	6.2	0.01	-2.3	-0.2	5.5	6.2
16	Vincent-SONGS	230kV	-2.29	20.00	98.2	-5.6	100.00	-1.7	99.0	17.9	1.0	21.5	0.00	-5.6	-1.7	17.9	21.5
17	Serrano-SONGS	230kV	-2.95	7.00	89.2	-3.8	100.00	-1.9	99.0	5.8	1.0	7.6	0.01	-3.8	-1.9	5.8	7.6
18	Mira Loma-SONGS	230kV	0.17	10.56	99.3	-2.5	100.00	0.2	99.0	9.2	1.0	11.3	0.01	-2.5	0.2	9.2	11.3
19	Big Creek-Magunden	230kV	-10.64	15.85	48.0	-11.1	100.00	-9.8	99.0	14.3	1.0	16.0	0.03	-11.1	-9.8	14.3	16.0
20	Magunden-Vincent	230kV	-9.52	16.76	60.9	-18.7	100.00	-9.6	99.0	10.8	1.0	18.9	0.00	-18.7	-9.6	10.8	18.9
21	Kramer-Lugo	230kV	-0.95	15.65	100.0	0.2	99.91	0.8	98.9	13.6	1.0	14.9	0.01	N/A	N/A	13.6	14.9

NOTE: During the study period of July 1 to December 31, 2012, the two generators at SONGS were not in operation. The angle difference limits, particulalrly in the SCE area, will be different when one or two generating SONGS units are back in normal operation. These results should be updated based on actual data obtained with the SONGS units in operation. These results can also be updated based on power flows cases run to represent many system conditions.

* Phasor data results were used for the John Day to Malin pair; for all others state estimator results were used to propsed alarm limits

** Alarm limits are proposed for pairs in the PG&E area because CAISO expects phasor data from these locations in the future (PMUs are or will installed).

5.3.2.7 Research Findings and Recommendations

Data availability for phasor data was only in the mid-50 to low 70 percent range.

Phasor data from PMUs in the PG&E area were unusable negating data for four pairs. The PMU originally installed at Mohave was removed from service.

Results from all data revealed unusually high angle differences for the Devers-Valley, North Gila-Miguel and Palo Verde-Devers pairs (68.1, 76.6 and 44.4 degrees respectively). State estimator data indicated that the Palo Verde-Devers and Devers-Valley lines were open from 11/2/2012 6:10 a.m. till 11/21/2012 10:05 p.m. The high angles described above occurred in November 2012.

The highest angle differences during normal conditions were: 38.9, 37.6 and 32.2 degrees for Palo Verde-Devers, Magunden-Vincent and Hassayampa-North Gila pairs respectively.

California ISO should obtain phasor data from the new PMUs in the PG&E area. These PMUs produced phasor data in IEC 61850 format, which requires a reader to convert to the IEEE C37-118 format that California ISO and WECC uses.

The proposed alarm limits should be used to monitor angle differences and to validate actual values observed in future operation of the California ISO system.

Angle difference with neighbor systems buses such as Palo Verde and Hassayampa and Springerville, Mead and Four Corners should be developed for use in California ISO operations.

Changes in system configuration such as new generating units change the proposed limits. A study update should be performed based on actual data obtained with those units in service.

Phasor data needs to improve in availability as well as in completeness. Voltage data was missing from the phasor data provided to EPG. Phasor data was also missing for extended periods of time.

5.3.2.8 Conclusions

Missing phasor data for the PG&E area prevented the calculation of angle differences for four important pairs in that area. These angles were of importance for California ISO operators since they corresponded to critical transmission paths.

Phasor data for pairs in the northwest near the California ISO system were not available except for the John Day-Malin.

Phasor data availability was in the order of mid-50 to low 70 percent. State estimator data availability was approximately 92 percent.

Average angle differences obtained with SE data were close to those obtained with phasor data except for the Big Creek-Magunden pairs (2.7 degrees difference).

All data analysis revealed the effect of line outages on the angle differences as demonstrated by the high angle difference on the Palo V erde-Devers pair due to outages of the Palo Verde-Devers line.

The methodology used to determine normal conditions seemed to provide reasonable angle differences results.

It is important to note that the results obtained in this study were based on data obtained with a system that excluded the two San Onofre Nuclear Generator Stations (SONGS) units. Since SCE announced the permanent closure of this nuclear plant, the angle differences obtained in this study, at least in the Southern California area, are applicable until new resources, if any, are developed in Southern California to replace SONGS.[1]

5.3.3 Step 3: Documentation of Phase Angle Baseline Process

5.3.3.1 Baseline Process

The objective of angle difference baselining was to obtain ranges of operation for the angle difference between pairs of substations for a predetermined period of time via the development of load duration curves and box-whisker plots. Such angle differences ranges could be used for comparison with results from another time period and for setting operating limits and alarms. The basic process to automatically obtain load durations curves include the following steps:

- Develop a program to automatically "clean" the phasor data received.
- Take the data received and place it in Excel work sheets.
- Load these Excel work sheets into MATLAB for analysis.
- Identify angle pairs for study and use these variables as tools to extract the data for the desired signals such as voltage angle signals.
- Calculate the phase angle difference for the selected angle pairs for a predetermined period of time (study period).
- For each month during the study period and for each selected angle pair, identify and save the minimum and maximum observed in a table.
- For those limits, note the time stamp of occurrence for future comparison and coincidence analysis.
- Stack the phase angle difference for each angle pair for the entire dataset.
- Use the data set to obtain the desired distribution plots: time duration plots and box-whisker plots.

5.3.3.2 Conclusions – Feasibility to Automate the Process of Obtaining Angle differences

EPG developed an algorithm to design an automated process that would include the steps described above. The functional specifications for the automation of this process and

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1 Research for this contract was done from April 2011 to December 2013; the bulk of this research was therefore not affected by the SONGS closure in June 2013.

development of this tool is included and shown in Appendix H. If the California ISO management elects to automate this process, EPG is available to support that need.

GLOSSARY

Term	Definition
AEA	Automated Event Analyzer
API	Application Programming Interface
ASM	Angular Sensitivity Module
BPA	Bonneville Power Administration
California ISO	California Independent System Operator
DNP	Distributed Network Protocol
*e*PDC	*enhanced* Phasor Data Concentrator
EPG	Electric Power Group, LLC
EMS	Energy Management System
Energy Commision	California Energy Commission
GUI	Graphical User Interface
IDM	Islanding Detection Module
IEC	Is a standard for the design of electrical substation automation. IEC 61850 is a part of the International Electrotechical Commission Technical Committee
IEEE	Institute of Electrical and Electronics Engineers
IP	Internet Protocol
kV	Kilovolt
MATLAB	High-level language and interactive environment for numerical computation, visualization, and programming
MMM	Mode Meter Module
MW	Megawatt
NASPI	North American SynchroPhasor Initiative
PG&E	Pacific Gas & Electric
PGDA	Phasor Grid Dynamics Analyzer
PI	Performance Index

P-V	Power Voltage
P-δ	Power Angle
PMU	Phasor Measurement Unit
RD&D	research, development, and demonstration
RTDMS	Real Time Dynamics Monitoring System
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SDK	Software Development Kit
SONGS	San Onofre Nuclear Generating Station
VSM	Voltage Sensitive Module
WECC	Western Electricity Coordinating Council
WISP	Western Interconnection Synchrophasor Program

REFERENCES

California Independent System Operator. Five Year Synchrophasor Plan. 2011.

APPENDIX A:
Integrate Phasor Data into PHI Historian through RTDMS, Functional and Design Specification for RTDMS Output Adaptor for California ISO PI Historian

Integrate Phasor Data into PI Historian through RTDMS

Final Functional & Design Specification for RTDMS Output Adaptor for CAISO PI Historian

Prepared for CAISO

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2/15/2013

Document Change History

Version No.	Document ID	Author(s)	Date	Reviewed / Edited / Approved by	Date of Internal Review	Description of Change
1.0	RTDMS to PI Functional & Design Spec.	Simon Mo	06/28/11			First version of the document
				Jim Dyer	6/30/11	
2.0		Simon Mo	11/12/12			Added RTDMS Calcuated values
3.0		Simon Mo	01/28/13			Updated section 2 and 3 to reuse DE's PI points and PI points attributes provided.
4.0		Simon Mo	02/15/13			Signal type naming convention updated.

Preface

The California Independent System Operator (CAISO) has been using the Real-time Dynamics Monitoring System (RTDMS[1]) from Electric Power Group, LLC (EPG) to provide the wide area monitoring through phasor functions under the project, 'Phasor Development, Analysis, and Research for Implementing Various Aspects of Phasor Technology at the CAISO Network, Grant Award Number PIR-10-068.' To meet the requirements of TASK 3, "INTEGRATE PHASOR DATA WITH CAISO PI HISTORIAN" of the contract, for performance management and PI buffering service requires (i) development of the PI interface that allows for tag management and data archiving into PI and (ii) the use of CAISO's PI API license for implementation on the CAISO PI system. EPG has licensed the PI SDK and completed the development of the PI interface that allows for tag management and data archiving into PI. This document specifies the functional requirements of RTDMS to PI interface.

[1] ®Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060259, and US Patent 8,401,710. All rights reserved.

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1. RTDMS to PI Historian Add-on Functionalities

RTDMS to PI Historian Add-on (RTDMS to PI interface) is an optional RTDMS output adaptor. The output adaptor is designed to enable easy storage of phasor data into PI Historian. Like other RTDMS output adaptors, the RTDMS to PI Add-on allows users to select PMUs/channels, sample rate, and maximum cut-off latency options. The Add-on performs the following functionalities:

- Configurable to enable/disable automatically create PI tags with configurable default tag attributes.
- Automatically detect input PMU/PDC configuration change and automatically resynchronize tags with PI server when automatically creating PI tags is enabled.
- Automatically generate I/O rate tag and periodically populate I/O data rate value.
- Map data quality flags to RTDMS status *digital set*.
- Archive all raw measurements including status, analog, digital, voltage phasor, current phasor, frequency, and df/dt, and calculated values including power, angle difference, power flow gate, mode, sensitivity, and oscillation along with PMU's date/time.
- Allow selection of PMUs/signals for archiving.
- Configurable archiving sample rate.
- High performance, no compression, and support PI API Buffering.
- PI Collective aware.
- Fully integrated with RTDMS so that there is no additional service to manage and failover.
- In auto PI point generation mode, point mapping through extended description and point source instead of tag name so that tag names are allowed to be changed.
- In manual PI point mapping mode, RTDMS supports reusing existing points in PI historian.
- Support PI SDK v1.4.x.

2 RTDMS to PI Tag Matching & Generation

RTDMS Server will provide two options to manage RTDMS signals and PI points association:

- **Automatic PI Point Generation**: RTDMS automatically create and manage PI points. This option is useful when no PI points have been created in PI historian.
- **Manual PI Point Matching**: RTDMS server will provide GUI to allow user manually associate a signal to PI points. RTDMS server will also provide import/export feature to batch the PI point's association process. It is useful when PI points are managed by PI or there are existing PI points which RTDMS Server will archive data to.

2.1 RTDMS to PI tag naming convention

2.1.1 Raw phasor measurement PI tag naming convention

Tag naming convention is useful for manual PI point matching and for data visualization. In general, a PI tag will include station name, channel name, and channel type separated with dot (.).

1. Naming convention for phasor and frequency measurement tags:

`station_name.measurement.type`

Here `station_name` is the PMU station name (mapped to C37.118 Config Frame's `STN`).

`measurement_name` is the PMU channel name (mapped to C37.118 Config Frame's `CHNAM`).

And `type` can be one of the following:

- `VMAG`: voltage magnitude
- `VANG`: voltage angle
- `IMAG`: current magnitude
- `IANG`: current angle
- `FREQ`: frequency
- `DFDT`: df/dt

2. Naming convention for digital and analog measurements:

`station_name.Digital[*].bit_channel_name`

`station_name.Analog[*]`

If there are more than one digitals or analogs, numbers are added to differentiate them.

3. Naming convention for status word & IORate

`station_name.Status`

The I/O performance tag name is `RTDMS.IORate`.

2.1.2 Derived values PI tag naming convention

Derived values include power, gateway power flow, angle difference, and system frequency.

1. Naming convention for calculated power values

`station_name.measurement.type`

Here `station_name` is the PMU station name (mapped to C37.118 Config Frame's `STN`).

`measurement_name` is the PMU current phasor channel name (mapped to C37.118 Config Frame's `CHNAM`).

And `type` can be one of the following:

- `MW`: real power
- `MVAR`: reactive power
- `MVA`: apparent power

2. Naming convention for derived values

Angle difference, system frequency, and gateway power flow are derived from raw measurements through simple linear processing.

`VIRTUALPMU.[derived_channel_name].type`

Here `VIRTUALPMU` is a virtual PMU name. All derived values are associated with this virtual PMU.

`derived_channel_name` is the derived value's channel name which are configured by user through RTDMS Management Tool application.

And `type` can be one of the following:

- `MW`: real power for gateway power flow
- `MVAR`: reactive power for gateway power flow
- `FREQ`: system frequency
- `DFDT`: system frequency df/dt
- `ANGD`: angle difference

3. Naming convention mode values

Mode values are calculated through RTDMS Advanced Data Processing module – mode calculation.

`Mode.[derived_channel_name].type`

`derived_channel_name` is the mode name which are configured by user through RTDMS Management Tool application.

And `type` can be one of the following:

- `Frequency`: mode frequency
- `Damping`: mode damping percentage
- `Energy`: mode damping energy

4. Naming convention oscillation values

Oscillation values are calculated through RTDMS Advanced Data Processing module – oscillation detection.

`Oscillation.[derived_channel_name].type`

`derived_channel_name` is the oscillation name which are configured by user through RTDMS Management Tool application.

And `type` can be one of the following:

- `Frequency`: oscillation frequency
- `Damping`: oscillation damping percentage

5. Naming convention sensitivity values

Oscillation values are calculated through RTDMS Advanced Data Processing module – oscillation detection.

`Sensitivity.[derived_channel_name].type`

`derived_channel_name` is the sensitivity name which are configured by user through RTDMS Management Tool application.

And `type` can be one of the following:

- `Slop`: sensitivity slop
- `YValue`: sensitivity value for y axis

2.2 Point Types

Point type for C37.118 phasor, frequency, analog tags, power, angle difference, mode, sensitivity, oscillation, and I/O performance tags is *float32.*

Point type for C37.118 digital is *int32*.

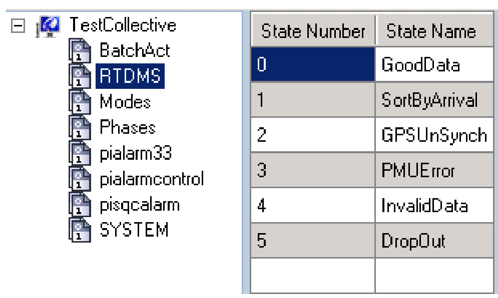
Point type for C37.118 parsed status is *digital*. The possible value of parsed status is described in section 2.3.

Automatically generated tag's point type attribute should **NOT** be modified at any time.

2.3 C37.118 to PI digital status mapping

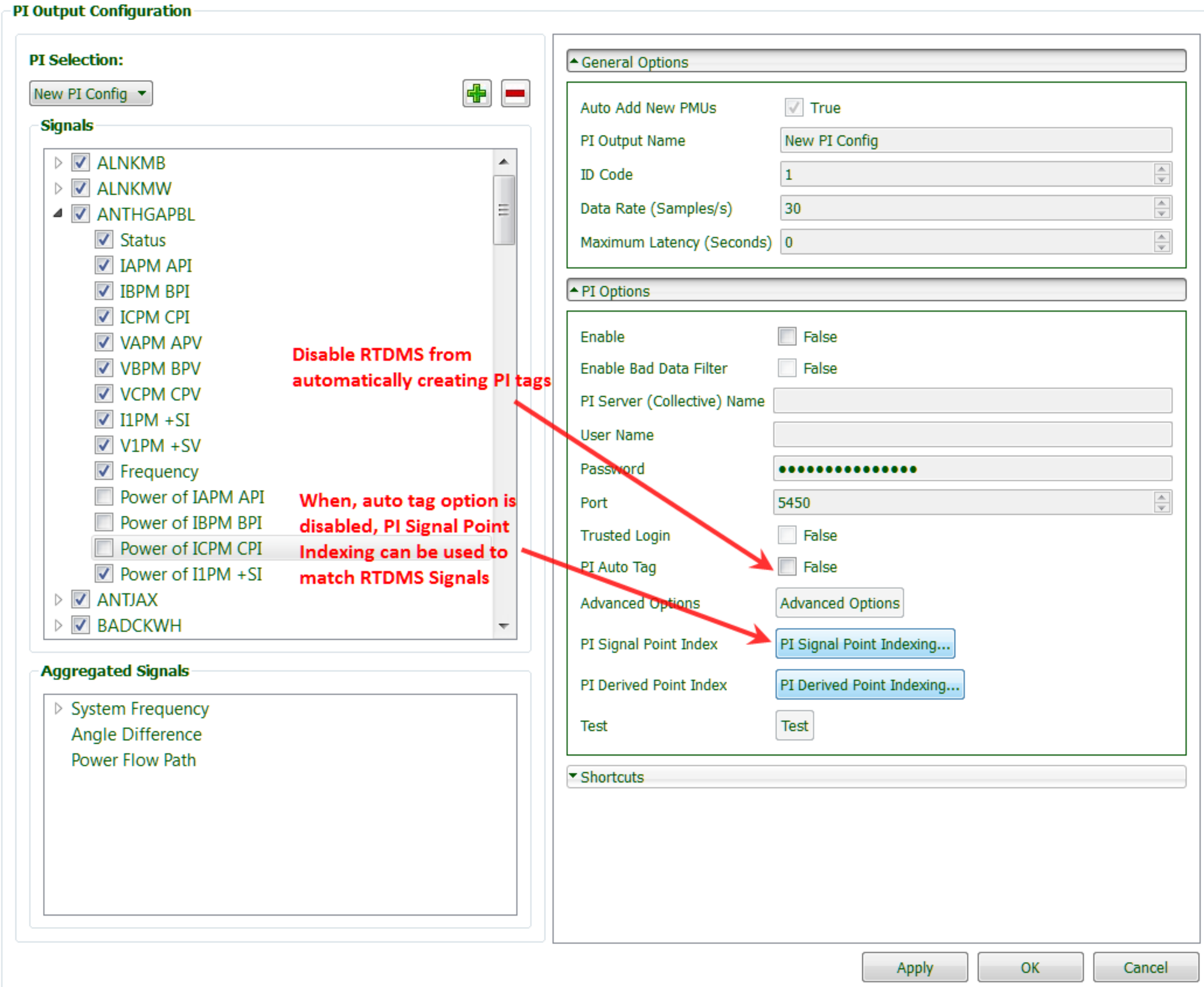
PMU Status word is saved as an integer. The status word is also parsed and mapped into a digital stat of `RTDMS` *digital set*. RTDMS to PI Add-on creates the digital set if it doesn't exist. The RTDMS digital set includes the following 6 digital stats:

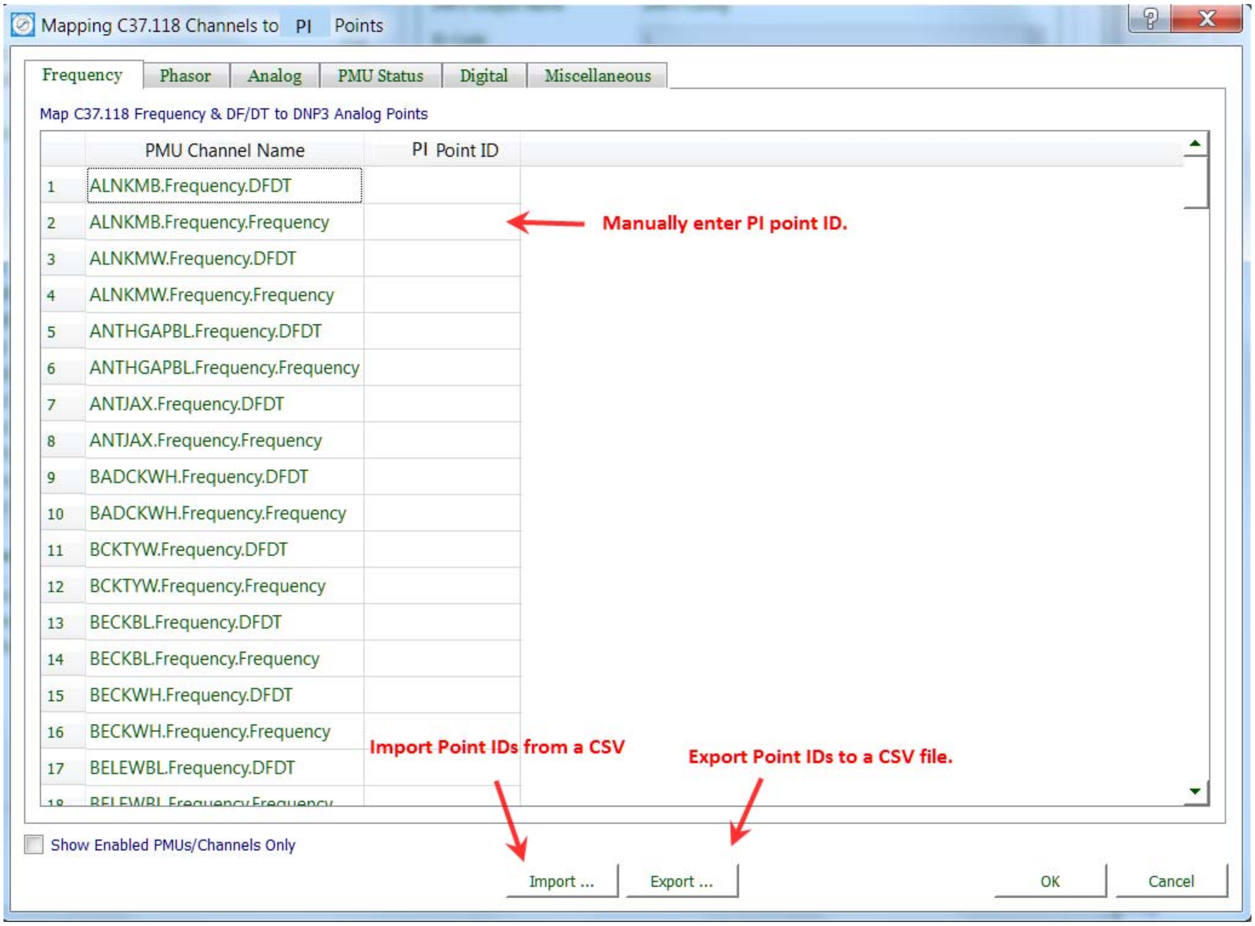
- `GoodData`: data is good and highest four bits of status word are cleared.
- `InvalidData`: data is in valid and status word Bit 15 is set.
- `PMUError`: pmu error including configuration error and status word Bit 14 is set.
- `GPSUnSynch`: pmu is out of synch, timestamp not trustworthy and status word Bit 13 is set.
- `SortByArrival`: data is sort by arrival, timestamp not trustworthy and status word Bit 12 is set.
- `DropOut`: all highest four C37.118 status bit are all set.



2.4 RTDMS to PI Points Matching

When "PI Auto Tag" is disabled, RTDMS Management Tool will allow user to configure PI point number to RTDMS signals or export/import PI point configuration through CSV file in batch process.


PI Output Configuration
PI Selection:
New PI Config
Signals
ALNKMB
ALNKMW
ANTHGAPBL
Status
IAPM API
IBPM BPI
ICPM CPI
VAPM APV
VBPM BPV
VCPM CPV
I1PM +SI
V1PM +SV
Frequency
Power of IAPM API
Power of IBPM BPI
Power of ICPM CPI
Power of I1PM +SI
ANTJAX
BADCKWH
Disable RTDMS from automatically creating PI tags
When, auto tag option is disabled, PI Signal Point Indexing can be used to match RTDMS Signals
Aggregated Signals
System Frequency
Angle Difference
Power Flow Path
General Options
Auto Add New PMUs
True
PI Output Name
New PI Config
ID Code
1
Data Rate (Samples/s)
30
Maximum Latency (Seconds)
0
PI Options
Enable
False
Enable Bad Data Filter
False
PI Server (Collective) Name
User Name
Password
Port
5450
Trusted Login
False
PI Auto Tag
False
Advanced Options
Advanced Options
PI Signal Point Index
PI Signal Point Indexing...
PI Derived Point Index
PI Derived Point Indexing...
Test
Test
Shortcuts
Apply
OK
Cancel



2.5 RTDMS PI Points Generation Automatically

When configured, RTDMS to PI interface will automatically create PI tags according to IEEE 37.118 config frame standard. In IEEE 37.118 standard, config frame specifies the device name (station name), measurement name, measurement type, and status. Measurement type includes frequency, df/dt, voltage magnitude, voltage angle, current magnitude, current angle, digital, and analog. Note that the digital type specified in IEEE 37.118 is **NOT** the same as *digital* point type in PI. A digital is a 16-bit unsigned integer in IEEE 37.118.

PI uses tags for archiving data. If a tag already exists in PI, RTDMS will not create another PI tag or update the tag. RTDMS will create PI tags only if the tags are not found in the PI Server. If RTDMS finds a matching point, the point number will be retrieved and used for data archiving later. The matching criterion is *exdesc* point attribute. RTDMS will fetch all points with specified *pointsource* or *pointsource*s and compare *exdesc* attribute. RTDMS Management Tool will provide user interface to configure *pointsource* or *pointsource*s. The default point source will be c37118.

RTDMS will create PI tag with default names as specified in section 2.1. The tag names are allowed to be changed later. The point's *exdesc* attribute is set as the same as default tag name. The *exdesc* attribute should **NOT** be modified at any time.

PI-SDK is used to create and match PI points.

RTDMS to PI interface will create PI points with default point attributes which are configurable. *RTDMS* Management Tool provides user interface to configure default point attributes for all IEEE 37.118 measurement types. The listed attributes' values can be changed any time later, except *engunits*. The attribute *engunits* should **NOT** be modified.

PI point attributes can be modified any time through OSISoft PI System Management Tools.

Signal Type	Tag Naming Convention	Engineering Unit	pointtype	Comments
PMU Status	[station name].Status		digital	Parsed from PMU STAT word. Refer to section 2.3
Frequency	[station name].Frequency.FREQ	Hz	Float32	
DF/DT	[station name].Frequency.DFDT	Hz/s	Float32	Frequency change over time
Voltage Magnitude	[station name].[channel name].VMAG	Volt	Float32	Line – line voltage. RTDMS Client displays voltage in line-line kV, conversion is needed at RTDMS Client side.
Voltage Angle	[station name].[channel name].VANG	Deg	Float32	
Current Magnitude	[station name].[channel name].IMAG	Amp	Float32	
Current Angle	[station name].[channel name].IANG	Deg	Float32	
Real Power	[station name].[channel name].MW	MW	Float32	RTDMS Calculated value: every current and voltage pair. For phase current, the calculated power should not be archived into PI.
Reactive Power	[station name].[channel name].MVAR	MVAR	Float32	RTDMS Calculated value: every current and voltage pair. For phase current, the calculated power should not be archived into PI.
Digital	[station name].Digital[*].bit_channel_name	Digital	Int32	
Analog	[station name].Analog*	Analog	Float32	
System Frequency	VIRTUALPMU.[sys freq name].FREQ	Hz	Float32	RTDMS Calculated value: average of selected PMU Frequencies
System	VIRTUALPMU.[sys freq name].DFDT	Hz/s	Float32	

DF/DT				
Angle Difference	VIRTUALPMU.[ang diff name].ANGD	Deg	Float32	RTDMS Calculated value: difference of two voltage angles
Path Real Power Flow	VIRTUALPMU.[corridor name].MW	MW	Float32	RTDMS Calculated value: sum of selected real power flow
Path Reactive Power Flow	VIRTUALPMU.[corridor name].MVAR	MVAR	Float32	RTDMS Calculated value: sum of selected reactive power flow
Mode Damping	Mode.[mode name].Damping	%	Float32	RTDMS Calculated value
Mode Frequency	Mode.[mode name].Frequency	Hz	Float32	RTDMS Calculated value
Mode Energy	Mode.[mode name].Energy		Float32	RTDMS Calculated value
P-V Sensitivity Slop	Sensitivity.[sens name].Slop	kV/100MW	Float32	RTDMS Calculated value
Q-V Sensitivity Slop	Sensitivity.[sens name].Slop	kV/100MVAR	Float32	RTDMS Calculated value
Angle Sensitivity Slop	Sensitivity.[sens name].Slop	Deg/100MW	Float32	RTDMS Calculated value
Sensitivity YValue	Sensitivity.[sens name].YValue		Float32	RTDMS Calculated value
Oscillation Damping	Oscillation.[osci name].Damping	%	Float32	RTDMS Calculated value
Oscillation Frequency	Oscillation.[osci name].Frequency	Hz	Float32	RTDMS Calculated value

Signal Type	**zero**	**span**	**Typical value**	**compressing**	**compdev**	**compdev percent**	**excdev**	**excdevpercent**	**displaydigits**
PMU Status	0	65535	GoodData	0					
Frequency	55	10	60	0	0.0002	0.0002	0.0001	0.0001	-4
DF/DT	-10000	20000	0	1	0.0002	0.0002	0.0001	0.0001	-4
Voltage Magnitude	0	1000000	500000	0	28	0.2	14	0.1	-2
Voltage Angle	-180	360	0	0	0.072	0.02	0.036	0.01	-4
Current Magnitude	0	10000	0	1	0.16	0.02	0.08	0.01	-2
Current Angle	-180	360	0	0	0.072	0.02	0.036	0.01	-4
Real Power	-10000	20000	0	1	1	0.02	0.5	0.01	-2
Reactive	-10000	20000	0	1	1	0.02	0.5	0.01	-2

Power									
Digital	0	65535							
Analog	-10000	20000	0	1	1	0.02	0.5	0.01	-2
System Frequency	55	10	60	0	0.0002	0.0002	0.0001	0.0001	-4
System DF/DT	-10000	20000	0	1	0.0002	0.0002	0.0001	0.0001	-4
Angle Difference	-180	360	0	0	0.072	0.02	0.036	0.01	-4
Path Real Power Flow	-10000	20000	0	1	1	0.02	0.5	0.01	-2
Path Reactive Power Flow	-10000	20000	0	1	1	0.02	0.5	0.01	-2
Mode Damping	-100	200	0	0	0.02	0.02	0.01	0.01	-2
Mode Frequency	0	100	0	0	0.02	0.02	0.01	0.01	-2
Mode Energy	0	1000000	0	1	1	0.02	0.5	0.01	-2
P-V Sensitivity Slop	-1000	2000	0	0	0.02	0.02	0.01	0.01	-2
Q-V Sensitivity Slop	-1000	2000	0	0	0.02	0.02	0.01	0.01	-2
Angle Sensitivity Slop	-1000	2000	0	0	0.02	0.02	0.01	0.01	-2
Sensitivity YValue	-1000	2000	0	0	0.02	0.02	0.01	0.01	-2
Oscillation Damping	-100	200	0	0	0.02	0.02	0.01	0.01	-2
Oscillation Frequency	0	100	0	0	0.02	0.02	0.01	0.01	-2

2.6 RTDMS PI Value's Data Quality

This quality flag for all phasor (magnitude and angle), frequency, df/dt, and power, analog, digital and derived values will be set based on the bad data detection methods specified in the design document of (RTDMS_DataQuality_Design_Spec_11092012 .doc). The measurements will be flagged as Bad, Uncertain, and Good quality by RTDMS. PI point's value will be set to questionable if the corresponding measurement's is not flagged as Good.

3. RTDMS to PI Historian Output Configuration

3.1 PI Historian Output Creation

To create a new output for PI Historian, switch to Output System Configuration. Select “PI Historian” as output data format and configure PI Historian Options:

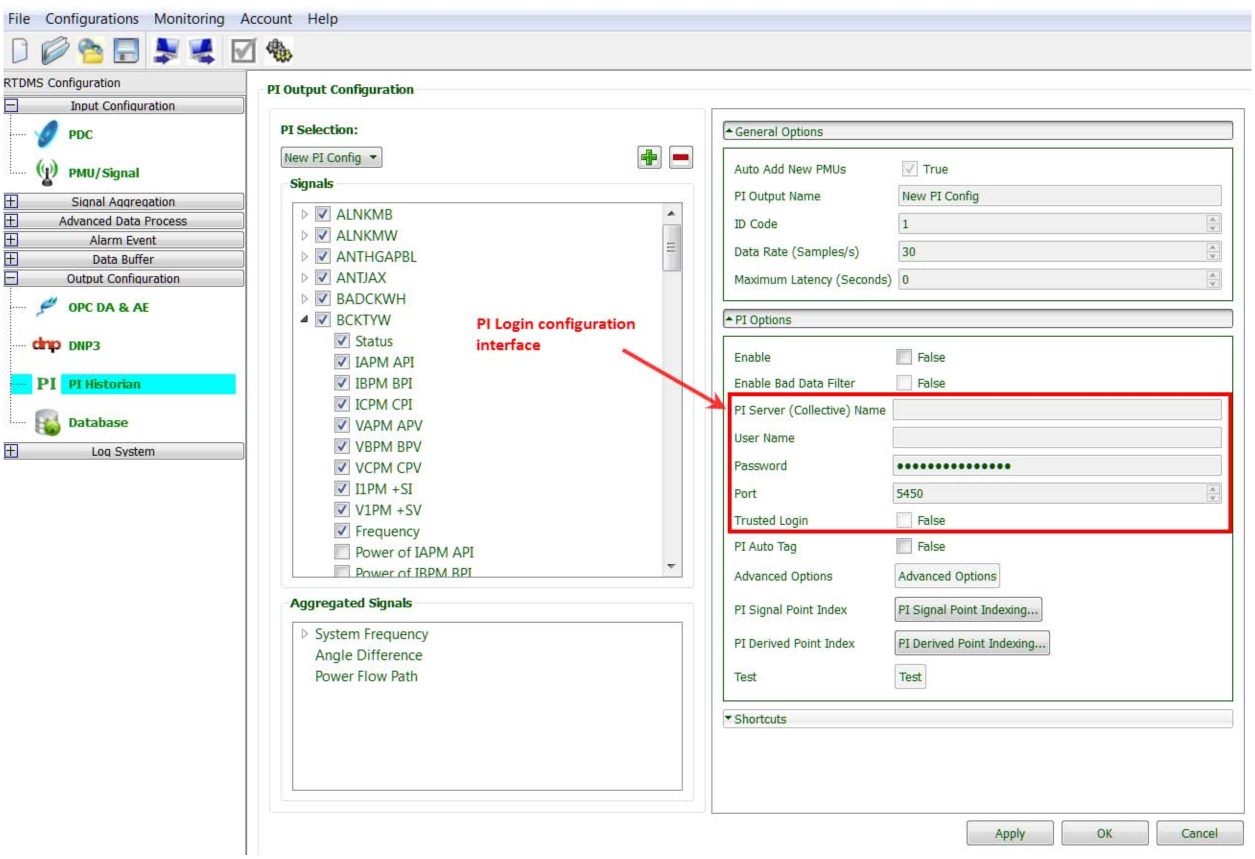
PI Server (Collective) Name: to enter the PI Server node name for a single PI Historian data archiving or the PI Collective name. For PI Server node name, it is recommended to use fully qualified domain name.

User Name: PI user name to log on. The user should have write permission.

Password: password for the user. Password is ignored if trusted login is checked.

Port: the port PI Server is listening on.

Trusted Login: use PI trust to authenticate the interface.



3.2 PI Historian Output Advanced Configurations

Click the "Advanced Options …" button will display the dialog box for user to configure advanced options as shown below.

There are three groups of settings: Point Matching PointSource Conditions, PI Tag Default Properties, and Performance & Runtime Options.

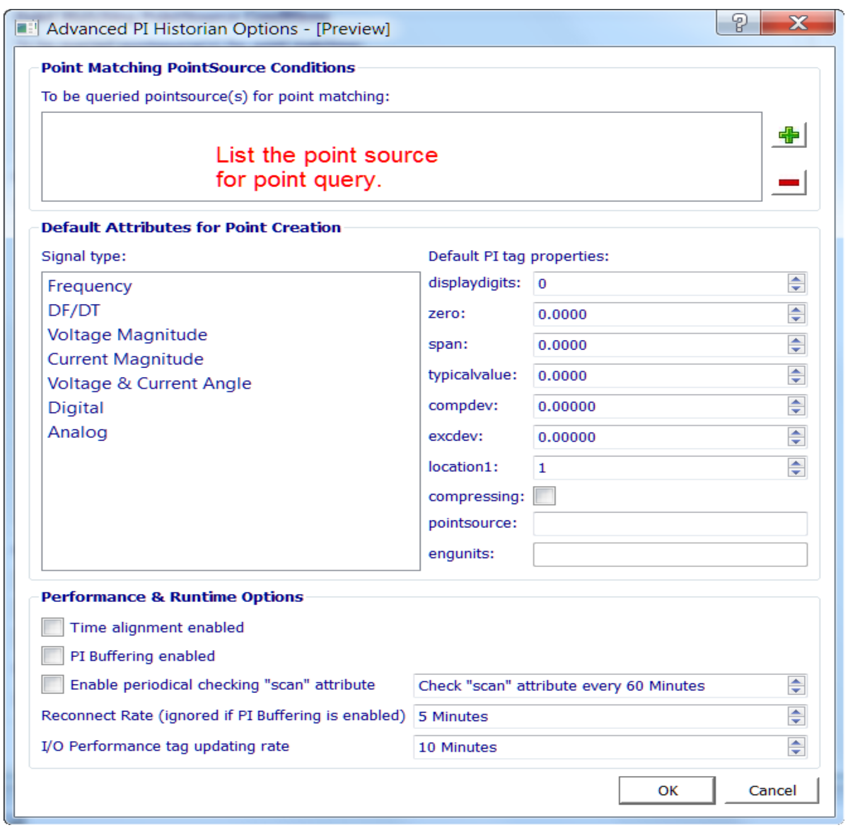
Point Matching PointSource Conditions list all *pointsources RTDMS* will use to match PI points when Auto Generate PI Tag is enabled.

PI Tag Default Properties configuration allows user to configure default PI tag attributes. The attribute names follow PI tag convention.

RTDMS will use these attributes to create PI tags for PI Server if the tag is not found in the PI Server. If the tag already exists, RTDMS will not create another PI tag or update the tag with these attributes. User should use PI System Management Tool to change attributes. That is, these attributes are used only once when tags are created.

Performance & Runtime Options allows user to control RTDMS' runtime behavior. When Time alignment enabled checkbox is checked, data will be time-aligned first before archiving into PI historian.

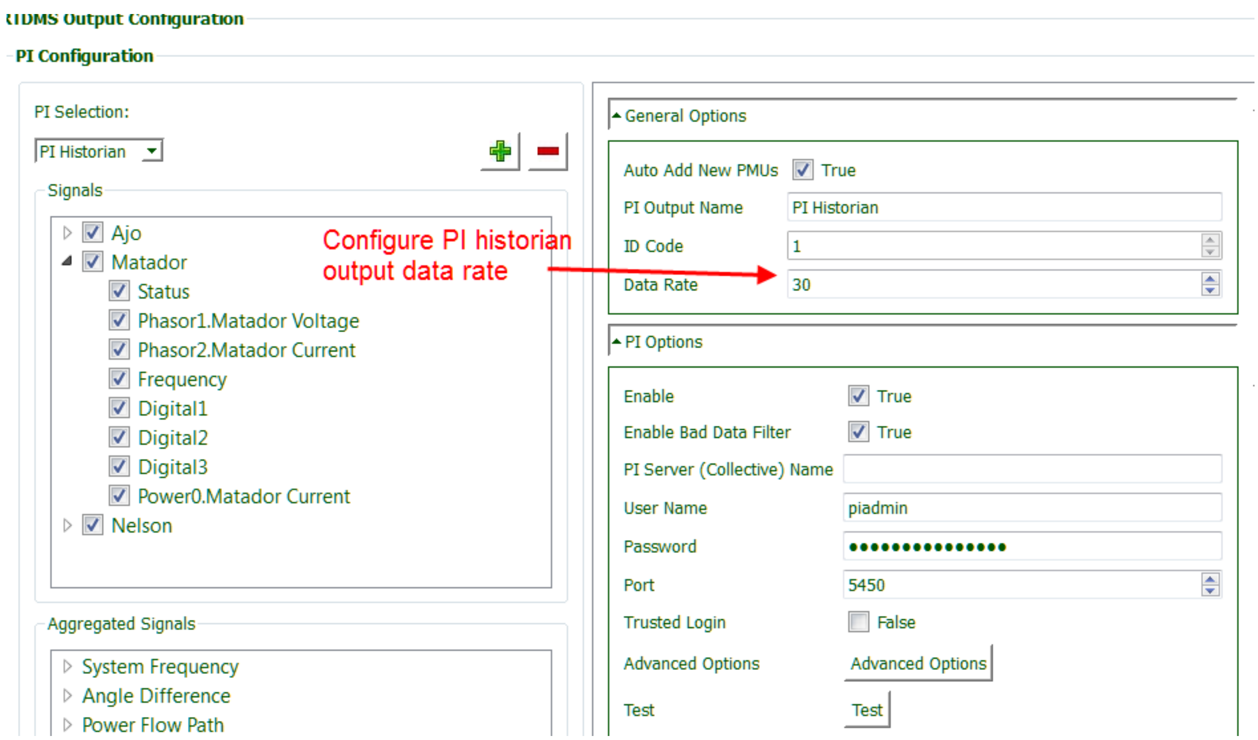
If PI Buffering enabled is checked, RTDMS will set the newly created PI tag's *shutdown* attribute's value to 0 (disabled).



3.3 Output Sample Rate and Maximum Cut-Off Latency

Output sample rate can be configured, 30 samples a second is the default value.

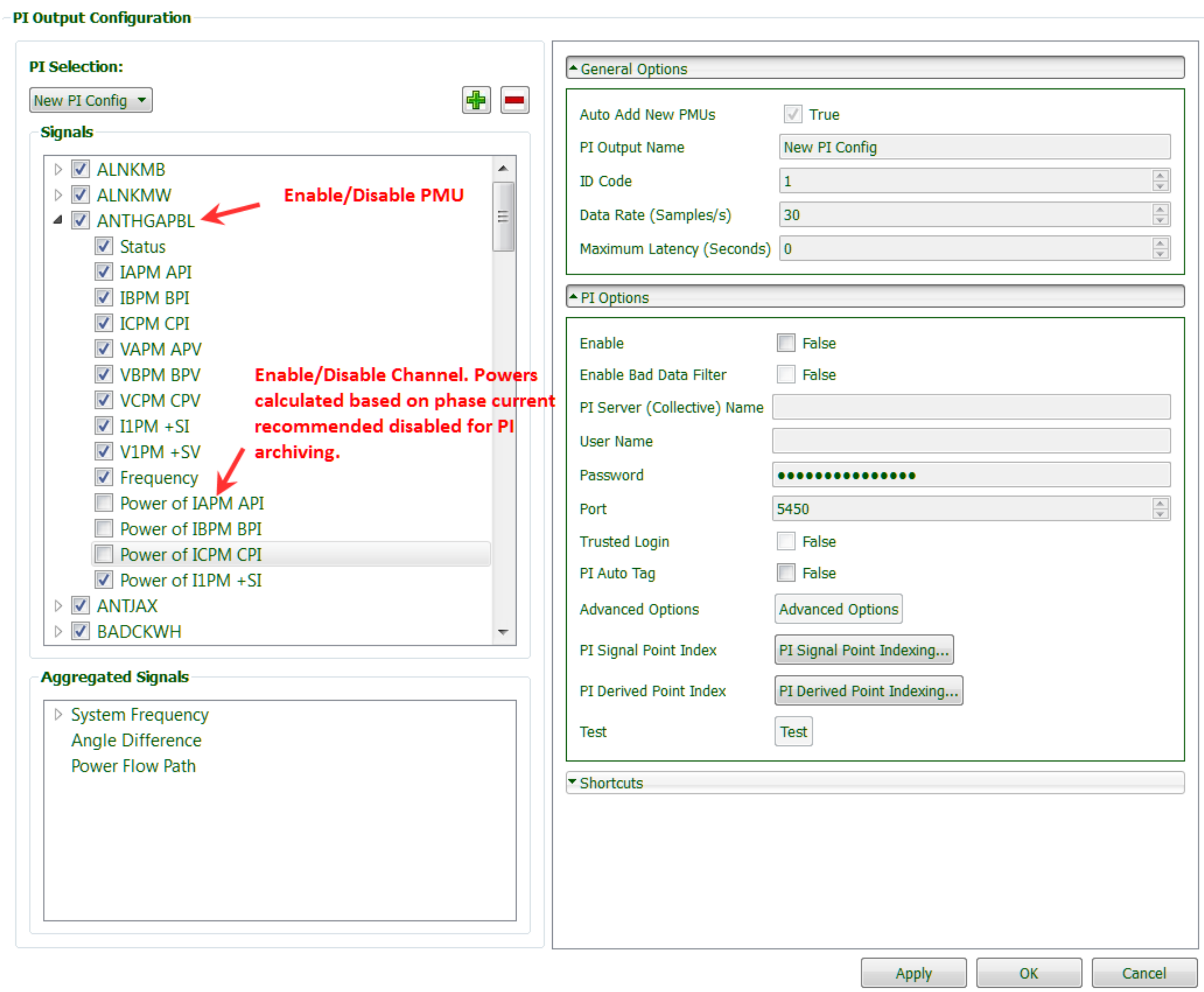
Maximum cut-off latency option is the longest waiting time allowed for any PMU data. It is only valid when data is time-aligned before archiving into database.



3.4 Enable/Disable PMU(s)/Channel(s) PI Archiving

Like other RTDMS output adaptors, the RTDMS to PI Add-on allows users to select PMU/channels. If a PMU is disabled, all channels associated with the PMU will be disabled for PI archiving.

Note, RTDMS automatically calculates power based for every current channel. However, the calculated power for phase current isn't always needed. In this case, it is recommended disabling those calculated powers from PI archiving to save disk space and improve archiving performance.



4. PI Collective

RTDMS to PI Historian Add-on is PI Collective aware. If the configured PI Node is a PI Collective or a PI Server belonging to a PI Collective, the RTDMS to PI Historian Add-on will replicate data to all PI Servers within the PI Collective.

RTDMS to PI Historian Add-on currently supports archiving to PI Collectives with up to four nodes.

5. RTDMS to PI Historian High Availability through PI API Node Buffering

5.1 PI API Node Buffering

From *PI-API Programmers' Help* document, as of version 1.6.0.0 of the PI API and buffer server, support for event distribution to a single PI server or multiple PI servers regardless of PI server status. To support multiple PI servers buffering, the PI servers must all have synchronized point databases (all target tags on all PI servers for the distributed events must be the same) and times; otherwise the distributed event may fail to be accepted by non-synchronized servers.

Buffering is enabled through the use of a configuration file, `piclient.ini`. Unless this file is modified to enable buffering, the PI-API will continue to send data directly to the home node. When enabled, the following calls will buffer all data sent to the designated PI server nodes.

It is recommended that buffering be disabled when installing, upgrading, and configuring *RTDMS* PI Historian Add-on on an API node. When *RTDMS* PI Historian Add-on is working satisfactorily, re-enable buffering.

5.2 PI API Node Buffering Configuration

From *PI-API Programmers' Help* document, configuration of buffering is achieved through entries in the `piclient.ini` file. The file is found in the dat subdirectory of the PIHOME directory (typically `c:\pipc\dat`) under Windows NT. On UNIX systems, the file is found in the dat subdirectory of the PIHOME directory (e.g. `/opt/piapi/dat`) . This file follows the conventions of Microsoft Windows initialization files with sections, items within sections, and values for items. If buffering parameters are changed, the buffering processes must be restarted for those changes to take effect.

5.2.1 General configuration

The maximum size of the buffer file may be adjusted by the *MAXFILESIZE* parameter. *RTDMS* PI Historian Add-on saves phasor/frequency/analog data in float32, status and digitals are saved as int32, and parsed status is saved as digital.

Increase *MAXTRANSFEROBJS* or decrease *SENDRATE* setting can increase the through put. Sample settings as following:

```
MAXFILESIZE=2000000

MAXTRANSFEROBJS=2000000

BUF1SIZE=2000000
```

```
BUF2SIZE=2000000

SENDRATE=2000
```

5.2.2 PI API node buffering configuration for a single PI server

Note the `MyPIServer` is the PI Server name where *RTDMS* PI Historian Add-on will send data to.

```
[APIBUFFER]

BUFFERING=1

MAXFILESIZE=2000000

MAXTRANSFEROBJS=2000000

BUF1SIZE=2000000

BUF2SIZE=2000000

SENDRATE=2000

[BUFFEREDSERVERLIST]

BUFSERV1=MyPIServer
```

5.2.3 PI API node buffering configuration for PI Collective

When *RTDMS* is required to send data to a PI Collective, it is recommended setting up and configuring *`Bufserv`* for n-way buffering so that *RTDMS* to PI Historian Add-on sends the data to all of the servers in the collective.

Note the `MyPIServer1` and `MyPIServer2` are the two collective member names in a PI collective where *RTDMS* PI Historian Add-on will send data to. If there are more collective members, add more items following the item in both section `BUFFEREDSERVERLIST]`and`[REPLICATEDSERVERLIST]`. The order of PI Server names in these two sections doesn't matter. This means that any interface running on the PIAPI node that specifies a connection to either collective member will have their events distributed to the buffers of both servers with a single data call.

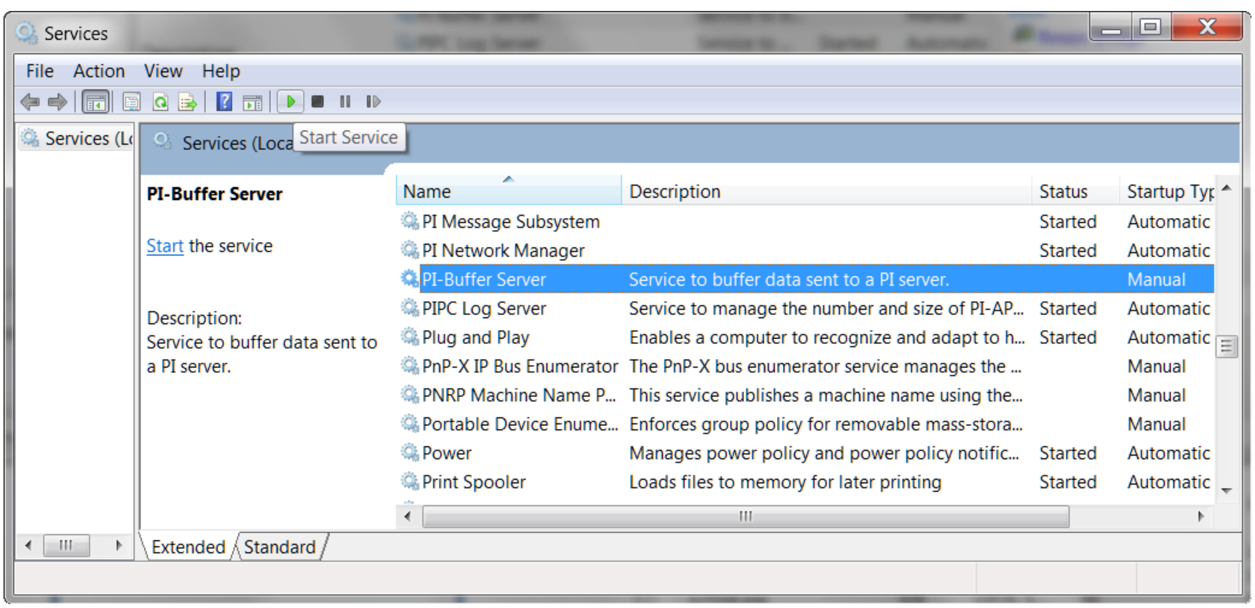
```
[APIBUFFER]

BUFFERING=1
```

```
MAXFILESIZE=2000000

MAXTRANSFEROBJS=2000000

BUF1SIZE=2000000

BUF2SIZE=2000000

SENDRATE=2000

[BUFFEREDSERVERLIST]

BUFSERV1=MyPIServer1

BUFSERV2=MyPIServer2

[REPLICATEDSERVERLIST]

REPSERV1=MyPIServer1

REPSERV2=MyPIServer2
```

5.2.4 Start/Stop PI API node buffering service

PI API Node Buffering Service can be started and stopped through *services.msc*. From the services console, find *PI-Buffer Server*, and start/stop it. `bufserv` is the process.

When the `bufserv` process is installed, the service must be given a username and password that has permissions to create and delete shared memory (for example, users who are part of the Administrator group).



APPENDIX B:
RTDMS Functional & Design Specification of RTDMS & EMS Integration through Distributed Network Protocol version 3.0 (DP3)

Real Time Dynamic Monitoring System (RTDMS)

Final Functional & Design Specification of RTDMS & EMS Integration through Distributed Network Protocol version 3.0 (DNP3)

Submitted to:
CAISO

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12/21/2012

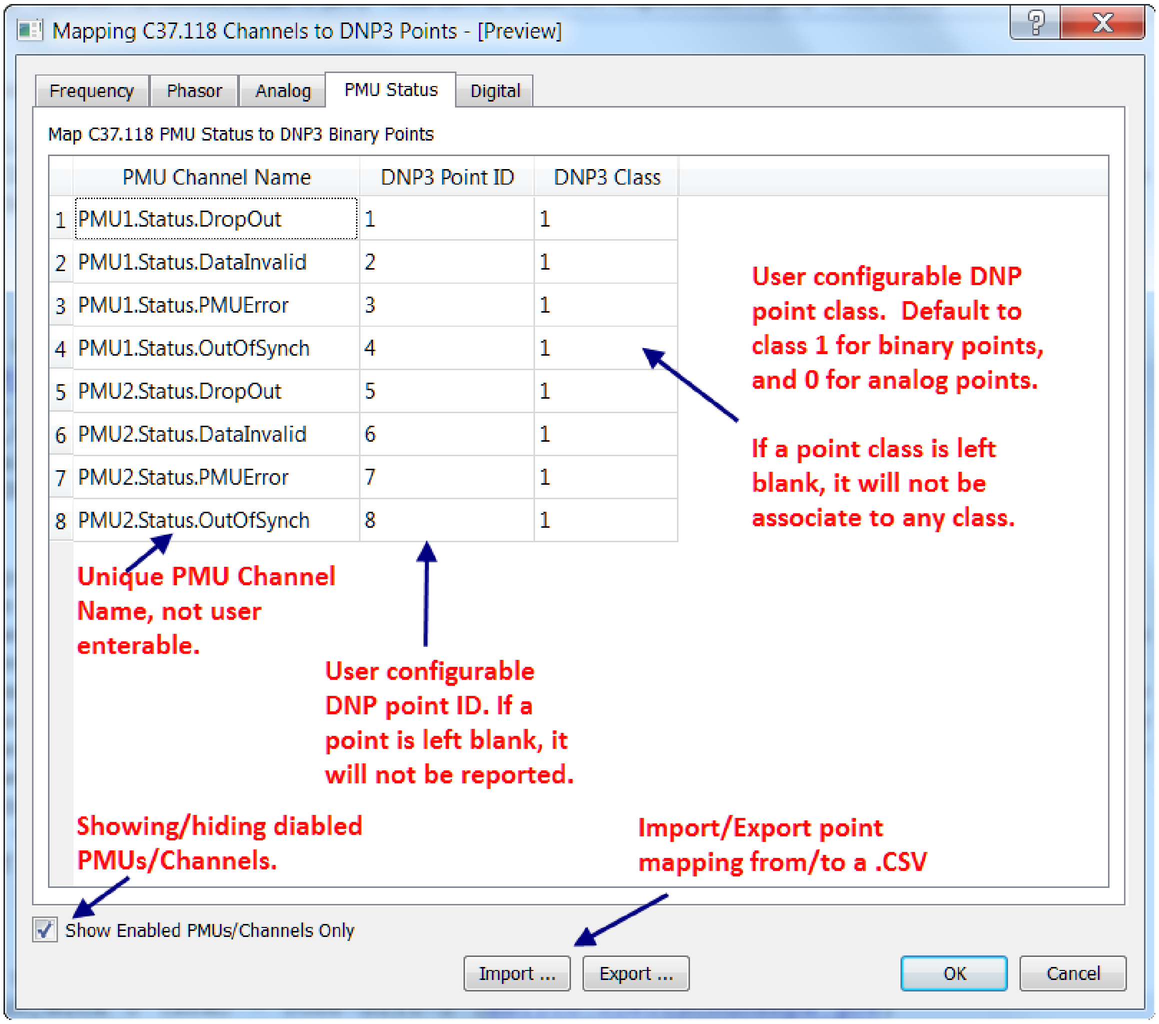
Document Change History

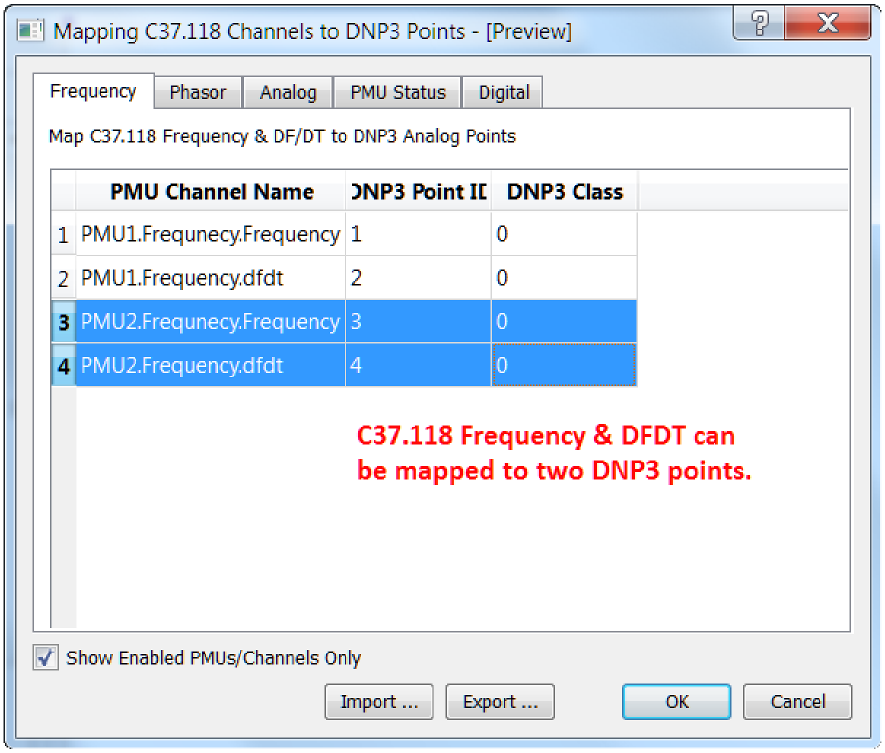
Version No.	Author(s)	Date	Reviewed / Edited / Approved by	Reviewed / Edited / Approved Date	Description of Change
1.0	Simon Mo	04/30/12			First draft, all sections.
2.0	Simon Mo	05/09/12			Updated to reflect the actual raw phasor data implementation.
3.0	Simon Mo	11/09/12			Add calcualated points.
4.0	Simon Mo	12/21/12			Updated section 3.4 and removed section 4.2.4 (Data Quality Testing) based on data quality detection methods available in RTDMS as specified in RTDMS_DataQuality_Design_Spec_1109 2012 .doc. Updated section 4.1 the DNP3 configuration user interface.

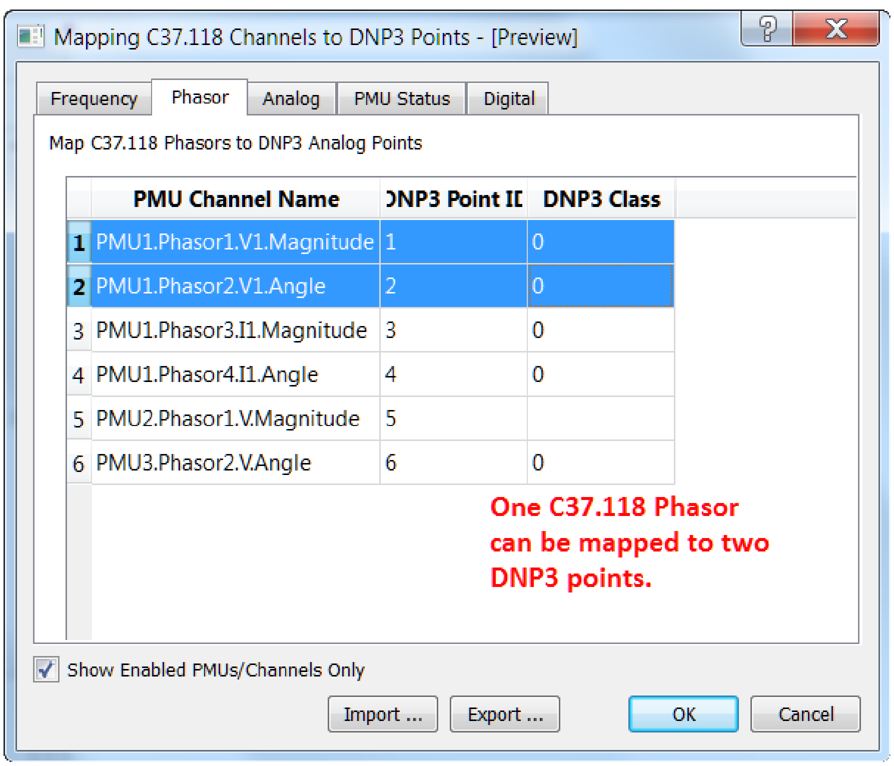
Preface

CAISO has been using the ePDC (*e*nhanced Phasor Data Concentrator) from Electric Power Group (EPG) to provide the wide area monitoring through phasor functions for CEC PIR-10-068 Project. To meet the requirements of TASK 3 "INTEGRATE PHASOR DATA WITH CAISO PI HISTORIAN/EMS" of the contract, EPG has submitted the design and functional specification of RTDMS to PI interface to CAISO. This document specifies the functional and design requirements to integrate phasor data into CAISO's EMS/SCADA.

Table of Contents


Mapping C37.118 Channels to DNP3 Points - [Preview]
Frequency
Phasor
Analog
PMU Status
Digital
Map C37.118 PMU Status to DNP3 Binary Points
PMU Channel Name
DNP3 Point ID
DNP3 Class
1 PMU1.Status.DropOut 1 1
2 PMU1.Status.DataInvalid 2 1
3 PMU1.Status.PMUError 3 1
4 PMU1.Status.OutOfSynch 4 1
5 PMU2.Status.DropOut 5 1
6 PMU2.Status.DataInvalid 6 1
7 PMU2.Status.PMUError 7 1
8 PMU2.Status.OutOfSynch 8 1
User configurable DNP point class. Default to class 1 for binary points, and 0 for analog points.
If a point class is left blank, it will not be associate to any class.
Unique PMU Channel Name, not user enterable.
User configurable DNP point ID. If a point is left blank, it will not be reported.
Showing/hiding diabled PMUs/Channels.
Import/Export point mapping from/to a .CSV
Show Enabled PMUs/Channels Only
Import ...
Export ...
OK
Cancel


Mapping C37.118 Channels to DNP3 Points - [Preview]
Frequency
Phasor
Analog
PMU Status
Digital
Map C37.118 Frequency & DF/DT to DNP3 Analog Points
PMU Channel Name
DNP3 Point ID
DNP3 Class
1 PMU1.Frequnecy.Frequency 1 0
2 PMU1.Frequency.dfdt 2 0
3 PMU2.Frequnecy.Frequency 3 0
4 PMU2.Frequency.dfdt 4 0
C37.118 Frequency & DFDT can be mapped to two DNP3 points.
Show Enabled PMUs/Channels Only
Import ...
Export ...
OK
Cancel


Mapping C37.118 Channels to DNP3 Points - [Preview]
Frequency
Phasor
Analog
PMU Status
Digital
Map C37.118 Phasors to DNP3 Analog Points
PMU Channel Name
DNP3 Point ID
DNP3 Class
1 PMU1.Phasor1.V1.Magnitude 1 0
2 PMU1.Phasor2.V1.Angle 2 0
3 PMU1.Phasor3.I1.Magnitude 3 0
4 PMU1.Phasor4.I1.Angle 4 0
5 PMU2.Phasor1.V.Magnitude 5
6 PMU3.Phasor2.V.Angle 6 0
One C37.118 Phasor can be mapped to two DNP3 points.
Show Enabled PMUs/Channels Only
Import ...
Export ...
OK
Cancel

1 Functional Requirements

Provide a DNP3 output from the RTDMS Server to provide configurable real-time alarming that integrates with the CAISO EMS. This output must be able to connect as a slave, responding to a connection request initiated by the SCADA Master. Direct data link connection between Alstom Energy Management System DNP front end servers and EPG RTDMS servers at Folsom and Alhambra locations. Communication protocol is DNP3 operating on TCPIP transport (DNP/IP). Level 2 DNP server (slave) compliance is required but with capability limited to the commands and responses listed in section 2.

CAISO DNP Clients will be configured for exception polling (Class 1 - Object 60, variation 2) for analogs and statuses. Default response shall be Object 32, variation 2 for analogs and Object 2, variation 2 for statuses. Master station address shall be 100, remote addresses shall be 1. IP address and specific IP port numbers for each slave will be provided at time of implementation.

It is required to send RTDMS alarms to DE EMS. Supporting Analog Object 32 variation 2 is not required but good to have in the future.

2 RTDMS DNP3 Protocol Compliance

1. The following two tables specify the objects, variations and qualifiers used for communications with the DNP3 RTUs. The first table is for the Master request and the second is for the Slave response.

Master Request Initiated by:	Function	Group	Variation	Qualifiers	Range	Each Data Point
2 second clock	01x	30	2	00x	Start/Stop	
RTU class events	01x	60	2,3,4,1	06x	No Range	
5 minute integrity	01x	1	2	00x	Start/Stop	
Demand scan	01x	1	2	00x	Start/Stop	
*AO Select	03x	41	2	17x	Quantity	AO11
*AO Operate	04x	41	2	17x	Quantity	AO11
*SBO Select	03x	12	1	17x	Quantity	SBO 11
*SBO Operate	04x	12	1	17x	Quantity	SBO 11

Remote	Function	Group	Variation	Qualifiers	Range	Each Data

Response for:						Point
*2 second clock	81x	30	2, 5	01x	Start/Stop	2 bytes data + 1 byte flags
***2 second clock	81x	32	2	01x	Start/Stop	2 bytes data + 1 byte flags
*RTU class events	81x	2	1	28x	Quantity	2 bytes data + 1 byte flag
5 minute integrity	81x	1	2	01x	Start/Stop	1 byte status + flags
Demand Scan	81x	1	2	01x	Start/Stop	1 byte status + flags
**AO Response	81x	41	2	17x	Quantity	AO11
**AO Response	81X	41	2	17x	Quantity	AO11
**SBO Select	81x	12	1	17x	Quantity	SBO 11
**SBO Operate	81x	12	1	17x	Quantity	SBO 11

* RTDMS will be DNP3 slave and able to respond to a range of points and all points for group 1 and 30 requests. RTDMS will also respond to group 2 variation 1 for binary change events. RTDMS will respond the queries of changes from a class poll as well as a direct binary change event poll. RTDMS will respond differently to a Class 0 (Integrity) poll compared to the Class 1 (Events) poll. The master will be sending out group 30 requests every 2 seconds. If there are any unread binary changes the RTDMS will set the Class 1 flag in the Internal Indications of the group 30 response, to alert the master to get the binary change events.

** The RTDMS DNP3 slave will not implement the AO and SBO responses. These command/response pairs are for supervisory control functions not used by the RTDMS. It receives and discards AO Select, AO Operate, SBO Select, SBO Operate commands from Master.

*** The RTDMS DNP3 slave will not implement group 32 variation 2 in the first release since it is a good to have requirements. Group 32 variation 2 can be supported in future release.

2 .The Maximum Data Link Frame Size in Octets:

- Transmitted is equal to 292.
- Received must be the same, 292.

3. The Maximum Application Fragment Size in Octets:

- Transmitted is equal to 2048. If greater than 2048, it must be configurable. This is configurable in the setup GUI.
  Received is equal to, 2048. The number of octets must be equal or greater than 249.

4. The Maximum Data Link re-tries is 0.

5. The Maximum Application Layer re-tries is 0.

6. The Data Link Layer Confirmation is not required. It must be disabled in LAN-WAN environment. Instead, TCP performs message confirmation.

7. The Application Layer Confirmation is required.

8. The Timeouts requirements while waiting for the following:
   - Data Link Confirm timeout is specified with parameter ProtocolTimeout2, which is 1000.
   - The complete Application Fragment is specified with parameter ProtocolTimeout1, which is 3000.
   - The Application Confirmation timeout is not required.
   - The Complete Application Response timeout is not required.
   - The Complete Transport Segment is required and specified with parameter ProtocolTimeout2.

9. The following controls might be supported by CAISO EMS but **NOT** by RTDMS DNP3 output:
   - Write binary outputs, batch-digital-output controls.
   - Select-Before-Operate.
   - Pulse width controls for set points and tap changers.

10. The SMP Master's expectations are as follows for Binary Input Change Events:
    - Binary events will be non-time-tagged.
    - Binary events will be with a quality flag.

11. The RTDMS DNP3 Slave's expectations are as follows for Reporting Binary Input Change Events when no specific variation requested
    - Binary change report is not implemented.

12. The RTDMS DNP3 Slave's expectations are as follows for Sending Unsolicited Responses:
    - The RTU slave will never send unsolicited responses.

13. The RTU Slave's expectations are as follows for Default Counter Object or Variation:
    - The RTU slave will not send counter information.

14. The RTDMS DNP3 Slave's expectations are as follows for Reporting Time-Tagged Binary Input Change Events when no specific variation requested:
    - The RTU slave will not report time-tagged binary input change events.

15. The RTDMS DNP3 Slave's expectations are as follows for Sending Static Data in Unsolicited Responses:

- The RTU slave will never report send unsolicited responses.

16. The RTDMS DNP3 Slave's expectations are as follows for Rolling over Counters:
    - The RTU slave will not have counters.

17. The RTDMS DNP3 Slave may send Multi-Fragment Responses.

3 Solution

The RTDMS will provide data down sampled from the phasor data rate by re-sampling (a selected data sample) with the initial delivery; filtered down sampling may be added later. Analog and digital data is included as follows:

- Digital data indications for measurement alarms.
- Analog PMU data for selected phasor, MW, and MVAR measurements (magnitude and angle are sent for each phasor). Phasor data may be absolute or relative.
- Digital data for selected PMU status and digital indication points.
- Digital data indications for PMU system problems.
- Data quality indication for each analog point.

A DNP3 interface will be an output function provided in the RTDMS. The configuration GUI will be developed to allow selecting the measurements/alarms and mapping measurements/alarms with EMS DNP3 points.

3.1 Signal Processing

Phasors are measurements of either voltage or current. They are supplied as a complex number representing RMS magnitude and phase. They may be scaled or not depending on the data type. Derived quantities like power need to be computed from these values. This interface will allow the following processing options:

- Convert phasor or analog data from floating point to 16-bit integer or the reverse. Scale factors from C37.118 configuration may be used automatically, or the user may enter their own scaling.

- The output can be down sampled with several options. Currently down sampling by a factor of N sends every N^{th} sample. Additional options are planned including averaging over a 1/N interval and averaging over a longer interval to eliminate aliasing. These are planned for the 4^{th} quarter 2012.

3.2 Interface Features

- Each signal can be given a number
- Each signal can be given a name
- The number of signals selected will be only limited by the DNP3 capability
- Alarms will be mapped to binary (Boolean) reporting value. The user can choose which alarms will be mapped to DNP3. When there is alarm, the point will be set. Otherwise, the point will be cleared. If the PMU input data is bad, reporting changes will be blocked to prevent incorrect reporting toggling that could possibly overload SCADA change registers.
- Phasor, frequency, dF/dt, MW, MVAR, and analog signals will be mapped to an analog reporting value. Phasors can be configured as rectangular or polar (default). They can be configured to report as 16-bit integer or 32-bit single precision floating point (default).
- Digital and status values will be mapped to a binary (Boolean) reporting value. The user can choose which values will be mapped to DNP3. If the PMU input data is bad, reporting changes will be blocked to prevent incorrect reporting toggling that could possibly overload SCADA change registers.
- The received data status including input failed and PMU sync lost will be self-reported by the RTDMS and will be available for DNP3 output as a binary value. Normal RTDMS monitoring applies logic to input data so that if no data is received for a period of time, the input is declared failed. When data input resumes, the input is declared restored. This logic will be mapped into the PDC data buffer so it can be included with data outputs. All data inputs will be included in this meta-data, so failure of any input can be reported.

3.3 Output features

- The communication will be available in Ethernet using the modes that are allowed in the DNP3 protocol. The RTDMS will be a TCP server which allows the EMS front end to be the client and initiate the connection.
- The output rate will be selectable, based on the need of the connected system and the capability of DNP3. With a polled system it will respond to the poll.

3.4 Data quality flag

Each DNP3 quantity has a 7 bit quality flag that indicates usability of the value. This quality flag for all phasor (magnitude and angle), frequency, df/dt, and power, analog, digital and derived values will be set based on the bad data detection methods specified in the design document of

(RTDMS_DataQuality_Design_Spec_11092012 .doc). The measurements will be flagged as Bad, Uncertain, and Good quality by RTDMS. These quality codes will be mapped to the DNP flag as follows:

DNP3 COMM LOST flag is used to indicate if a PMU is reporting data or not. If a measurement's quality code is BAD with Not Connected as sub-status, COMM LOST is set (not reporting). Otherwise it is cleared.

DNP3 ONLINE flag is used to indicate if a measurement is valid or not. If quality code is Good Quality, the ONLINE flag for that quantity will be set (binary 1, good). Otherwise it will be cleared (binary 0, bad).

PMU status points represented by will always have the ONLINE bit set (1, good).

For Alarm binary points, COMM LOST is always cleared and ONLINE is always set since alarms are generated based on measurements with GOOD data quality.

DNP3 Points	**Data Quality**	**PMU Sending Data to RTDMS**	**COMM LOST**	**ONLINE**
DNP3 quality flag for all measurements points	BAD with Not Connected sub-status	No	1	0
	GOOD and UNCERTAIN with Subnormal sub-status	Yes	0	1
	All other quality codes	Yes	0	0
DNP3 quality flag for PMU Status Data Invalid, PMU Error, Out of Synch points	BAD with Not Connected sub-status	No	1	1
	All other quality codes	Yes	0	1
DNP3 quality flag for Drop Out PMU point	All quality codes	Yes	0	1
	All quality codes	No	0	1
Alarm points	Alarms are generated based on filter data only.	Not Applicable	0	1

3.5 Limitations

The interface will only report static (instantaneous) analog (group 30, variation 2 & 5), static binary (Boolean) values (group 1, variation 2), and binary events (group 2, variation 1).

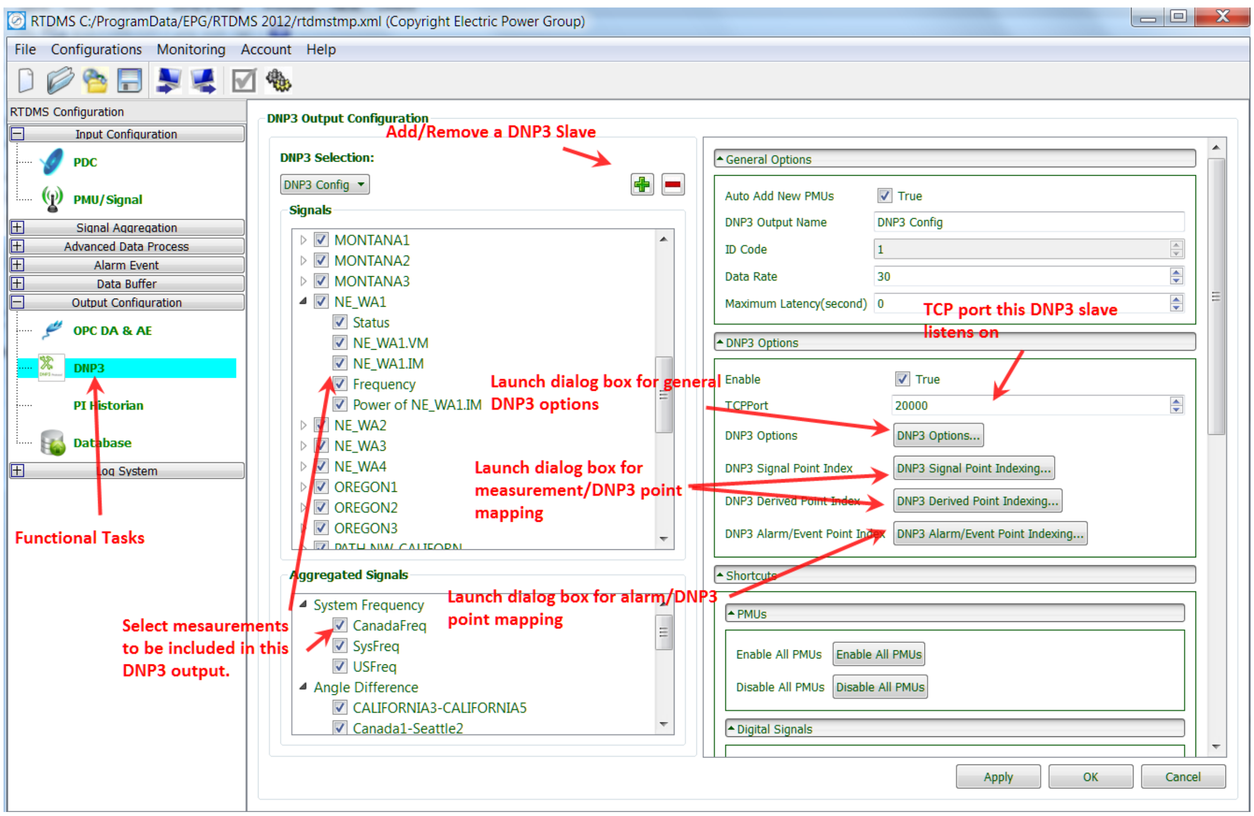
4. RTDMS Configuration GUI Design

4.1 DNP3 Output Adaptor Configuration Panel

DNP3 will be added into output's data format selection. When DNP3 is selected as the format, its configuration will be shown as below.

The TCP will be used as the default communication option. In this case, RTDMS will listen on a port (default to 19999 or 20000) and wait for DNP3 Master to connect. Once connected, RTDMS will wait for Master's command, parse the command, and response accordingly. The RTDMS won't send un-solicited responses.

Just like other RTDMS output adaptors, PMU/channels and calculated values can be enabled or disabled from the DNP3 output. Only enabled channels and calculated values with valid DNP3 point index will be included in the DNP3 response. DNP3 point mapping is described in section 4.3.

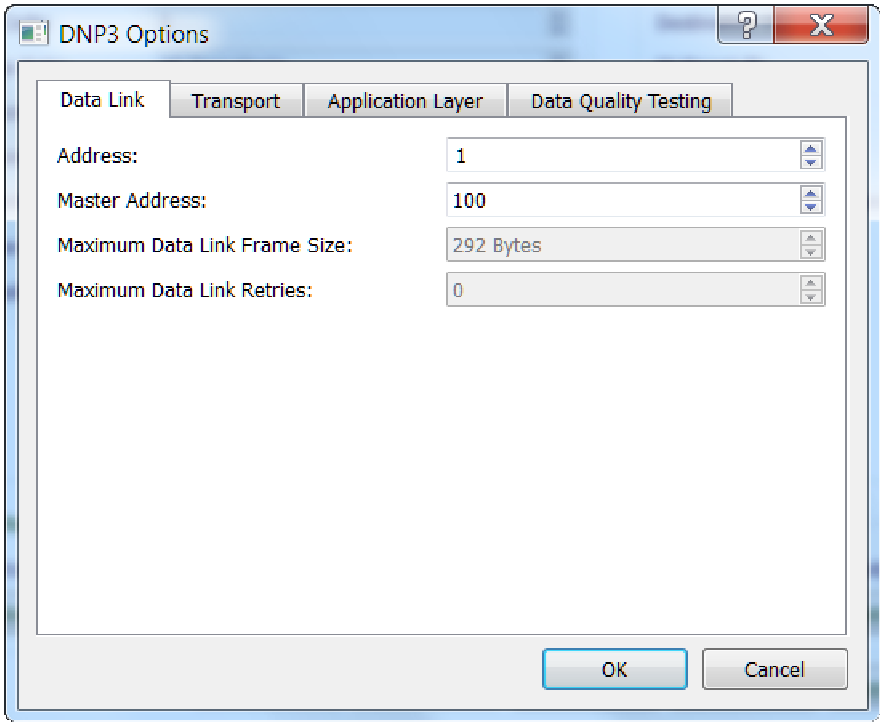


4.2 DNP3 Options

This dialog is used to configure DNP3 specific options. It has four tabs for options of Data Link, Transport, Application Layer, and Data Quality Testing.

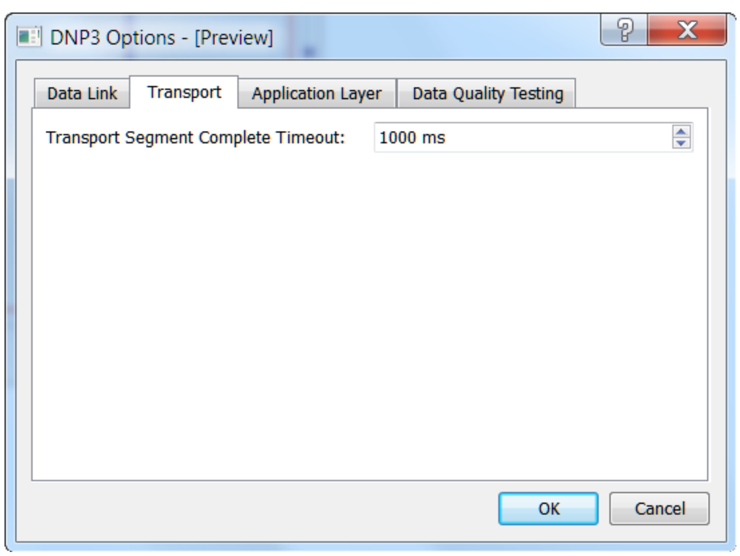
4.2.1 Data Link

This tab is used to configure options required by Data Link Layer, including RTDMS DNP3 slave address and the address of DNP3 Master (default 100) which will poll RTDMS.



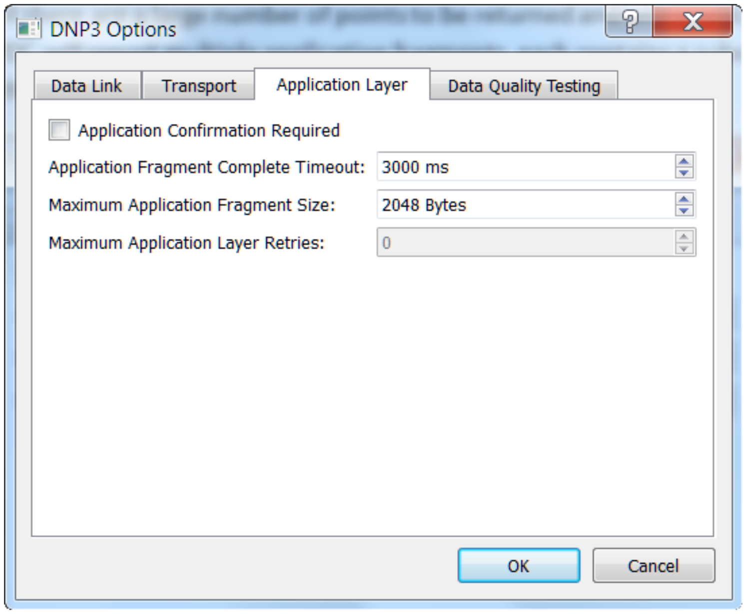
4.2.2 Transport

This tab is used to configure options required by Transport Layer. Only one option will be configurable: Transport Segment Complete Timeout with default value of 1000 ms.



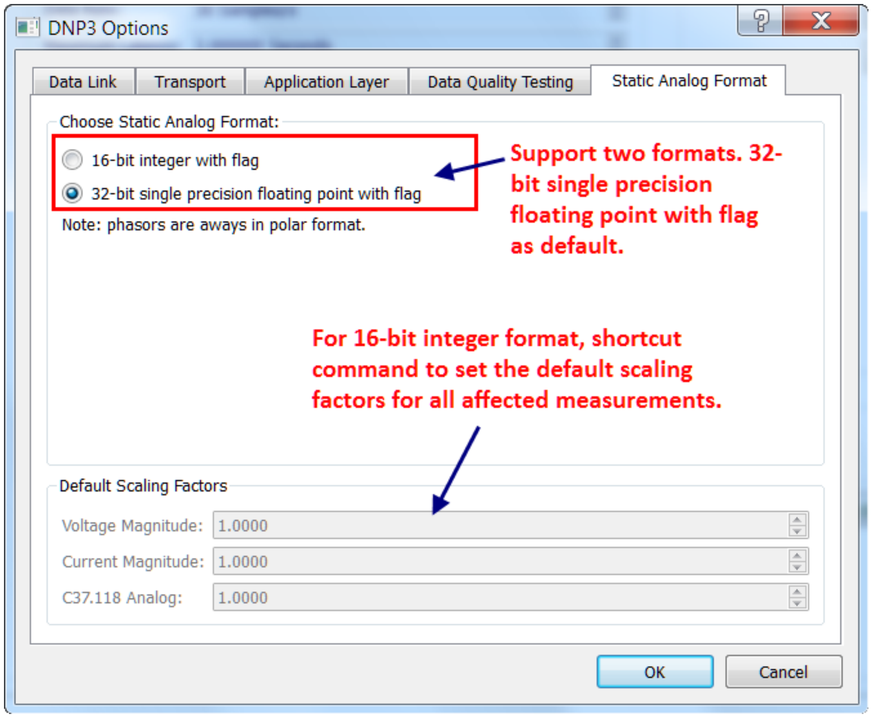
4.2.3 Application Layer

This tab is used to configure options required by Application Layer. The maximum application fragment size is 2048 bytes. If there are a large number of points to be returned and one application fragment is not big enough, RTDMS will report multiple application fragments, each contains a subset of points so that size will be within the maximum fragment size limit.



4.2.4 DNP3 Static Analog Data Format

For DNP3 analogs, their format can be configured using through the following user interface. In default, all analogs will be in 32-bit single precision floating point with flag.



4.3 IEEE37.118 to DNP3 Point Index Mapping

RTDMS will provide a dialog box to allow user mapping IEEE 37.118 channels to DNP3 points. IEEE 37.118 channels are grouped into five categories: PMU Status, Frequency, Phasors (voltage and current), Analog, and Digital. For each category, IEEE 37.118 channels will be listed alone with user editable cell for user to enter a DNP3 point. The user entered DNP3 point number will be validated for range and duplication (0-65355). If the DNP3 point number call is blank, the channel associated with it won't be sent to EMS.

User can also configure point class for each channel. In default, digitals will be Class 1 and analogs will be Class 0. If the point class cell is blank, the point won't be assigned to any DNP3 point class.

RTDMS GUI is designed to import/export in CSV file format for DNP3 point mapping (import/export button will be added to following DNP3 point mapping GUI). In the export CSV file, point ID edited with RTDMS GUI will be included. When a CSV file is imported, point IDs will be overwritten for matched signals with those specified in the CSV file. The CSV file should have following columns:

- PMU Name: unique name to identify a PMU
- RTDMS Signal Name: unique name created by RTDMS to identify a signal associated with the PMU
- Signal Name: signal name received from PMU

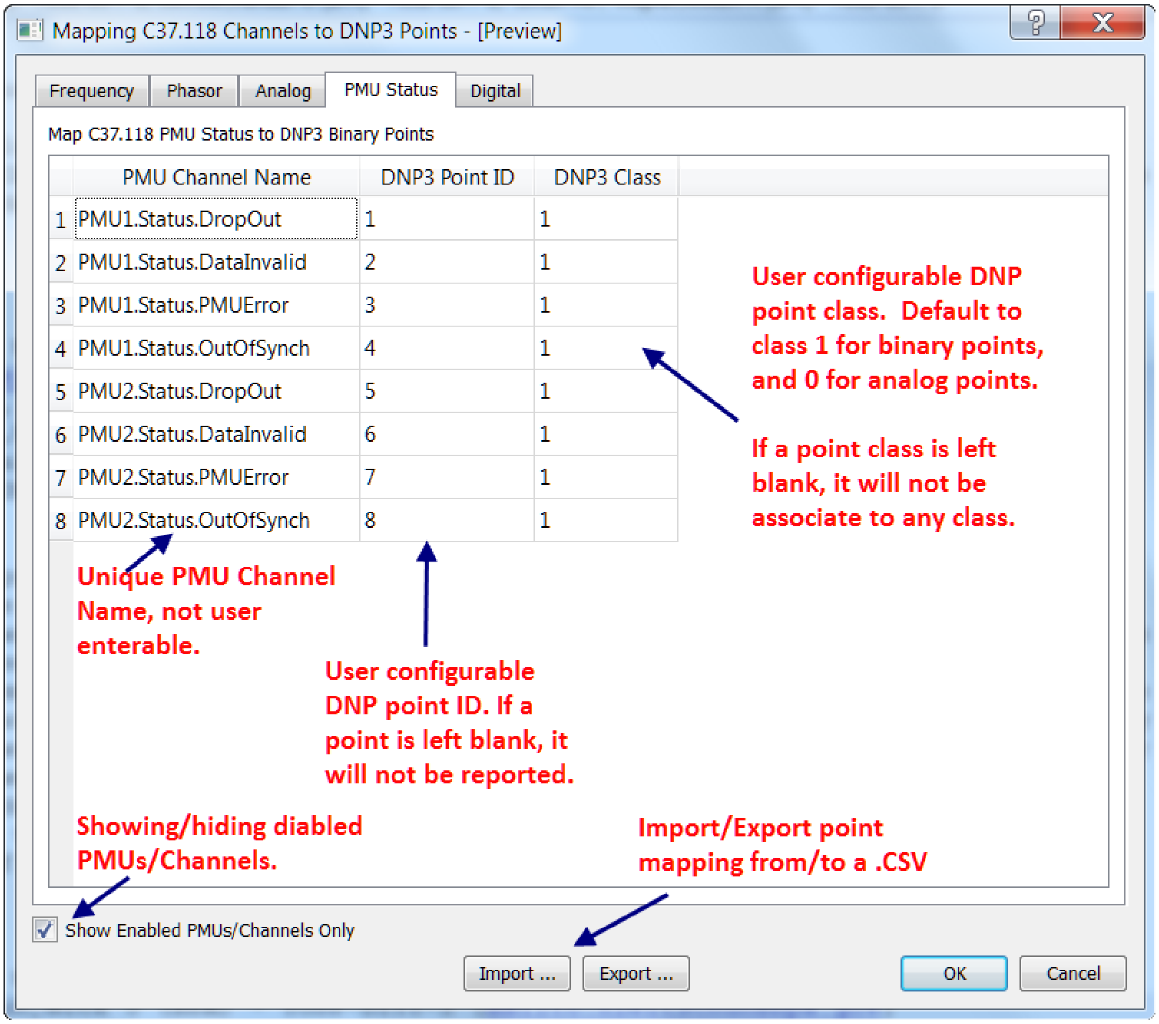
- DNP3 Point ID: DNP3 point mapped to the signal
- Class: Class ID mapped to the signal

When Redundant Data Source selection is enabled for the DNP3 output, for every pair of PMUs, only the points mapped to Primary PMU will be used. The points mapped to alternate PMUs will be ignored and no data will be populated.

4.3.1 PMU Status

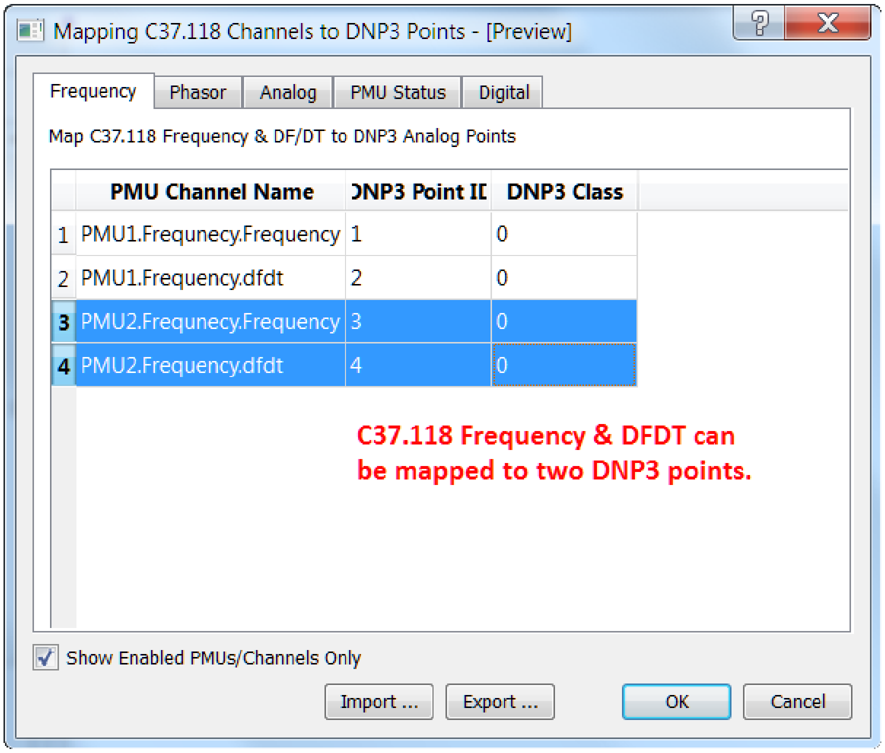
PMU Status will be mapped to four DNP3 binary points whose data quality flag will always be set to "good" in DNP3 response:

- Data Dropout: 0 – data available and communication is up, 1 – dropout or missing data (no data received from PMU, which indicates a PMU or communication problem, that is communication down) . Not needed since all values now are having COMM LOST flag.
- Data Invalid: 0 – valid, 1 – invalid
- PMU Error: 0 – no error, 1 – error
- Out of Sync: 0 – GPS in synch and sort by time, 1 – GPS out of synch OR sort-by-arrival



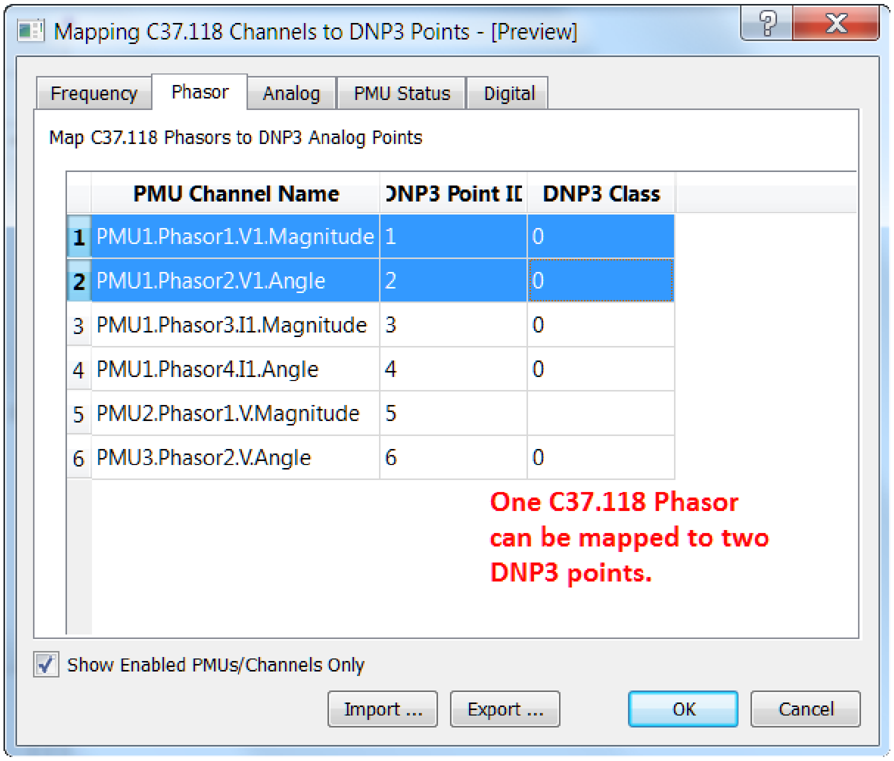
4.3.2 Frequency

Frequency and DF/DT will be mapped to two DNP3 analog points.



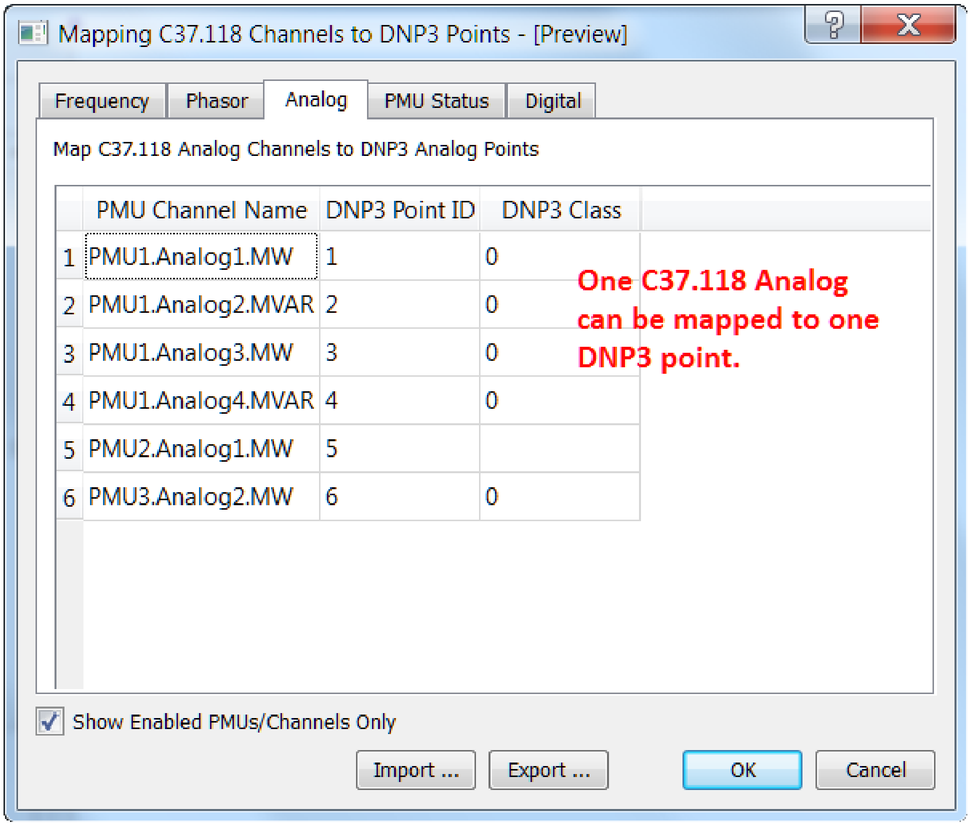
4.3.3 Phasor

Voltage/current magnitude and angle will be mapped to two DNP3 analog points.



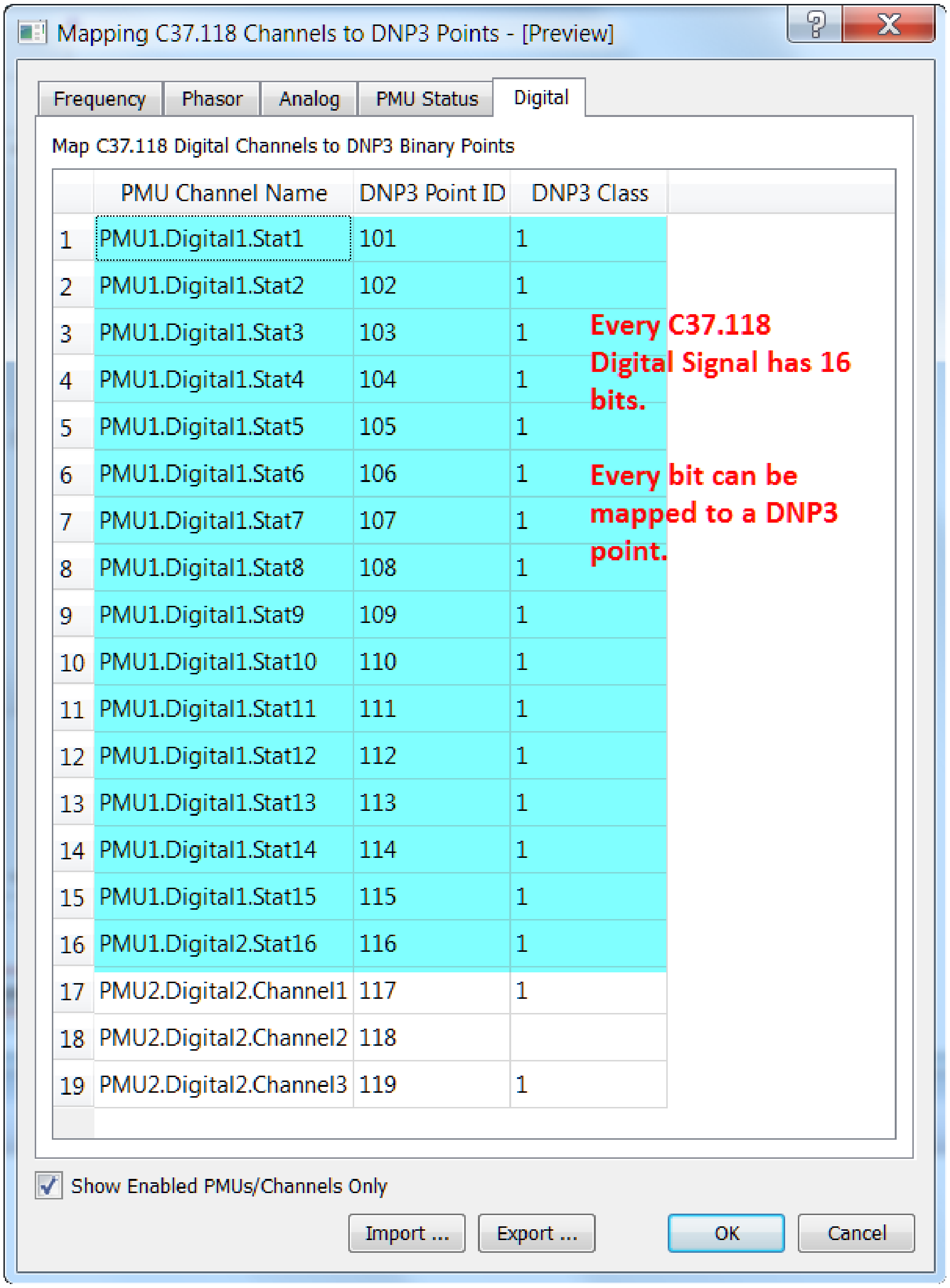
4.3.4 IEEE 37.118 Analog Channels

IEEE 37.118 analog could be sampled data such as control signal or transducer value. Every analog will be mapped to one DNP3 analog point.



4.3.5 IEEE 37.118 Digital Channels

IEEE 37.118 digital is a 16-bit status word. It could be bit mapped status or flag. Any bit can be mapped to a DNP3 binary point. And One IEEE 37.118 digital can be mapped to 16 DNP3 binary points at most.



4.4 RTDMS Alarm to DNP3 Point Index Mapping

4.4.1 RTDMS Alarms

Up to 8 (4 hi and 4 low) level of alarms can be detected by RTDMS. For every measurement, every level can be enabled or disabled. For example, if only 2 levels (high level 1 and low level 1) are needed, other 6 levels can be disabled.

For alarms not available in EMS, they're good candidates to be saved into EMS. The following table lists alarms available in RTDMS and highlighted ones are recommended saving into EMS.

ID	Alarm Type	Priority	Unit	Description
1	H4 Frequency	1	mHz	High Frequency Level 4
2	H3 Frequency	2	mHz	High Frequency Level 3
3	H2 Frequency	3	mHz	High Frequency Level 2
4	H1 Frequency	4	mHz	High Frequency Level 1
5	L1 Frequency	4	mHz	Low Frequency Level 1
6	L2 Frequency	3	mHz	Low Frequency Level 2
7	L3 Frequency	2	mHz	Low Frequency Level 3
8	L4 Frequency	1	mHz	Low Frequency Level 4
9	H4 Voltage	1	pu	High Voltage Level 4
10	H3 Voltage	2	pu	High Voltage Level 3
11	H2 Voltage	3	pu	High Voltage Level 2
12	H1 Voltage	4	pu	High Voltage Level 1
13	L1 Voltage	4	pu	Low Voltage Level 1
14	L2 Voltage	3	pu	Low Voltage Level 2
15	L3 Voltage	2	pu	Low Voltage Level 3

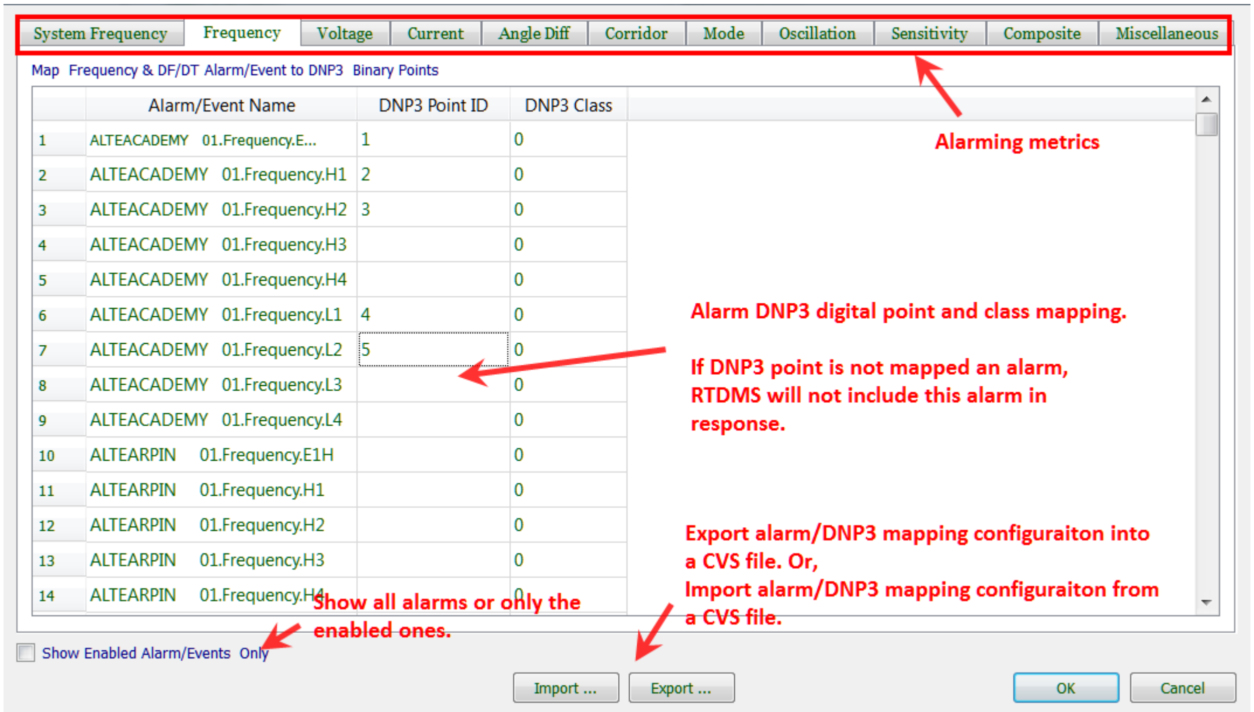
16	L4 Voltage	1	pu	Low Voltage Level 4
17	H4 Current	1	A	High Voltage Level 4
18	H3 Current	2	A	High Voltage Level 3
19	H2 Current	3	A	High Voltage Level 2
20	H1 Current	4	A	High Voltage Level 1
21	L1 Current	4	A	Low Current Level 1
22	L2 Current	3	A	Low Current Level 2
23	L3 Current	2	A	Low Current Level 3
24	L4 Current	1	A	Low Current Level 4
25	H4 MW Flow	1	MW	High MW Flow Level 4
26	H3 MW Flow	2	MW	High MW Flow Level 3
27	H2 MW Flow	3	MW	High MW Flow Level 2
28	H1 MW Flow	4	MW	High MW Flow Level 1
29	L1 MW Flow	4	MW	Low MW Flow Level 1
30	L2 MW Flow	3	MW	Low MW Flow Level 2
31	L3 MW Flow	2	MW	Low MW Flow Level 3
32	L4 MW Flow	1	MW	Low MW Flow Level 4
33	H4 MVAR Flow	1	MVAR	High MVAR Flow Level 4
34	H3 MVAR Flow	2	MVAR	High MVAR Flow Level 3
35	H2 MVAR Flow	3	MVAR	High MVAR Flow Level 2
36	H1 MVAR Flow	4	MVAR	High MVAR Flow Level 1
37	L1 MVAR Flow	4	MVAR	Low MVAR Flow Level 1
38	L2 MVAR Flow	3	MVAR	Low MVAR Flow Level 2
39	L3 MVAR Flow	2	MVAR	Low MVAR Flow Level 3
40	L4 MVAR Flow	1	MVAR	Low MVAR Flow Level 4

41	H4 Angle Difference	1	Deg	High Angle Difference Level 4
42	H3 Angle Difference	2	Deg	High Angle Difference Level 3
43	H3 Angle Difference	3	Deg	High Angle Difference Level 2
44	H1 Angle Difference	4	Deg	High Angle Difference Level 1
45	L1 Angle Difference	4	Deg	Low Angle Difference Level 1
46	L2 Angle Difference	3	Deg	Low Angle Difference Level 2
47	L3 Angle Difference	2	Deg	Low Angle Difference Level 3
48	L4 Angle Difference	1	Deg	Low Angle Difference Level 4
49	H1 Frequency Transient	4	mHz	High Frequency Transient Level 1
50	L1 Frequency Transient	4	mHz	Low Frequency Transient Level 1
51	H1 Voltage Transient	4	pu/s	High Voltage Transient Level 1
52	L1 Voltage Transient	4	pu/s	Low Voltage Transient Level 1
53	H1Current Transient	4	A	High Current Transient Level 1
54	L1 Current Transient	4	A	Low Current Transient Level 1
55	H1 Angle Difference Transient	4	Deg	High Angle Difference Transient Level 1
56	L1 Angle Difference Transient	4	Deg	Low Angle Difference Transient Level 1

57	L2 Angle Difference Transient	3	Deg	Low Angle Difference Transient Level 2
58	L1 Damping	4	%	Low Damping Level 1
59	L2 Damping	4	%	Low Damping Level 2
60	H1 Sensitivity	4	kV/100 MW	High Sensitivity Level 1
61	H2 Sensitivity	4	kV/100 MW	High Sensitivity Level 2
62	Load Drop	4		Load Drop detected (planned for post Jan release)
63	Generation Trip	4		Generation Trip (planned for post Jan release)
64	System Separated	4		System Separated Transient (planned for post Jan release)
65	Line Outage	4		Line Outage Transient (planned for post Jan release)
66	Composite Alarm	4		Complex alarms based on basic alarms

4.4.2 RTDMS Alarms and DNP3 Digital Point/Class Mapping

RTDMS will provide a dialog box to allow user mapping alarms generated by RTDMS to DNP3 digital points. Alarms associated with measurements of Frequency/System Frequency, Voltage, Current, Angle Difference, and Power Flow Path can be mapped to DNP3 digitals points. Complex alarms including mode low damping, sensitivity, oscillation, and composite alarm can also be mapped to DNP3 digitals points. The alarms will be listed alone with user editable cell for user to enter a DNP3 point. The user entered DNP3 point number will be validated for range and duplication (0-65355). If the DNP3 point number call is blank, the channel associated with it won't be sent to EMS.


System Frequency
Frequency
Voltage
Current
Angle Diff
Corridor
Mode
Oscillation
Sensitivity
Composite
Miscellaneous
Map Frequency & DF/DT Alarm/Event to DNP3 Binary Points
Alarm/Event Name
DNP3 Point ID
DNP3 Class
1 ALTEACADEMY 01.Frequency.E... 1 0
2 ALTEACADEMY 01.Frequency.H1 2 0
3 ALTEACADEMY 01.Frequency.H2 3 0
4 ALTEACADEMY 01.Frequency.H3 0
5 ALTEACADEMY 01.Frequency.H4 0
6 ALTEACADEMY 01.Frequency.L1 4 0
7 ALTEACADEMY 01.Frequency.L2 5 0
8 ALTEACADEMY 01.Frequency.L3 0
9 ALTEACADEMY 01.Frequency.L4 0
10 ALTEARPIN 01.Frequency.E1H 0
11 ALTEARPIN 01.Frequency.H1 0
12 ALTEARPIN 01.Frequency.H2 0
13 ALTEARPIN 01.Frequency.H3 0
14 ALTEARPIN 01.Frequency.H4 0
Alarming metrics
Alarm DNP3 digital point and class mapping.
If DNP3 point is not mapped an alarm, RTDMS will not include this alarm in response.
Export alarm/DNP3 mapping configuraiton into a CVS file. Or,
Import alarm/DNP3 mapping configuraiton from a CVS file.
Show all alarms or only the enabled ones.
Show Enabled Alarm/Events Only
Import ...
Export ...
OK
Cancel

APPENDIX C:
RTDMS Automated Event Analyzer Functional Specifications

California Energy Commission
Grant Award PIR-10-068

Real Time Dynamics Monitoring System (RTDMS)
Automated Event Analyzer Functional Specifications (Task 4)

Electric Power Group, LLC
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Pasadena, CA 91101
Tel: (626) 685 2015

August 2013

Document Change History

Version No.	Document ID	Author(s)	Date	Reviewed / Edited / Approved by	Date of Internal Review	Description of Change
0.1	RTDMS 2012 Automated Event Analyzer Functional Spec.	Kevin Chen	08/01/11			First draft of the scope of the document
0.2		Kevin Chen	03/26/12			Updated incident classificatoin algorithm
0.3		Kevin Chen	06/15/12			Added Oscillation Detection, Mode Meter, Voltage Sensitivity and Angle Sensitivity Modules
0.4		Kevin Chen	06/28/12			Updated islanding detection algorithm
0.5		Kevin Chen	07/06/12			Updated generation trip, load shedding, line outage detection algrithms
0.6		Kevin Chen	07/19/12			Incorporated comments and feedbacks
0.7		Kevin Chen	08/19/13			Updated client visualization, comments and feedbacks

Table of Contents

Figures

1 Introduction

The Automated Event Analyzer (AEA) application of Real Time Dynamics Monitoring System[1] (RTDMS™) runs in real-time and utilizes Phasor Measurement Units (PMU) data to provide grid operators with information immediately following a system event to enhance the corrective actions of the operators and improve the stability and reliability of the electric grid.

The AEA application continuously performs event detection, classification, location estimation, and analysis in real-time, including oscillations, voltage stability and islanding events. AEA then presents to operators a summary of results of all the relevant information via 'yellow pop ups'; a "more" button immediately brings up more detailed diagnostics and shows operators all of the relevant metrics at a glance.

This application consists of the following modules:

- Oscillation Detection Module
- Mode Meter Module
- Voltage Sensitivity Module
- Angular Sensitivity Module
- Islanding Detection Module
- Composite Alarms Module

One or more synchrophasor signals are independently input into each module via an input data block and each module operates independently, which can be turned on and off individually. A simplified AEA system architecture diagram is shown in Figure 1. Each module exchanges data with RTDMS Server and RTDMS Phasor Archiver Database, i.e., fetching input signals from database and saving analysis results back to database. Downstream applications then pick up the results and present to the users.

[1] ®Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060259, and US Patent 8,401,710. All rights reserved.

RTDMS® 2012 Automated Event Analyzer System Architecture
Confidential

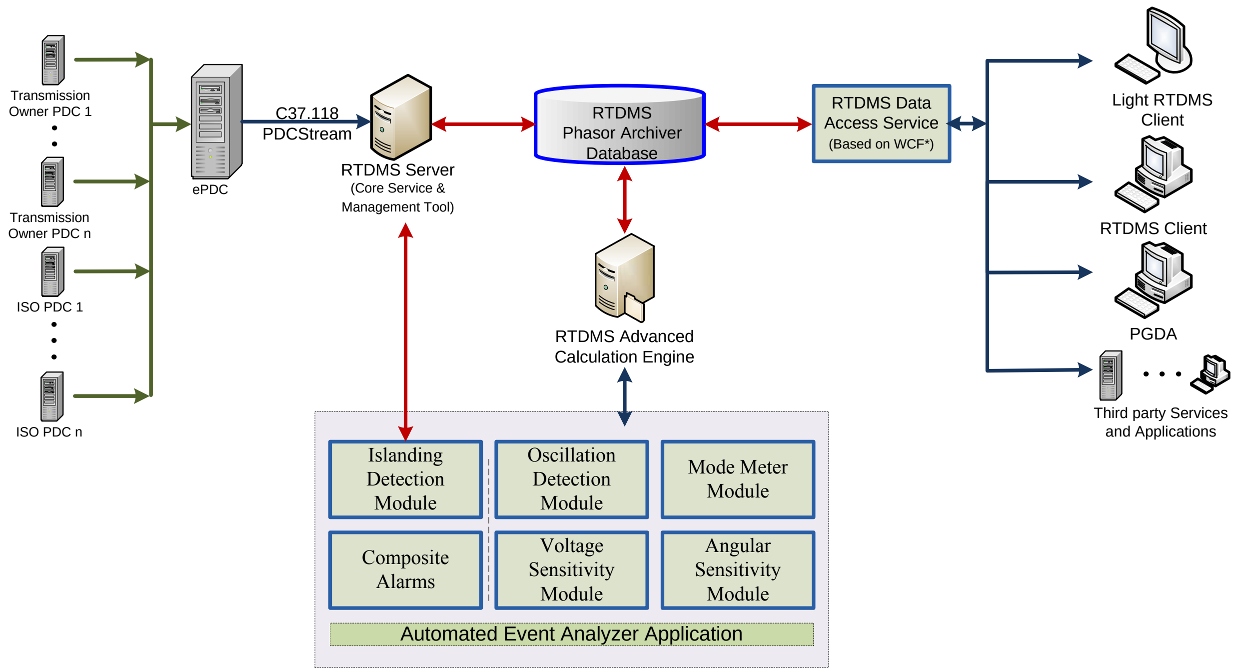

Figure 1. RTDMS 2012 Automated Event Analyzer System Architecture

2 Application Functions

This section discusses functionalities of each individual Automated Event Analyzer (AEA) module.

2.1 Oscillation Detection Module

The Oscillation Detection Module (ODM) is designed for rapid identification of system conditions at the time of a disturbance. It automatically detects electromechanical frequency oscillations and damping levels immediately following system disturbances, and is intended to complement detection methods traditionally used in steady state conditions. The AEA application will detect oscillations that may be unexpected or unknown to operators.

Figure 2 shows the signal flow diagram of the ODM. A synchrophasor input data is passed into a Preprocessing function within the module. The Preprocessing function creates required pseudo synchrophasor signals, conducts preliminary analyses on the data, and adds the processed data to an internal analysis buffer. Once the data analysis buffer is completely full, each signal in the analysis buffer is individually passed to a Root Mean Square (RMS) Oscillation Energy detection function. Each RMS Oscillation Energy detection function only operates on one signal. Upon each call to a given executable of the module, the appropriate outputs are subsequently passed to RTDMS Phasor Archiver Database.

Allowed synchrophasor and pseudo synchrophasor signals calculated by the module and used in the Oscillation Detection function include voltage magnitude, voltage angle, linear combinations of voltage angles, real-power flows, reactive power flows, and linear combinations of power flows. Algorithm and parameter settings can be defined by the user through RTDMS Server.

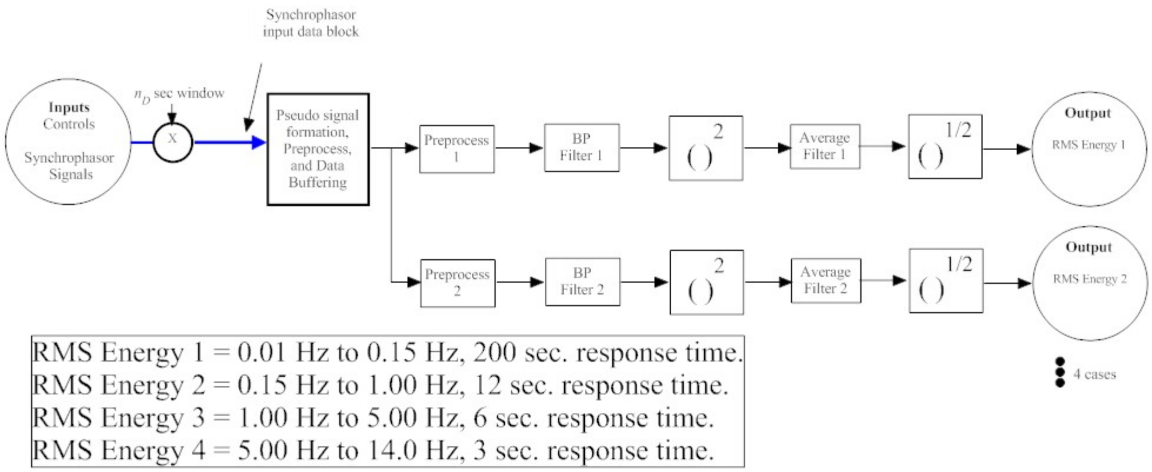

Figure 2. Signal flow diagram for the Oscillation Detection Module

2.2 Mode Meter Module

The Mode Meter Module (MMM) utilizes phasor measurement data to identify poor damping and wide-area oscillations on the grid by identifying the dominant oscillatory mode frequencies, magnitudes and damping.

Figure 3 shows the signal flow diagram of the MMM. A synchrophasor input data block is passed into a Preprocessing function within the module. The Preprocessing function creates required pseudo synchrophasor signals, conducts preliminary analyses on the data, and adds the processed data to an internal analysis buffer. The data is then passed to parallel Mode Meter Estimation functions, each with a different data window size and/or algorithm settings. For each mode, a Results Selection function then analyzes the outputs of the parallel Mode Meter Estimation functions to obtain the optimal mode damping and frequency estimation result. The estimated mode and synchrophasor data are then passed to a Mode Shape Estimation function which estimates the mode shape. Upon each call to the module, the appropriate outputs are subsequently passed to the RTDMS Phasor Archiver Database.

A single pseudo synchrophasor signal calculated by the Preprocessing function is used to estimate a given mode. Allowed synchrophasor and pseudo synchrophasor signals calculated by the module and used in the Mode Meter Estimation function include a linear combination of synchrophasor voltage angles; or, a linear combination of real-power flows. The mode shape is estimated from synchrophasor voltage angles. Algorithm and parameter settings are defined through RTDMS Server.

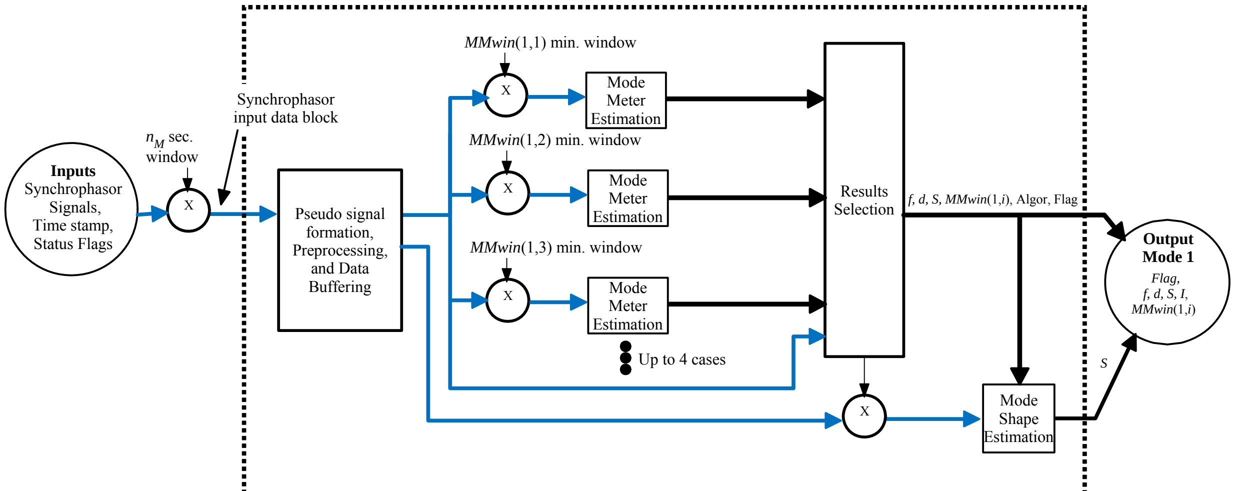

Figure 3. Signal flow diagram for the Mode Meter Module

2.3 Voltage Sensitivity Module

The Voltage Sensitivity Module (VSM) provides the users with a current real-time assessment of the slope of the power-voltage (PV) or reactive power-voltage (QV) curve and alarms them when the sensitivities exceed a user pre-defined threshold. The voltage sensitivity can be defined as change in voltage as a function of power flow on a transmission line given in kV per 100 MWs change or kV per MW change. By monitoring the rate of change or slope, the margin from the nose point can be approximated.

The user will be able to select critical buses, corridors or load pockets to monitor through the analysis to identify potential voltage problems in the system. The pairs of voltage magnitude signals and power flow signals are the input for the VSM. Algorithm and parameter settings are defined through RTDMS Server. Based on the time window size, the VSM will perform a linear polynomial fit for pairs of data for every update, and calculate the corresponding sensitivity value. The results are subsequently saved in the RTDMS Phasor Archiver Database.

2.4 Angular Sensitivity Module

The Angular Sensitivity Module (ASM) provides the users with a current real-time assessment of the slope of the δ-PV curve and alarms them when the slope exceeds a user pre-defined threshold. The angular sensitivity can be defined as change in angle as a function of power flow on a transmission line, and it can be measured in degrees per 100 MWs or degree per MW.

A user will be able to select critical corridors or load pockets to monitor for potential angular stability problems in the system. The pairs of angle difference signals and active power flow signals are the input for the ASM. Algorithm and parameter settings are defined through the RTDMS Server. The ASM will perform a liner polynomial fit for pairs of data at each update, and calculate the corresponding rate of change. The results are subsequently saved in the RTDMS Phasor Archiver Database.

2.5 Islanding Detection Module

The Islanding Detection Module (IDM) is a very efficient tool for detecting islanding conditions in the power system. IDM utilizes the frequency signals and/or voltage angle signals as input to the module, i.e., the frequency difference method and the change of angle difference method. The users can select either of these two implementation methods or use both simultaneously. A signal flow diagram of the IDM is shown in Figure 4.

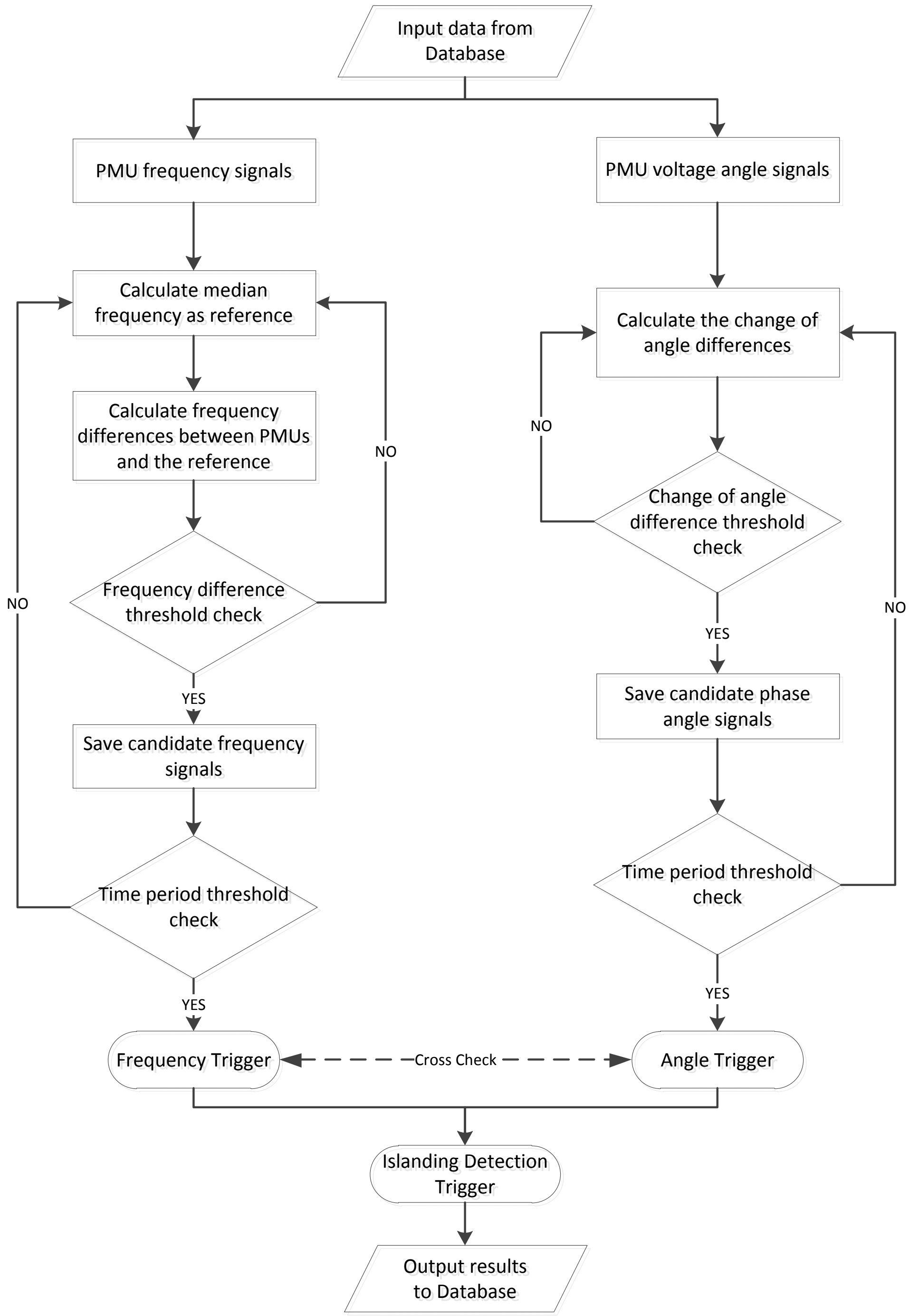

Figure 4. Signal flow diagram for the Islanding Detection Module

For the frequency difference method, all PMU frequency signals are considered. The detection algorithm calculates the median frequency of all the PMUs as the reference frequency, and it then compares the differences between PMUs and the reference frequency. The IDM locates PMUs that exceed a defined threshold for a selected period of time.

For the change of angle difference method, all PMU voltage angle signals are considered. The initial phase angle differences are periodically updated during steady state conditions. A time interval for phase angle comparison is set to check the accumulated angle difference once the system is separated.

For the combination implementation, each method performs independently, once one is triggered, the IDM will conduct a cross check between the two methods to validate each other.

Once islanding condition is detected, the algorithm loops itself again and performs the same detection within the two islands to determine if the case at hand is one of island within island. The resulting, including detection flag, islanded PMU information, and average frequency values in the separated systems are subsequently saved in the RTDMS Phasor Archiver Database.

2.6 Composite Alarms Module

The composite alarms are to use current alarms and perform logical combination of them to generate composite alarms. In RTDMS Server, eight or four levels of alarms configuration is available. Based on the existing alarms, simple Boolean logic, such as “AND”, “OR” and “NOT” should be used to perform logical combination of them to generate composite alarms.

The generated composite alarms will be saved in the RTDMS database and further get pushed to the RTDMS Client. From RTDMS Client, composite alarms will become a new metric row in the incident indicator, where user can associate composite alarms with jurisdictions. If a composite alarm gets triggered, the corresponding alarm entry will populate the alarm grid view. At the time of alarm occurrence, the automated event analysis window is designed to pop up and show this composite alarm information.

A new “Composite” configuration will be added under “Alarm Event” tab. For this configuration, user will be able to add new composite alarms, specify alarm name, priority, level, message, area, source and description. Then an alarm expression editor will be available to choose existing alarms to form composite alarms, using “AND” logical operation, as shown in Figure 5.

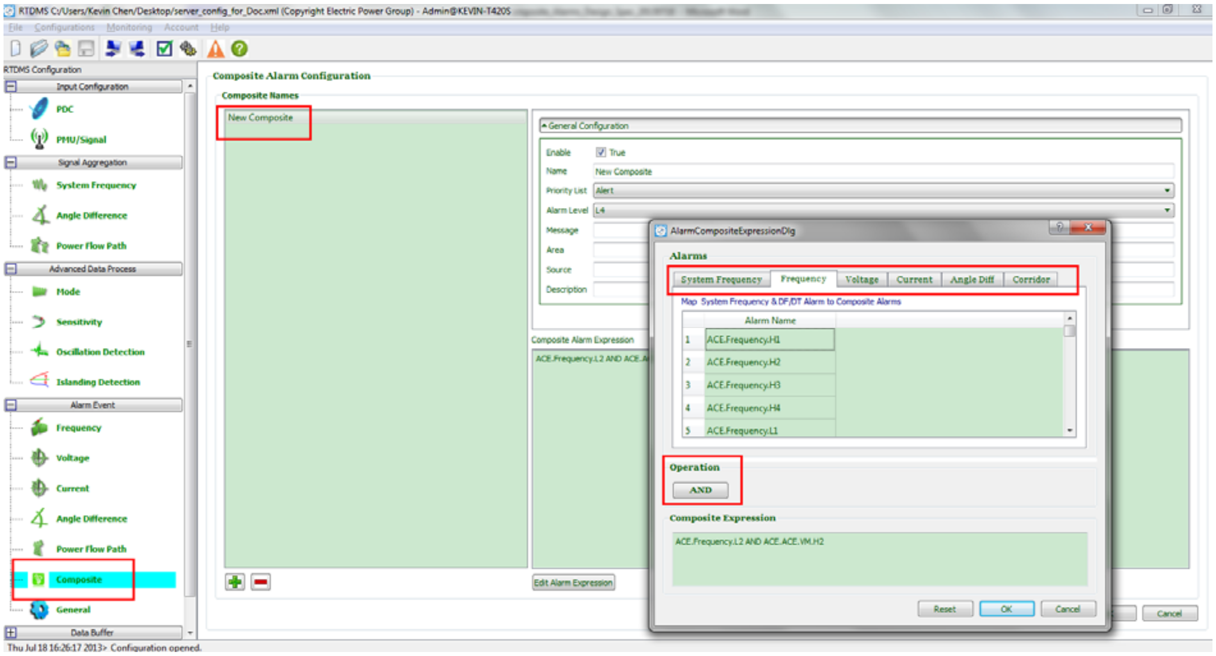

Figure 5. RTDMS Server Configuration for the Composite Alarms Module

3 ApplicationVisualization

3.1 Incident Indicator

Additional rows will be added to the RTDMS Client incident indicator to reflect alarms/event from the above event analysis modules, as shown in Figure 6.

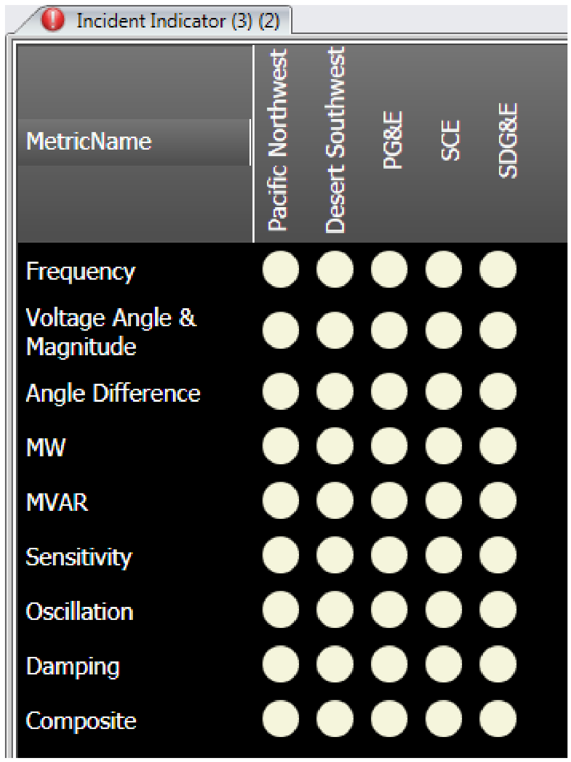

Figure 6. Sample Incident Indicator

3.2 Pop up window

For each analysis module, at the time of alarm occurrence, the automated event analysis window is designed to pop up on the user configured map layer and show associated information, including the following:

- Alarm occurrence time
- Alarming signals/PMUs
- Alarming signal value

A sample event analysis pop up window is shown in Figure 7. When multiple alarms happen relatively the same time, multiple pop-up windows will be shown on the same map layer.

However, an option will be provided for the user to set the maximum number of pop ups that can be seen at one time.

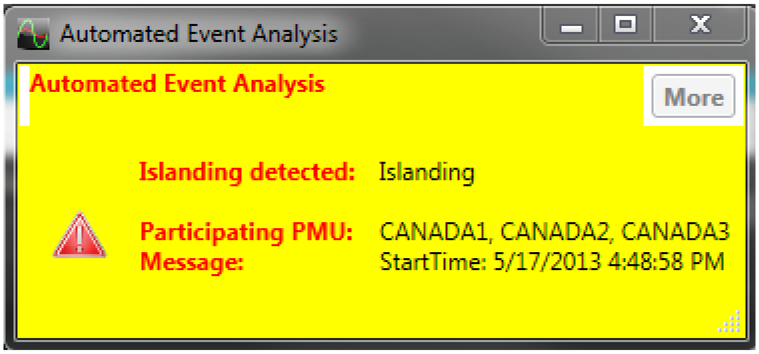

Figure 7. Sample Automated Event Analysis Pop Up Window

3.3 Detailed Event Analysis Display

After clicking of "more" button on the event analysis pop up window, a detailed event analysis display will be called up to present key metric info associated with the event. This display will include a snapshot of measurements and analysis results for system frequency, voltage, angle difference, oscillation and sensitivity.

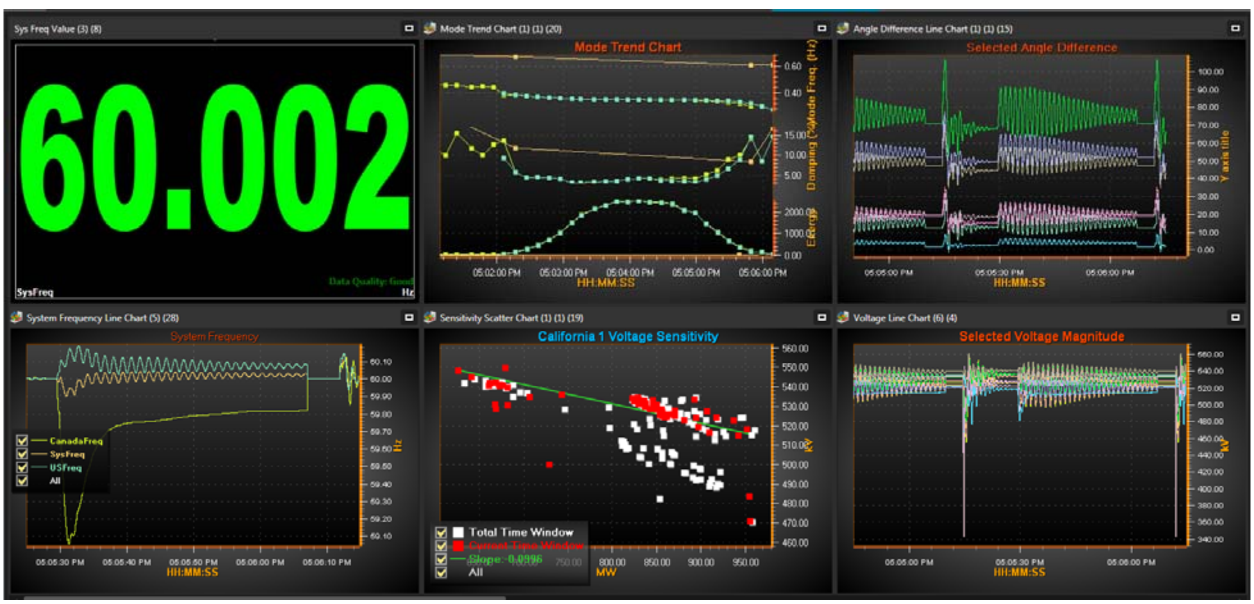

Figure 8. Sample Detailed Event Analysis Display

4 References

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[3] Tate, J.E.; Overbye, T.J.; , "Double line outage detection using phasor angle measurements," Power & Energy Society General Meeting, 2009. PES '09. IEEE , vol., no., pp.1-5, 26-30 July 2009

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APPENDIX D:
RTDMS 2012 Visualization Wizard Design Specifications

Real-Time Dynamic Monitoring System (RTDMS) 2012 Visualization Wizard Design Specifications (Final)

Submitted to CASIO

Electric Power Group, LLC
201 South Lake Avenue, Suite 400
Pasadena, CA 91101
Tel: (626) 685 2015

03/10/2013

Document Change History

Version No.	Document ID	Author(s)	Date	Reviewed / Edited / Approved by	Date of Internal Review	Description of Change
1.0	RTDMS 2012 Client Design Spec.	Simon	09/22/11			First version of the document
		Simon	11/01/11			Section 2 & 4 updated
		Uday	05/02/12			Updated section 9
		Pankaj	05/02/12			Updated section 6
		Simon	05/03/12			Updated rest sections
		Simon	03/10/13			Added section 9, 10, 11, 12, 13, & 14.

Preface

CAISO has been using the RTDMS (Real Time Dynamics Monitoring System) from Electric Power Group (EPG) to provide the wide area monitoring through phasor functions for CEC #2 Project. To meet the requirements of TASK 5 “Transition RTDMS to Production Quality Grade” of the contract, EPG is submitting the design and functional specification of RTDMS 2012 to CAISO.

Contents

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1. Introduction

Real Time Dynamics Monitoring System (RTDMS™) has been evolved since its inauguration in 2003. RTDMS versions 1 to 5 are based on DCOM technology and mainly as server/client two-layer desktop applications. As new requirements arise and technologies advancements, RTDMS has been re-architected as server/database/interface/client four-layer enterprise application. RTDMS Server, RTDMS Phasor Archiver Database, and RTDMS Intelligent Synchrophasor Gateway have been implemented. RTDMS Client, the presentation layer, is the last to be designed and implemented. This document provides the detailed design of new RTDMS Client, that is, RTDMS 2012 Client.

2. Functional Requirements

This section outlines overall functional requirements to be implemented.

2.1 Power System Requirements

2.1.1 RTDMS Design and Functions

- RTDMS provides a global view of key metrics
- For each metric, users can define alarms and threshold values
- If an alarm or a threshold is violated, users are alerted visually via color coded traffic lights
- RTDMS drill down architecture enables the users to diagnose the problem, identify the location of problem, assess current system condition by review of the different metrics, and reach conclusions on what actions should be taken
- Typical current uses of RTDMS are for wide area situational awareness, event assessment and analysis, identification of degradation of key performance metrics for corrective reliability actions, real time monitoring in control rooms
- RTDMS design offers users a global and local view as well as flexibility to analyze and assess key power grid metrics to form a good composite assessment of grid conditions. The current functionality is well suited for operating engineers and planners but presents some limitations for operators

2.1.2 Operator Needs – Items to Consider for RTDMS

- Operators rely on EMS/SCADA in carrying out daily operations
- Phasor technology needs to provide additional value to operators so that it can be embraced and made a part of their daily operations
- Operators are trained to monitor and act
- Operators do not have the time to perform event diagnostics – they are focused on what may happen next rather than what has happened
- If operators don't find value in using Phasor technology in everyday operation, they will not adopt the technology
- Phasor applications need to integrate with daily operations – use for preventing major blackouts which are infrequent and may occur once in 10 years, is not enough for adoption
- Applications for operators have deliver value, be simple to use, don't require analysis and detective work, and point to actionable displays
- Roll out of phasors technology in real time operations needs to be managed – start with simple items that can be integrated in daily operations that provide value to operators
- With adoption, add new functions and uses that can be integrated in operations

2.1.3 Approach for New RTDMS Functions and Features for Operators

- Utilize the RTDMS platform to run a portfolio of independent applications based on different metrics and decision processes
- Automate the decision process and present actionable results to operators
- Enable operators to utilize the applications based on user preferences

2.1.4 RTDMS Design Steps to link metrics to displays for use by Operators

- Metrics - RTDMS provides information on metrics eg phase angles, frequency
- Alarms and Thresholds - For each metric, users can establish alarms and thresholds
- Displays - Once a metric crosses a threshold, RTDMS displays that via color coded traffic lights
- Assessment – for each threshold violation, the assessment process is to review other metrics, diagnose the situation, reach conclusions and develop menu of actions for operators
- Conclusions – these may include type and location of event, summary of key associated metrics that provide a total picture for operators
- Action – based on conclusions, actions may be to contact RC in neighboring footprint, change generation, flows, loads, or capacitance
- Displays – present metrics, conclusions and actions to operators via pop up displays

2.1.5 Examples of Daily Use Applications – Goal is to develop displays that give operators answers and action options (pop up displays for example)

- Incident Locator: 2 components – detection and location. Use synchrophasor data to detect event, identify event location, and characterize event based on signature (frequency drop, recovery etc)
- Islanding Detector: check for PMU's with frequency deviation above a threshold (user settable). Check frequencies and phase angles to identify groupings that represent islands (need algorithms)
- Deviation Detector: Compare predicted angles with measured angles and generate alarms when deviations exceed thresholds (settable). Predicted angles can be inputted into RTDMS from daily operating plan (security constrained economic dispatch). Requires manual or automated input of angle limits from operating plan
- Oscillation Detector – identify which generators are oscillating against each other and needed corrective actions
- Frequency Response Calculator
- Generator Performance Validator – calculate frequency response and compare to expected response. Flag issues related to poor performance – PSS, excitation etc
- Voltage Stability Monitor – if phase angles exceed thresholds, check voltage sensitivities on intermediate buses and translate into recommended operator action (eg high angle and high sensitivity = action to improve voltage support)
- Margin calculator – use PMU readings to calculate margins and menu of actions to increase margins (V & R integration)
- Power system information shall be organized and presented to the user in a manner that allows the user to immediately become aware of any condition requiring urgent attention, to quickly grasp the most significant aspects of a situation, and to have fast access to related data for the investigation of details of the information presented. For example, PMU data from all connected PMU devices and phasor data applications generated alarms and their calculation results shall be

able to be presented on a 2-D geographic map with grid system diagrams for user to assess the overall wide-area system situation in real-time.

- Display indicators shall indicate the power system condition as: “Normal”, “Alert”, “Serious”, “Critical”, or “Interruption”. An alarm shall be generated whenever a new system status is reached or entered. This alarm shall be annunciated at all the user/operator stations by an audible alarm and flashing of the indicator. Separate acknowledgement shall be required for the indicator at each console.

2.2 Software System Requirements

2.2.1 Stability Requirements

The system is required to have 99.99% availability.

2.2.2 Performance and Scalability Requirements

System shall perform well when more and more PMUs are added into the system.

2.2.3 Extendibility Requirements

System shall be able extended to include more functions such as composite alarms, fault detection in the future.

2.2.4 Usability Requirements

The system should adopt simple, fast, and unambiguous operating and navigating procedures to guard against user errors. Whenever feasible, single-step procedures should be used, such as initialization a function by clicking a button, for frequently used functions and for critical functions. Common and frequently employed actions shall be initiated from toolbars. The use of pop-up dialog menus which overlay portions of one or more windows shall be kept to a minimum or transparency.

It is required to thoughtful use of borders or frames to visually group information that logically belongs together. Color shall be used sparingly for the following purposes: to distinguish different dynamic states, for clarification purposes, and to highlight important information. Color shall not be used for decorative purposes.

On-line help shall be readily available on displays and shall be designed to present useful information and explanations to the inexperienced user. The System shall conform, as much as possible to the Microsoft Windows standards for the on-line help function (e.g., pressing the F1 function key shall open the Help directory window).

The time data, such as PMU time stamp, shall be stored in the system in Coordinated Universal Time and displayed in local time zone. It shall be possible to have the option for turn on/off automatic daylight saving adjustment.

The detailed design of the user interfaces, including navigation trees and menu bars, the format and contents of dialog menus, the colors of display features such as menu bars, window borders, display background, and the operational procedures, shall be selectable by the individual users.

2.2.5 Security Requirements

System shall meet NERC CIP requirements.

3. Design Goal and Overall Architecture

This section describes RTDMS system architecture and the key supporting technologies.

3.1 Design Goal

3.1.1 Built to last, built for change

Flexible and extendible.

3.1.2 Multi-data sources

Real-time, historical, event phasor data and other data sources such as EMS, PI through ISG and different adaptors

3.1.3 Due-deployment over LAN and over Web

Standalone & Web applications.

3.2 Over Architecture

3.2.1 RTDMS System Architecture

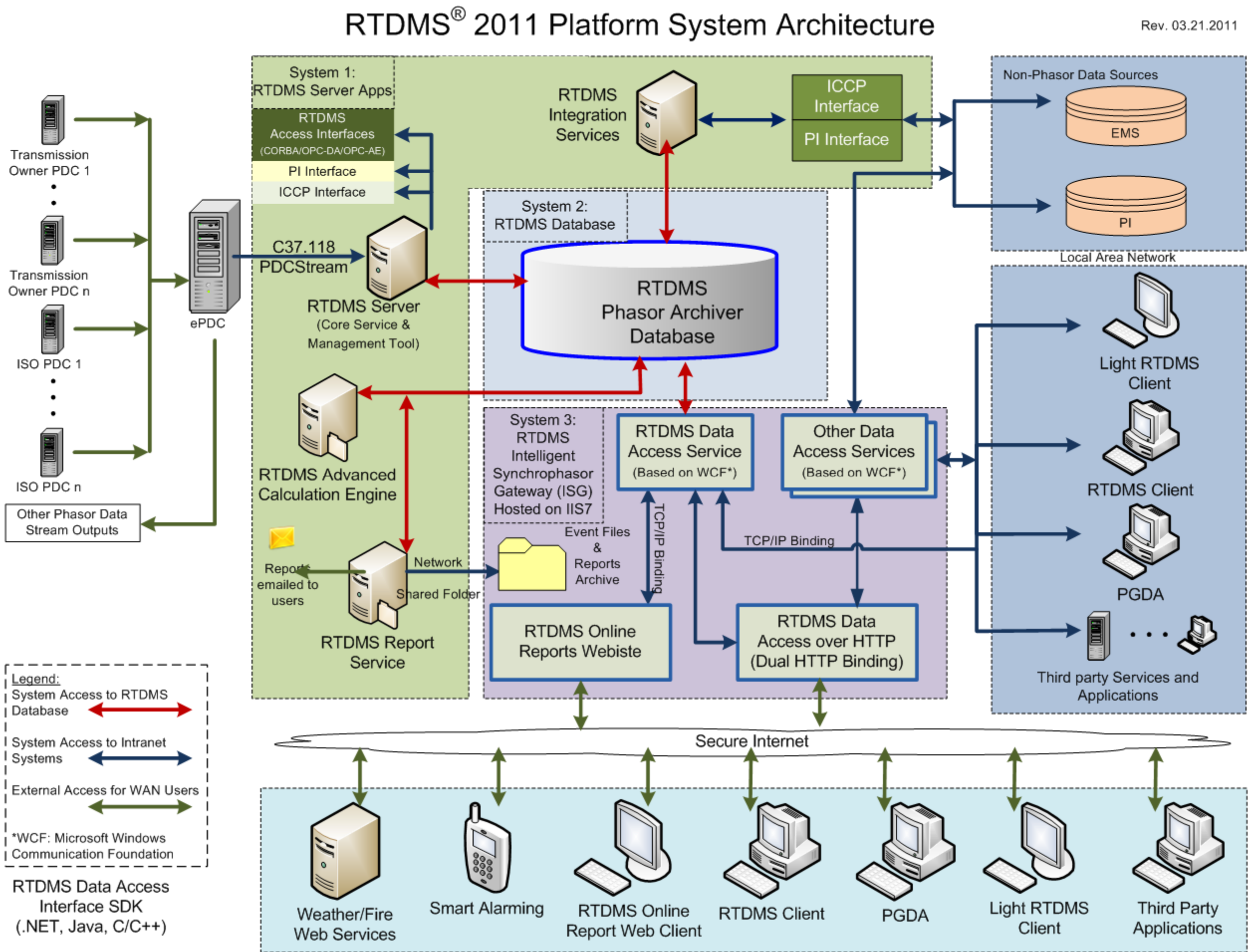


Figure 1 RTDMS System Architecture

3.2.2 RTDMS Visualization Wizard Architecture

ISG Driven Architecture:

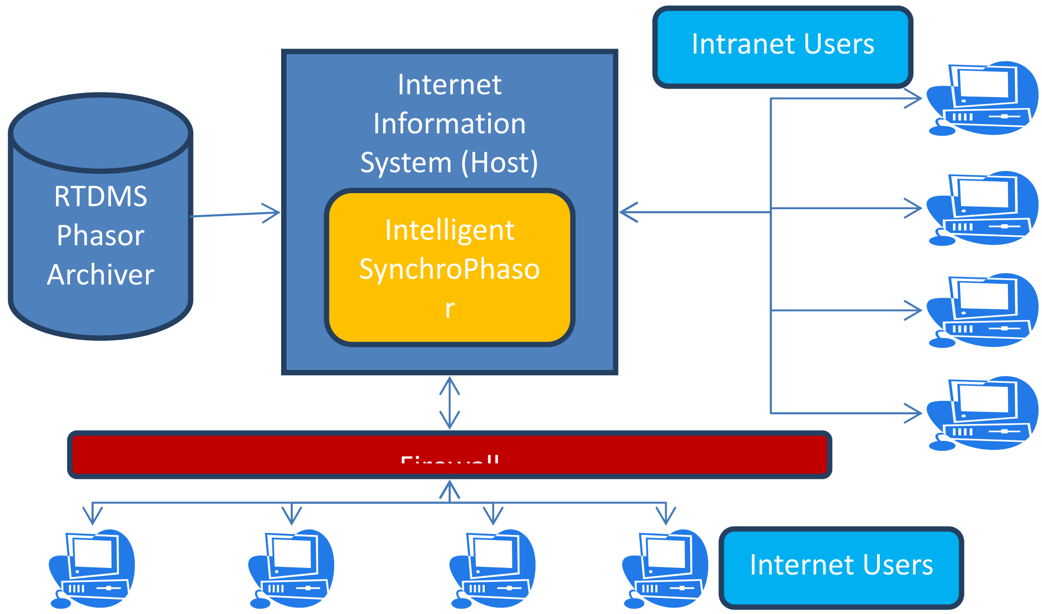


Figure 2 ISG Architecture

Block diagram of RTDMS Visualization:

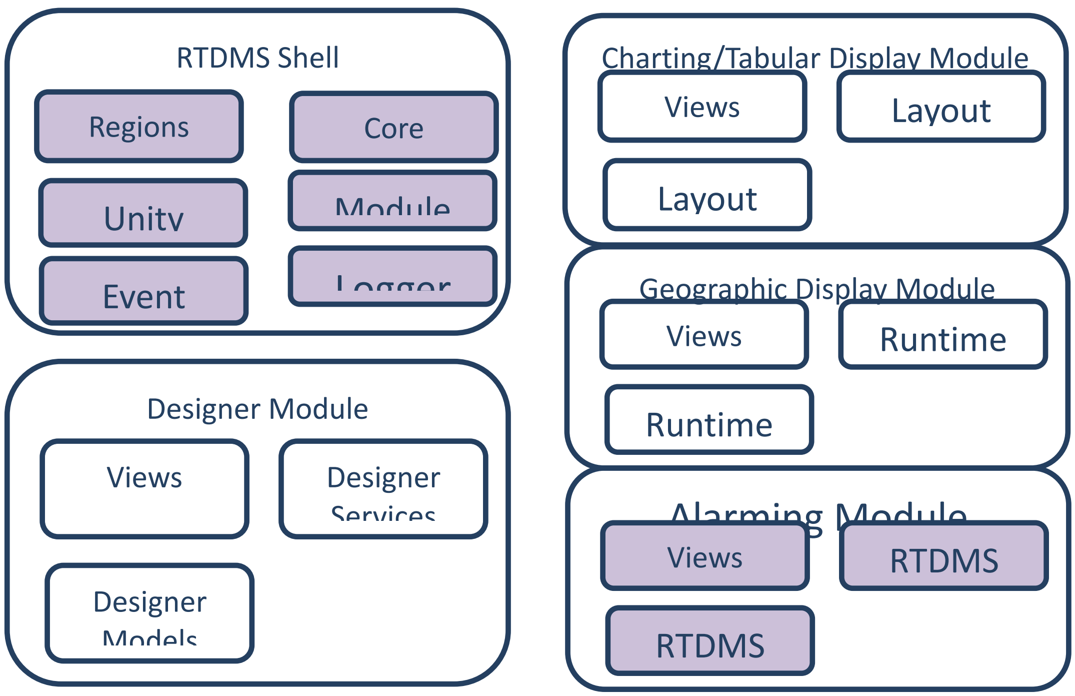


Figure 3 RTDMS Client Block Diagram

3.3 Technology and Third Party Libraries

RTDMS Client 2012 will base on Windows Presentation Foundation technology and heavily utilizing Prism 4 library to achieve flexibility, reusability, and plug-n-play.

3.3.1 Platform - Windows Presentation Foundation

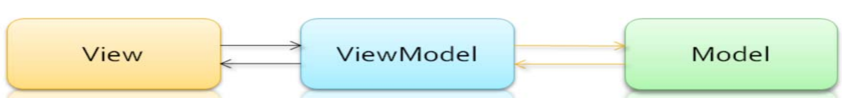
Windows Presentation Foundation will be used as the key technology.

- Next-generation presentation system for building Windows client applications
  - desktop applications
  - Silverlight Rich Internet Applications (RIAs)
  - Windows Phone 7 applications
- Visually stunning user experiences
  - Resolution-independent
  - Vector-based rendering engine
  - Built to take advantage of modern graphics hardware
- Features that include:
  - Extensible Application Markup Language (XAML)
  - controls, data binding, layout
  - 2-D and 3-D graphics, animation, styles, templates
  - documents, media, text, and typography

3.3.2 MVVM Library – Prism 4

Prism Library has following features:

- Create an application from modules that can be built, assembled, and, optionally, deployed by independent teams using WPF or Silverlight.
- Minimize cross-team dependencies and allow teams to specialize in different areas, such as user interface (UI) design, business logic implementation, and infrastructure code development.
- Use an architecture that promotes reusability across independent teams.
- Increase the quality of applications by abstracting common services that are available to all the teams.
- Incrementally integrate new capabilities.
  - Build for change
  - Build to last



Model-View-ViewModel (MVVM) Pattern for WPF Applications Development in Prism 4.0

- The components are decoupled from each other
- Allowing for components to be swapped
- Allowing internal implementation to be changed without affecting the others
- Allowing components to be worked on independently
- Enabling isolated unit testing

Model:

- Responsible is for business logic and data
- Implements change notification for properties and collections
- implement validation interfaces

View:

- Defines structure, appearance and interactivity of the user interface
- Implemented as a Window, UserControl, Page, DataTemplate, or custom control
- Has little or no code-behind
- Controls data bind to view model public properties
- Behaviors can invoke view model public methods

View Model:

- Responsible for UI logic and data for the view
- Provides a layer of abstraction between the view and the application domain or model
- Plays the role of an adapter between the view and the model when required
- Maintains state for the view, State changes are communicated to the view via data bindings.

Prism 4 framework modules:

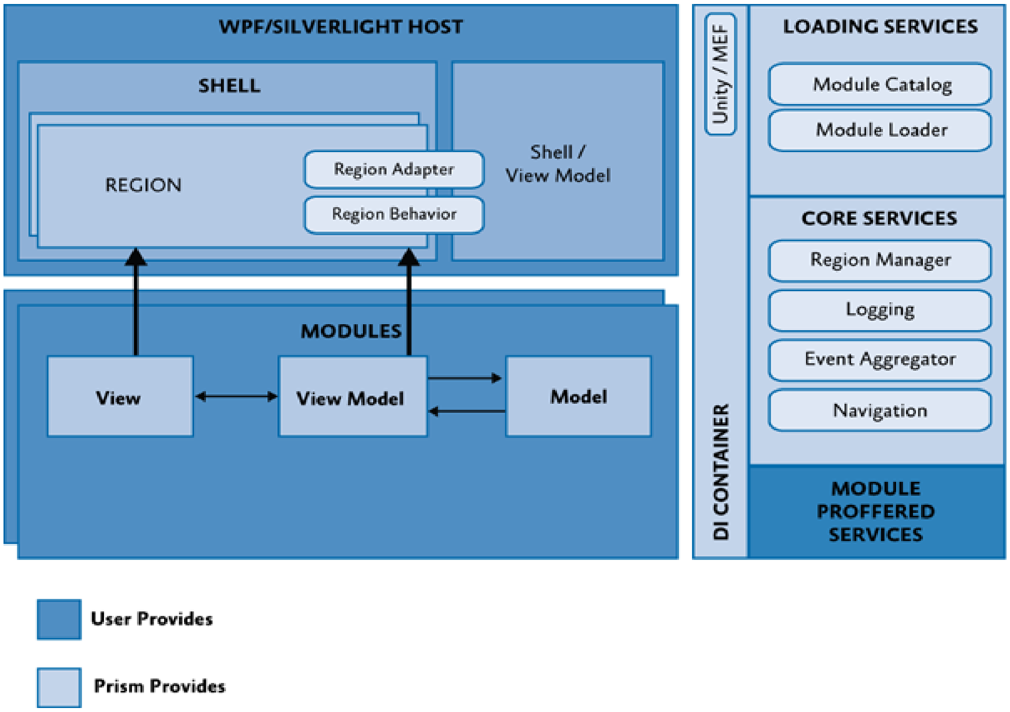


Figure 4 Prism 4 Modules

3.3.3 User Controls - Infragistics

Infragistics' NetAdvantage for WPF Line of Business 2011 Vol. 2 is used for user interface development.

3.3.4 Arction Lightning - charting

Arction's LightningChart Ultimate will be used for charting for its superior performance.

3.3.5 - Geospatial Display

ESRI's ArcGIS API for WPF 2.2 will be used for geospatial display for its features.

3.4 Key Modules & Design Risk Control

3.4.1 Key Modules

Client Framework	Foundation of RTDMS Client

Client GUI	Graphic User Interface
Client Data Service	Module to retrieve from multi sources, manage, and serve data to visualization components
Client Charts	Module of charting including trending, YY chart, bar chart etc
Client Map	Module of layered geospatial display
Client Alarm Viewer	Alarm message display and management
Client Location Indicator	Jurisdiction-measurement matrix
Client Display Manager	Managing views (charts, geospatial, alarm viewer, location indicator etc) into displays.

3.4.2 Risk Control

Arction Lightning Chart is used for high performance plotting. Arction Lightning Chart requires specific video cards and large memory. The performance of plotting will not be optimal on desktops which do meet minimum requirements. EPG will provide the minimum requirements to run RTDMS Client 2012.

4. User Interface Design

This section describes the detailed design of user interface.

4.1 User Interface Structure

4.1.1 User Interface Layout

The high level of user interface layout is show below. The application window is divided into 5 top level areas: Menu, Display, Toolbar, Global Display, and Status Bar.

A Display is a container of Views. A View can be a chart, a geospatial visual, a jurisdiction situational awareness locator, or other components. Views will be named also. If there are several Displays, they are organized by Tab Control.

The Global Display is a container of Views. There will be only one Global Display. The Global Display is a good container for global information such as traffic lights, alarms, etc. The Global Display will be dockable (?).

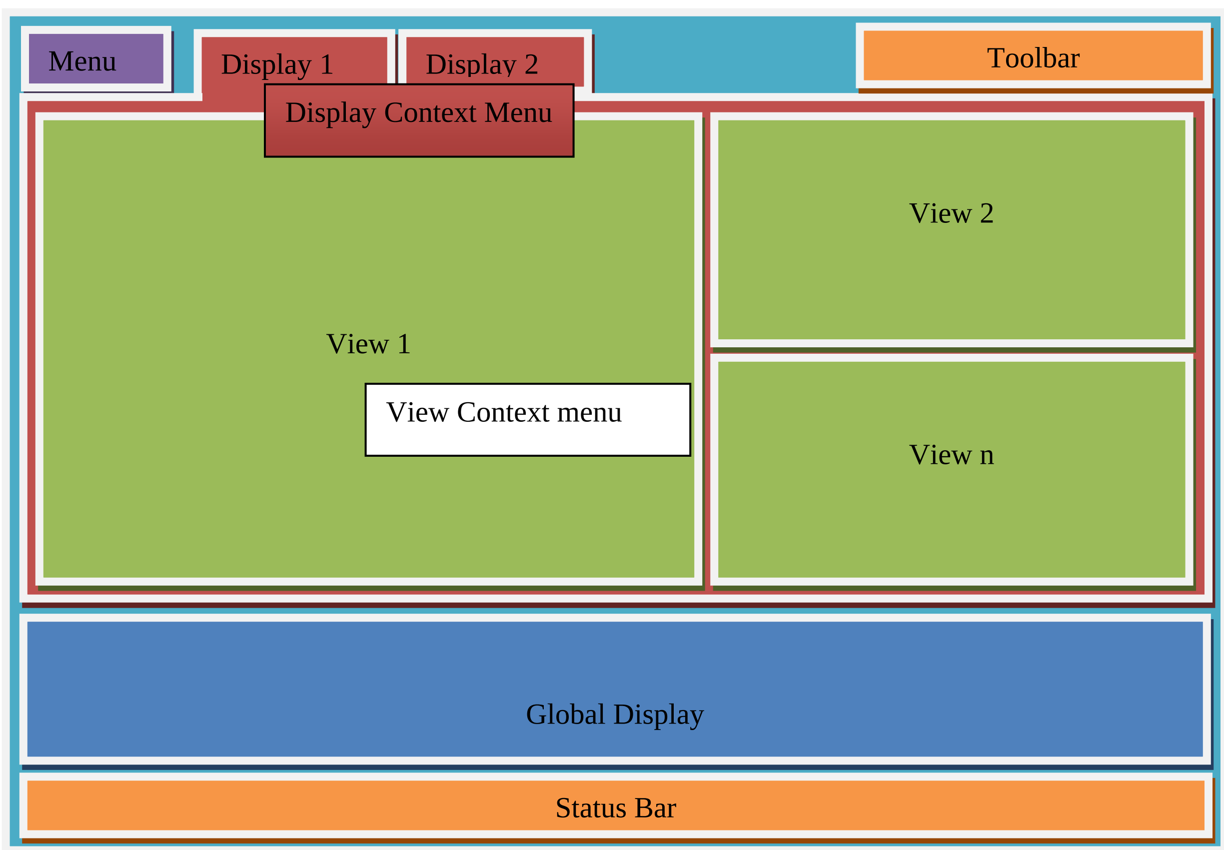


Figure 5 RTDMS Client GUI Layout

4.1.2 Display Tab Control

Displays are organized by Tab Control. A Display tab's name will be display's name. Double click the tab's name will enter editing mode to allow user to change display name.

A number of Views can be contained within a Tab Control. The Display container can have windows layout, tiles layout, and EPG special layout. EPG special layout is to be defined.

4.1.3 Jurisdiction Situational Awareness View

The Jurisdiction Situational Awareness View as shown below will be implemented as an EPG user control which can be placed into any Display. The control will come with its context menu to edit the properties.

4.1.4 Dynamic Information View

Dynamic Information View will be implemented as a list user control. New significant messages will be added on the top. If there is no new message for certain period of time, the text will fade away. The text will appear again when mouse pointer enters the control. The number of maximum messages allowed is configurable through its context menu.

4.1.5 Alarm/Event View

The Alarm/Event View will be implemented as a grid user control. Its best location is Global Display area. It can also be contained in Display area.

4.1.6 Application Menu

The application level menu will be implemented as "Menu" shown in Figure 5.

4.1.8 Context Menu

Display and Views will have context menu to support command at Display and View level only.

4.1.7 Toolbar

Part of Application Menu and Display level context menu will be also available on Toolbar to provide quick access of the commands.

4.1.9 Login & Splash Screen

Four fields: URL of ISG, user name, password, and domain. The default URL of ISG is the one specified during the client installation. The domain will be automatically discovered by the client along with "RTDMS Local User" in a list box for selection.

4.2 Application Menu

The Menu will define the application level commands. View level commands will be through context menu.

Table 1 Application Menu

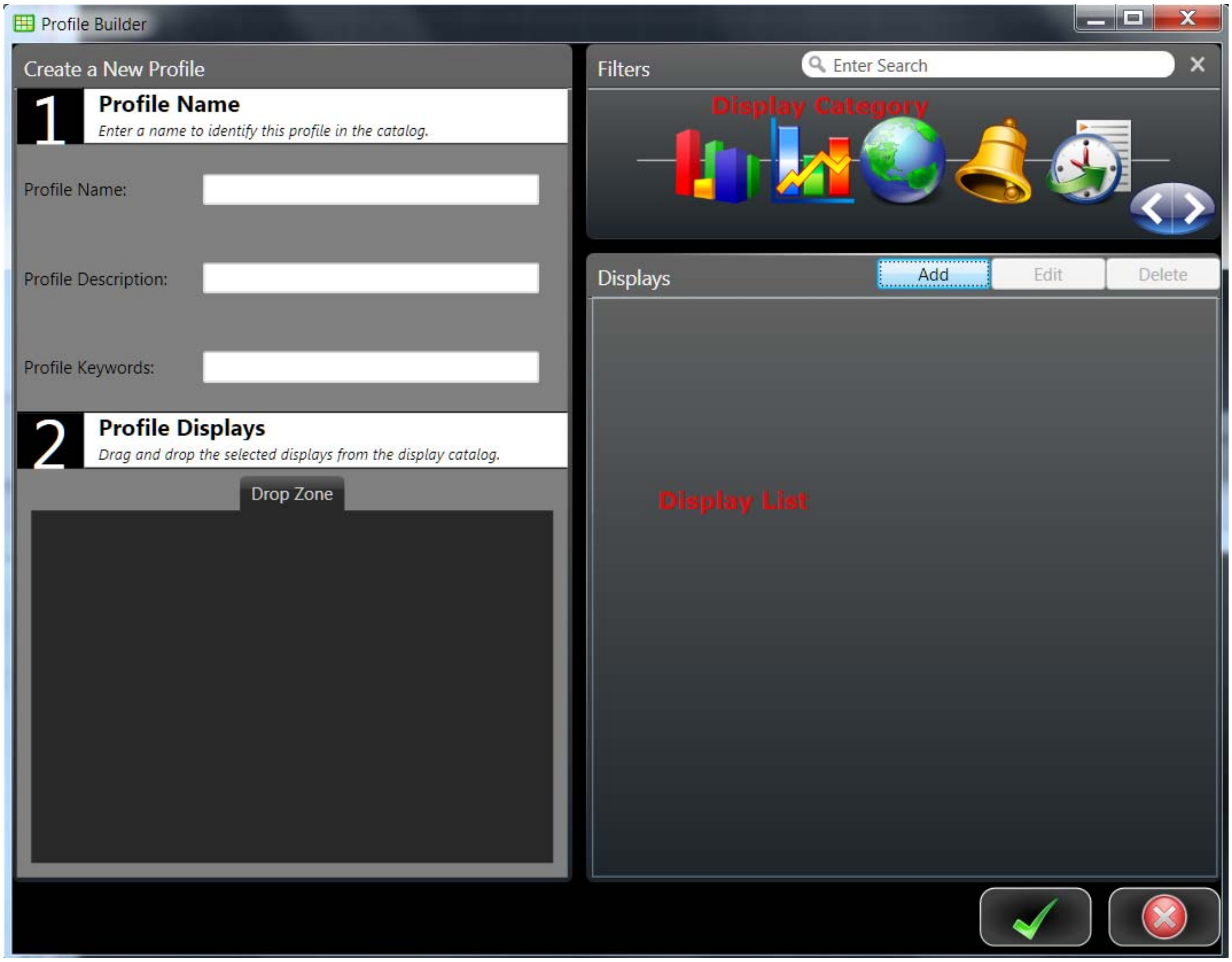
Menu Item	Sub Menu Item	Description
New Profile …		Open a dialog box to start a new Profile with a blank Display
Open Profile …		Open a dialog box to load a Profile from database (share point)
Save Profile …		Save the current Profile into database
Save Profile As …		Open a dialog box to save the current Profile in another name into database.
Publish Profile …		Publish the current Profile into database so other users can share it.
Separator		
Page Setup …		Open a dialog box to setup print page
Print Preview		Open a print preview dialog box for the current display
Print …		Open a dialog box to print the current display
Separator		
Favorites		
	Add Current Display to Favorites	Add the current display to user's favorites.
	Add All Displays to Favorites	Add all displays to user's favorites.
	Manage Favorites …	Open favorites management window to browse and manage all favorite displays
Tools …		
	Pause Real-time Display	All tabs will be paused
	Resume Real-time Display	All tabs will be resumed
	Undo	
	Redo	
	Separator	
	Replay …	Open a dialog box to choose start time, end time, and current time for replay. "VCR" buttons will be shown and enabled.
	Open Online Reports	Open RTDMS Online Reports application
	Load Event Files …	Open a dialog box to browse and load event file in COMTRADE format event file.
	Display Builder …	Open integrated RTDMS Display Builder application
	Separator	
	Database Editor …	Open database editor application to manage displays.
Separator		
Preferences …		Open a dialog box to brows and set user preferences.

Help		
	RTDMS Help	Open help file for RTDMS Client. The help file will include a section about release notes.
	Online Support	Open RTDMS support web portal
	Users’ Group	Open RTDMS Users’ Group portal
	Open Log	Open application log file
	About RTDMS	Open a message box displaying version number and trademark/copy right of RTDMS
Exit		Exit RTDMS Client application

4.2.1 Menu Item “New Profile …”

It is used to create a new display Profile from scratch. When clicked,

1) Create New Profile wizard will be displayed.
2) When “Add” button is clicked, go to display generator as shown in section 4.3.2. The new display will be listed in the display list box.
3) When “Delete” button is clicked, the current selected display will be removed from the list box in memory and deleted from database after user confirms the action.
4) When “Edit” button is clicked, go to display generator with selected display configuration as shown in section 4.3.2.
5) When “OK” button is clicked, the new profile will be saved into database. All current displays tabs will be closed. Prompt user to save current profile if modified. The new profile will be visualized.



4.2.2 Menu Item "Open Profile ..."

It is used to load a display Profile from central database. When clicked,

1) Prompt user to save current Profile if not yet.
2) "Open Profile …" modal window will appear to allow user browse user and public available Profiles.
3) All current display tabs will be closed.
4) The selected Profile will be retrieved and configured displays will be retrieved, de-serialized, and displayed. During the process, progress should be given to users.

4.2.3 Menu Item "Save Profile ..."

It is used to save a display Profile to the central database. When clicked,

1) Prompt user to enter Profile information, such as Profile name and description, if the Profile is new (not exist in database yet).
2) Update central database related tables with user id, console id, save time, and content of displays/views.

3) The process progress should be given to users.

4.2.4 Menu Item “Save Profile As …”

Open a dialog box to save the current Profile in another name into database. When clicked,

1) If the Profile is new (not exist in database yet), do the steps as described in section 4.2.3. Otherwise,
2) Prompt user to enter Profile information, such as Profile name and description.
3) Update central database related tables with user id, console id, save time, and content of displays/views.
4) The process progress should be given to users.

4.2.5 Menu Item “Publish Profile …”

Publish the current Profile into database so other users can share it. When clicked,

1) Set the Profile isPublic as true.
2) Do the steps as described in section 4.2.4.

4.2.6 Menu Item “Favorites -> Add Current Display to Favorites”

Add the current display to user’s book mark. When clicked,

1) Popup a dialog box for user to enter display alias name and favorite description the display, by default the alias name is the display name, and Favorite description is the display description.
2) Insert/Update the current display to Client_Favorite table.
3) Confirmation message box will be given either successful or failure.

4.2.7 Menu Item “Favorites -> Add All Displays to Favorites”

Add all displays to user’s book mark. When clicked,

1) Insert/Update the all displays to Client_Favorite table.
2) Confirmation message box for every display will be given either successful or failure.

4.2.8 Menu Item “Favorites -> Manage Favorites …”

Manage user’s favorites. When clicked,

1) Popup a window for favorite’s management listing user’s favorites.
2) Command provided to edit alias names and descriptions, and search/delete a favorite.

4.3 Display Context Menu

There will be context menu for every tab.

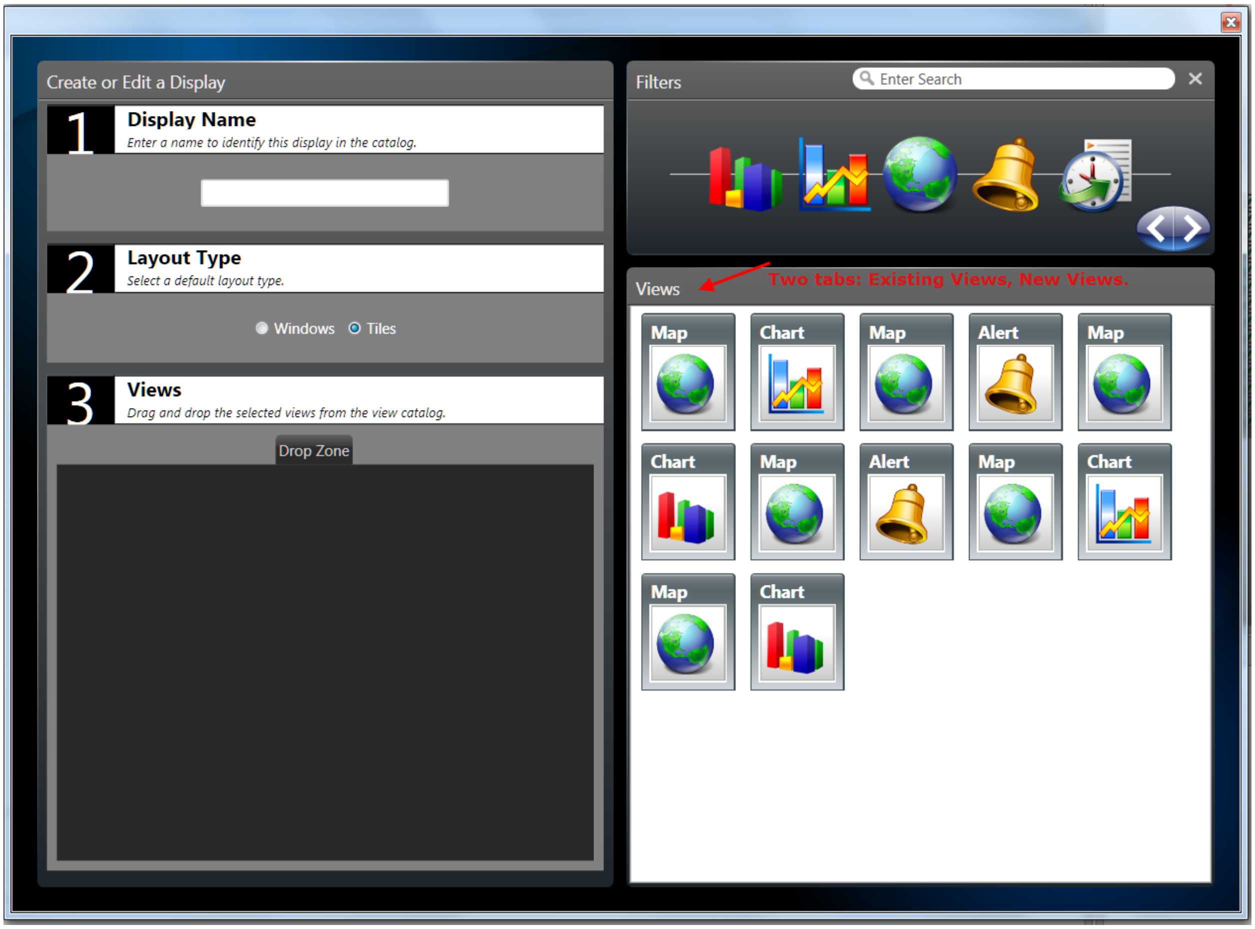
Table 2 Display Tab Context Menu

Menu Item	Sub Menu Item	Description
New Display …		Open display creation wizard to create a new display
Open Display …		Open Display Directory window to load a display from

		database
Edit Display …		Edit current display
Save Display …		Save the current display into database
Save Display As …		Open a dialog box to save the current display into another name
Publish Display …		Publish the current display into database to share with other users
Remove Display		Delete current display from database
Separator		
Save Display As Image …		Open a dialog box to save the current display as images in PNG, JPG formats
Export Display Data …		Open a dialog box to specify data format (CSV format in the first release) and file name
Print …		Open a dialog box to print the current display
Separator		
Add Current Display to Favorites		Add the current display into user's favorite list
Close Display		Close the current display. Closed displays can be brought back when "Show Closed Display" context menu is clicked.
Close Other Displays		Warning message will be displayed first
Detach Display		Show current display in another window, toggle to Attach Display when detached
Separator		
Layout		
	Tile Style	Change the current display's layout to Tile Style from Window Style
	Window Style	Change the current display's layout to Window Style from Tile Style
	Restore Views	Restore all views' size and position
Reset Views		Reset all views of the current display to their default zooming/panning level
Separator		
Pause Real-time Display		All views within the current display will be paused
Resume Real-time Display		All views within the current display will be resumed
Separator		
Search …		Search content in a display …

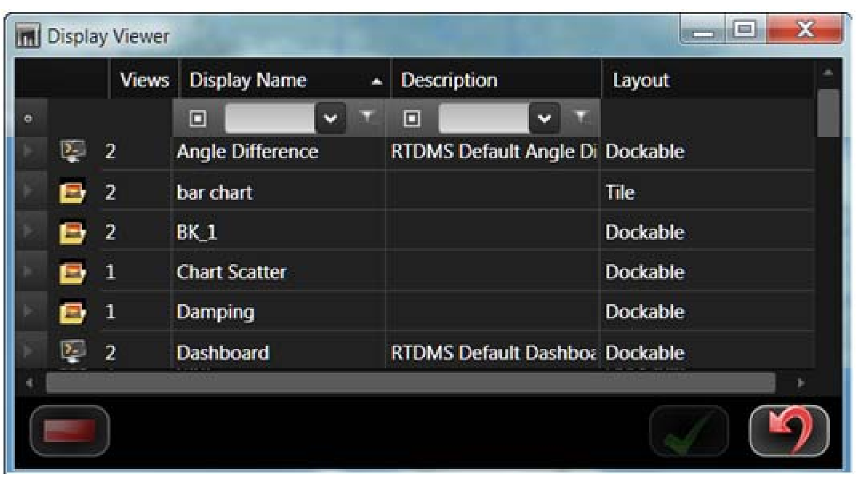
4.3.1 Menu Item "New Display …"

1) New Display wizard will be shown.



4.3.2 Menu Item "Open Display …"

A dialog box will popup listing all available displays available for the user.



4.3.3 Menu Item "Save Display …"

Save current display to database. A confirmation message box will be displayed.

4.3.4 Menu Item "Save Display As …"

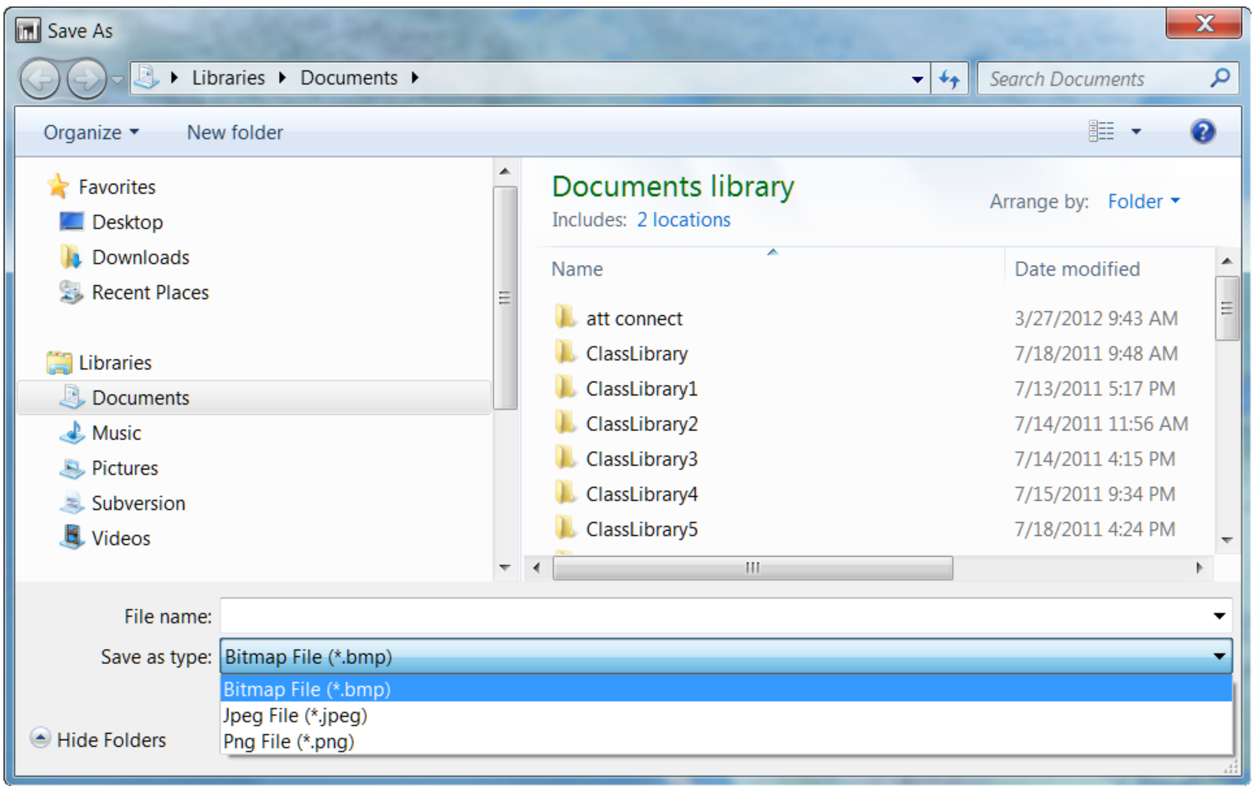
Save current display into different name.

4.3.5 Menu Item "Publish Display …"

Publish current display for selected users.

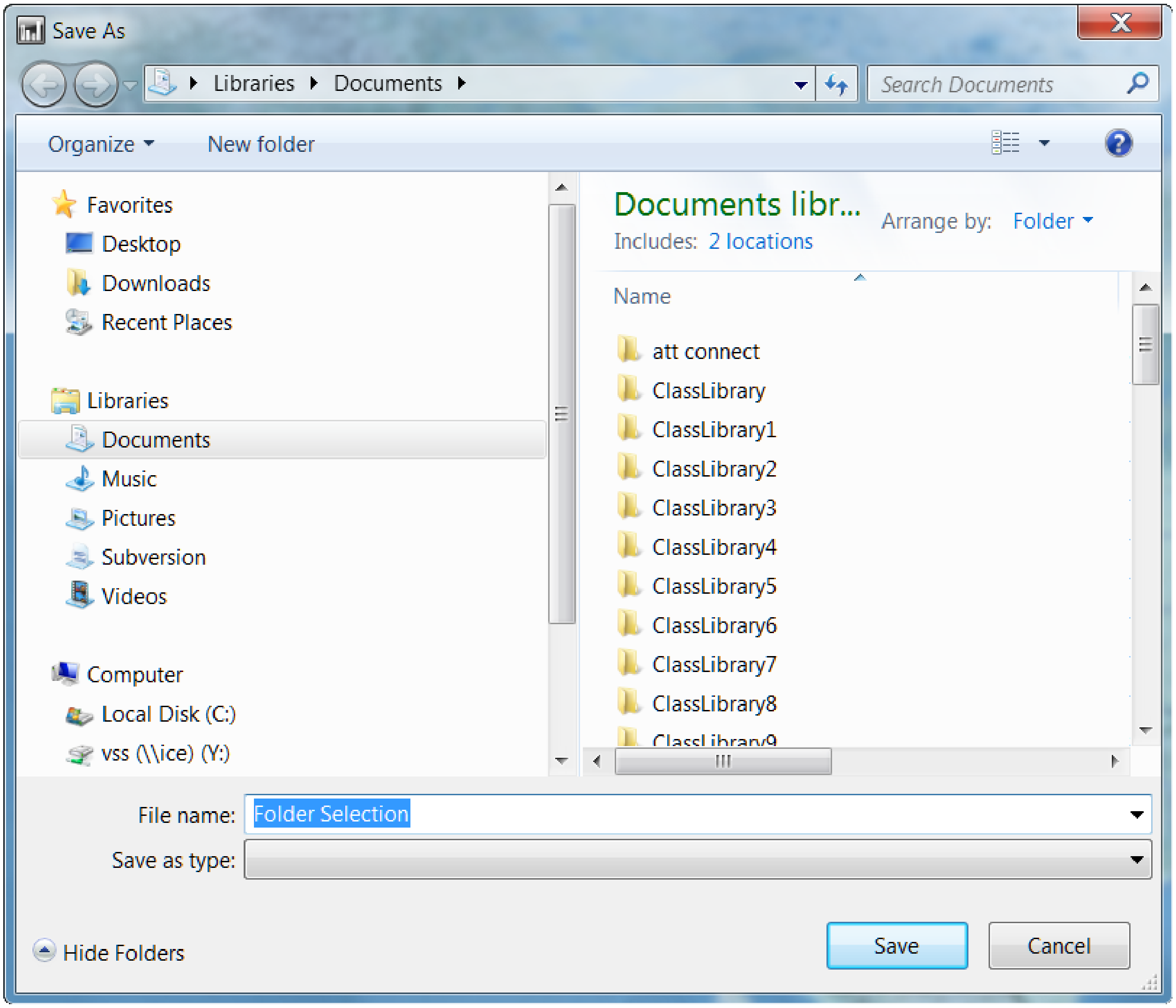
4.3.6 Menu Item "Save Display as Image …"

Three image formats (BMP, PNG, and JPG) will be supported.



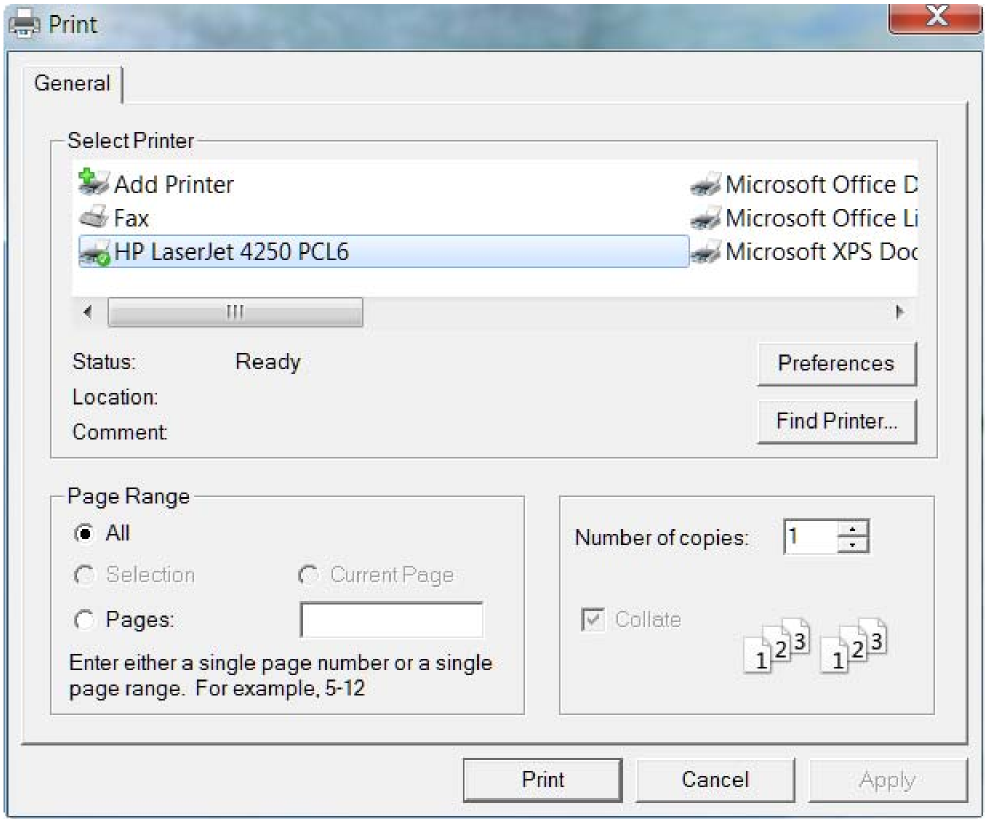
4.3.7 Menu Item "Export Display Data …"

Every view in the current display will export its data into its own file.



4.3.8 Menu Item "Print …"

Show standard Print dialog box and print the current display.



4.3.9 Menu Item “Favorite Current Display”

4.3.10 Menu Item “Close Display”

The display will be closed.

4.3.11 Menu Item “Close Other Displays”

Other displays except the current display will be closed.

4.3.12 Menu Item “Detach Display”

Make the current display floating.

4.3.13 Menu Item “Layout-> Tile Style”

4.3.14 Menu Item “Layout-> Window Style”

4.3.15 Menu Item “Layout-> Restore Views”

4.3.16 Menu Item “Reset Views”

Reset all views into their default XY limits and zoom level.

4.3.17 Menu Item “Pause Real-time Display”

Pause real-time display

4.3.18 Menu Item “Resume Real-time Display”

Resume real-time dispay

4.3.19 Menu Item “Search …”

Search for displayed items.

4.4 View Context Menu

Context menu will be associated with every View sperately. It’s important to have the common menu items named the same:

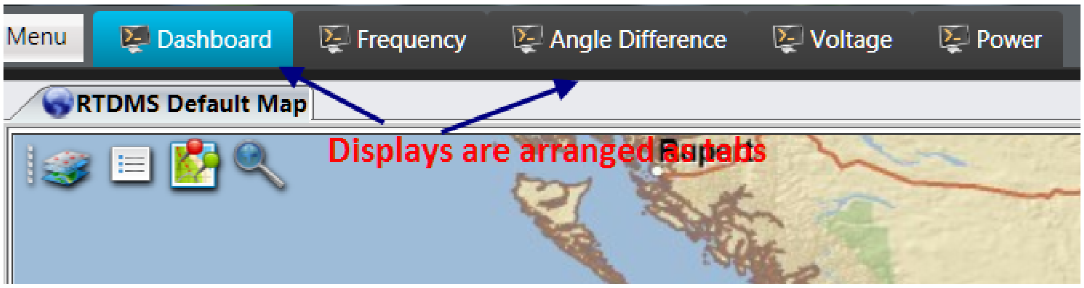
For all chart and geospatial views, the following menu items will be implemented. For some special views additional menu items will be implemented. For non-chart/geospatial views, context menu will be different and view dependent.

Table 3 View Context Menu

Menu Item	Sub Menu Item	Description	Apply To
Reset		Reset current view’s zooming level	
Pause		Just this view	
Play		Just this view	
Move To …		Open a dialog box to choose a display the view will be moved to	
Save View		Save the current view into database	
Save View As …		Open a dialog box to save current view as a view file into database	
Publish View …		Publish current view into database	
Separator			
Save View As Image		Open a dialog box to save the current view into an image file	
Export View Data …		Open a dialog box to export current view’s data into a CSV file.	
Print Preview …			
Print …		Print current view	
Separator			
Copy to Clipboard …		Copy the view to the clipboard	
Properties …		Open View properties editor to select data, duration, and configure visual options.	
Toolbox …		Open toolbar overlay on left corner of the map.	Map Only
Help …		Context help for this view	

4.5 Navigation from One Display to Another

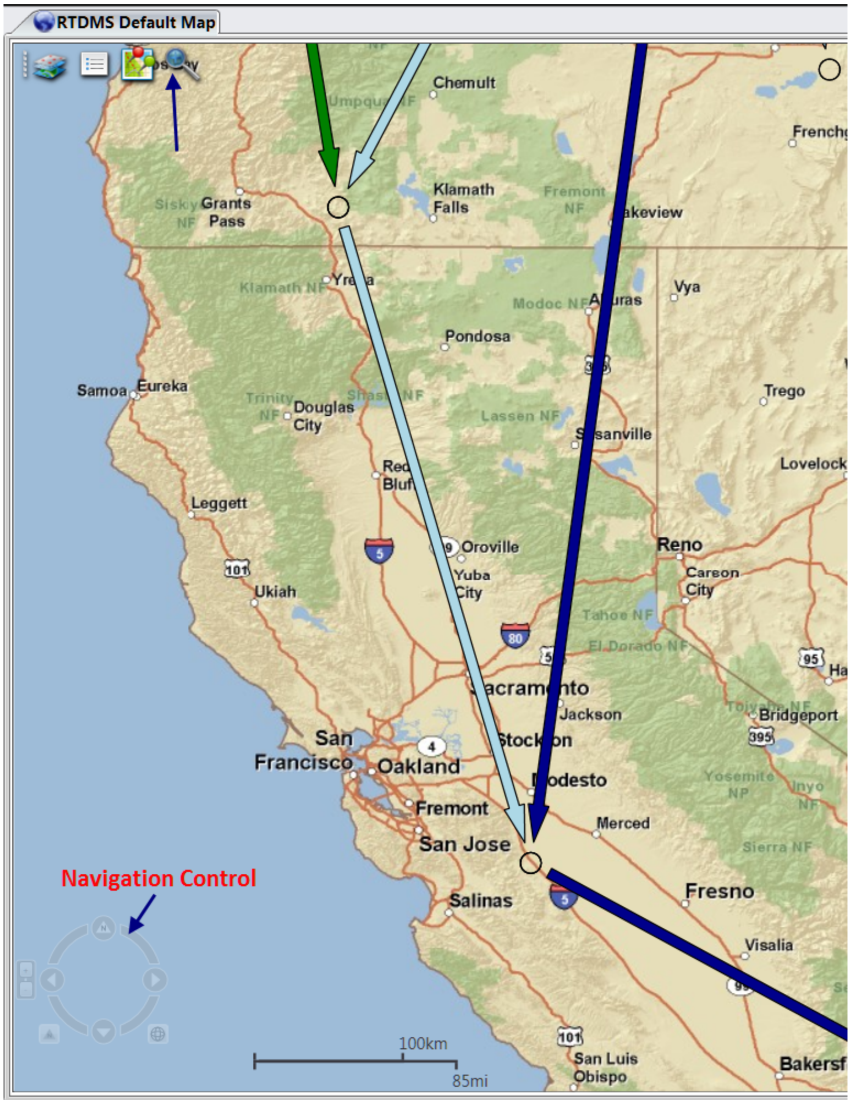
By clicking the Display tabs.



4.6 Zooming/Panning

Through mouse control. Charting: use Lightening Chart convention.

Geospatial: user ArcGIS convention.



4.7 Picking/Finding/Marker Visual Objects within a Display

4.8 View Layout Management

Menu -> Layout

4.9 Display Style (Theme) Management

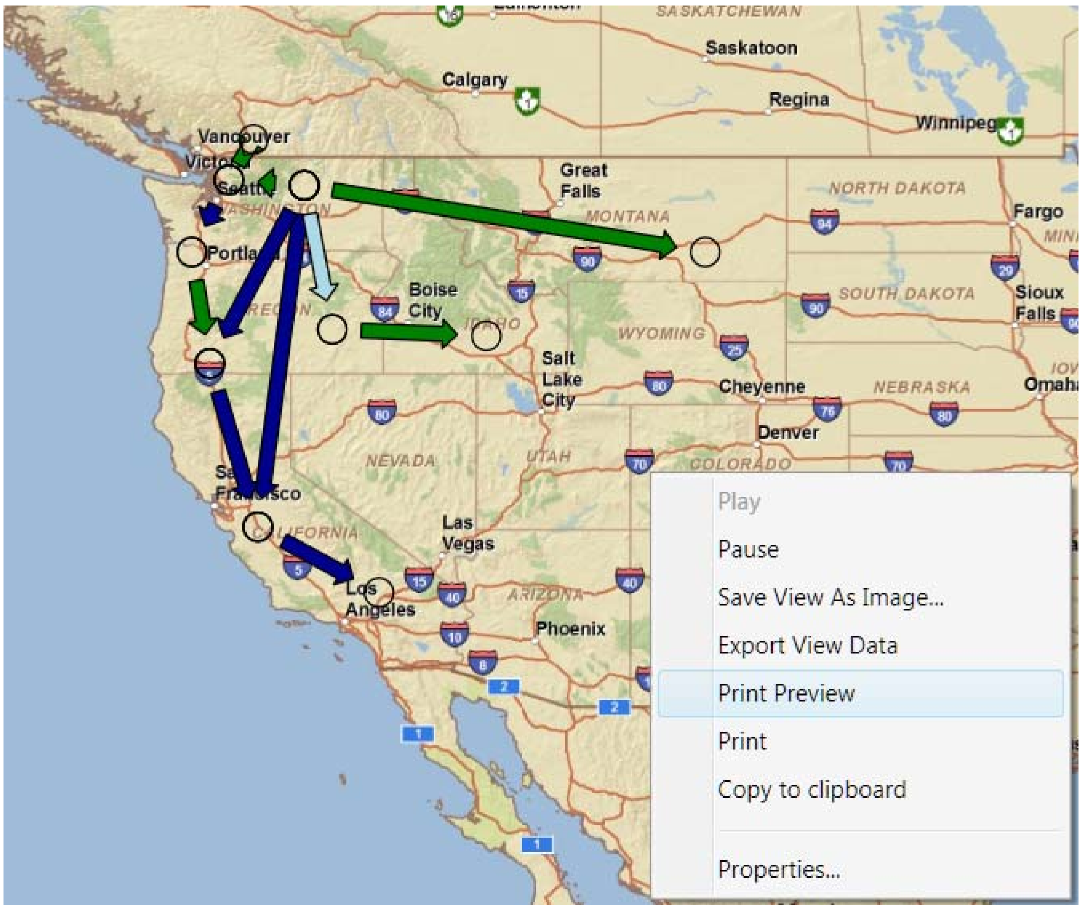
Menu -> Preferences …

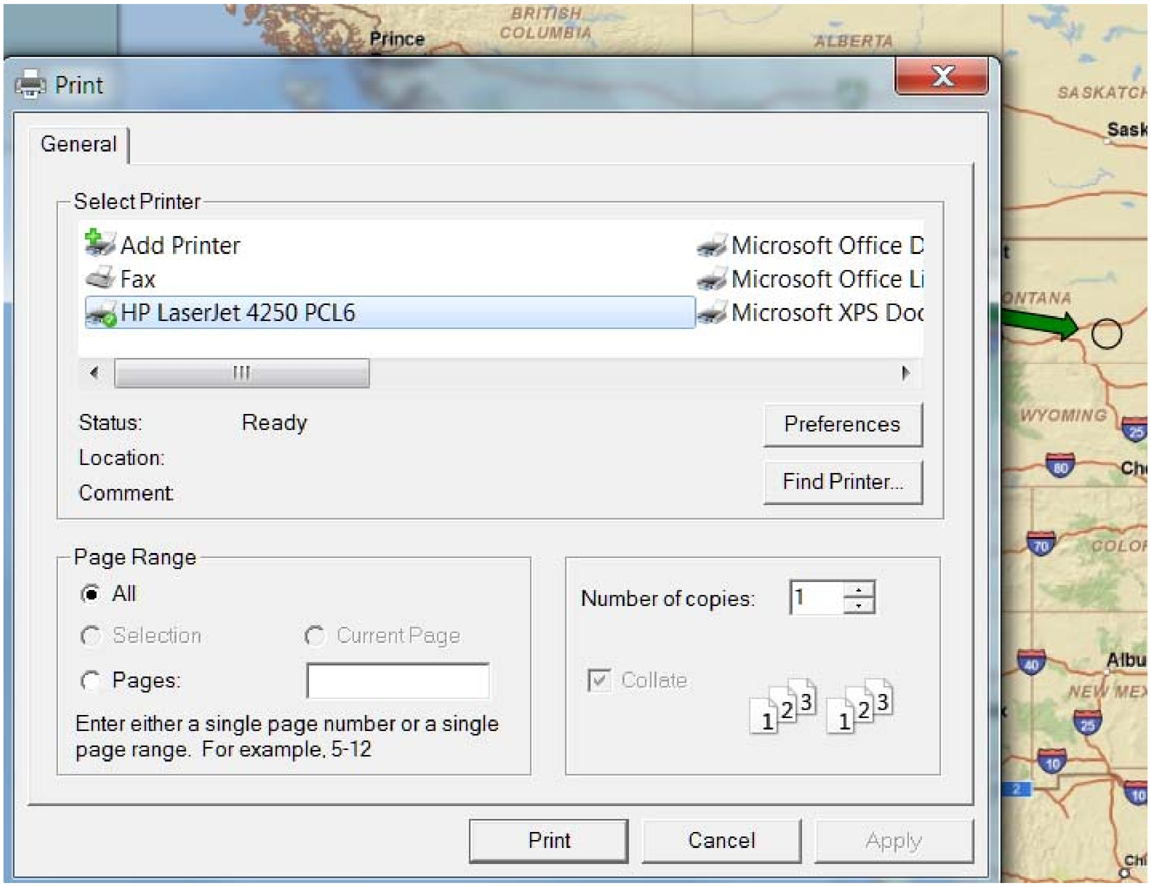
4.10 Exporting Data, Exporting As Images

Menu->Export Data …: Export current Display's Views' data into selected data format and with specified name.

4.11 Printing

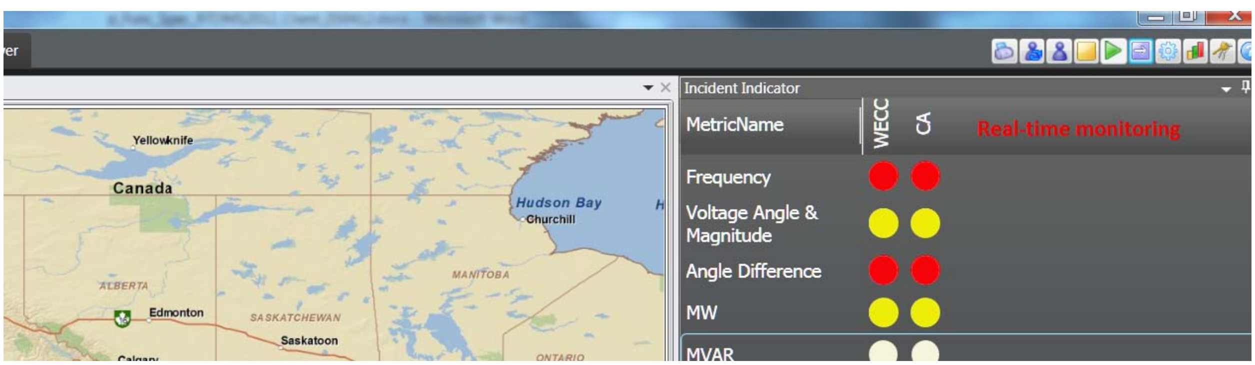
All view will provide print capability through context menu.

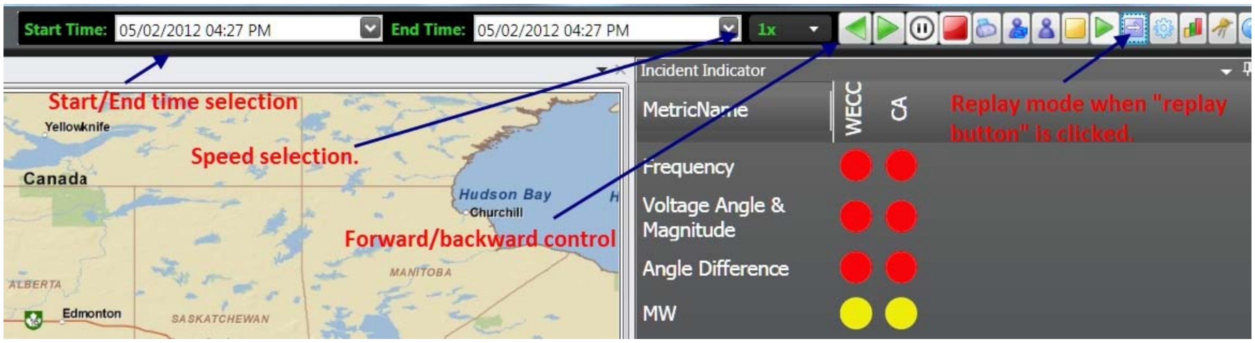




4.12 Replay and Study Mode

Replay allows playing historical data. In replay mode, user can select start/end time, forward/backward, and speed. User can switch back to real-time in any time.





4.13 Load/Display Event Files

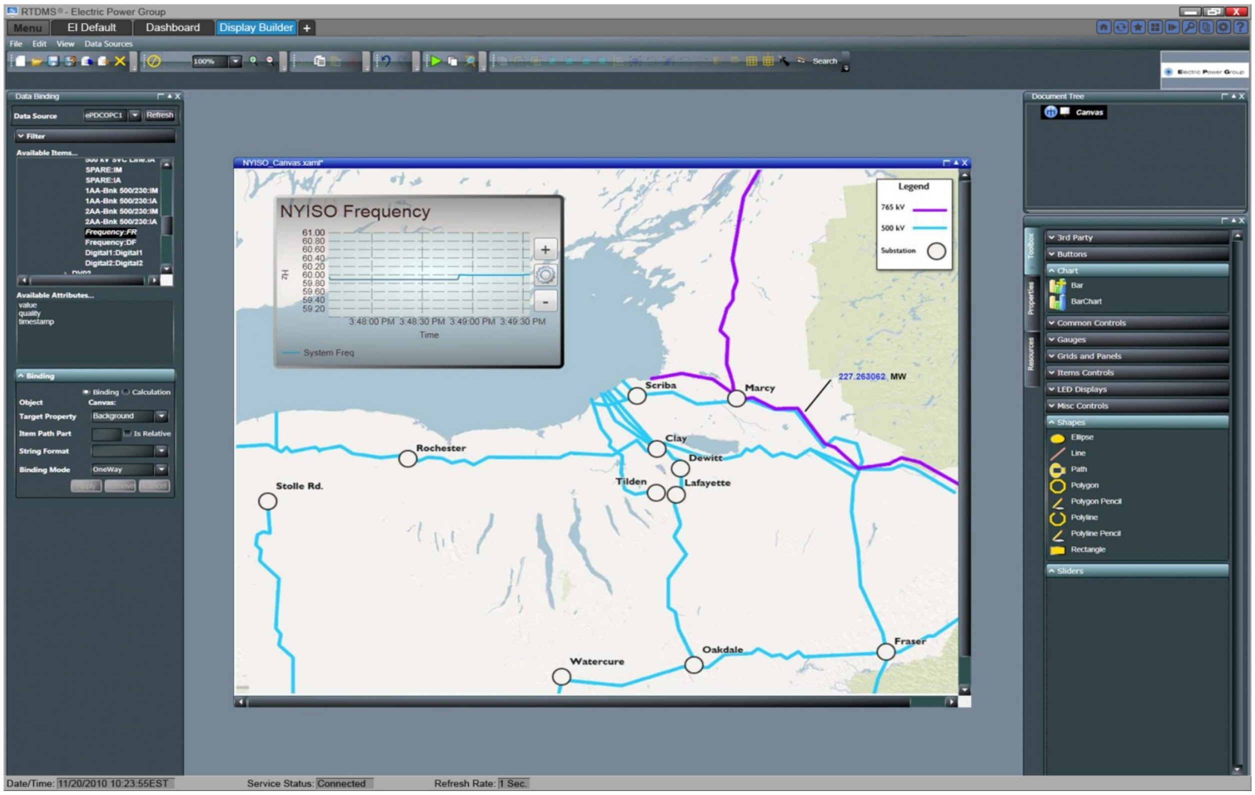
Future release.

4.14 View/Filter/ Alarms and Events

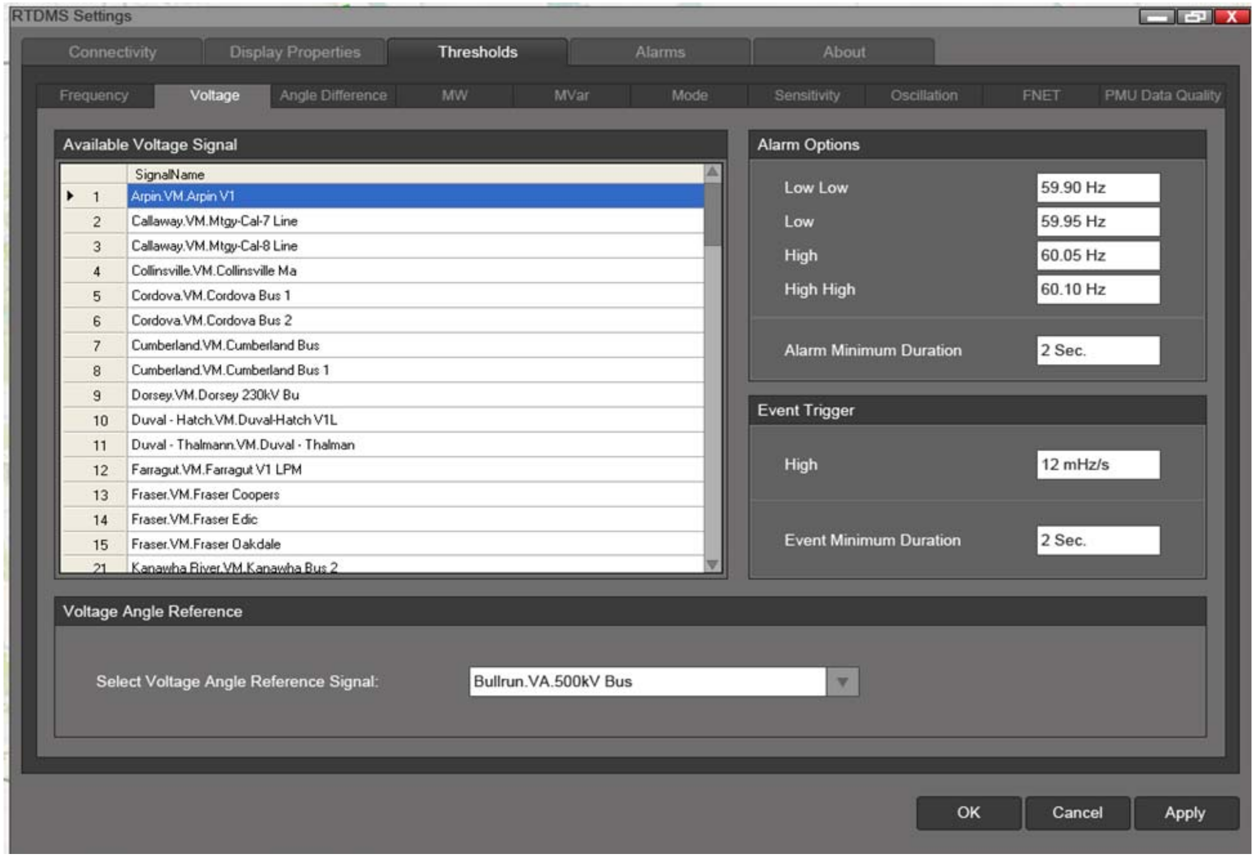
Alarm/Event view control will be implemented as a separate module which can be plugged in to Global Display area or Display area.

4.15 Display Designer Integration

Future release.



4.16 System-wide Options (Preferences)


RTDMS Settings
Connectivity
Display Properties
Thresholds
Alarms
About
Frequency
Voltage
Angle Difference
MW
MVar
Mode
Sensitivity
Oscillation
FNET
PMU Data Quality
Available Voltage Signal
SignalName
1 Arpin.VM.Arpin V1
2 Callaway.VM.Mtgy-Cal-7 Line
3 Callaway.VM.Mtgy-Cal-8 Line
4 Collinsville.VM.Collinsville Ma
5 Cordova.VM.Cordova Bus 1
6 Cordova.VM.Cordova Bus 2
7 Cumberland.VM.Cumberland Bus
8 Cumberland.VM.Cumberland Bus 1
9 Dorsey.VM.Dorsey 230kV Bu
10 Duval - Hatch.VM.Duval-Hatch V1L
11 Duval - Thalmann.VM.Duval - Thalman
12 Farragut.VM.Farragut V1 LPM
13 Fraser.VM.Fraser Coopers
14 Fraser.VM.Fraser Edic
15 Fraser.VM.Fraser Oakdale
21 Kanawha River.VM.Kanawha Bus 2
Alarm Options
Low Low 59.90 Hz
Low 59.95 Hz
High 60.05 Hz
High High 60.10 Hz
Alarm Minimum Duration 2 Sec.
Event Trigger
High 12 mHz/s
Event Minimum Duration 2 Sec.
Voltage Angle Reference
Select Voltage Angle Reference Signal: Bullrun.VA.500kV Bus
OK
Cancel
Apply

5. Geospatial View Design

This section describes detailed geospatial view design.

5.1 Geographical View Requirements

The geospatial view is designed to display layers (not limited to) described in the next section. The layers can be created and toggled on/off by user. The geospatial view is designed to adapt to different data sources, dynamic or static.

5.2 Geographical View Layers

5.2.1 Mapping System (ESRI/Bing/Shape File)

ESRI ArcGIS WPF control will be used for its rich features including clustering and shape file overlay. The control will connect to SERI website for the base map. A local geospatial database is not in immediate need and will address the issue when it becomes an issue.

The map layer is the bottom layer in default. Dynamic layers' objects will have their behaviors changed (color, animation, etc) only and be deleted only when objects are removed from the layer and recreated only when objects are added to the layer.

5.2.2 Measurement Overlays

Measurement layers are dynamic and the most important. Data sources are not limit to RTDMS measurements. The RTDMS basic measurement layers are listed in following.

- Frequency (scattered or contour)
- Voltage Magnitude with sub-layers (DC, 750 kV, 500 kV, 345 kV, 230 kV, 138 kV, <138 kV) (scattered or contour)
- Voltage Angle with sub-layers (DC, 750 kV, 500 kV, 345 kV, 230 kV, 138 kV, <138 kV) (scattered or contour)
- Angle Difference (scattered)
- Active Power (scattered only)
- Reactive Power (scattered only)
- Sensitivity (scattered only)
- Mode (scattered only)
- Oscillation (scattered only)

5.2.3 Electric Infrastructure Overlays

The Electric Infrastructure Overlays are static. The data source is in shape file format. There're three layers:

- Transmission Lines with sub-layers (DC, 750 kV, 500 kV, 345 kV, 230 kV, 138 kV, <138 kV), color coded & Line thickness
- Substations with sub-layers (DC, 750 kV, 500 kV, 345 kV, 230 kV, 138 kV, <138 kV?), different color & size
- Power Plants with sub-layers (Coal, Hydro, Natural Gas, Nuclear etc), different symbol, size, & color

5.2.4 Electric Market Overlays

Electric Market Overlays are static. The data source is in shape file format. Following layers are designed to be included:

- IOU Service Territories
- Non IOU Service Territories
- Holding Company Service Territories
- Federal Regions
- Planning Areas
- Control Areas
- ISO Zones
- Regional Transmission Organizations
- NERC Regions and NERC Sub regions

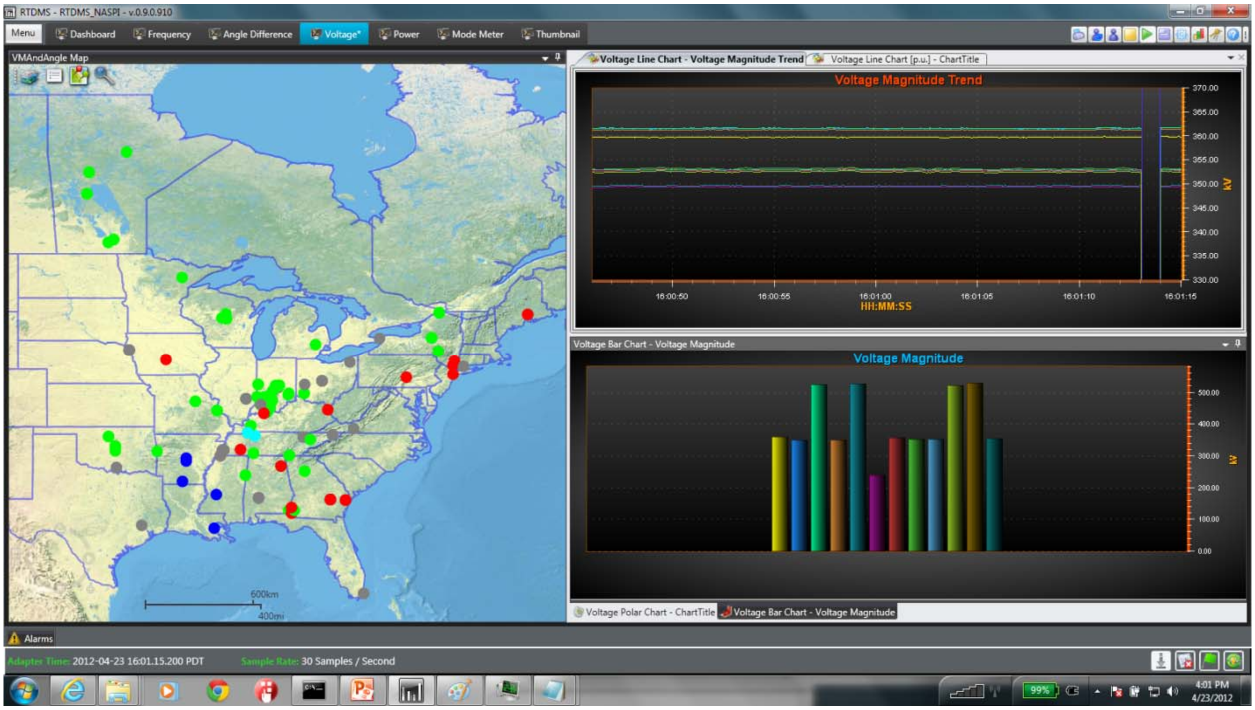
5.2.5 Environmental Information Overlays

The Environmental Information Overlays are dynamic but updated infrequently. The update rate is dependent on data source which will be provided by National Weather Service (http://weather.gov/).

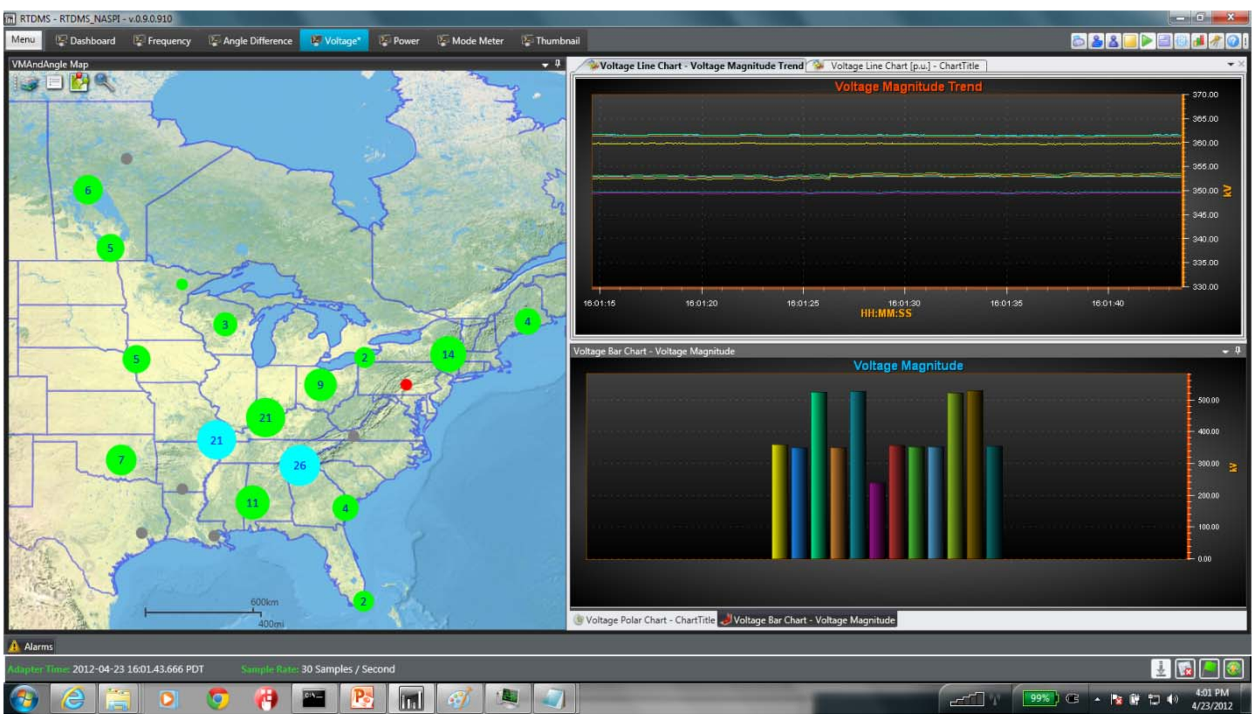
- Weather Observation (radar)
- Weather Warning (Blizzard, Storm, High Wind, Flood etc)
- Weather Forecast (Temperature, Precipitation, Wind Speed/Direction, etc)
- Fire
- Earthquake

5.2.6 Level of Detail and De-clustering

When zoomed in, measurements will be scattered around.



When zoomed out, near-by voltage measurements are clustered into a big dot which is colored coded based on the worst of them.



5.3 Layer Management Wizard

When “Map View Builder” context menu is selected, a Map View Builder wizard will be shown as modal window for user to create or edit a map view. The map layer categories are listed in section 5.2 Geographical View Layers.

5.4 Map Layer Property Editor

The Map Layer Property Editor allows user to configure look & feel properties and:

For Measurement Layers: allow data selection through Signal Selection control.

For Environment Layers: allow to choose data provider (URL).

For Map Layers: allow to select different type of base map (URL).

5.5 Map Toolbar

The toolbar will be displayed on top of the map on the left corner in default. It provides commands for editing, bookmarking, toggle on/off legend, searching etc.

5.6 Correlation between Geospatial View and Other Views

Geospatial view and location indicator view will be correlated. Click on an area in the location indicator, it will automatically zoom to the area.

6. Chart View Design

There are different types of charts available in RTDMS 2012 for visualization of phasor data. These high speed charts are capable of rendering data with 120 or more samples per second with refresh rate of 10 milliseconds.

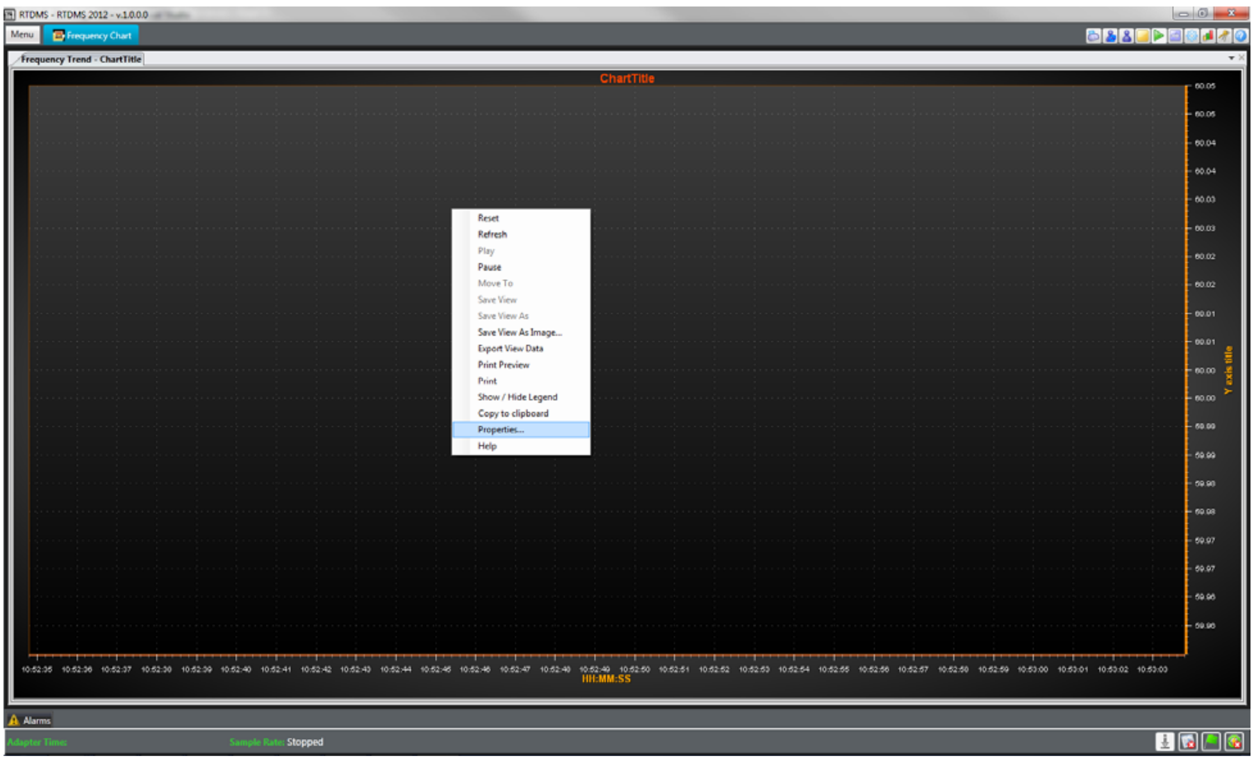
There is Line chart, Bar Chart, Scatter chart, Polar Chart, Waterfall plot, Gauge chart etc. included in RTDMS 2012 for high speed data visualization.

6.1 Chart Design Overview

RTDMS 2012 allows user to select and build his own display which can include charts, Maps, Incident Indicators on the fly with Profile and Display builder so each user can have his own display and profile.

When it comes to build a chart view user can select type of charts from available chart type's editor.

Once user added chart to a display user can select signal by right click context menu→ Properties.



A Chart Properties editor will pop up with charts properties and select signal Button in the same window

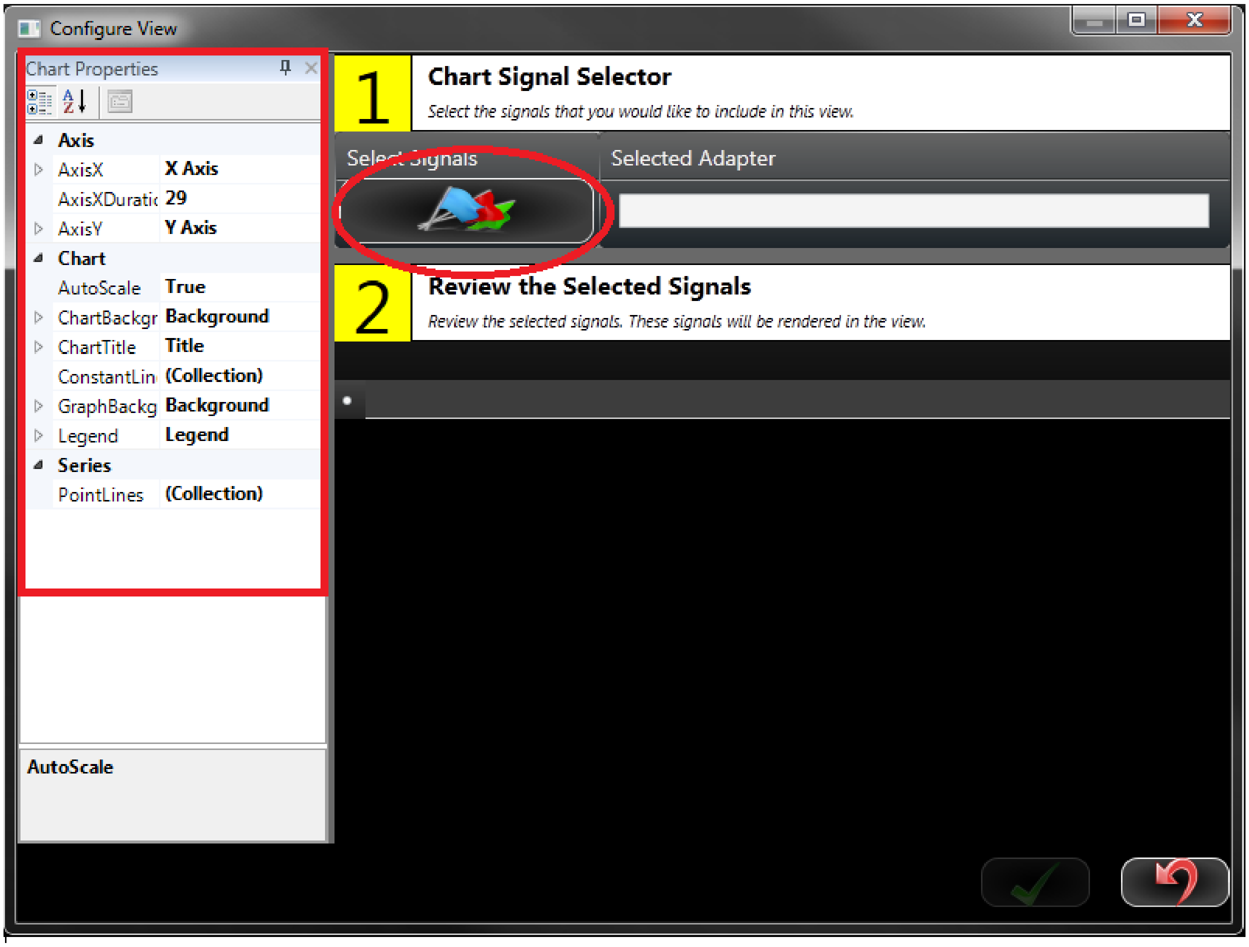
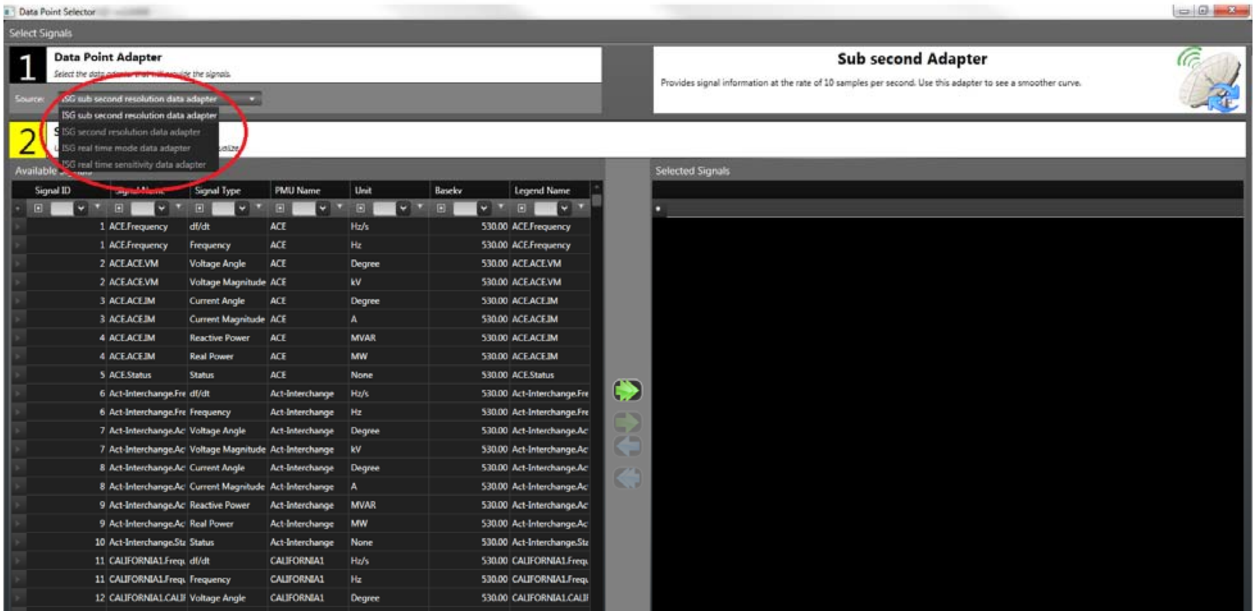


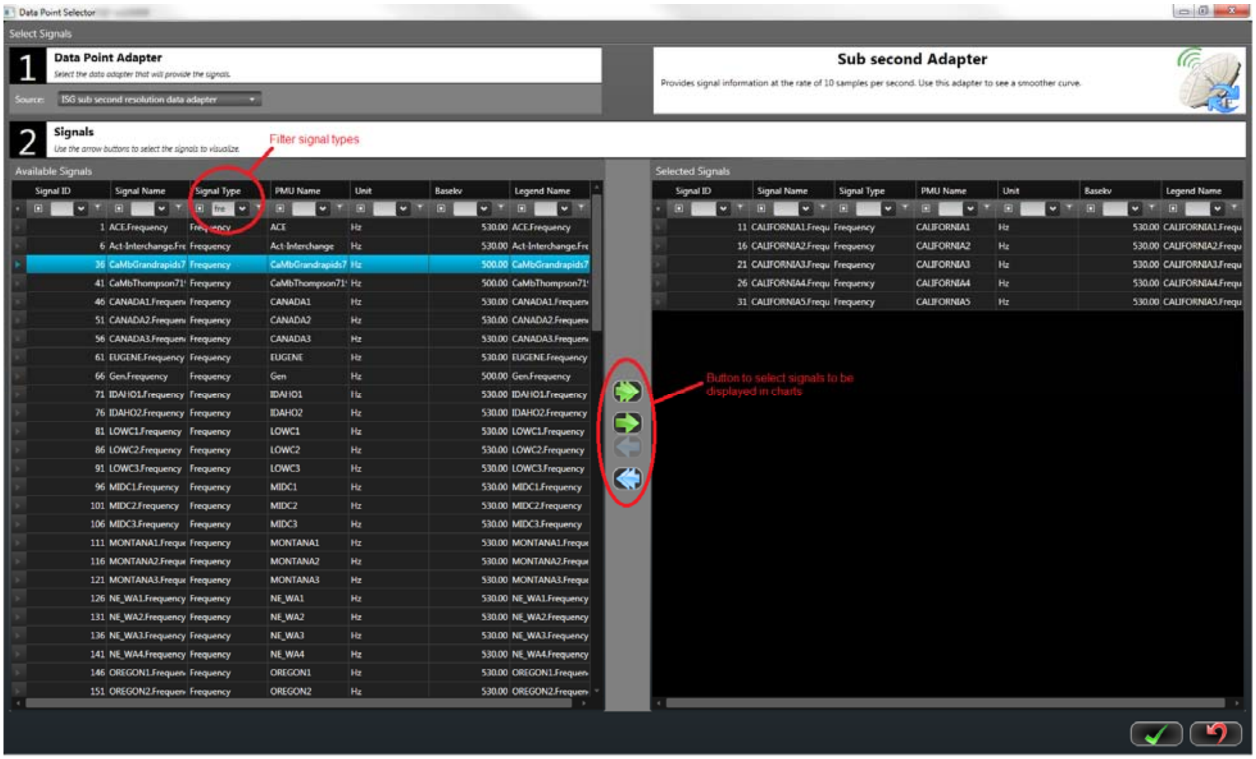
Chart properties used to configure look and feel of the charts background, Fonts, Label, chart title, X and Y Axis title, font etc.

Signal Selector dialog also used to select data adapter (Sub Second Data Adapter, Second Average Data Adapter, Mode Data Adapter, and Sensitivity Data Adapter) as displayed in below picture

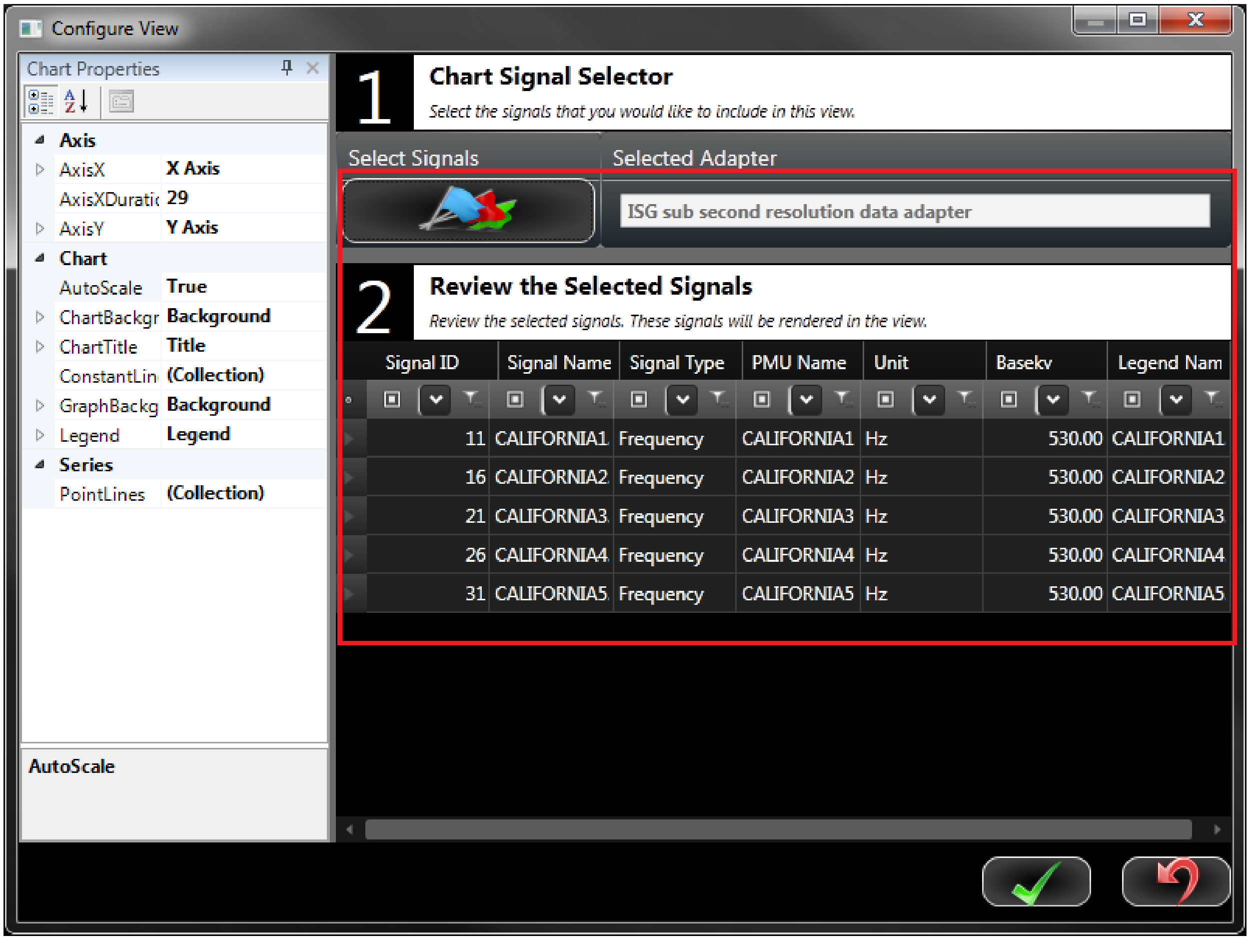


Once user select the **Data Point Adapter** dropdown list it will display the entire signal list available for selected adapter.

User can also use filter from the grid view to selected signal type let's say Frequency. Also green button can be used to select signal which user would like to see in the charts. Simultaneously blue arrow button can be used to deselect the signal from right hand side grid in the data point selector dialog.



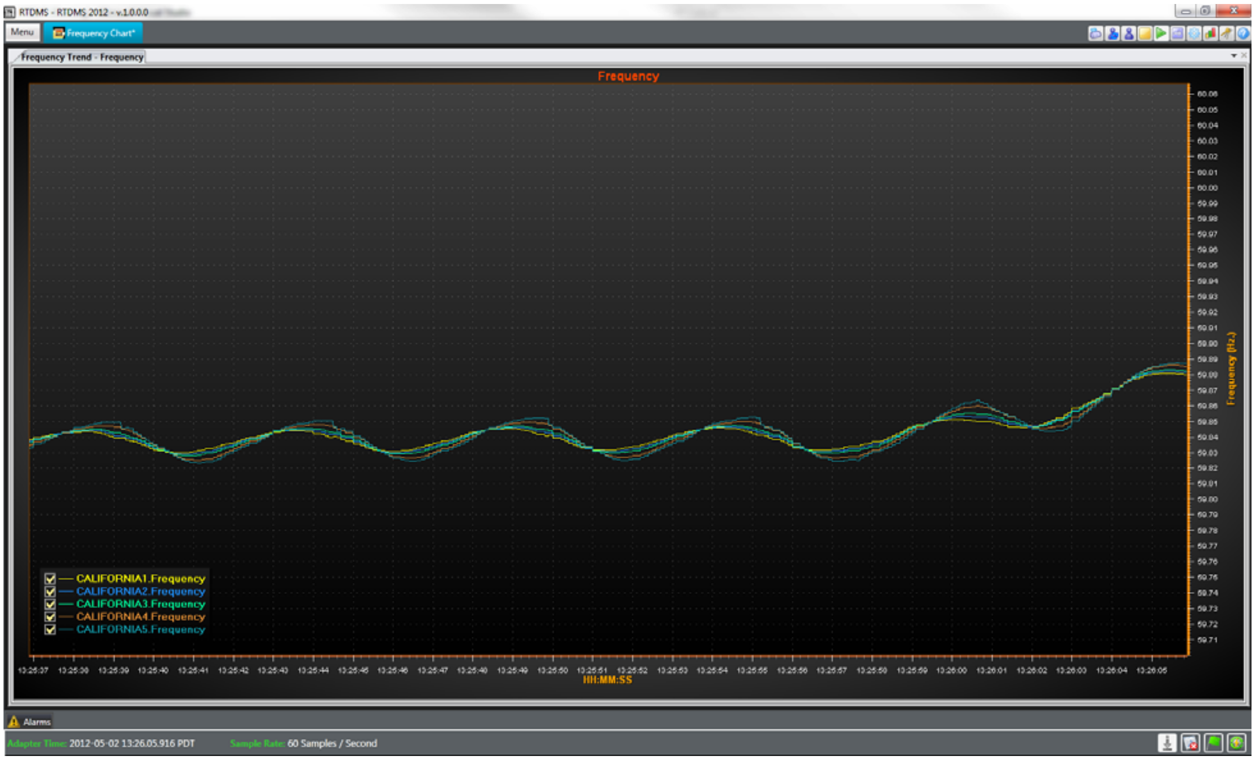
Once user selected some signal from the above window and click on the **OK** button. You will below window with user selected data adapter and selected signals



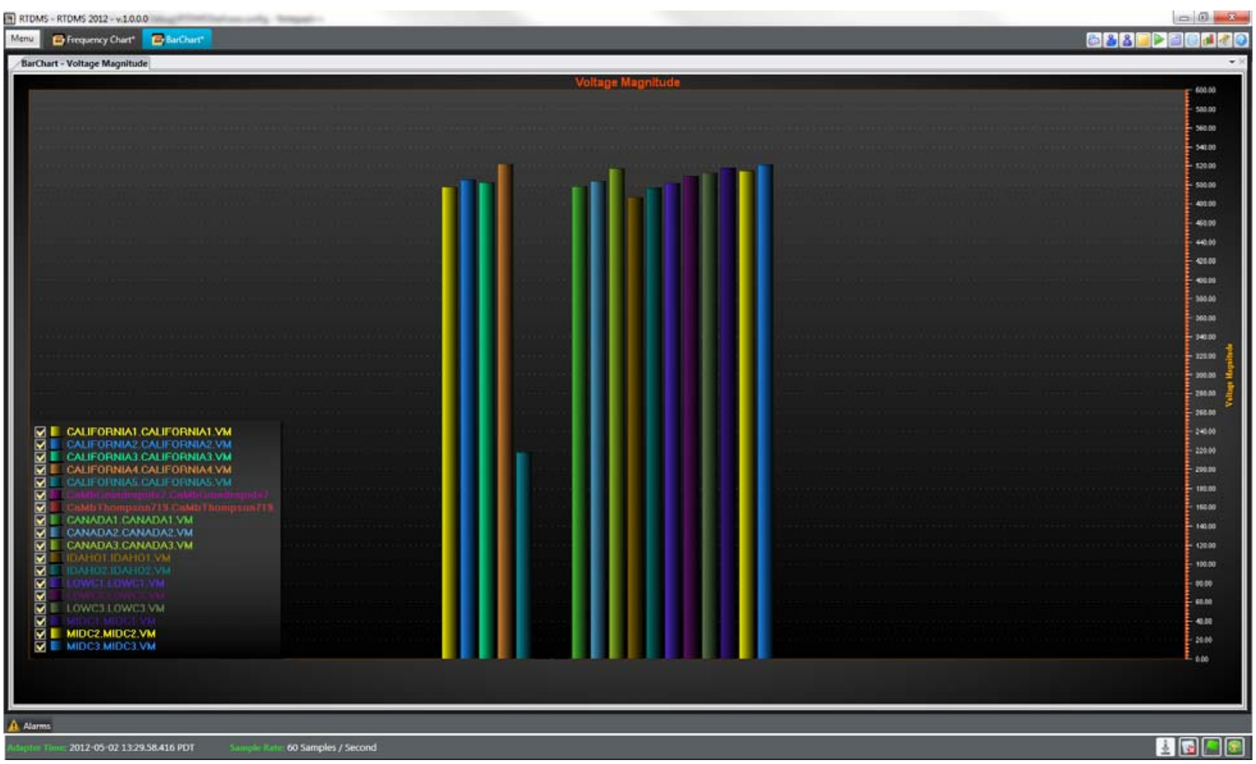
The process to build charts with signal is same for all charts.

Some of the chart type you can see in the below pictures.

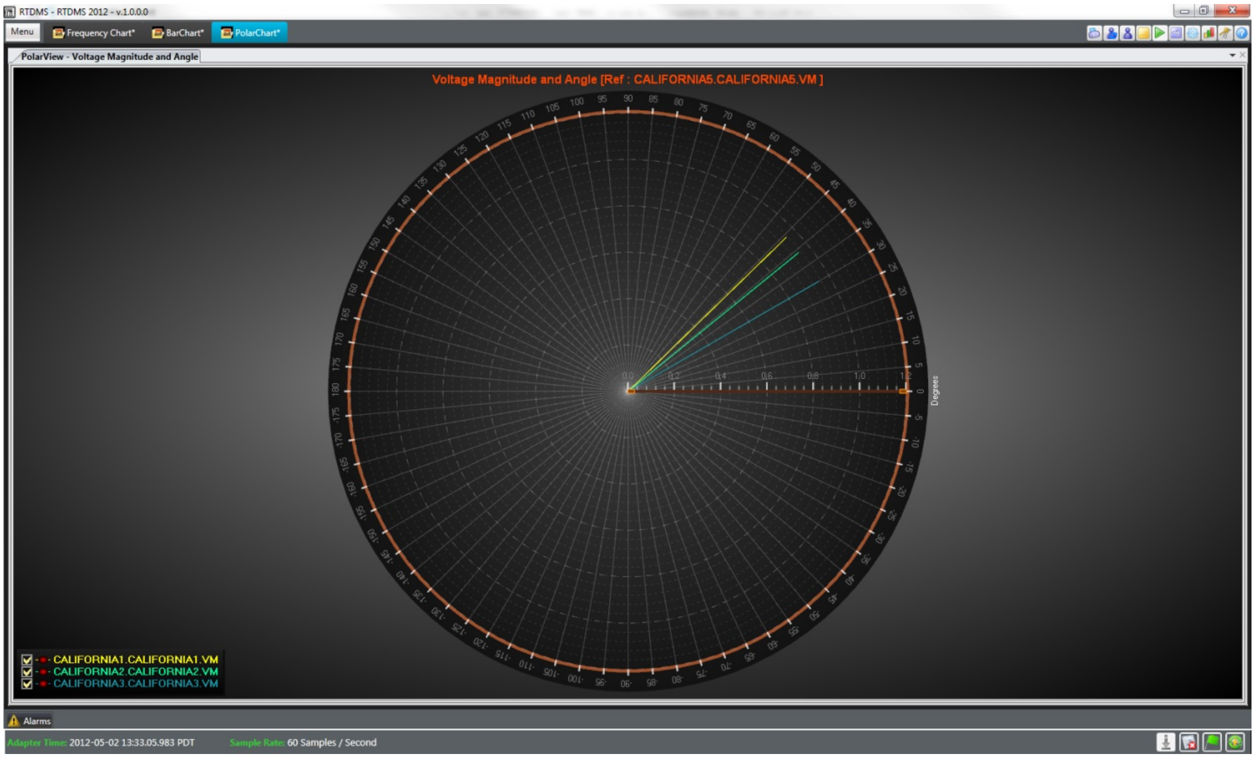
6.2 Trending Plot


Frequency Trend - Frequency
Frequency
CALIFORNIA1.Frequency
CALIFORNIA2.Frequency
CALIFORNIA3.Frequency
CALIFORNIA4.Frequency
CALIFORNIA5.Frequency
Frequency (Hz)
HH:MM:SS
Alarms
Sample Rate: 60 Samples / Second

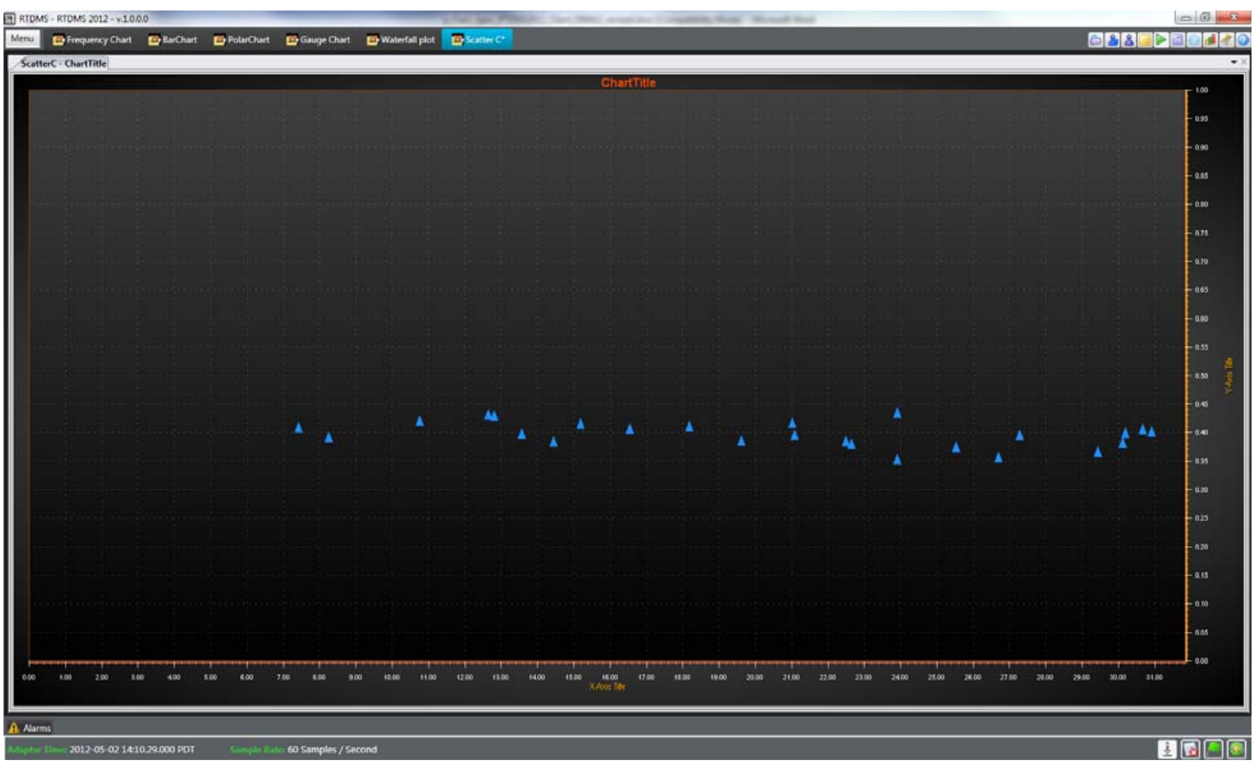
6.3 Bar Chart


BarChart - Voltage Magnitude
Voltage Magnitude
CALIFORNIA1.CALIFORNIA1.VM
CALIFORNIA2.CALIFORNIA2.VM
CALIFORNIA3.CALIFORNIA3.VM
CALIFORNIA4.CALIFORNIA4.VM
CALIFORNIA5.CALIFORNIA5.VM
CANADA1.CANADA1.VM
CANADA2.CANADA2.VM
CANADA3.CANADA3.VM
LOWC3.LOWC3.VM
MIDC2.MIDC2.VM
MIDC3.MIDC3.VM
Voltage Magnitude
Alarms
Sample Rate: 60 Samples / Second

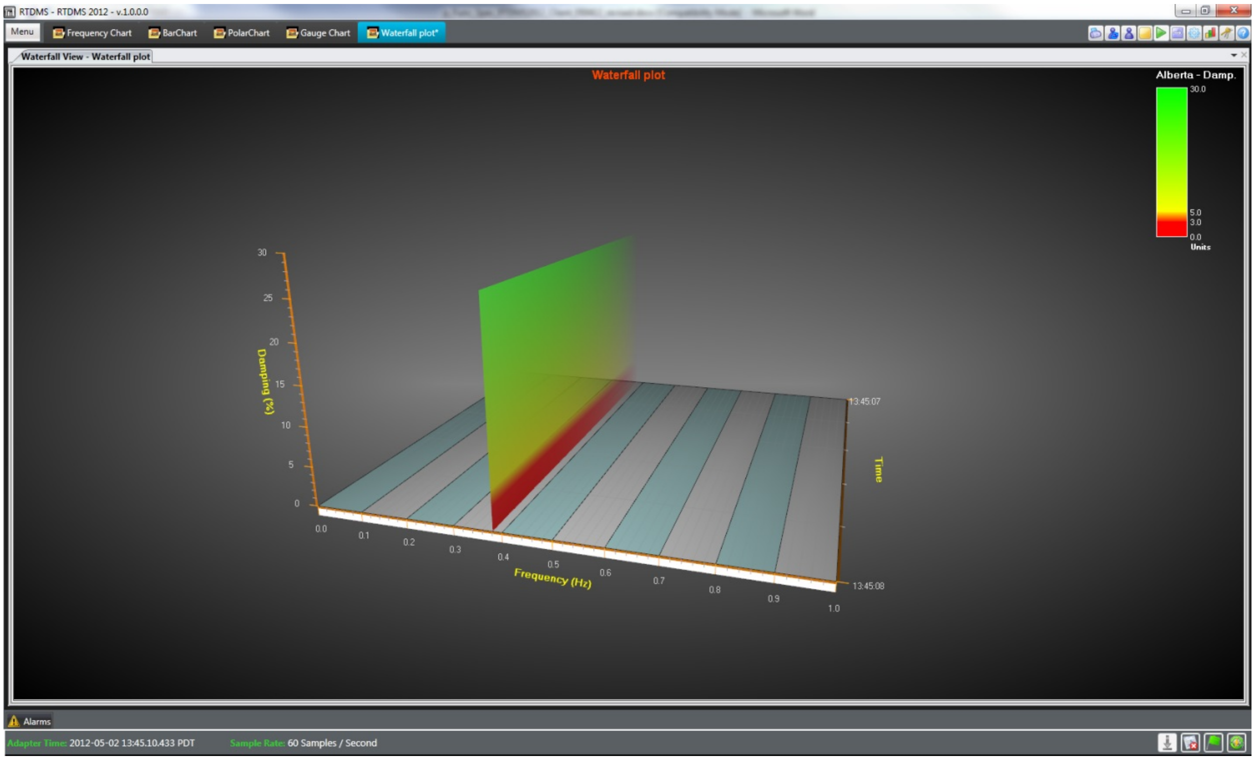
6.4 Polar Chart



6.5 Scatter Chart



6.6 Waterfall Plot



6.7 Gauge Chart

7. Alarm View Design

Three types alarm sources are to be implemented with the current version of RTDMS 2012, with possibility to adapt to other alarm sources such as ones from EMS. The three alarm sources are:

RTDMS Server Alarms – generated by RTDMS Server in real-time and saved in database. Class “A”. Only alarms a user can access will be retrieved from database and displayed. An alarm is accessible by user when the user has the permission to view the PMU of which the alarm signal belongs to.

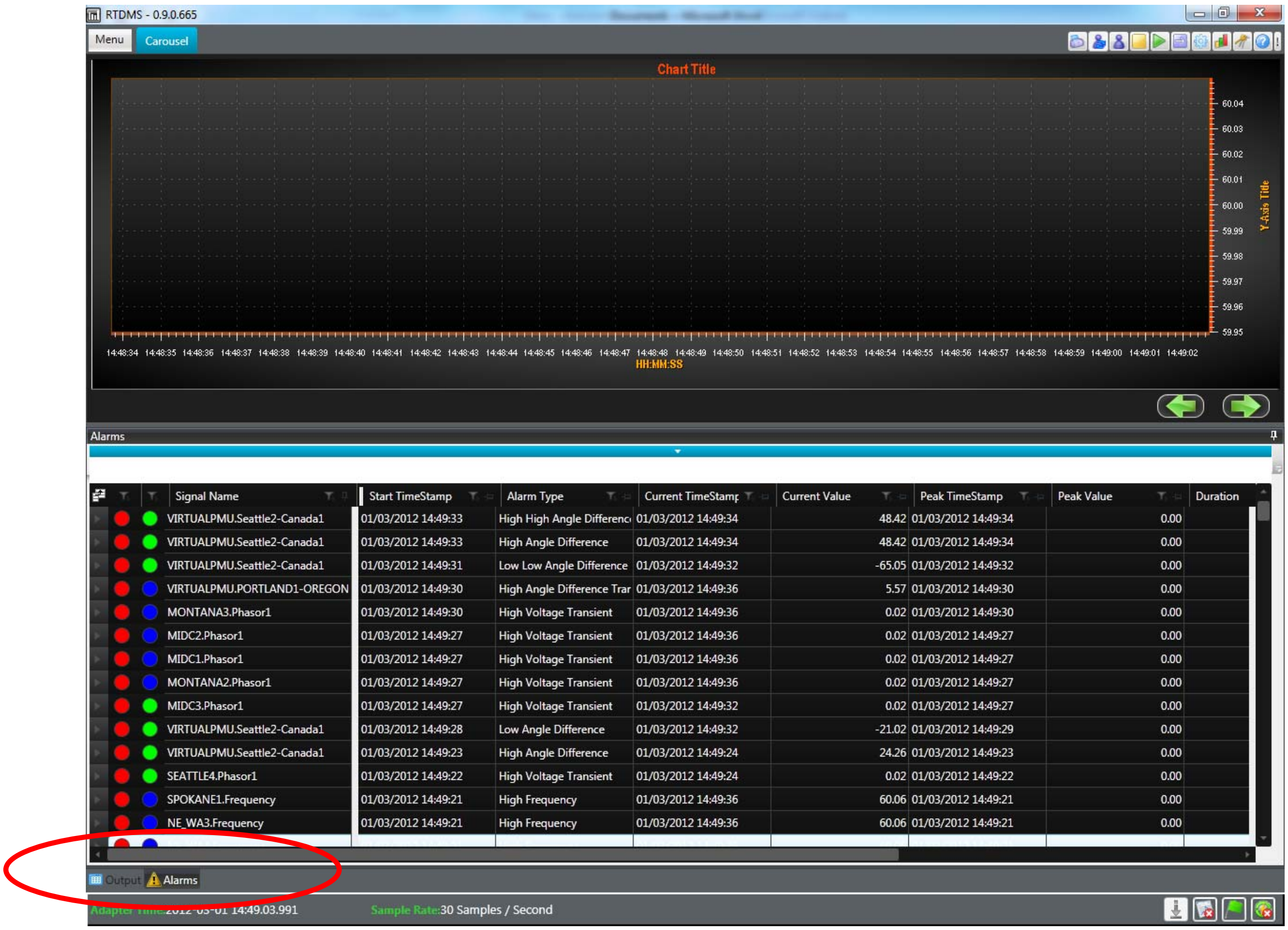
NOTE: Access control to be implemented in the next phase.

User Alarms – Alarms generated for user selected signals and user configured thresholds. User alarms won’t be saved back to database. Class “O”.

Point of Interest – created by user by entering messages through GUI. Point of interest messages will be saved back to database. Class “M”.

Screen:

Alarms will be displayed in a grid control. These alarm records are displayed globally in the application view.



The record contains details of the alarm such as

1. Alarm Status: Status of the alarm (
    a. Acknowledged – green ellipse
    b. Deleted – blue ellipse
    c. Normal – red ellipse
2. Alarm State:
    a. Entering –red ellipse
    b. Staying – blue ellipse
    c. Leaving – green ellipse
3. Signal Name : Measurement point name prefixed with PMU name
4. Start Timestamp: The start time of the alarm.
5. Alarm Type : Alarm type, such as high frequency, low voltage etc

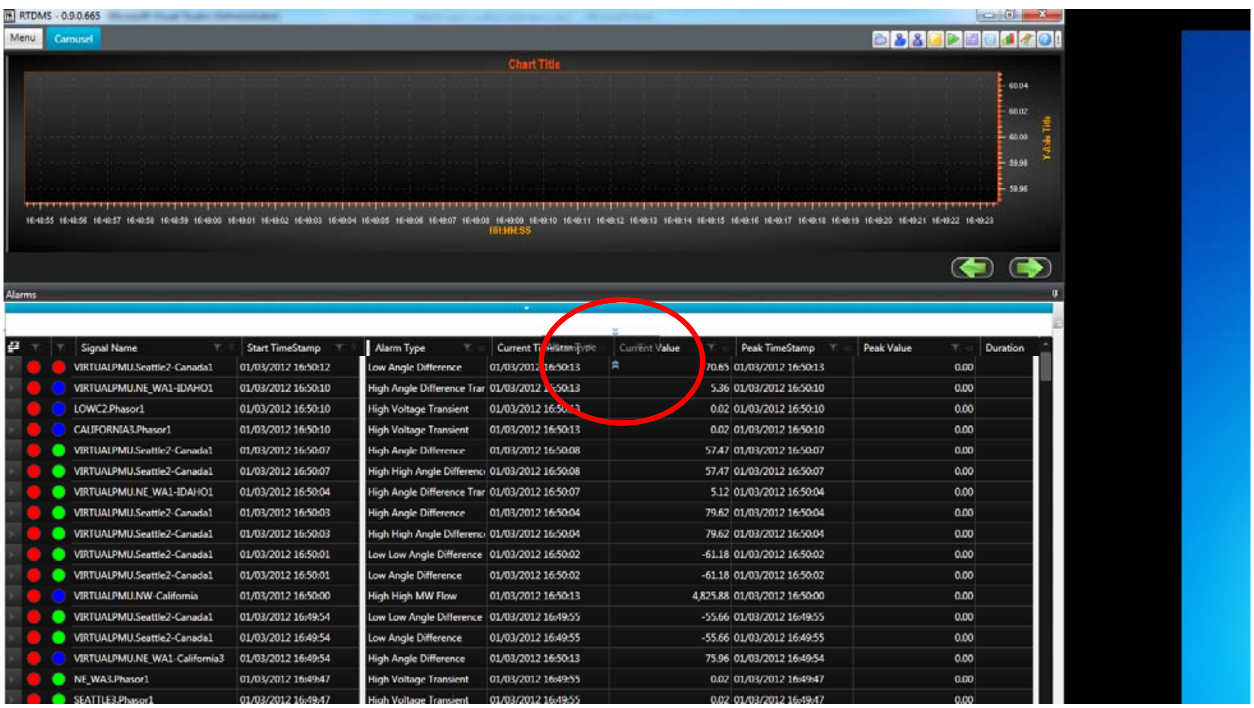
6. Current Timestamp: Current time stamp of the alarm record i.e. in case of transient alarm
7. Current Value: current value of the signal
8. Peak Timestamp: the date/time when the alarm in worst case. (Determined by RTDMS server).
9. Peak Value: the measurement value at peak time. (Determined by RTDMS server.)
10. Duration: The duration the alarm lasts and its unit is in seconds.
11. Jurisdiction: The area where the alarm happened.
12. Comment: comment on the alarm.
13. Unit: unit determined for the signal.

The alarms are subscribed to the Alarm Service of the RTDMS ISG.

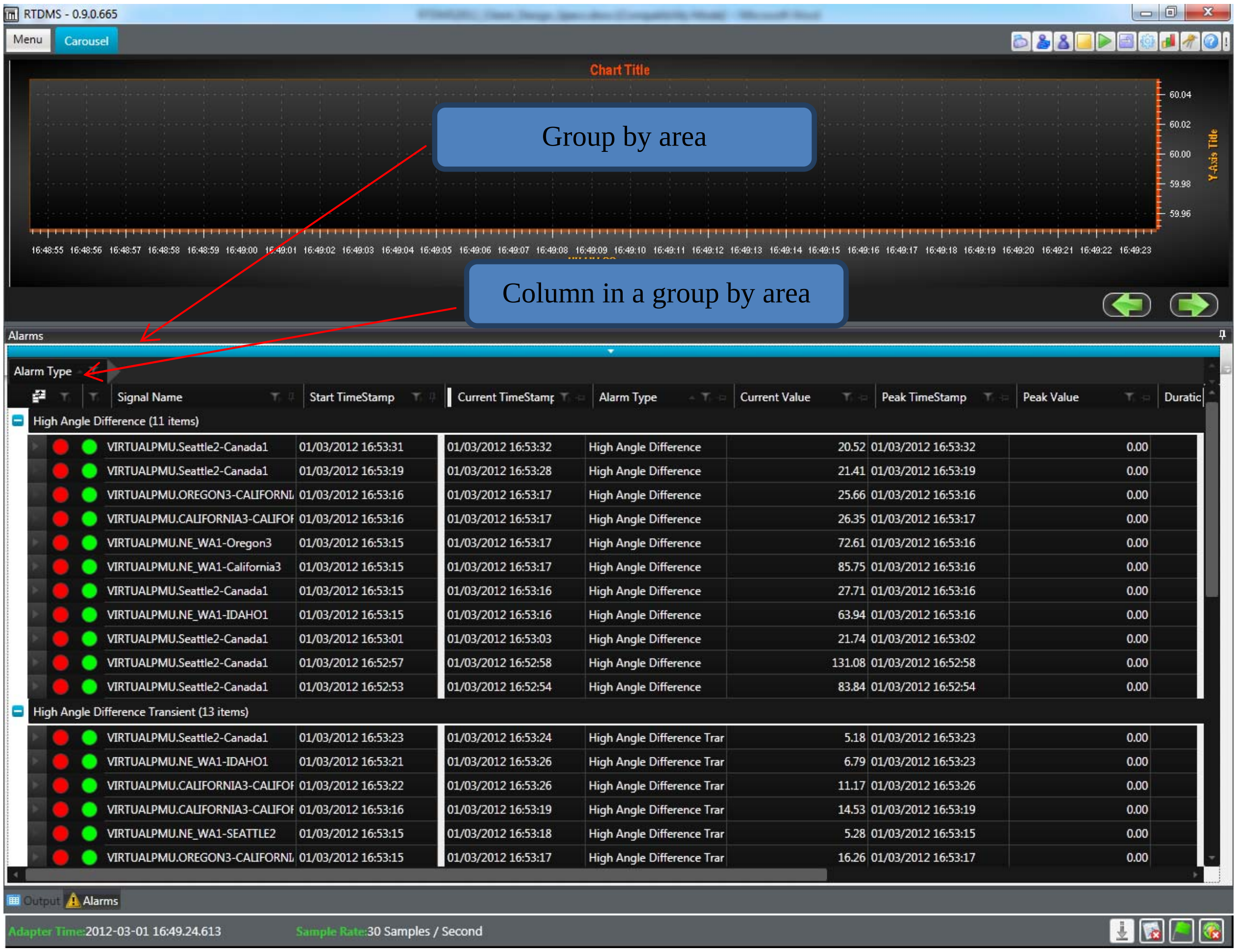
On receiving the alarms, the alarm records are inserted in a FIFO order into the grid. There is a grid limit set at 250. Once the alarm records reaches limit, the records that that inserted at the beginning are removed from the grid view and the limit is maintained at this limit. The grid display limit is configurable and it can be maintained via the properties editor.

Alarm Fields, Sorting, Filtering, Searching, Grouping

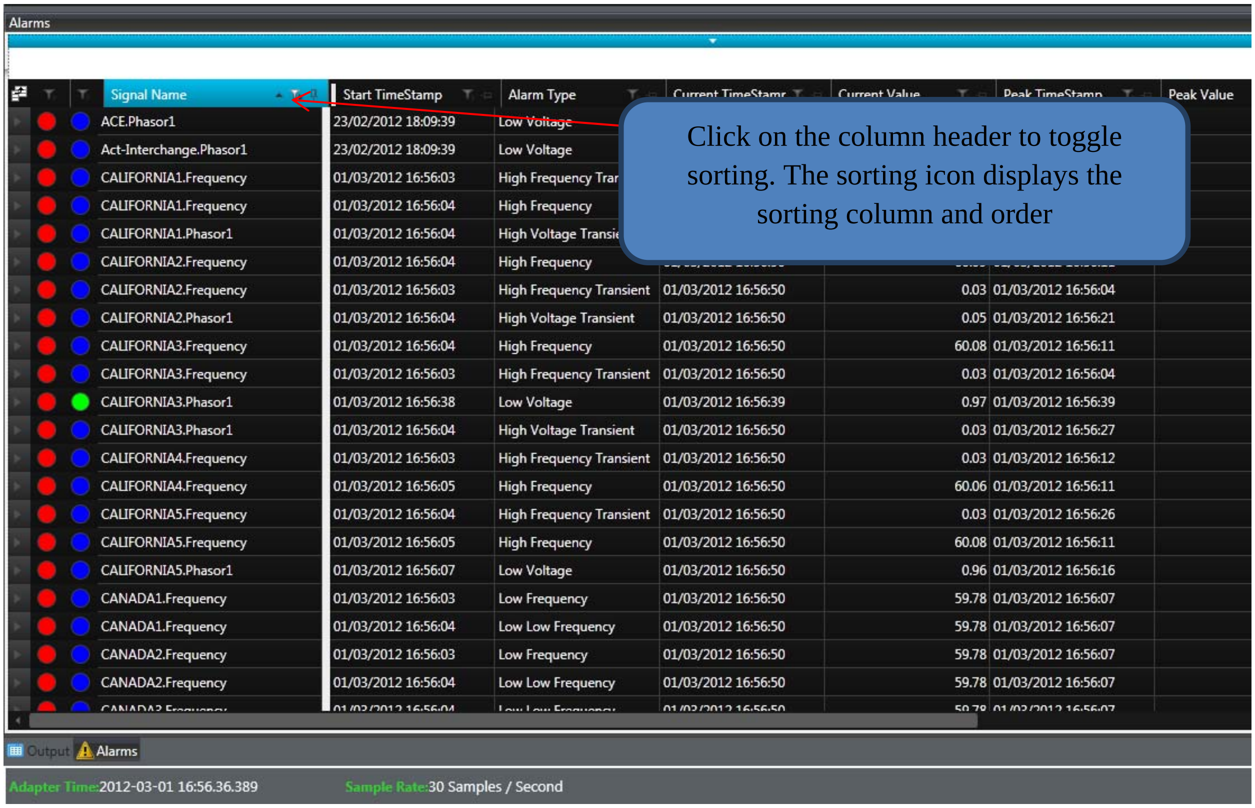
The column fields in the grid can be repositioned. Select a column and drag the column to a desired position. On viewing the arrow indicator (as shown in pic) drop the column.



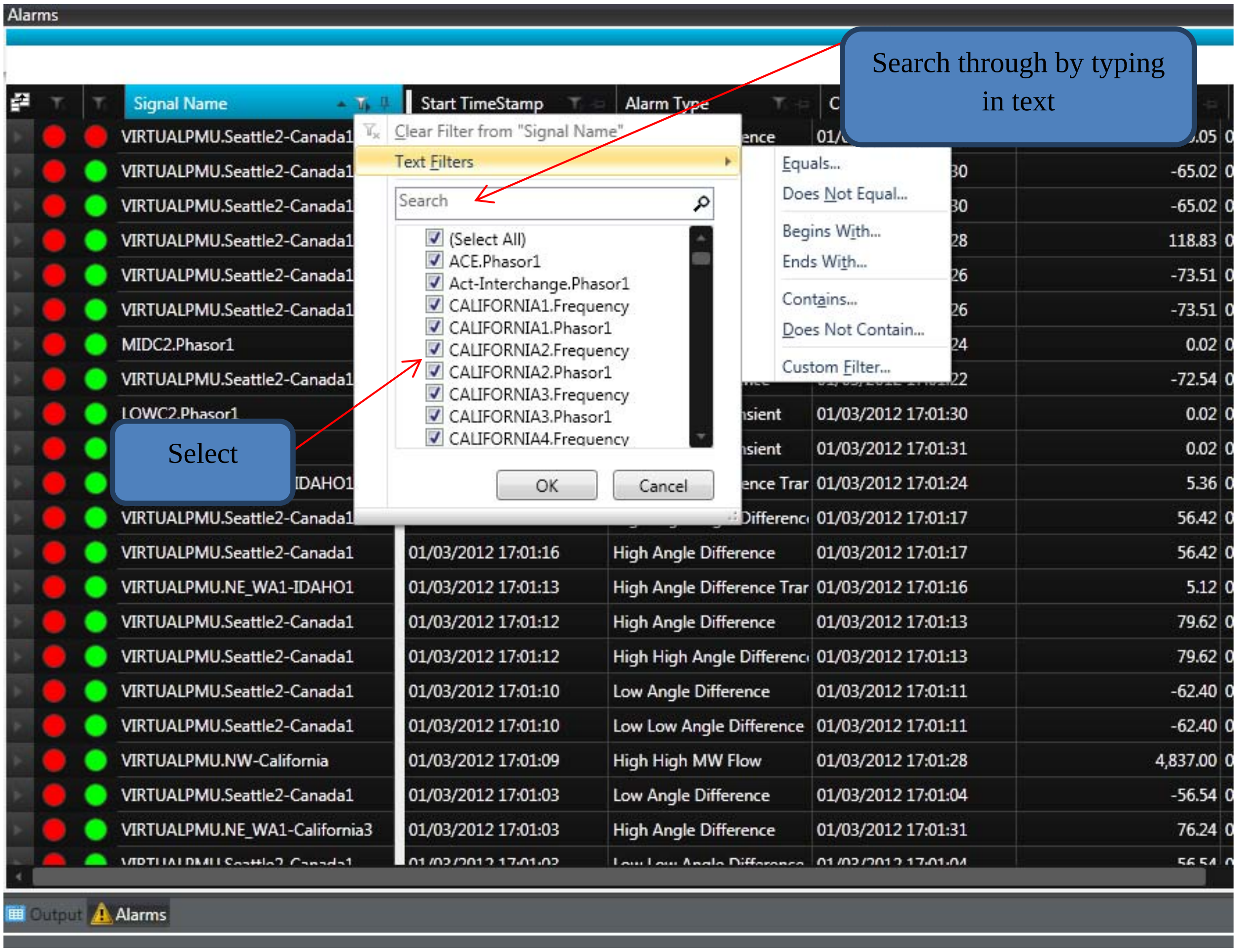
The column fields in the grid can be grouped. Drag the column on the group by area at the top of the grid



The column fields in the grid can be sorted.

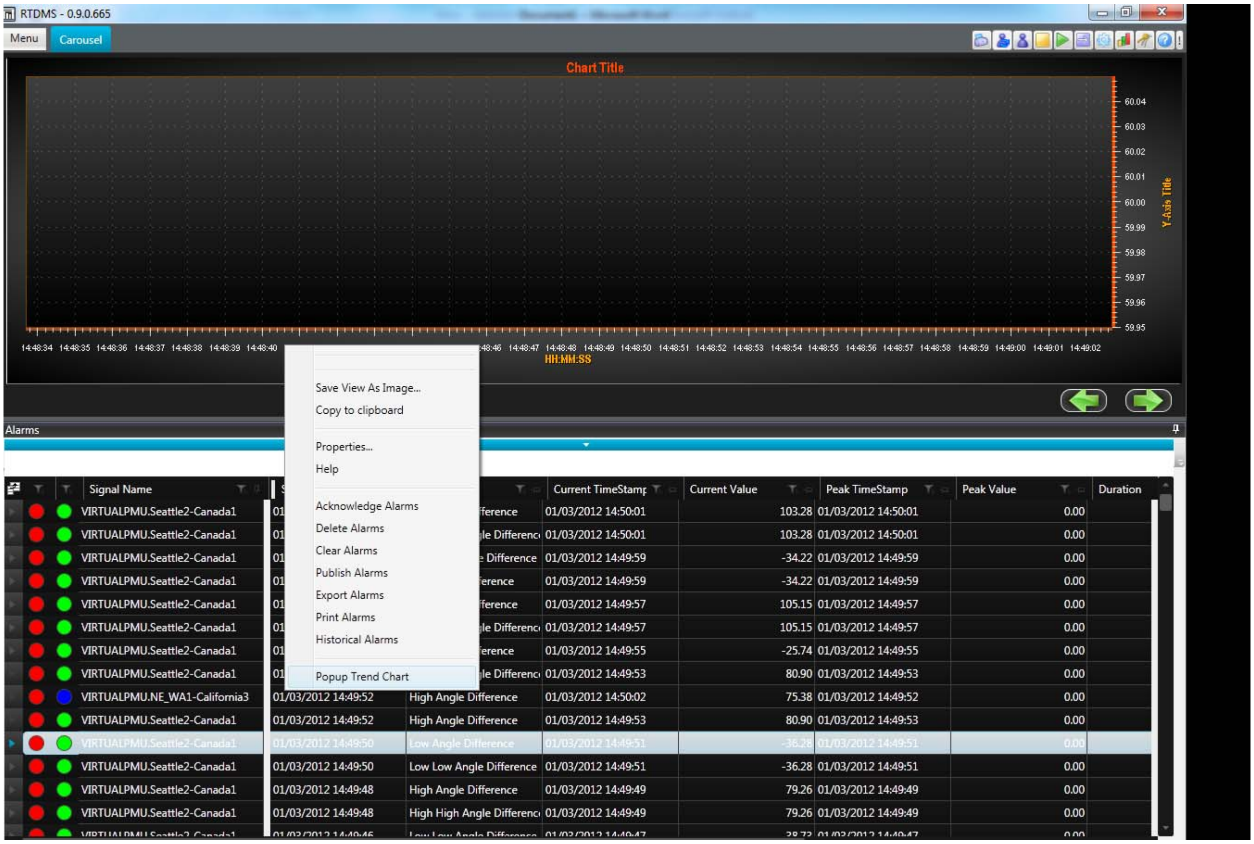


The column fields in the grid can be filtered. Microsoft Excel style filtering and searching will be implemented.



RMB Options:

On right click on the alarm grid control, the following options are displayed.

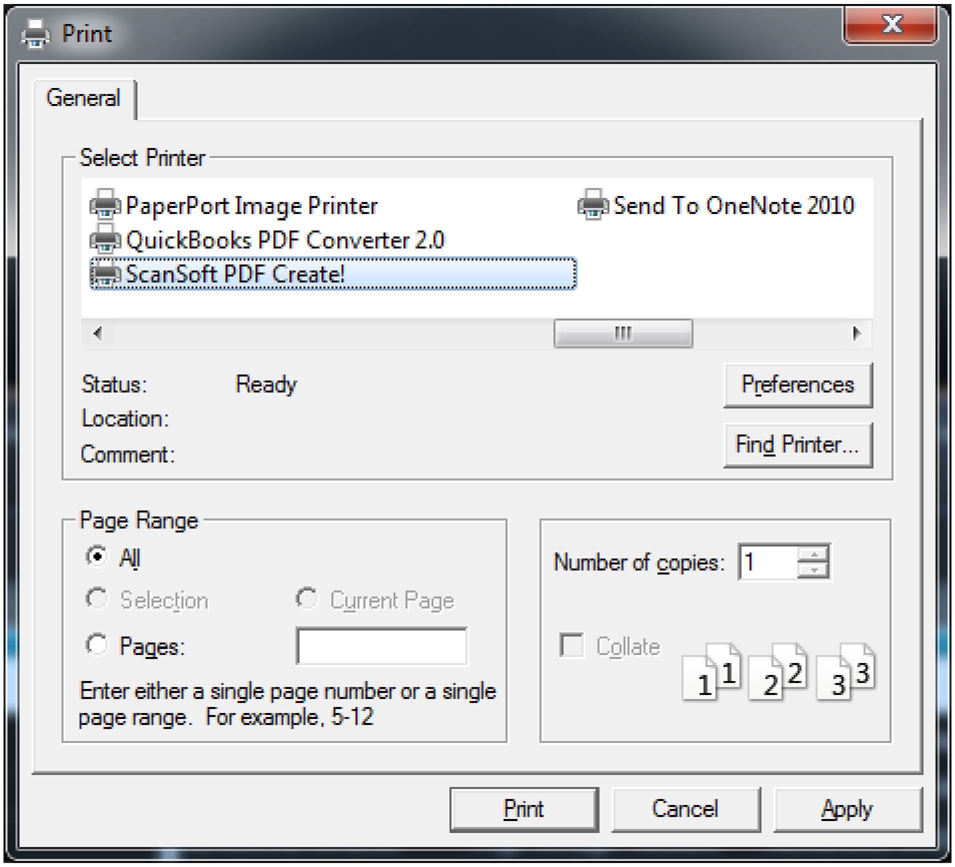


To set the preference on the alarms, right click on the alarm data grid. The following RMB(right mouse button) options are available.

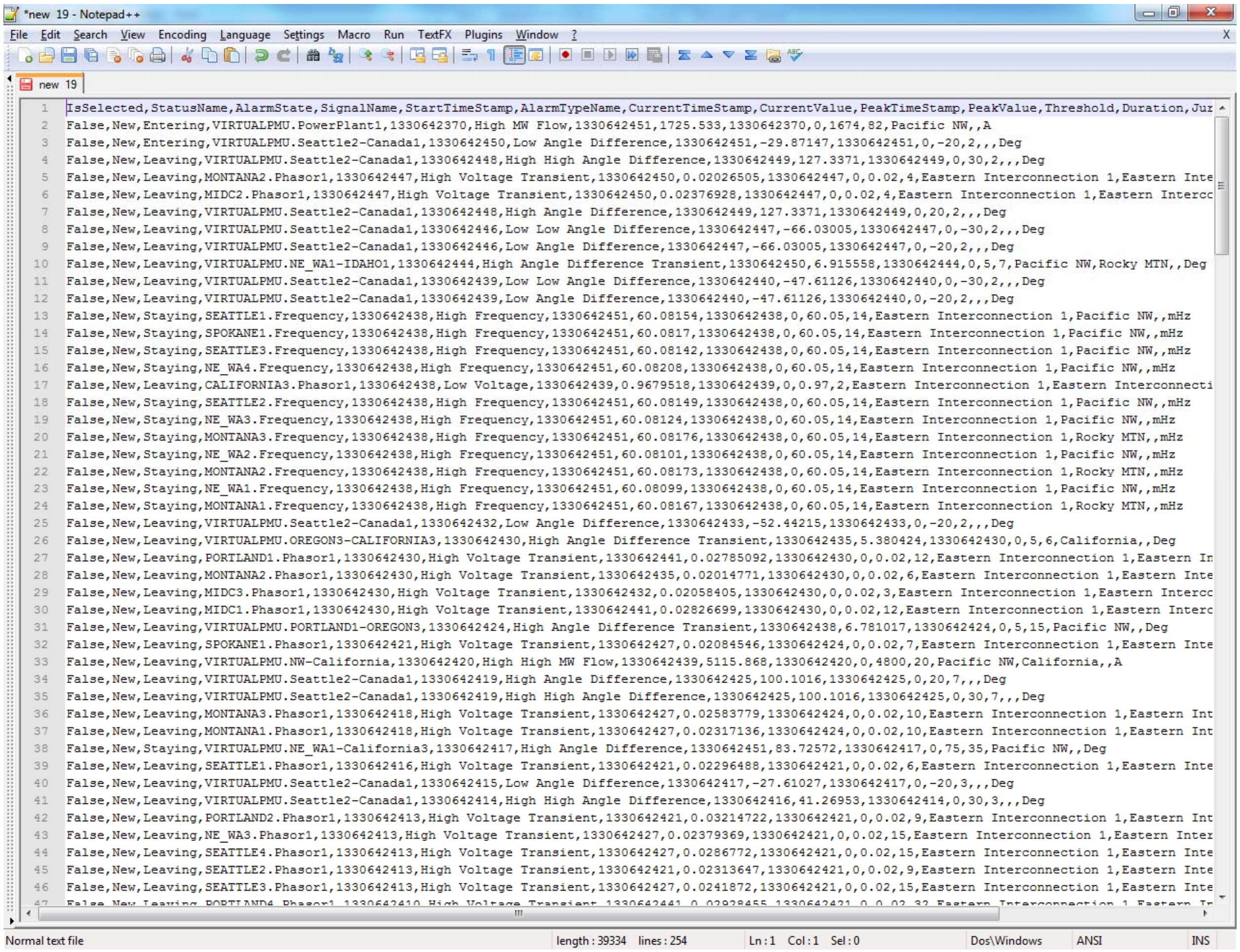
1. Save View as Image
2. Copy to Clipboard
3. Properties
4. Help
5. Acknowledge alarms
6. Delete alarms
7. Clear alarms
8. Publish alarms
9. Export alarms
10. Print alarms
11. Historical alarms
12. Popup Trend Chart.

The following describes the above RMB option functionality. (ref RMB options)

1. Save View as Image: On click of the "Save view as image", the contents of the grid view are sent to the printer (can print as pdf).



2. Copy to Clipboard: The contents of the grid view are copied to the clipboard as text.




```
IsSelected,StatusName,AlarmState,SignalName,StartTimeStamp,AlarmTypeName,CurrentTimeStamp,CurrentValue,PeakTimeStamp,PeakValue,Threshold,Duration,Jur
False,New,Entering,VIRTUALPMU.PowerPlant1,1330642370,High MW Flow,1330642451,1725.533,1330642370,0,1674,82,Pacific NW,,A
False,New,Entering,VIRTUALPMU.Seattle2-Canada1,1330642450,Low Angle Difference,1330642451,-29.87147,1330642451,0,-20,2,,,Deg
False,New,Leaving,VIRTUALPMU.Seattle2-Canada1,1330642448,High High Angle Difference,1330642449,127.3371,1330642449,0,30,2,,,Deg
False,New,Leaving,MONTANA2.Phasor1,1330642447,High Voltage Transient,1330642450,0.02026505,1330642447,0,0.02,4,Eastern Interconnection 1,Eastern Inte
False,New,Leaving,MIDC2.Phasor1,1330642447,High Voltage Transient,1330642450,0.02376928,1330642447,0,0.02,4,Eastern Interconnection 1,Eastern Interco
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False,New,Leaving,VIRTUALPMU.Seattle2-Canada1,1330642446,Low Angle Difference,1330642447,-66.03005,1330642447,0,-20,2,,,Deg
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False,New,Staying,SEATTLE1.Frequency,1330642438,High Frequency,1330642451,60.08154,1330642438,0,60.05,14,Eastern Interconnection 1,Pacific NW,,mHz
False,New,Staying,SPOKANE1.Frequency,1330642438,High Frequency,1330642451,60.0817,1330642438,0,60.05,14,Eastern Interconnection 1,Pacific NW,,mHz
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False,New,Staying,SEATTLE2.Frequency,1330642438,High Frequency,1330642451,60.08149,1330642438,0,60.05,14,Eastern Interconnection 1,Pacific NW,,mHz
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False,New,Leaving,MIDC1.Phasor1,1330642430,High Voltage Transient,1330642441,0.02826699,1330642430,0,0.02,12,Eastern Interconnection 1,Eastern Interc
False,New,Leaving,VIRTUALPMU.PORTLAND1-OREGON3,1330642424,High Angle Difference Transient,1330642438,6.781017,1330642424,0,5,15,Pacific NW,,Deg
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False,New,Leaving,VIRTUALPMU.NW-California,1330642420,High High MW Flow,1330642439,5115.868,1330642420,0,4800,20,Pacific NW,California,,A
False,New,Leaving,VIRTUALPMU.Seattle2-Canada1,1330642419,High Angle Difference,1330642425,100.1016,1330642425,0,20,7,,,Deg
False,New,Leaving,VIRTUALPMU.Seattle2-Canada1,1330642419,High High Angle Difference,1330642425,100.1016,1330642425,0,30,7,,,Deg
False,New,Leaving,MONTANA3.Phasor1,1330642418,High Voltage Transient,1330642427,0.02583779,1330642424,0,0.02,10,Eastern Interconnection 1,Eastern Int
False,New,Leaving,MONTANA1.Phasor1,1330642418,High Voltage Transient,1330642427,0.02317136,1330642424,0,0.02,10,Eastern Interconnection 1,Eastern Int
False,New,Staying,VIRTUALPMU.NE_WA1-California3,1330642417,High Angle Difference,1330642451,83.72572,1330642417,0,75,35,Pacific NW,,Deg
False,New,Leaving,SEATTLE1.Phasor1,1330642416,High Voltage Transient,1330642421,0.02296488,1330642421,0,0.02,6,Eastern Interconnection 1,Eastern Inte
False,New,Leaving,VIRTUALPMU.Seattle2-Canada1,1330642415,Low Angle Difference,1330642417,-27.61027,1330642417,0,-20,3,,,Deg
False,New,Leaving,VIRTUALPMU.Seattle2-Canada1,1330642414,High High Angle Difference,1330642416,41.26953,1330642414,0,30,3,,,Deg
False,New,Leaving,PORTLAND2.Phasor1,1330642413,High Voltage Transient,1330642421,0.03214722,1330642421,0,0.02,9,Eastern Interconnection 1,Eastern Int
False,New,Leaving,NE_WA3.Phasor1,1330642413,High Voltage Transient,1330642427,0.02379369,1330642421,0,0.02,15,Eastern Interconnection 1,Eastern Inter
False,New,Leaving,SEATTLE4.Phasor1,1330642413,High Voltage Transient,1330642427,0.0286772,1330642421,0,0.02,15,Eastern Interconnection 1,Eastern Inte
False,New,Leaving,SEATTLE2.Phasor1,1330642413,High Voltage Transient,1330642421,0.02313647,1330642421,0,0.02,9,Eastern Interconnection 1,Eastern Inte
False,New,Leaving,SEATTLE3.Phasor1,1330642413,High Voltage Transient,1330642427,0.0241872,1330642421,0,0.02,15,Eastern Interconnection 1,Eastern Inte
```
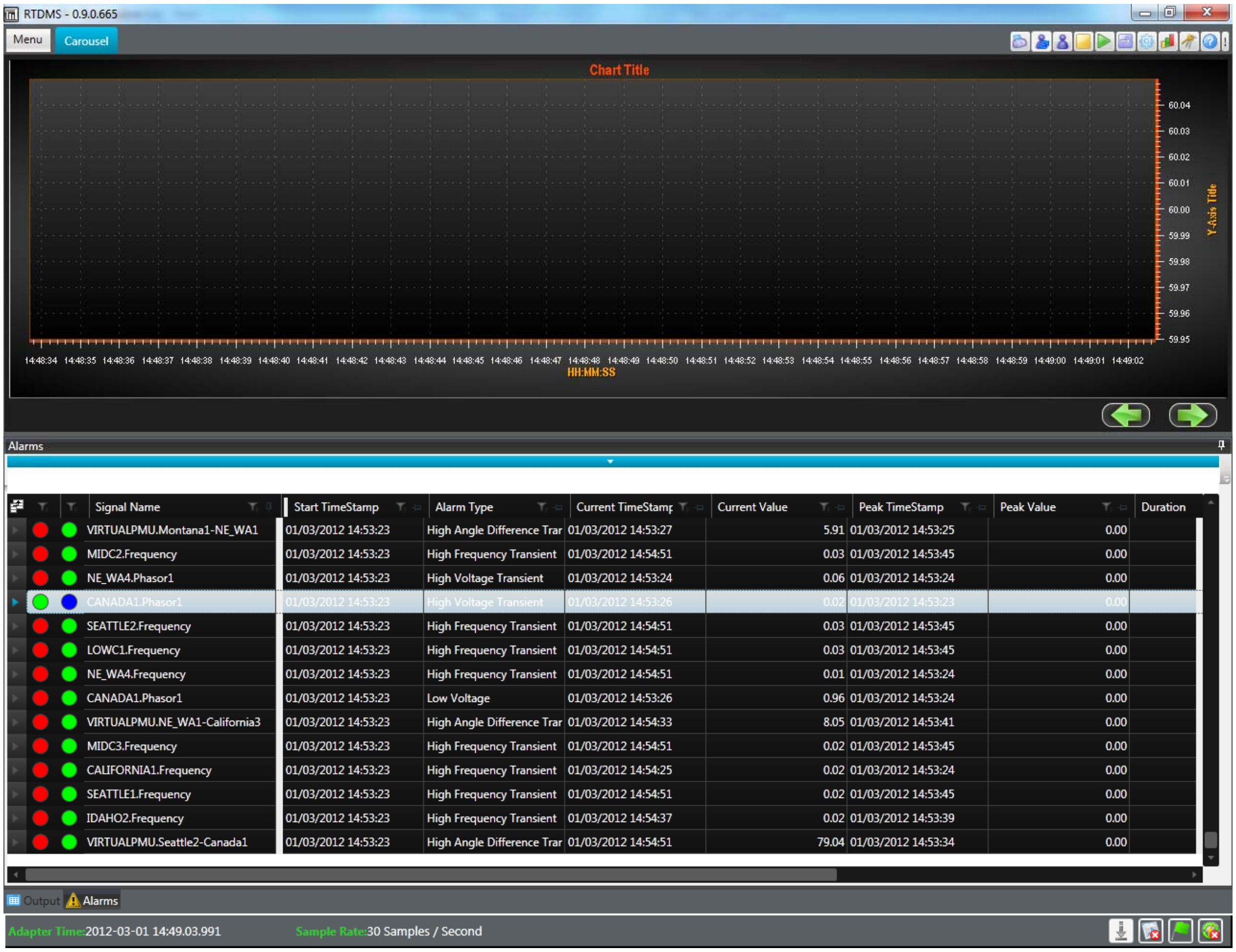


3. Properties: On click on properties, an alarm properties preference editor is displayed as a modal window. (ref: alarm properties window)
4. Help:
5. Acknowledge alarms: On select of the alarm records and click on “Acknowledge alarms”, the alarms records are acknowledged by the user. When an alarm is acknowledged, its status will be changed to acknowledged and saved in database. In the alarm status grid column the ellipse color is turned green. All users viewing the alarms will be notified of the acknowledgement. Also this functionality can be achieved by selecting the records and pressing the “A” key.

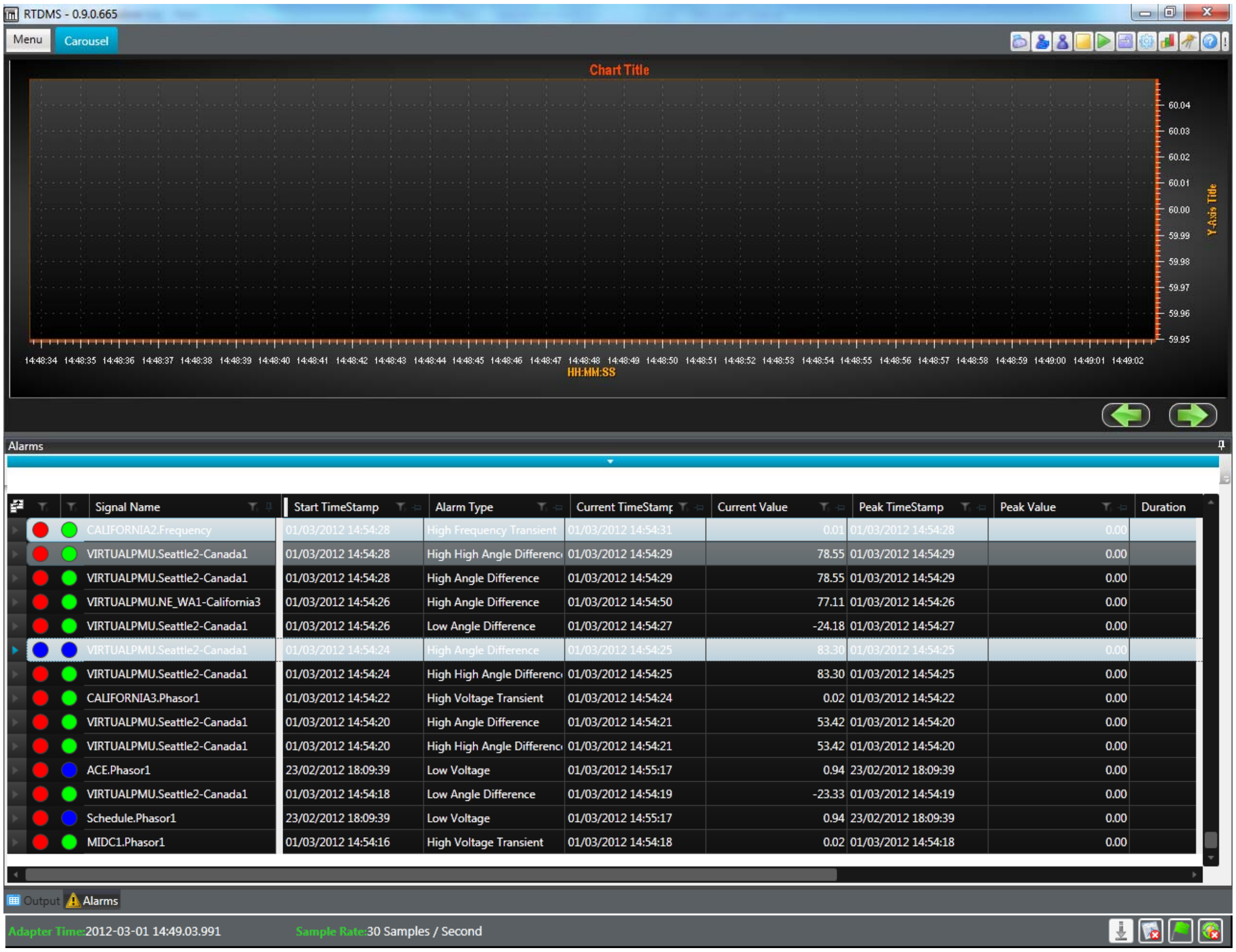
   Note:

   Access rights for users to acknowledge will be incorporated in the next phase.

   Auto acknowledgment of alarms will be incorporated in the next phase. Theoretically only case/type 2 alarms are suitable candidates for auto acknowledgment.



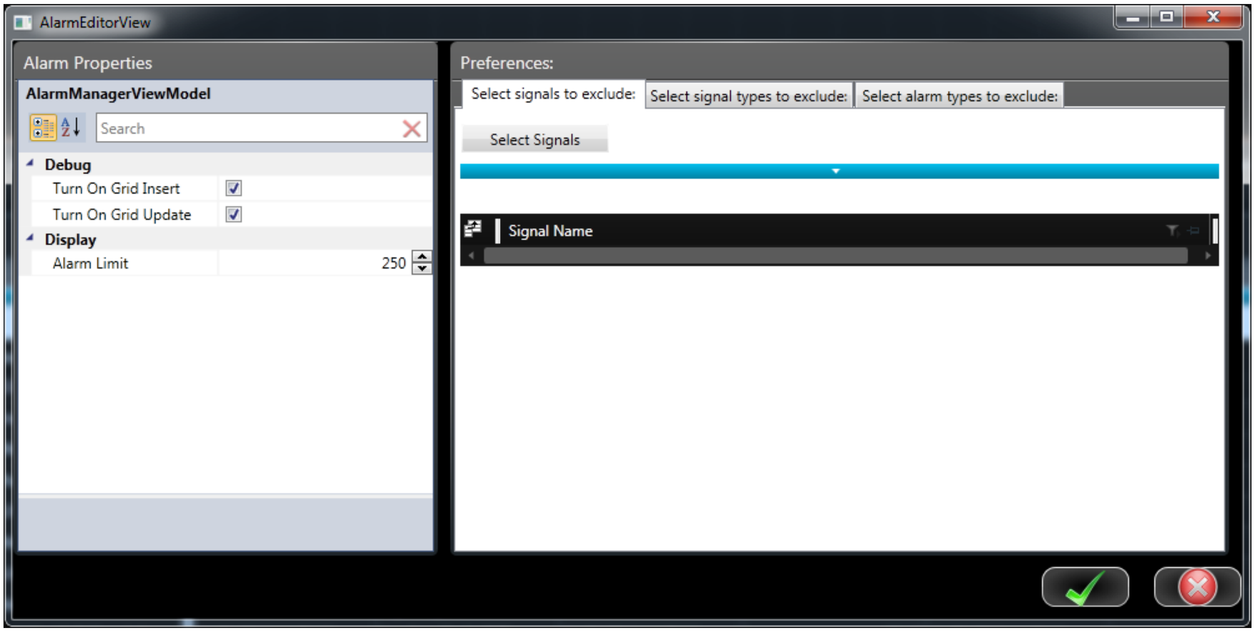
6. Delete alarms: On select of the alarm records and click on “Delete alarms”, the alarms records are deleted by the user. When an alarm is deleted, its status will be changed to deleted and saved in database. In the alarm status grid column the ellipse color is turned blue. All users viewing the alarms will be notified of the deletion. Also this functionality can be achieved by selecting the records and pressing the “D” key.
   Note: Access rights for users to delete alarms will be incorporated in the next phase



7. Clear alarms: On select of the alarm records and click on “Clear alarms”, the alarms records are cleared from the grid view of the user. This functionality does on the local view of user and does not affect any other users viewing the alarms. Also this functionality can be achieved by selecting the records and pressing the “C” key.
   Note: Access rights for users to clear alarms will be incorporated in the next phase
8. Publish Alarms: On select of the alarm records and click on “Publish alarms”, the selected alarm signals are published. Any other view subscribing to these signals will receive the alarm information. For e.g. On selecting an alarm signal record and clicking on publish, if a respective map view is being viewed by the user, the location of the signal is zoomed in the map view.
9. Export Alarms: On click of export alarm, the contents of the grid view is exported to an excel file.
10. Print Alarms: On click of print alarm, the contents of the grid view are sent to the printer.
11. Popup Trend chart: On select of the alarm record, and clicking on the popup trend chart, a line chart window is displayed to the user with the selected alarm signals to view the trend.


RTDMS - 0.9.0.665
Menu
Carousel
Chart Title
Y-Axis Title
Trend Chart
Chart Title
Y-Axis Title
HH:MM:SS
Alarms
Signal Name
Value
Peak TimeStamp
Peak Value
Duration
EUGENE.Phasor1
VIRTUALPMU.Se
OREGON3.Frequ
LOWC1.Frequen
IDAHO1.Phasor1 01/03/2012 14:55:03 Low Low Voltage 01/03/2012 14:55:04 0.84 01/03/2012 14:55:04 0.00
OREGON2.Phasor1 01/03/2012 14:55:03 Low Low Voltage 01/03/2012 14:55:04 0.84 01/03/2012 14:55:04 0.00
LOWC1.Frequency 01/03/2012 14:55:03 High High Frequency 01/03/2012 14:55:04 60.13 01/03/2012 14:55:03 0.00
PORTLAND3.Frequency 01/03/2012 14:55:03 High Frequency 01/03/2012 14:55:04 60.13 01/03/2012 14:55:03 0.00
MIDC3.Frequency 01/03/2012 14:55:03 High High Frequency 01/03/2012 14:55:04 60.13 01/03/2012 14:55:03 0.00
CALIFORNIA1.Phasor1 01/03/2012 14:55:03 Low Voltage 01/03/2012 14:55:04 0.88 01/03/2012 14:55:04 0.00
IDAHO1.Phasor1 01/03/2012 14:55:03 Low Voltage 01/03/2012 14:55:04 0.84 01/03/2012 14:55:04 0.00
OREGON2.Phasor1 01/03/2012 14:55:03 Low Voltage 01/03/2012 14:55:04 0.84 01/03/2012 14:55:04 0.00
IDAHO2.Phasor1 01/03/2012 14:55:03 Low Low Voltage 01/03/2012 14:55:04 0.88 01/03/2012 14:55:04 0.00
IDAHO1.Frequency 01/03/2012 14:55:03 High Frequency 01/03/2012 14:55:04 60.13 01/03/2012 14:55:04 0.00

Alarm properties window:



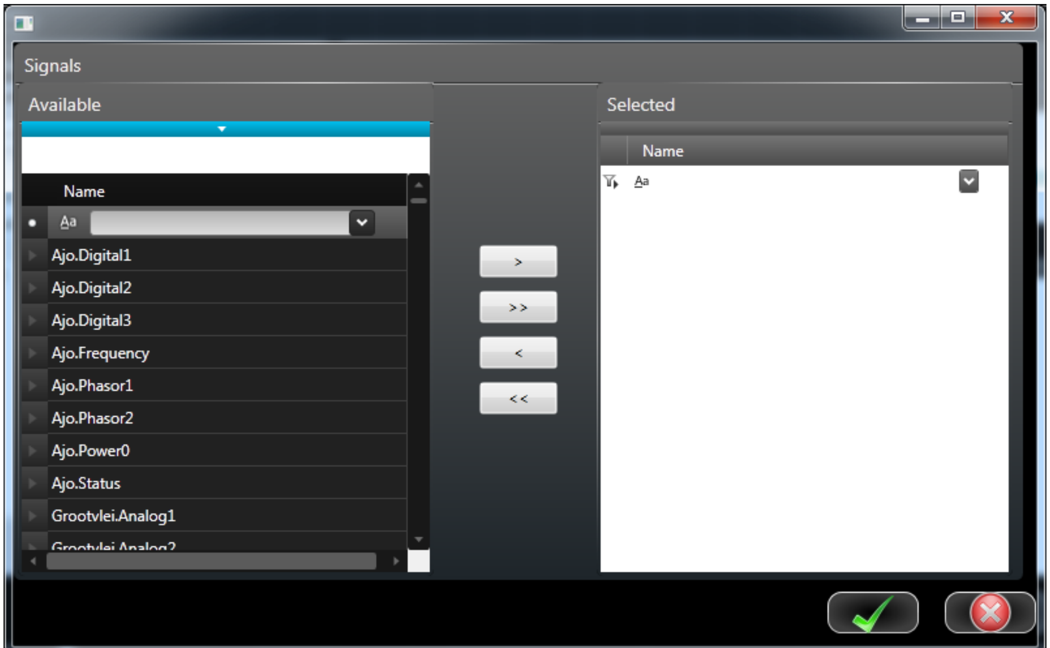
On click of properties the above properties dialog window is displayed to the user to set the preferences:

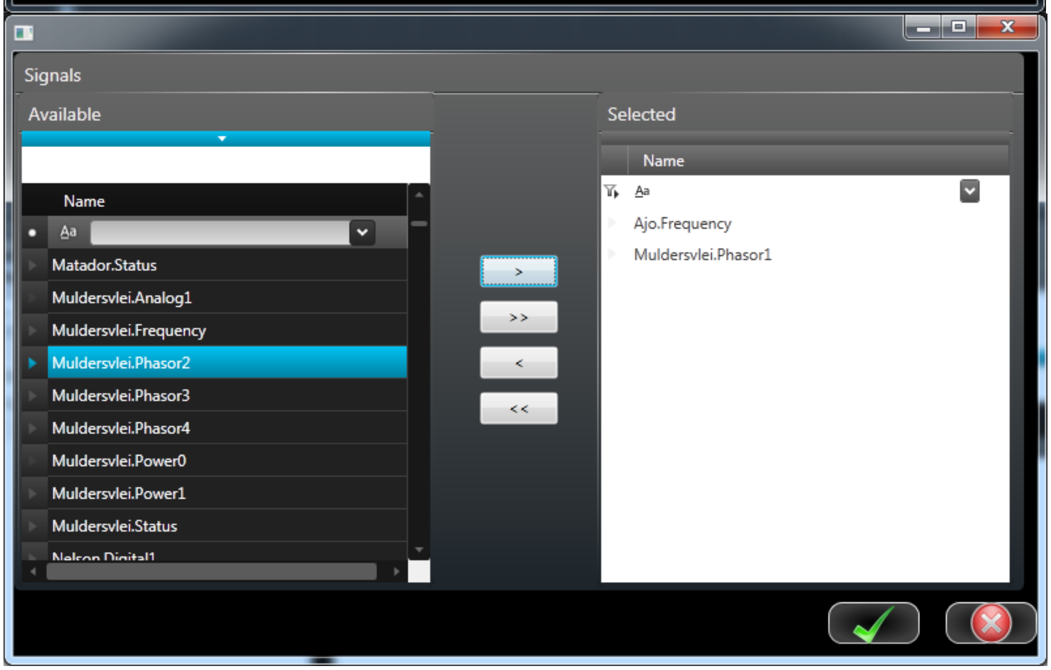
This dialog consists of:

1. Property grid:
   a. Alarm Limit: This value determines the number of alarm records to be displayed in the grid view.
2. Preferences:
   a. Signals to exclude: select signal names to exclude from being displayed in the grid.
   b. Signal types to exclude: select signal types to exclude from being displayed in the grid.
   c. Alarm types to exclude: select alarm types to exclude from being displayed in the grid.

Signals to exclude: On click of select signal button in the "Select signals to exclude" tab area, the following dialog window is displayed to the user. The dialog window displays a list of available signals and a list of selected signal if any. The user can select the signals from the available list box and move them to the selected signal list box. The user has the flexibility to add or remove the signals from the selected signal list box. On click of "OK" the signals in the selected list box are filtered from the incoming alarm records and thus not being displayed on the grid.

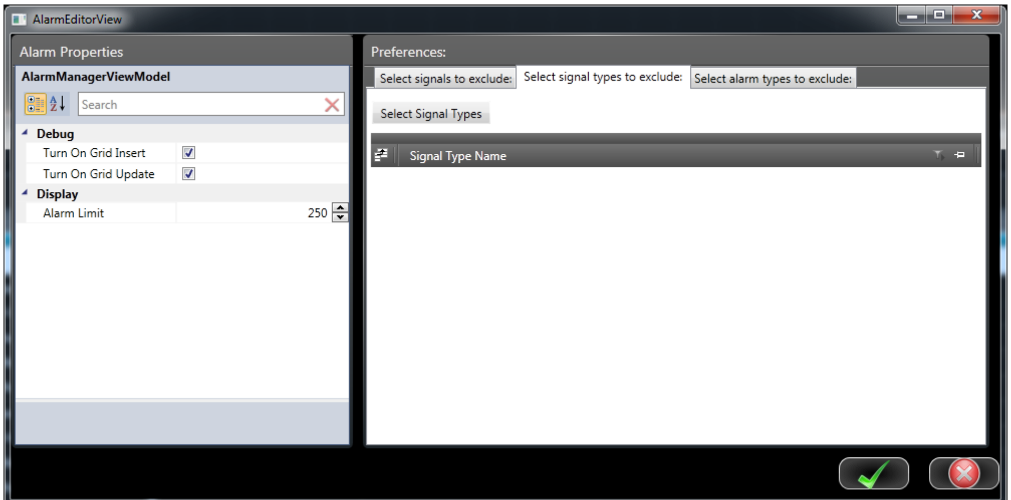
NOTE: Since the alarm view is global to the application view and does not belong to any profile, these values are currently maintained only for the current session. However if the alarm view is part of a display/profile, then the values are stored.

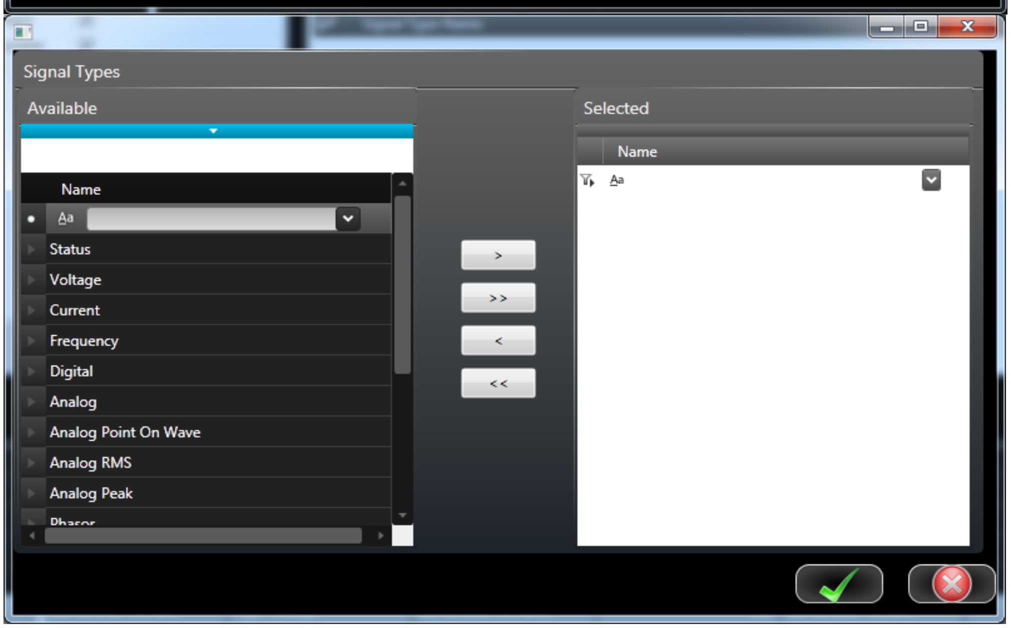




Signal types to exclude: On click of select signal type's button in the "Select signal types to exclude" tab area, the following dialog window is displayed to the user. The dialog window displays a list of available signal types and a list of selected signal types if any. The user can select the signal types from the available signal types list box and move them to the selected signal types list box. The user has the flexibility to add or remove the signal types from the selected signal types list box. On click of "OK" the signal types in the selected signal type's list box are filtered from the incoming alarm records and thus not being displayed on the grid.

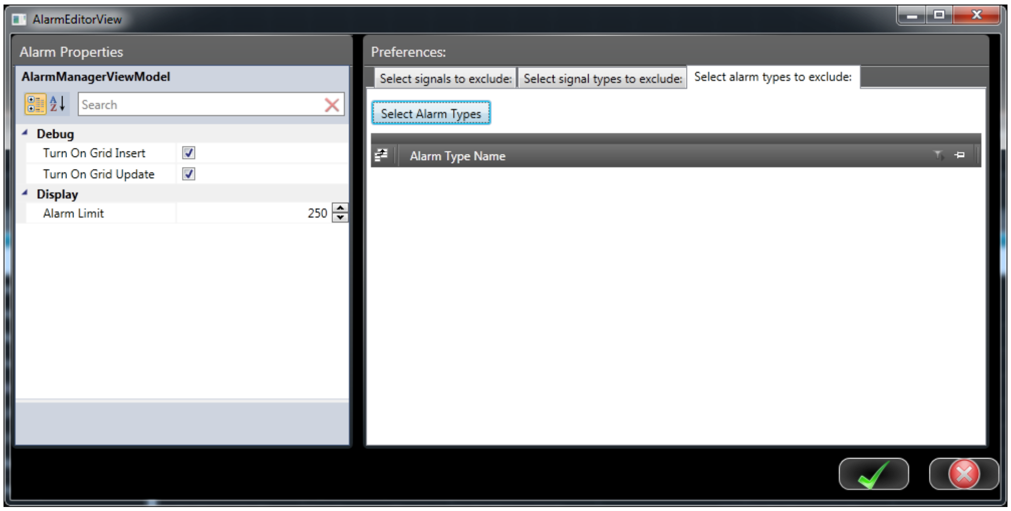
NOTE: Since the alarm view is global to the application view and does not belong to any profile, these values are currently maintained only for the current session. However if the alarm view is part of a display/profile, then the excluded signal types values are stored.





Alarm types to exclude: On click of select alarm type's button in the "Select alarm types to exclude" tab area, the following dialog window is displayed to the user. The dialog window displays a list of available alarm types and a list of selected alarm types if any. The user can select the alarm types from the available alarm types list box and move them to the selected alarm types list box. The user has the flexibility to add or remove the alarm types from the selected alarm type's list box. On click of "OK" the alarm types in the selected alarm type's list box are filtered from the incoming alarm records and thus not being displayed on the grid.

NOTE: Since the alarm view is global to the application view and does not belong to any profile, these values are currently maintained only for the current session. However if the alarm view is part of a display/profile, then the excluded alarm types values are stored.



8. Location Indicator View Design

8.1 Introduction

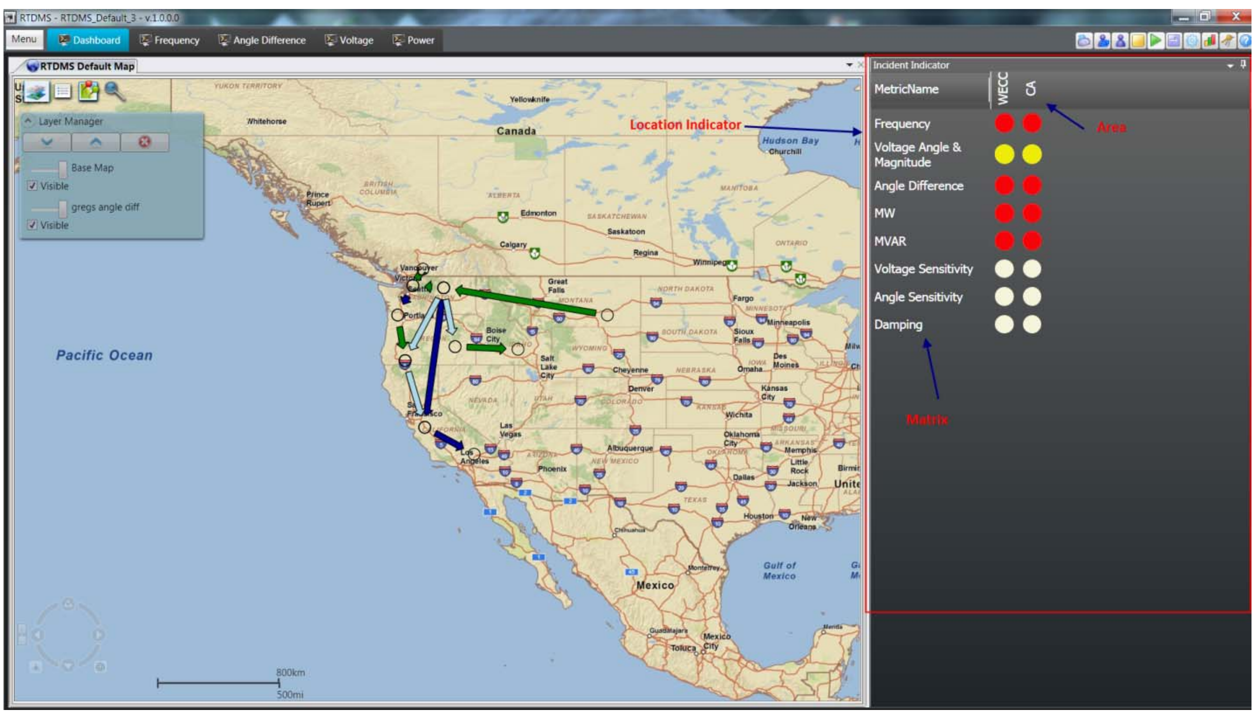
Location Indicator is to provide region-based status according to monitoring matrix. Since it provide the overview of all areas' performance from a glance, it is a very useful tool for wide area monitoring.

8.2 Metrics

Supported metrics shall include frequency, voltage angle and magnitude, angle difference, MW, MVAR, Voltage Sensitivity, Angle Sensitivity, and Damping.

8.3 Location Indicator View

The Location Indicator view is shown as following screenshot.



9. Annotations

9.1 Annotation Services

Two services have been designed for annotations:

1. **AnnotationsService** : This service is for creating, fetching and deleting annotations to a particular view which will be saved to database.

Method Name	Description	Input & Output (AnnotationsSearchCriteria)
GetAllViewAnnotations	This method is used to fetch all the annotations for a particular view both public and private ones	Input : User ID, View ID Output : AnnotationsCollection
GetViewAnnotation	This method is for fetching a single annotation of a view	Input : Annotation ID Output : Annotation
SaveViewAnnotation	Method to save an annotation to the database	Input : User ID, View ID & Annotation Output : Annotation (saved annotation with ID)
DeleteViewAnnotation	Method is to delete an annotation from database	Input : Annotation ID Output : True / False

2. **AnnotationsNotificationService** : Service is for real time communication of addition / modification of annotations to other users, who are viewing the same View (Map). Each RTDMS 2012 client will subscribe to this service to get notifications from these services. Whenever an

annotation that is public, is being added to a view and saved, others will get notification of annotation, then that particular view will fetch the annotation with content (can be image URL, Video content, calculated notes formula, text) from DB and renders it on that instance.

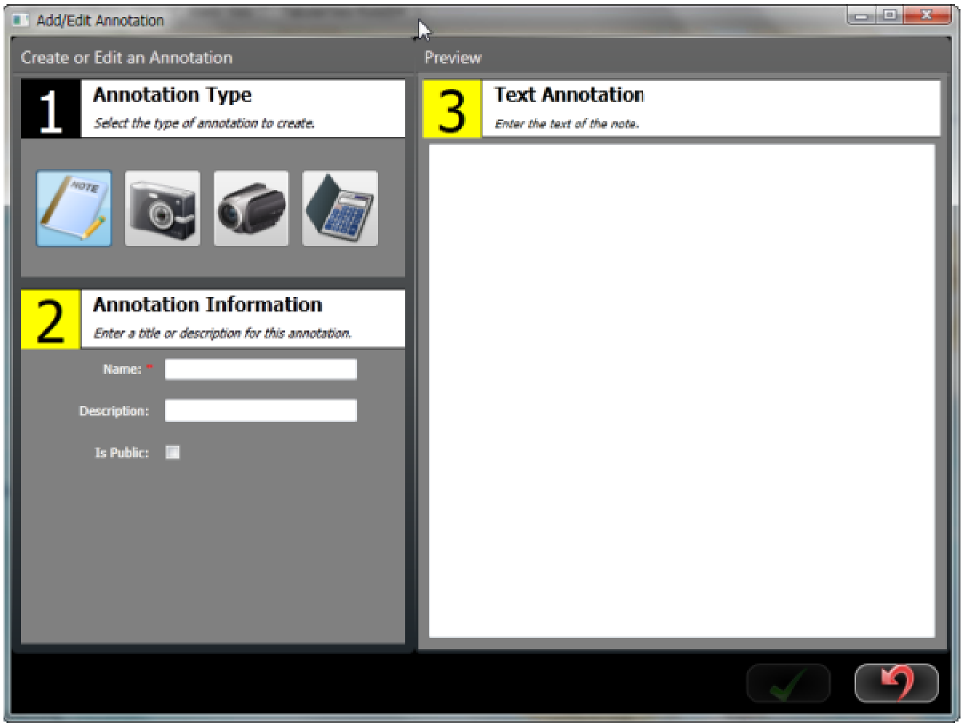
Method Name	Description	Input & Output (AnnotationsSearchCriteria)
Subscribe	Method is for subscribing to annotations notification	Input : NA Output : Subscription Token (string)
Unsubscribe	Method for unsubscribing to annotations notifications	Input : Subscription Token Output : NA
Ping	Method is used to ping the service periodically to maintain active connection	Input : DateTime Output : DateTime (same as input datetime)

9.2 Creating Annotations

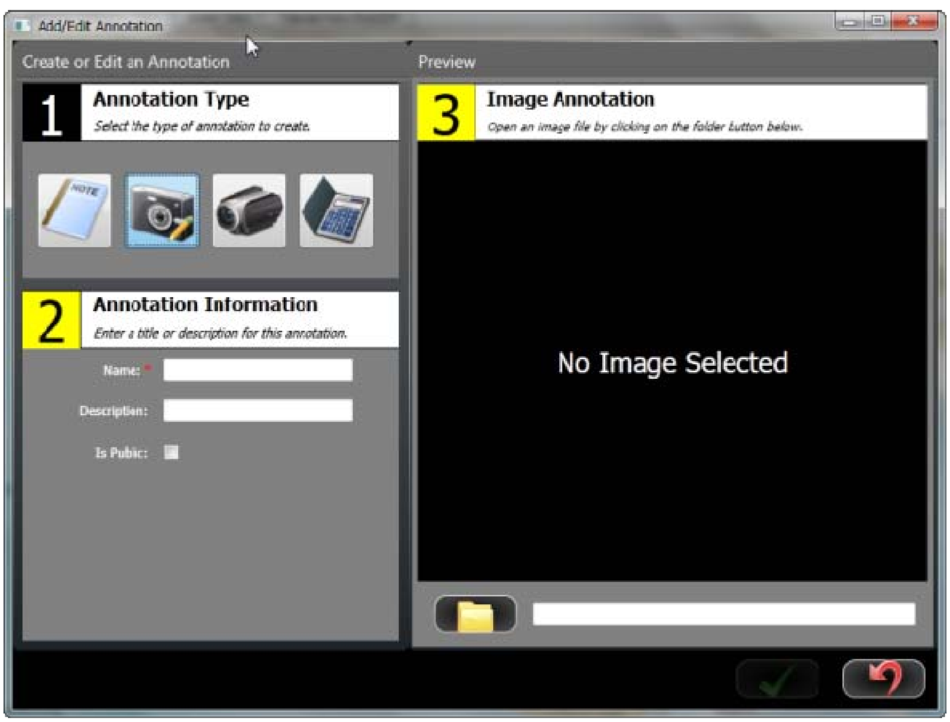
Annotations can be created on any map by using the "Add Annotation…" option provided in the context menu. Clicking on this option displays a dialog and allows the user to choose the type of annotation.

The following types of annotations are supported.

a) Text Annotation

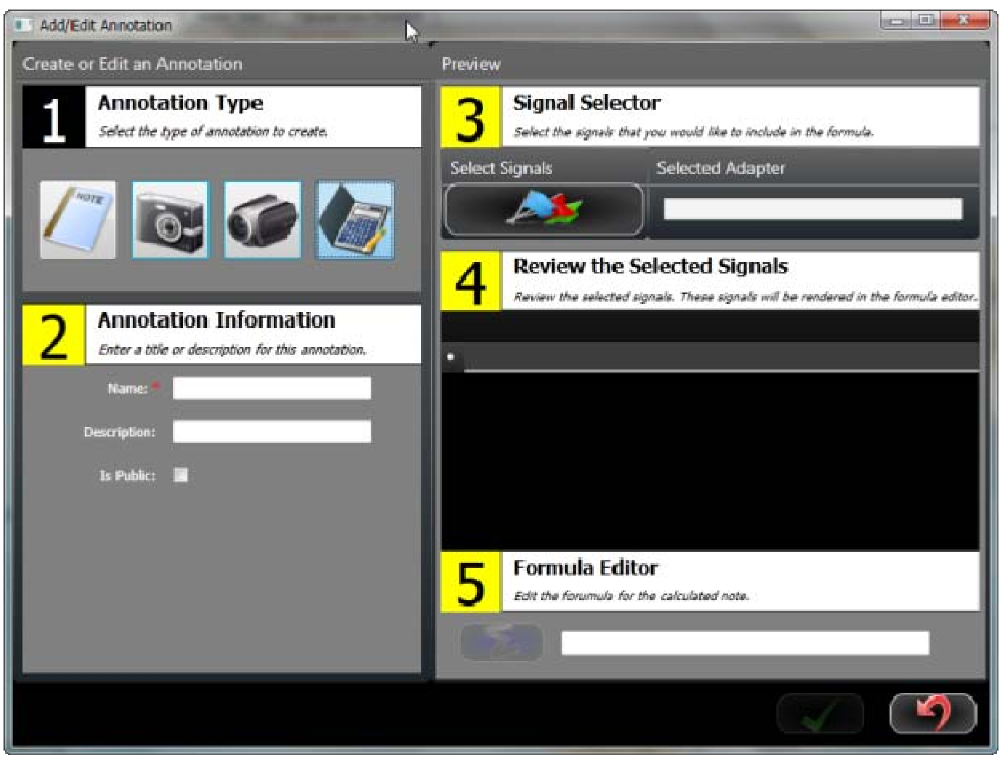


b) Image Annotation

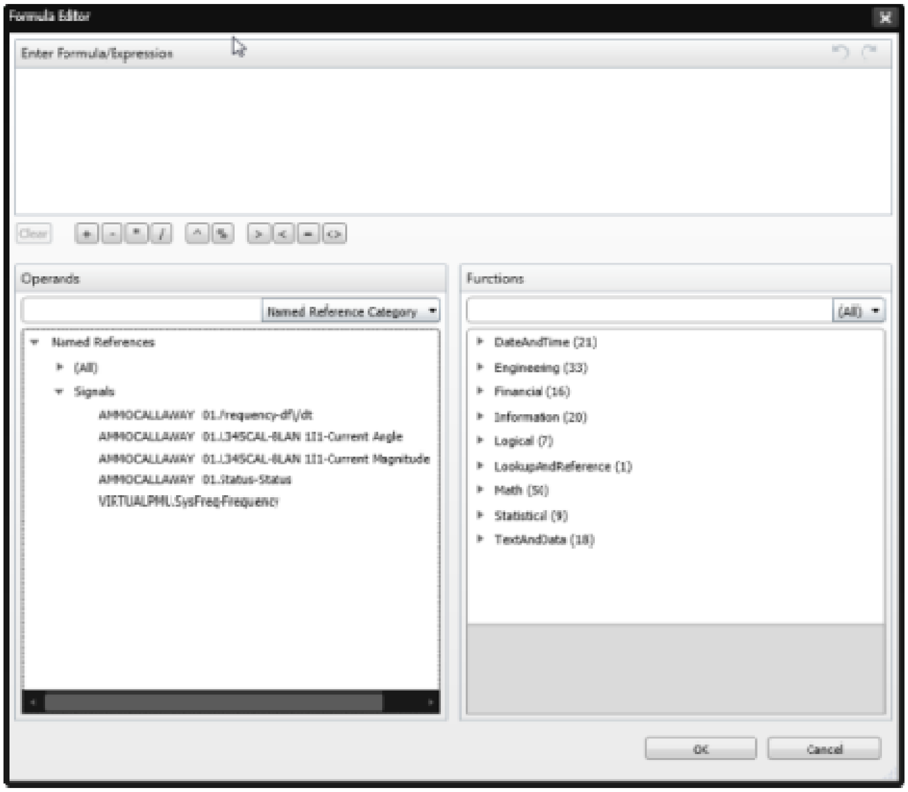


c) Video Annotation

d) Calculated Notes Annotation



a. To create a formula, the signals that need to be part of the formula can be selected from the data point selector. The selected signals are displayed in the grid. The formula editor can be opened by clicking on “Create / Edit Formula”. This displays the formula editor as shown below.



The signals can be combined together along with operators and functions to create a formula. This formula is then saved to the database and stored as part of the annotation content. When the formula is rendered on the map, the formula is evaluated and the resultant value is displayed.

Annotations can also be made visible to other users by checking the option “Is Public” in the dialog. The annotation is persisted to the database when the OK button is clicked. If the annotation is made public, a notification is sent to all the logged in users who have the view open. The notification makes use of Callback methods provided by Windows Communication Foundation (WCF). Whenever a user receives a notification, it is displayed as a balloon tooltip in the status bar. The tooltip can be clicked to navigate to the view that received the notification. Annotations created by a user are persisted and are rendered when the view is rendered.

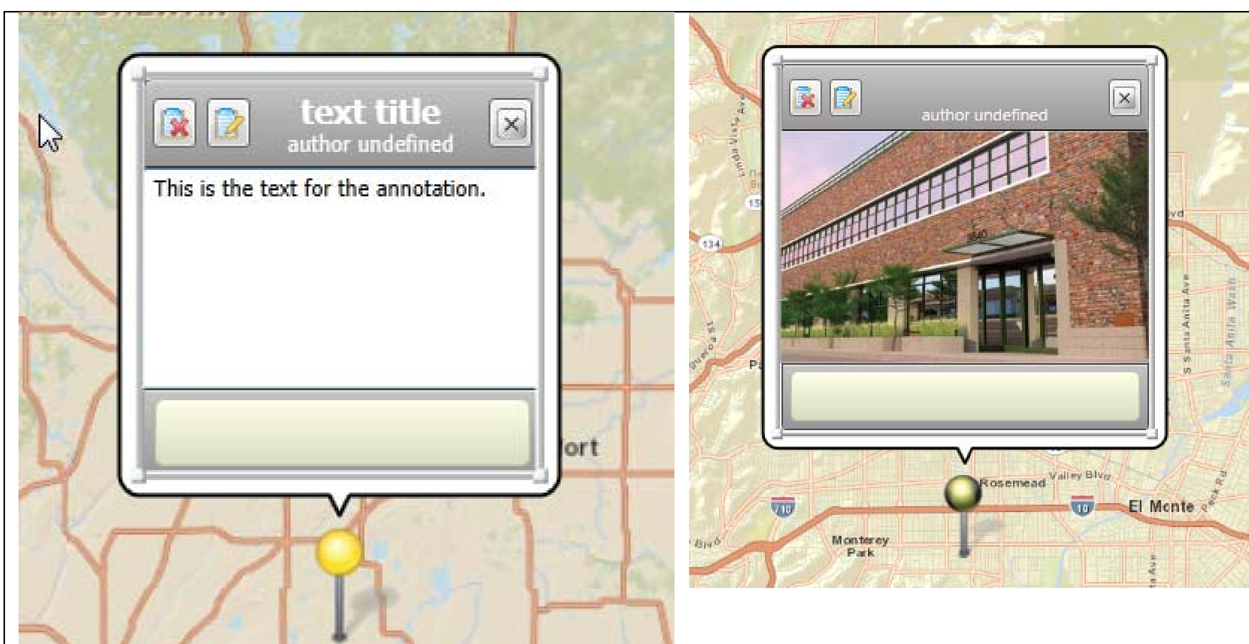
The following table has been designed to store the annotations added / edited by a user.

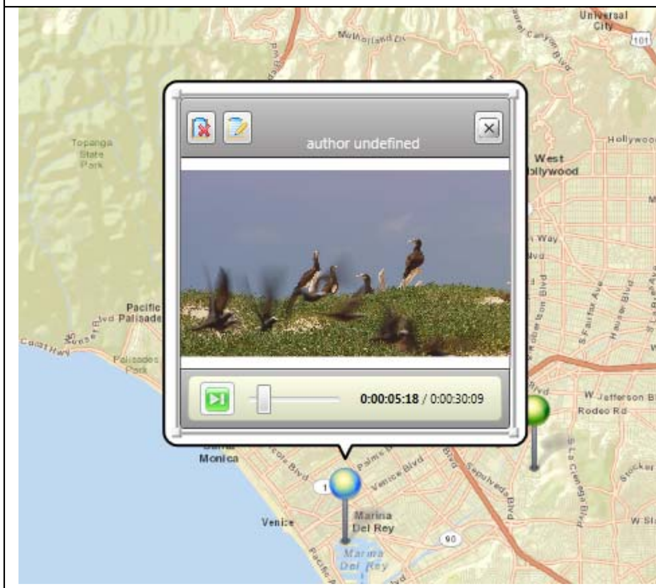
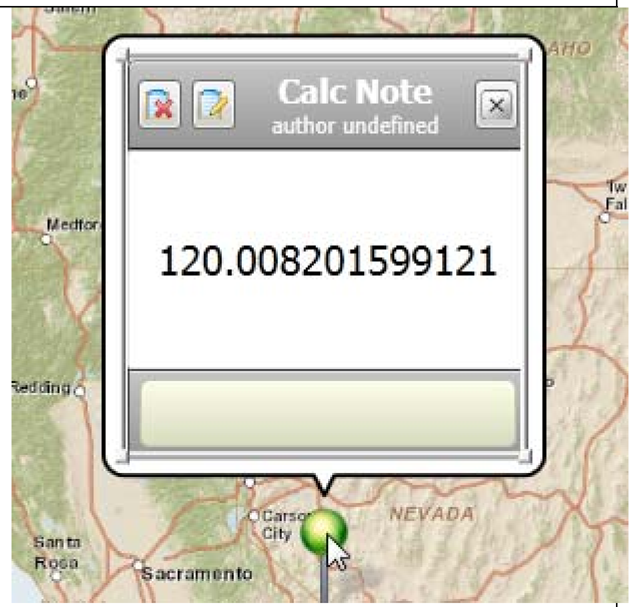
Table: Client_Annotations		
Column Name	**Data Type**	**Description**
ID	int	Primary Key
ViewID	int	The unique identifier of the view to which the annotation belongs to.

Type	smallint	The type of annotation. 0 - Text 1 - Image 2 - Video 3 - Calculated Notes
Description	Varchar(256)	Description of the annotation
Content	Varbinary(Max)	The content of the annotation.
UserID	int	The unique identifier of the user who has created the annotation.
IsPublic	bit	0 - False 1 - True
LocationX	float	The X coordinate of annotation.
LocationY	float	The Y coordinate of annotation.
FileName	Varchar(256)	The file name. This field will be used only if the annotation is of type Image / Video.
CreatedAt	DateTime	The date and time when the annotation was created.
UpdatedAt	DateTime	The date and time when the annotation was updated.

9.3 Displaying Annotations

Annotations marked on maps by the presence of a pushpin. Clicking on the pushpin will bring up the respective annotation for viewing. When the annotation is displayed, the user can delete or edit the annotation. Please see the two screenshots of sample annotations below.

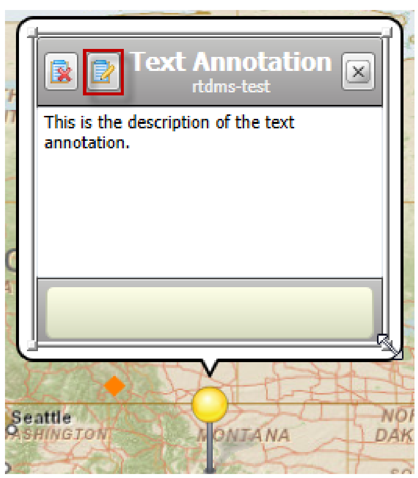


Text Annotation	Image Annotation
	
Video Annotation	Calculated Notes Annotation

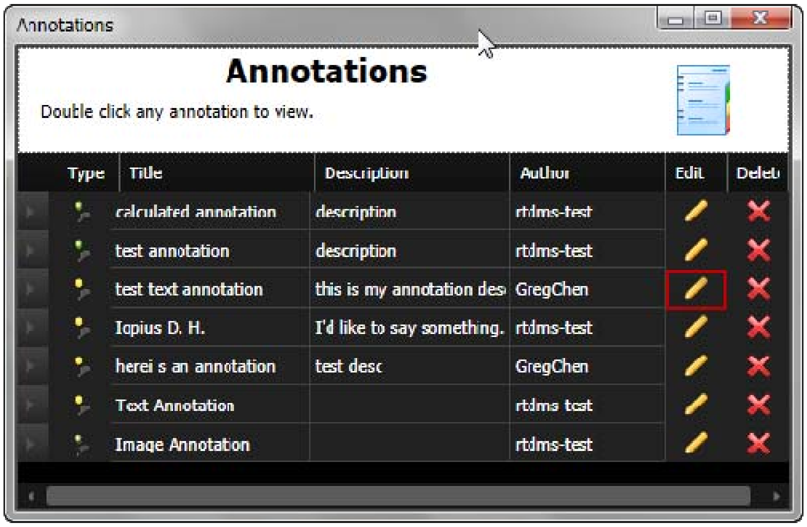
9.4 Editing Annotations

Annotations can be edited in the following two ways.

- Opening the annotation popup by clicking on the “Push Pin” and clicking on the “Edit” button as shown below.



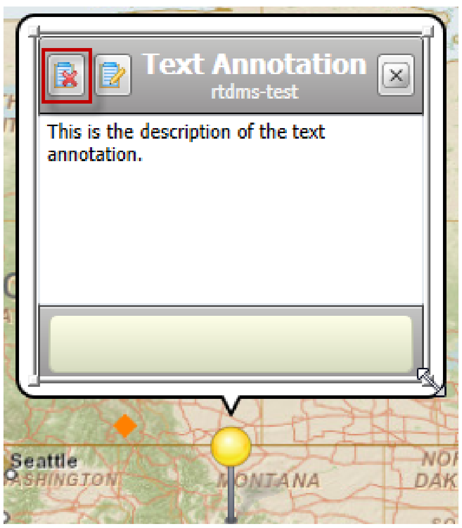
- Opening the Annotation List popup and clicking on the “Edit” button as shown below.



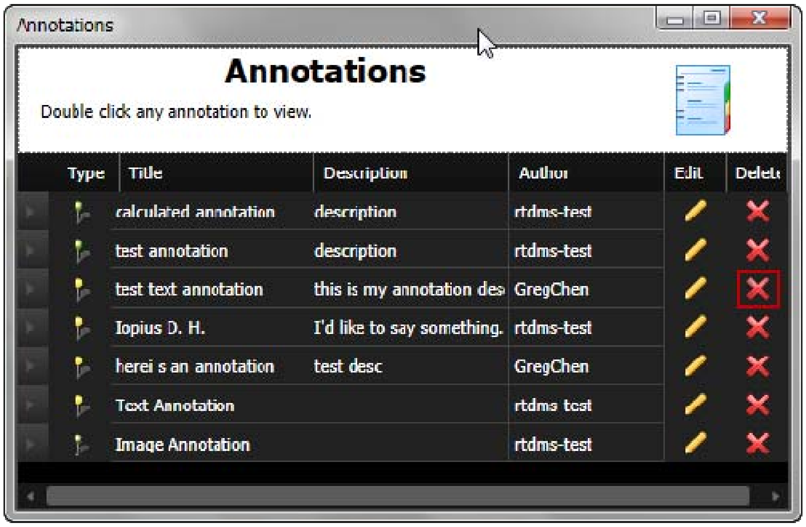
9.5 Deleting Annotations

Annotations can be deleted only by the user who has created it or by users who have the privilege to do so. They can be deleted in the following two ways.

- Opening the Annotation popup by clicking on the “Push Pin” and clicking on the “Delete” button as shown below.



- Opening the Annotation List popup and clicking on the “Delete” button as shown below.



9. 6 Cut / Copy and Paste Annotations

Annotations uses the windows clipboard to support cut and paste and copy and paste operations. These clipboard operations are available by right clicking on the annotation pin and selecting the command from the context menu.

Function	Description
Cut and Paste	Moves the selected annotation to a new location.
Copy and Paste	Creates an identical annotation at a new location.

9.7 Save Profile As

The current logic of saving a profile with a new name resulted in changes done to a display or view in the original profile being reflected in the new profile. Hence the logic is now changed so that changes done to the original profile will not get reflected in the profile that has been saved with a new name.

Clicking on the "Save Profile As" button will display a new dialog that has three fields namely

a) Profile Name
b) Description
c) Keywords

On click of "OK" button, the names of all the displays, views and layers present in the profile are made unique and then saved to the database.

The logic of making a name unique is done as follows:

a) The current name of the entity in consideration is taken and compared to see if any other entity starts with the same name.
b) The count of the list obtained is used in the new name.
c) The new name will be in the format **CurrentName (List Count)**, where List Count is the count obtained in the above step.

Note: Changes such as adding a layer to a map is immediately saved to the database and hence the same will get reflected in the new profile that is saved with a new name.

9.8 Save Display As

The current logic of saving a display with a new name resulted in changes done to a view in the original display being reflected in the new display. Hence the logic is now changed so that changes done to the original display will not get reflected in the profile that has been saved with a new name.

Clicking on the "Save Display As" button will display a new dialog that has three fields namely

d) Display Name
e) Description
f) Keywords

The logic of making a name unique is done as follows:

d) The current name of the entity in consideration is taken and compared to see if any other entity starts with the same name.
e) The count of the list obtained is used in the new name.
f) The new name will be in the format **CurrentName (List Count)**, where List Count is the count obtained in the above step.

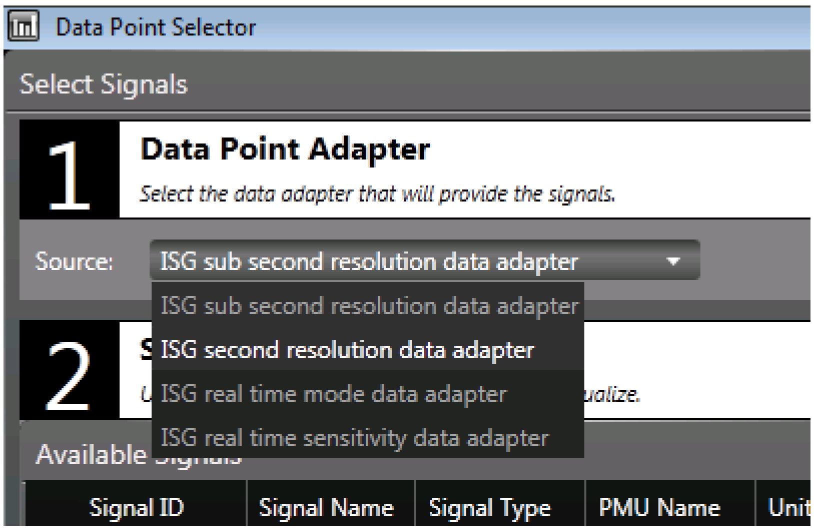
Note: Changes such as adding a layer to a map is immediately saved to the database and hence the same will get reflected in the new profile that is saved with a new name.

10. Data Service, Logging Service, and other Utility Services

This section describes how data will be retrieved from ISG or other data sources and feed/format data to views.

Data service, logging services are available through Core Services module.

Data service is a container which contains all the real time and historic data adapters. Below picture shows the available list of real time data adapters (respective historic data adapters are present for these real time adapters)



Each adapter is responsible for fetching respective data from ISG and formats it in a universal interface (as shown in section 10.1) and serve the clients (views). These adapters are capable to handle their own re-connectivity with ISG in case of disconnection and have their own respective historic adapters to serve same data.

10.1 Multi Data Sources Support

Multi data source support is achieved using the above said data adapters. As the data point update is using a single interface (IDataPoint) new data sources can be plugged into the system by writing respective data adapters and adding them to the data service.

10.2 Real-time Data

The real time data, sub second resolution, second resolution data, mode data and sensitivity data are fetched from ISG using respective data adapters and served to the registered data point collections. Please see the class diagram 11.1 interaction diagram for more details.

10.3 Historical Data

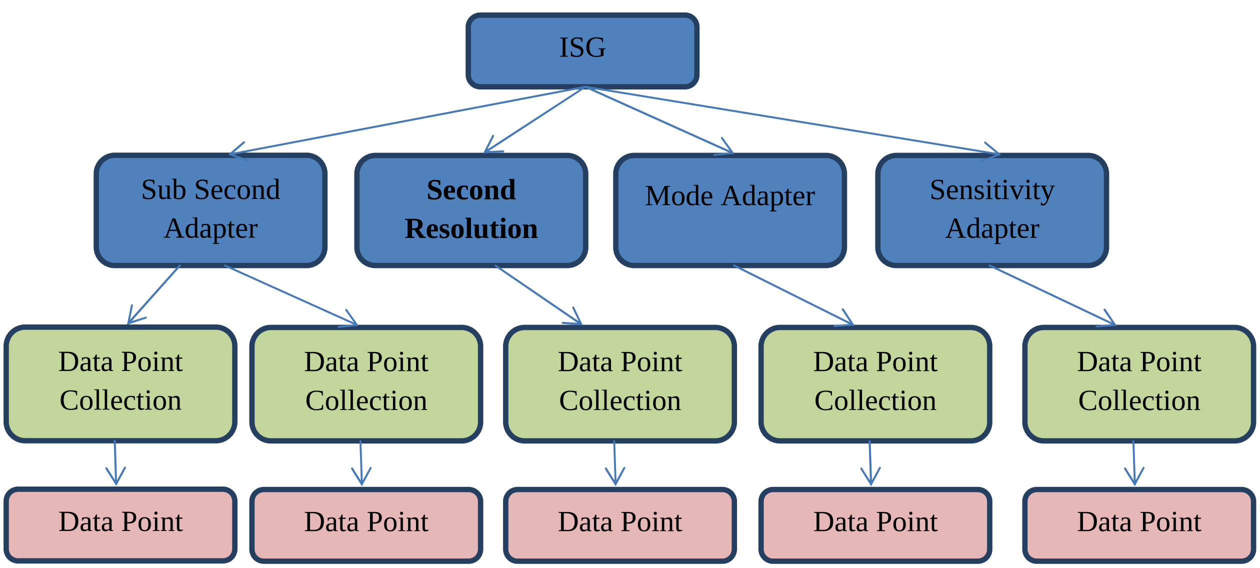
All the real time data adapters have respective historic data adapters viz., historic sub second resolution, historic second resolution data, historic mode data, historic sensitivity data. The adapters are switched from real time to historic and vice versa automatically on user replay / resume / stop commands using the toolbar.

10.4 Event Files Data

Simon, we don't have it yet.

10.5 Data and Display Interaction

Data is updated to each views (charts, maps) using data point. Each data point is updated whenever new data is fetched from ISG. These data points are grouped into data point collection (each view has one or more collections) which will be subscribed to the adapters using register / unregister methods.



10.6 Logging Service

Logging service used to log the error messages to a file, which can be found in \log folder.

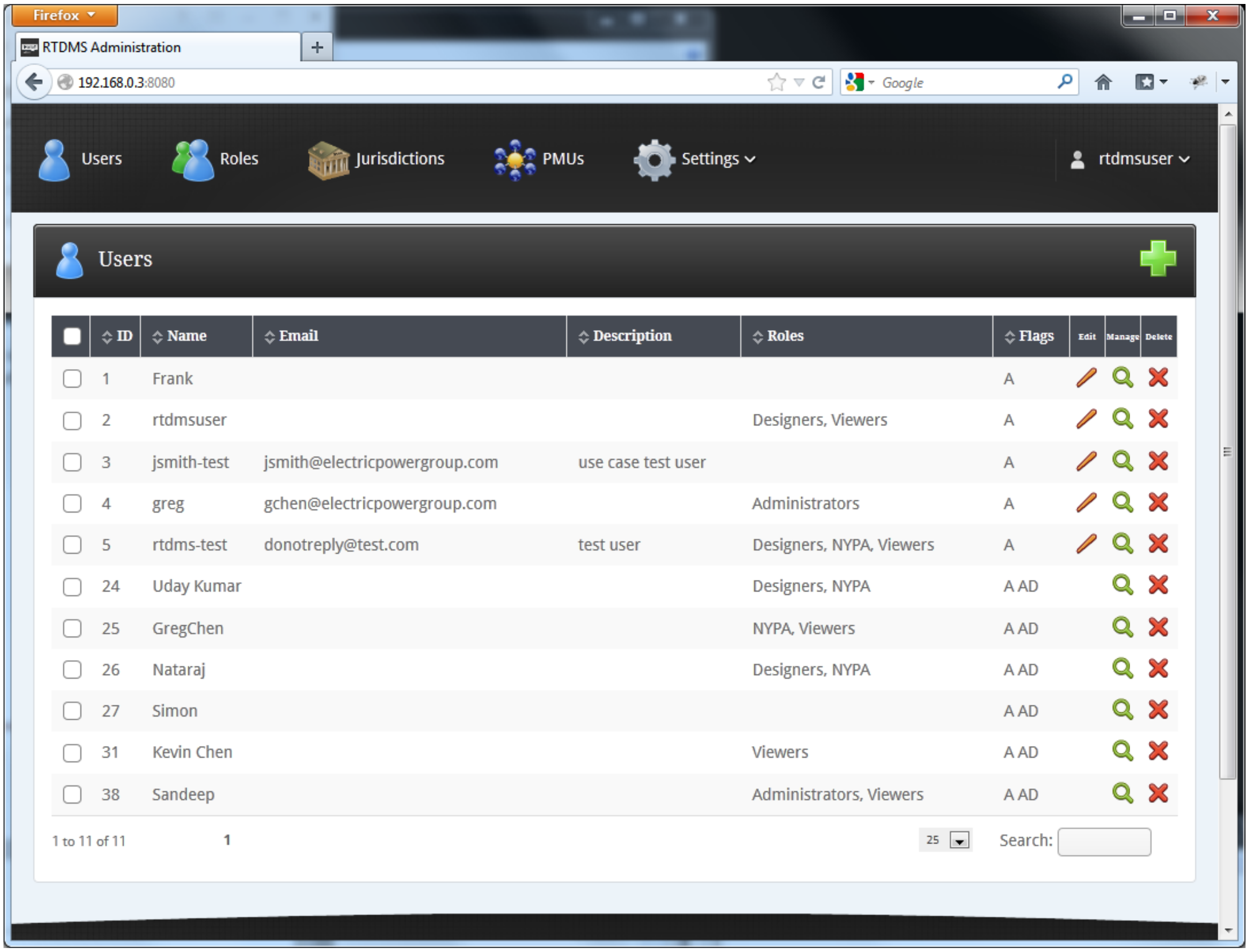
11. Administrator Web App

11.1 Role-Based Security

RTDMS implements role-based security and Active Directory (LDAP) integration to support users, roles, and privileges. Users belong to one or more roles, and roles contain one or more privileges. An administrator is tasked with creating users and roles, then assigning users to those roles.

RTDMS supports two types of users and two types of roles – RTDMS users / roles and Active Directory users / roles. Following is a table that explains the differences between all types of users and roles.

Name	Definition	Notes
System User	A user that is created via the Admin Web App.	System users are editable via the RTDMS web app. Editing includes making changes to user name, login name, password, etc.
System Role	A role that is created via the Admin Web App.	System roles are editable via the Admin Web App.
AD User	An Active Directory user that has been granted access to RTDMS.	AD users are managed outside of RTDMS. An AD user may be granted access to RTDMS directly or by belonging to an AD Group that has RTDMS access.
AD Role	An Active Directory group that has been granted access to RTDMS. All Active Directory users in this group are granted access to RTDMS.	AD groups are managed outside of RTDMS. All of the AD users in the group are granted access when a group is granted access. To remove an AD user's access, this user must be removed from the AD group.



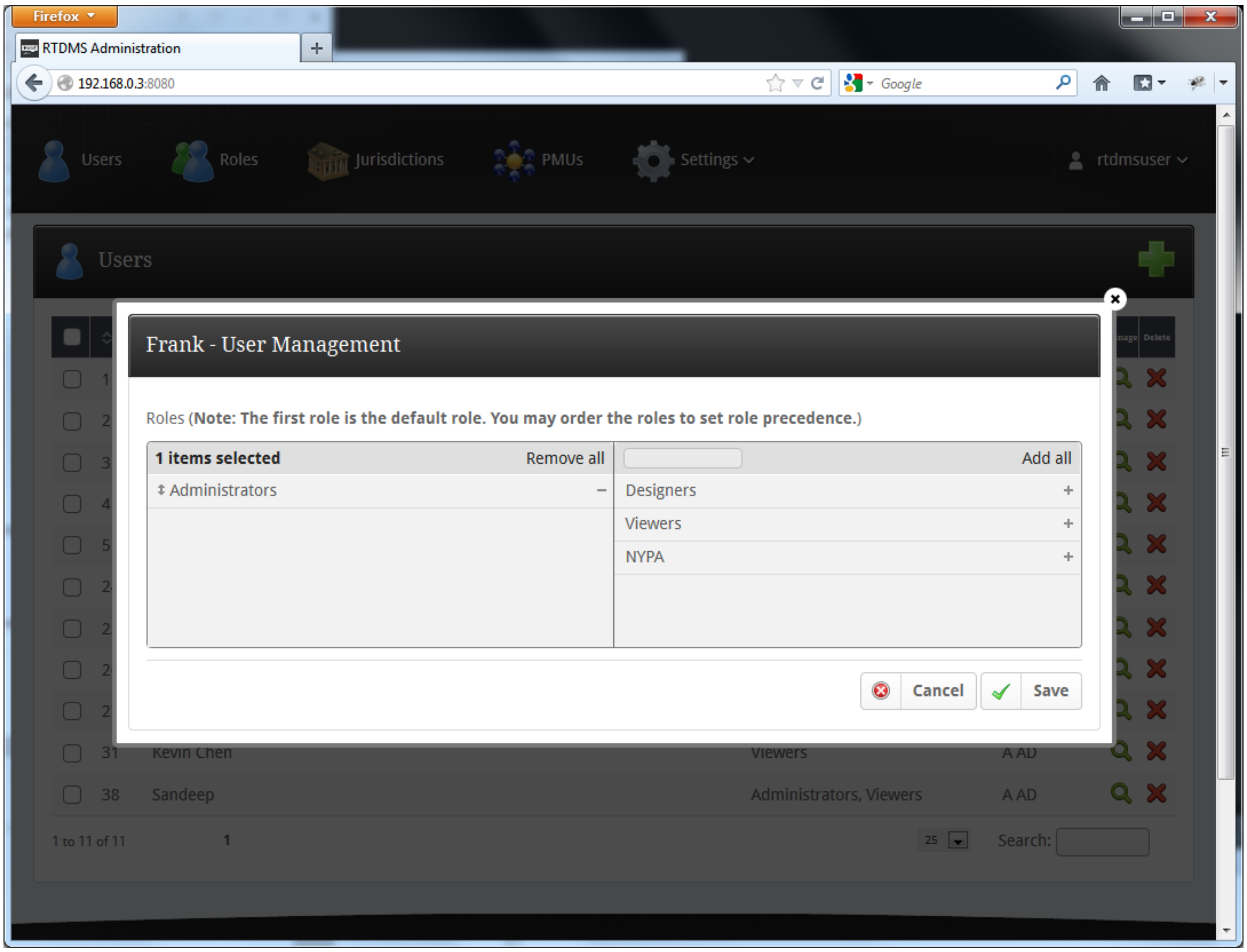
The User page is shown in the screenshot above. The roles page is very similar so all the concepts that are applicable to the user are also applicable to a role. First off, notice the list of users are presented in a grid. The columns are:

1. ID – The system generated ID for the user
2. Name – The name of the user
3. Email - The user email address
4. Description – Additional notes about a user.
5. Roles – A comma separated list of roles the user belongs to.
6. Flags –A: Active User, AD: Active Directory User
7. Edit – Push to edit the user details. This is not available for AD users.
8. Manage – Push to assign roles / permissions / pmus
9. Delete – Push to delete the user

To add a user, click on the large green + icon located just above the grid's top right corner.

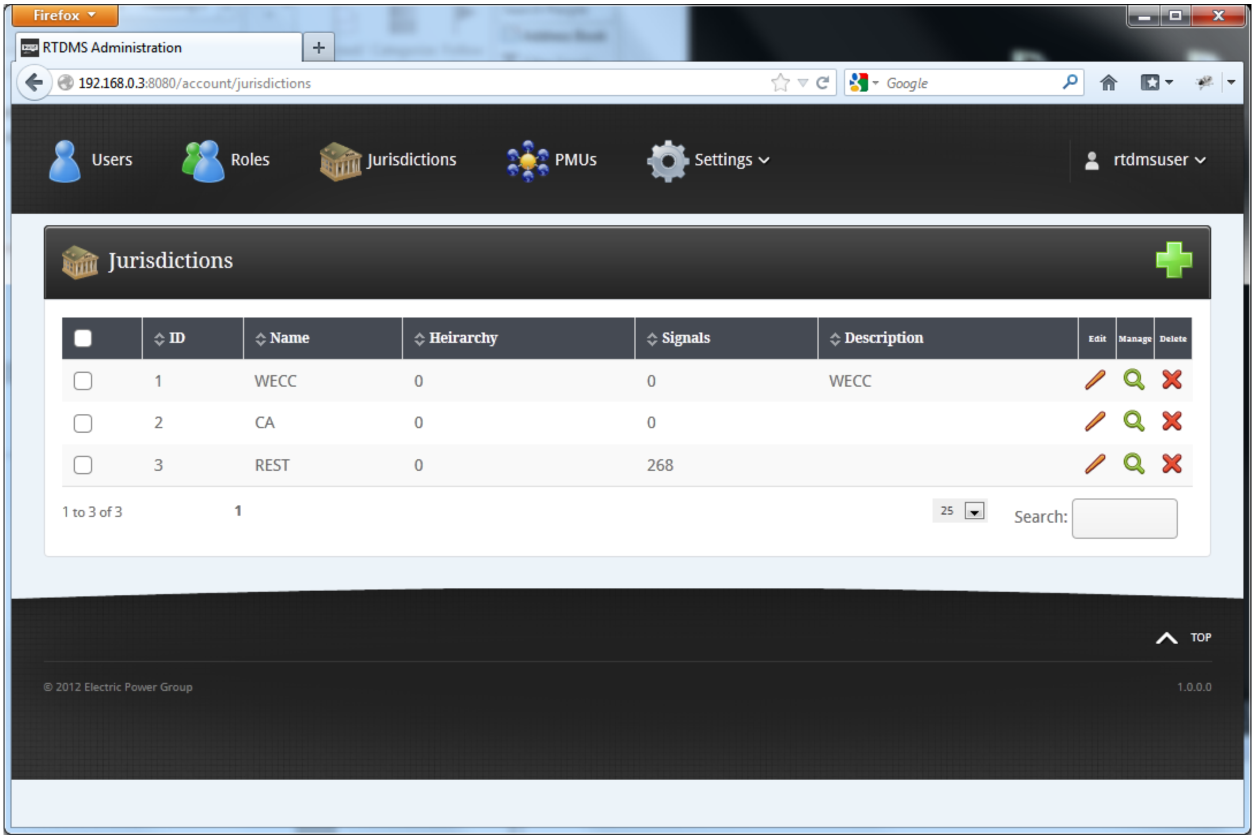
The User Management dialog is show below. This is what pops up afte clicking on the "Manage" button. Assign roles by moving roles from the right hand side to the left hand side. You can drag and drop your selection, double click on the selection, or press the "Add all" link to add all, and the "Remove all" link to remove all.

This management dialog is common throughout the RTDMS Administration Web App and the concepts just described are common throughout the system.

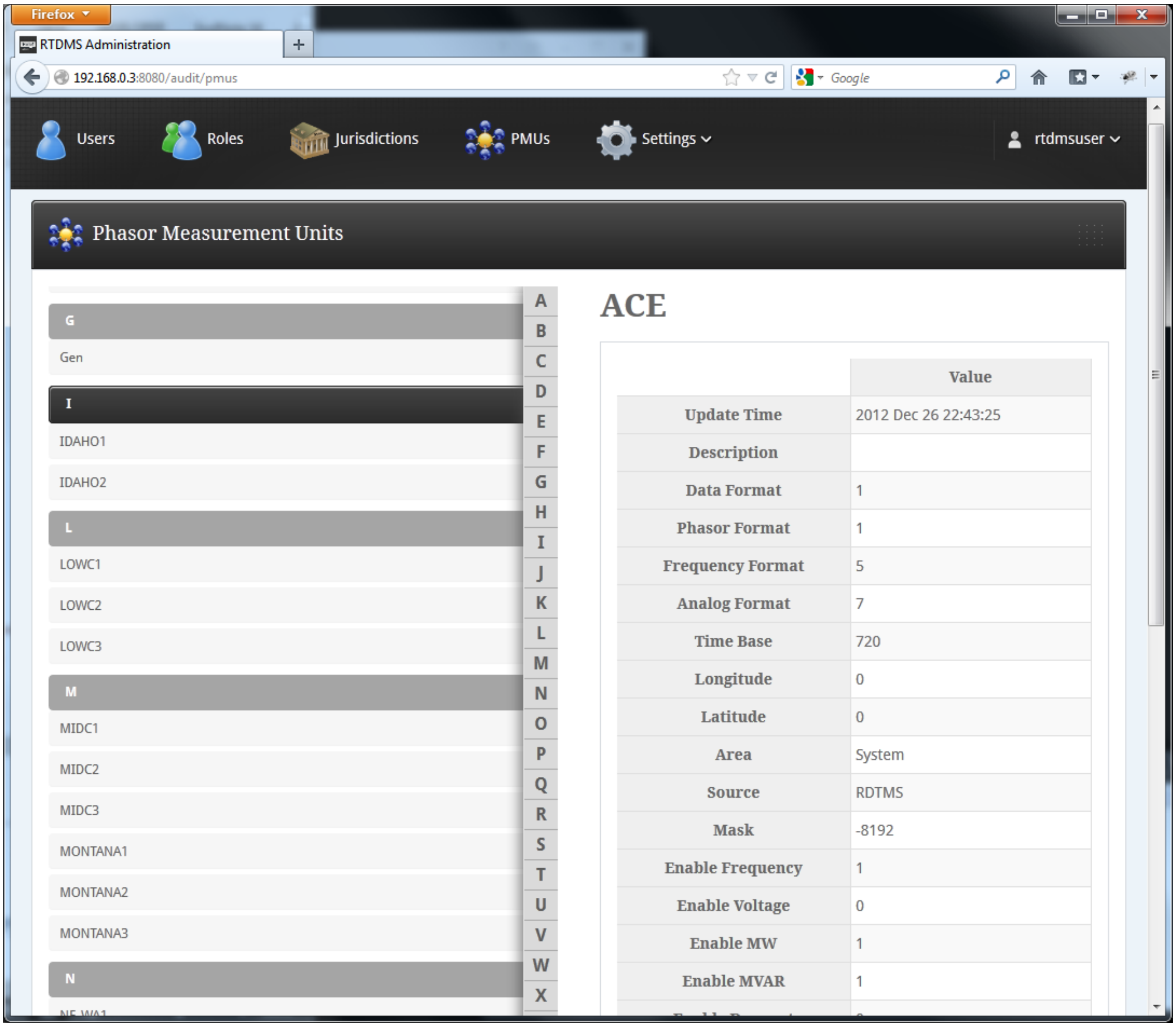


11.2 Jurisdictions

Managing jurisdictions follows a consistent implementation with managing users and roles. The key difference is jurisdictions contain a collection of signals, just as a role contains a collection of users.

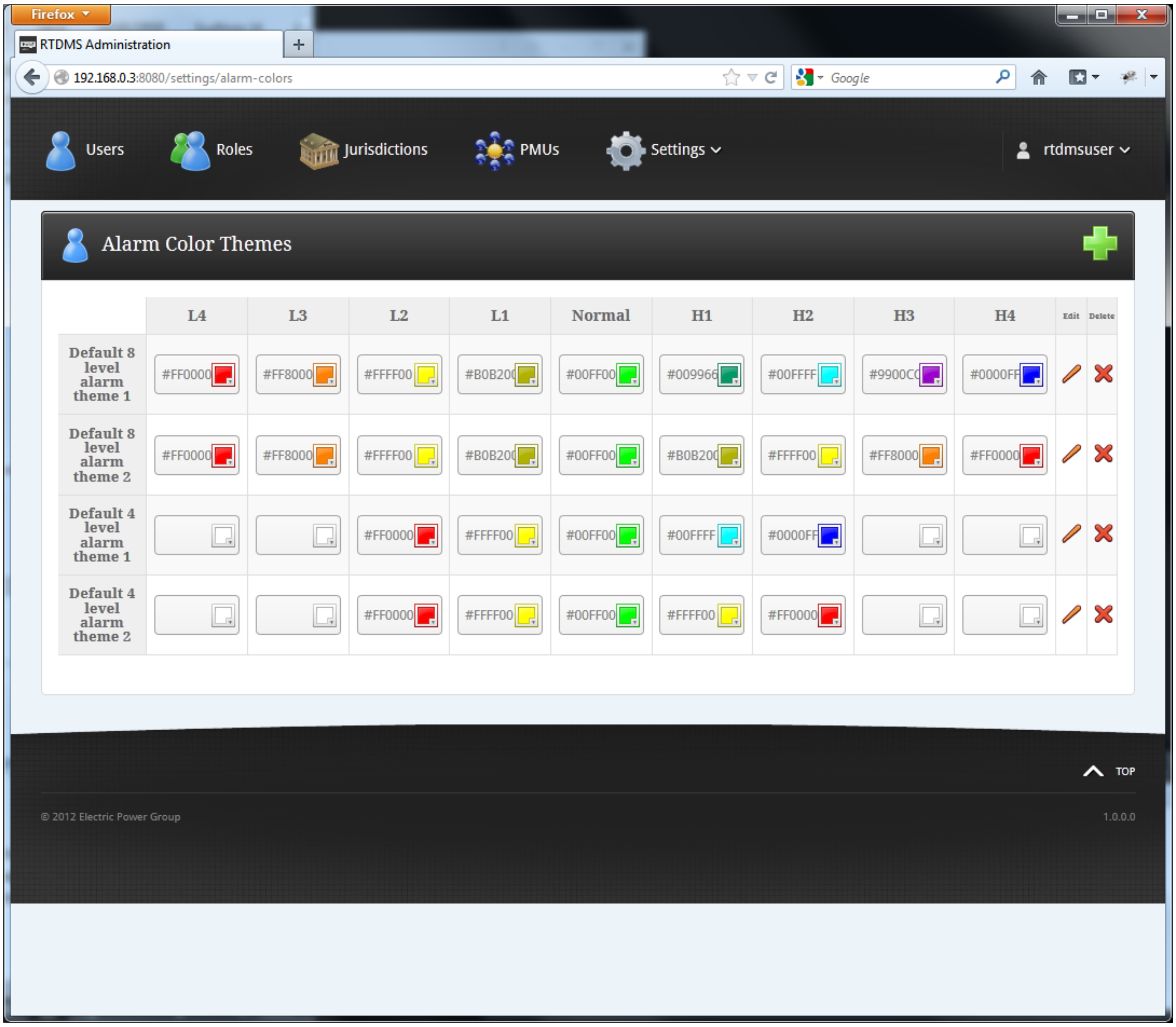

Firefox
RTDMS Administration
192.168.0.3:8080/account/jurisdictions
Google
Users
Roles
Jurisdictions
PMUs
Settings
rtdmsuser
Jurisdictions
ID
Name
Heirarchy
Signals
Description
Edit
Manage
Delete
1 WECC 0 0 WECC
2 CA 0 0
3 REST 0 268
1 to 3 of 3
1
25
Search:
TOP
© 2012 Electric Power Group
1.0.0.0

11.3 PMUs

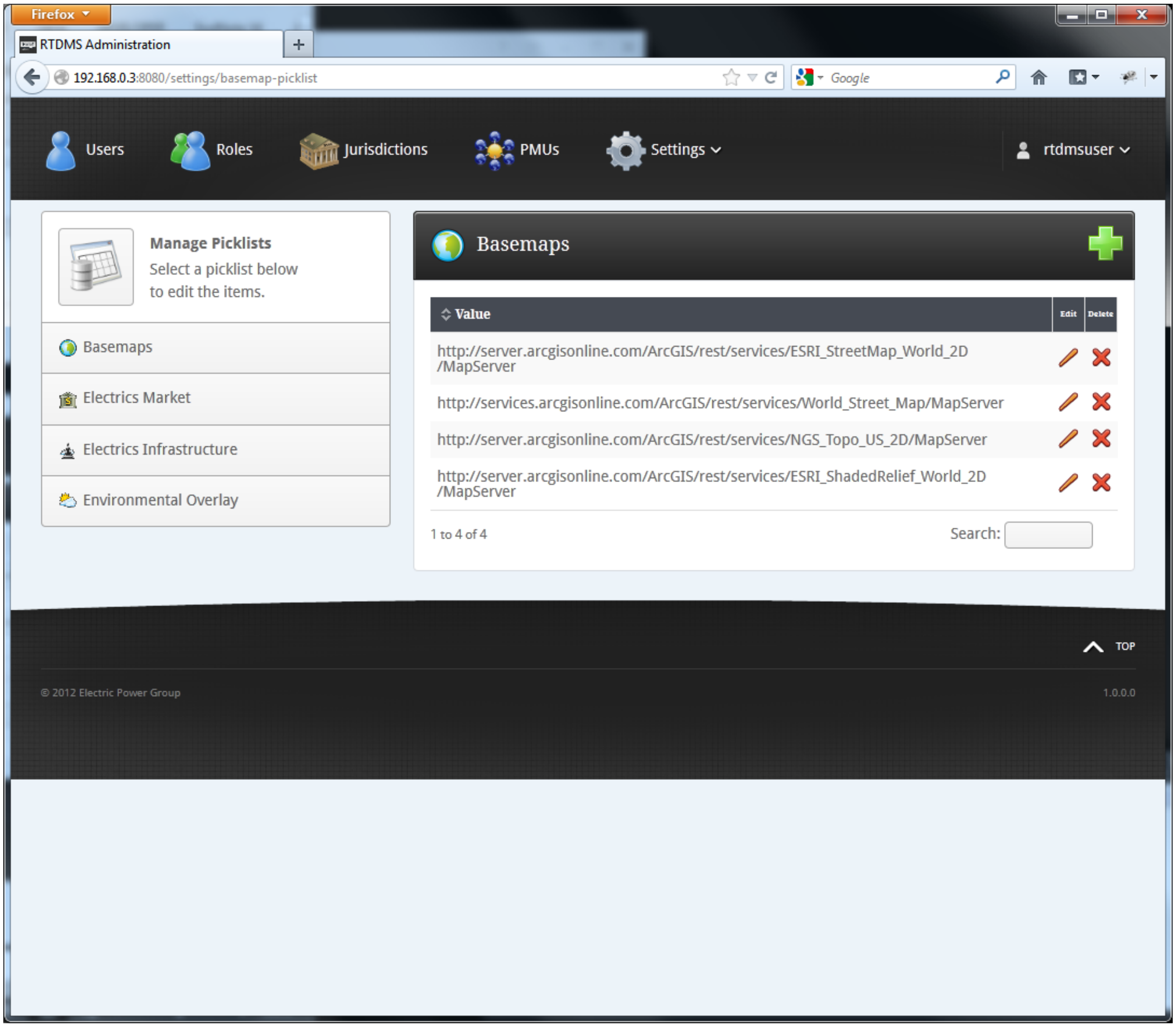


The PMU page is shown above and provides a complete list of all PMUs. Select a PMU from the list on the right to view detailed information about the PMU on the left hand side of the page.

11.4 Alarm Colors



11.5 Pick Lists

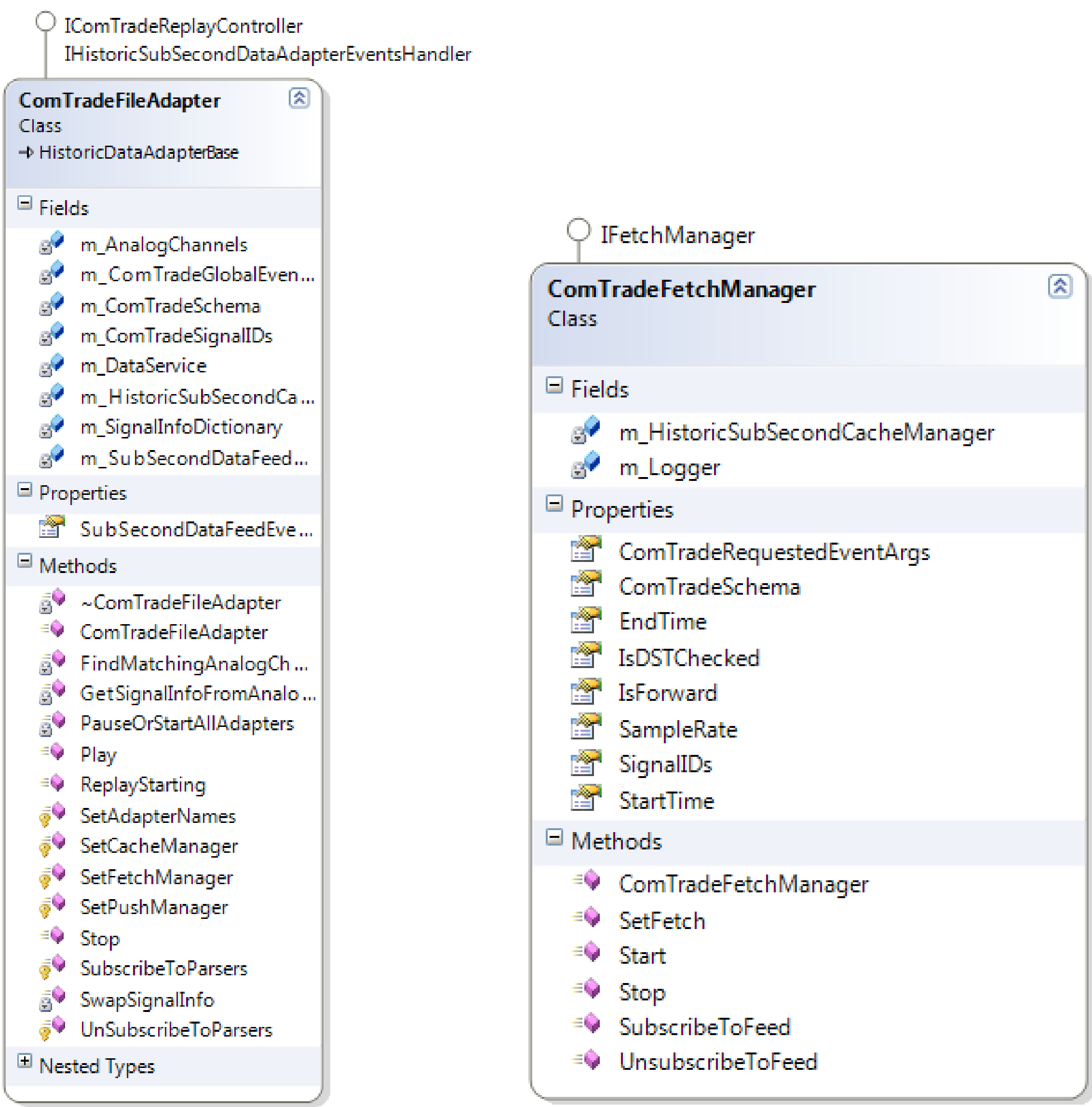


12. COMTRADE File Replay

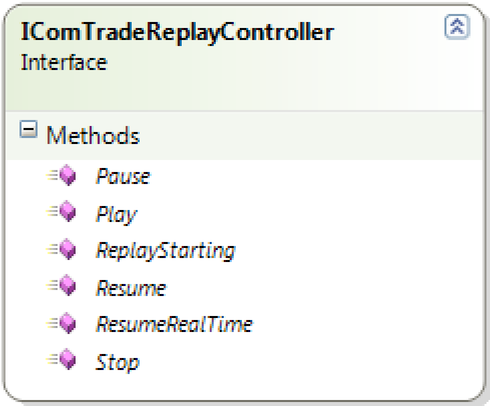
12.1 ComTradeFileAdapter

For supporting COMTRADE file replay new adapter ComTradeFileAdapter is added to RTDMS.CoreServices.

This adapter is similar to any historic data adapter deriving from HistoricDataAdapterBase and implements IComTradeReplayController.



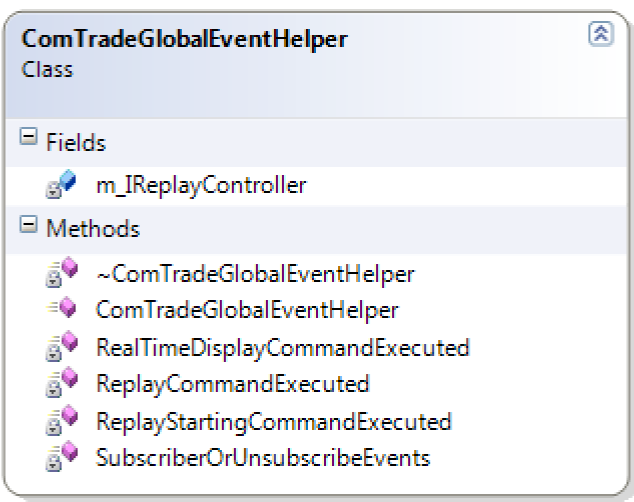
12. 2 IComTradeReplayController



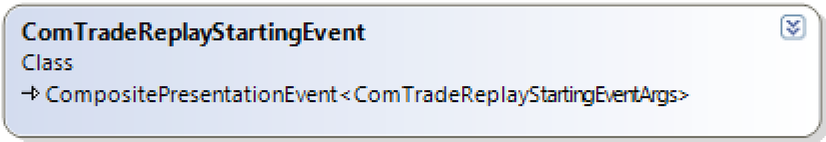
IComTradeReplayController interface implemented by ComTrade Data Adapter controls the play, pause, resume, stop etc.. methods hooking up to a helper class as described below.

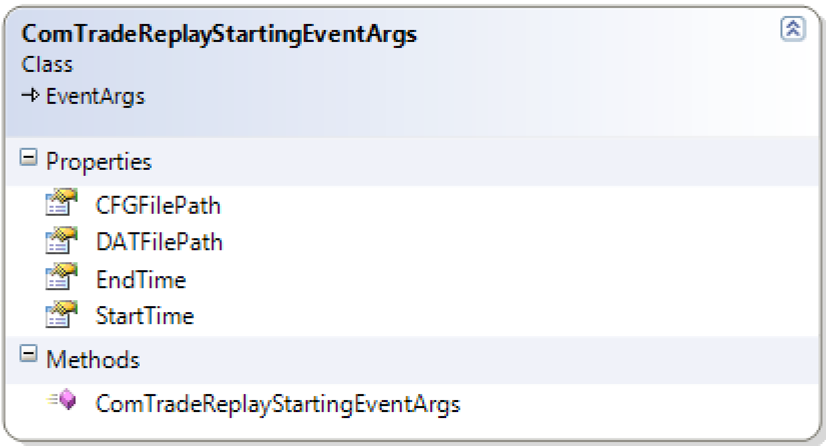
12.3 ComTradeGlobalEventHelper

Helper class ComTradeGlobalEventHelper is created to hook up to two global CompositeEvents to control the ComTrade Data Adapter.



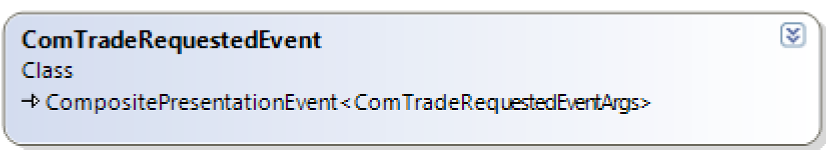
12.4 ComTradeReplayStartingEvent

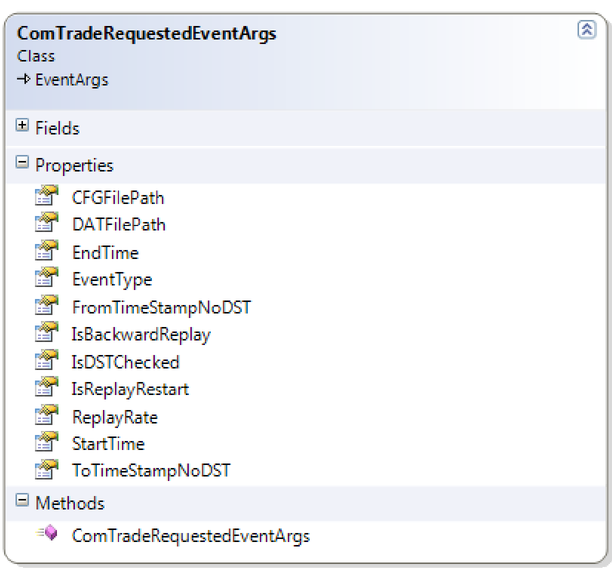




This event is fired before firing the actual ComTrade replay event to get the start and end time parsed from config file which will be used by charts to set the X-Axis limits accordingly.

12.5 ComTradeRequestedEvent

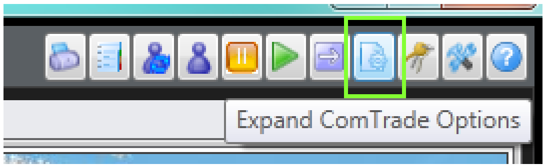




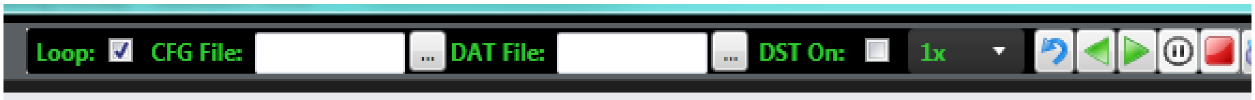
ComTrade Requested Event to start, pause, resume and stop comtrade file replay.

12.6 Visualization Wizard UI changes

A new toolbar button is added to open ComTrade replay control.



ComTrade replay control is integrated to the above click. Standard play, pause, resume and stop controls are provided to replay.



12.7 DST adjustments for historical and event files

DST On/Off check boxes are provided for both ComTrade and ISG replay controls as shown in previous section to adjust to DST changes.

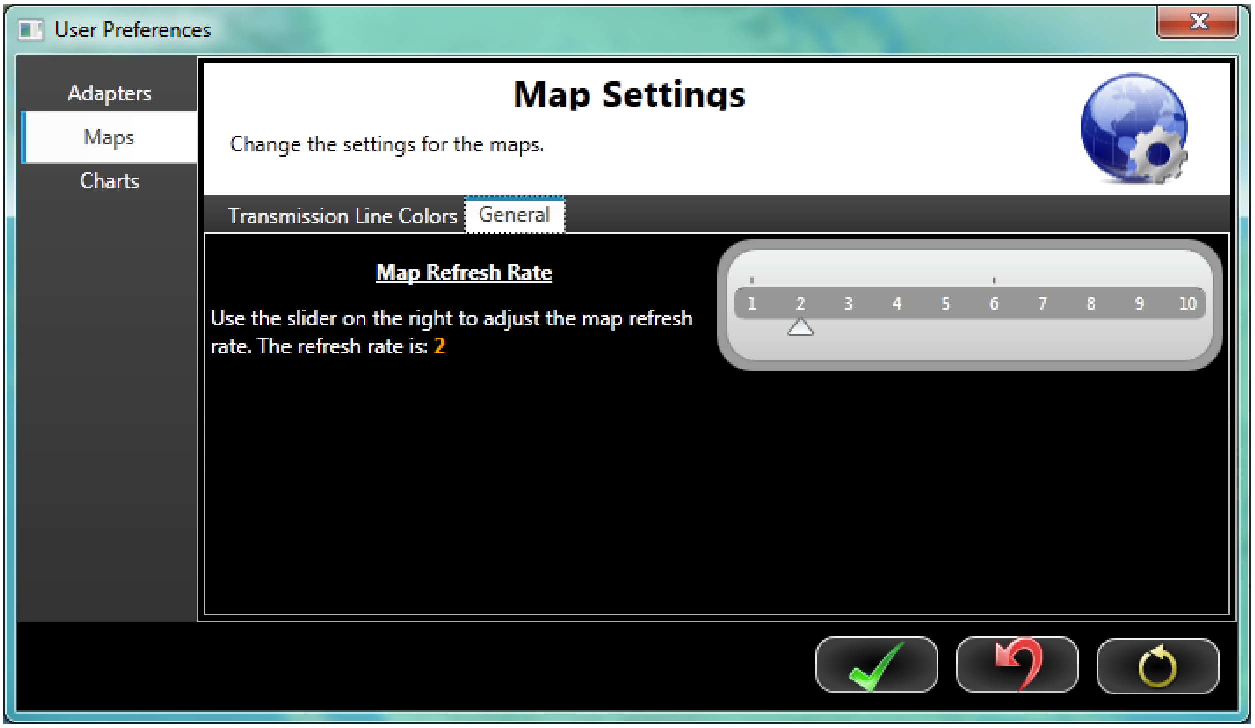
Case 1 : If current system date is in DST, the check box label will be DST Off. On check of this checkbox 1 hour will be subtracted from the current replay time.

Case 2 : If current system date is not in DST, the check box label will be DST On. On check of this checkbox 1 hour will be added to the current replay time.

13. User determined refresh rates for map/contour

This is to provide user with a capability to control the refresh rate for contour / cluster updates / map tooltips.

13.1 Visualization Wizard UI Changes



Above page with Map Refresh Rate is added to user preferences dialog to control map refresh and will be serialized to user preferences to DB for retrieving it back in later user sessions.

14. User Preferences

User preferences dialog allows logged in user to change his default application configurations for Data Adapters settings, Maps settings and Charts settings.

14.1 Adapter Settings

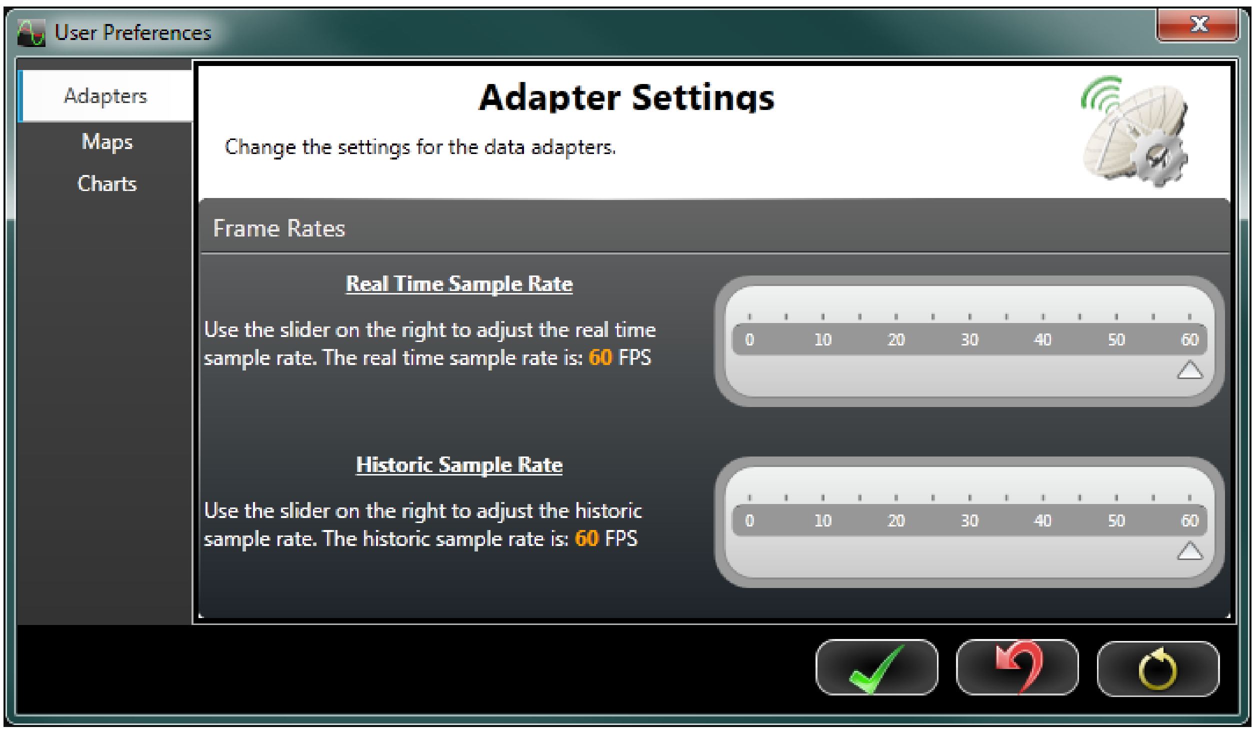
This tab allows user to change the following data adapter settings :

Real Time Sample Rate : User can change the sub second data sample rate using this. Default matches with the RTDMS server sub second sample rate. The value can only be down sampled as required. The value is number of samples per second.

Note : Change in this value will be applied on reset of profile or restart of application.

Real Time Sample Rate : User can change the historic sub second data sample rate using this. Default matches with the RTDMS server sub second sample rate. The value only can be down sampled as required. The value is number of samples per second.

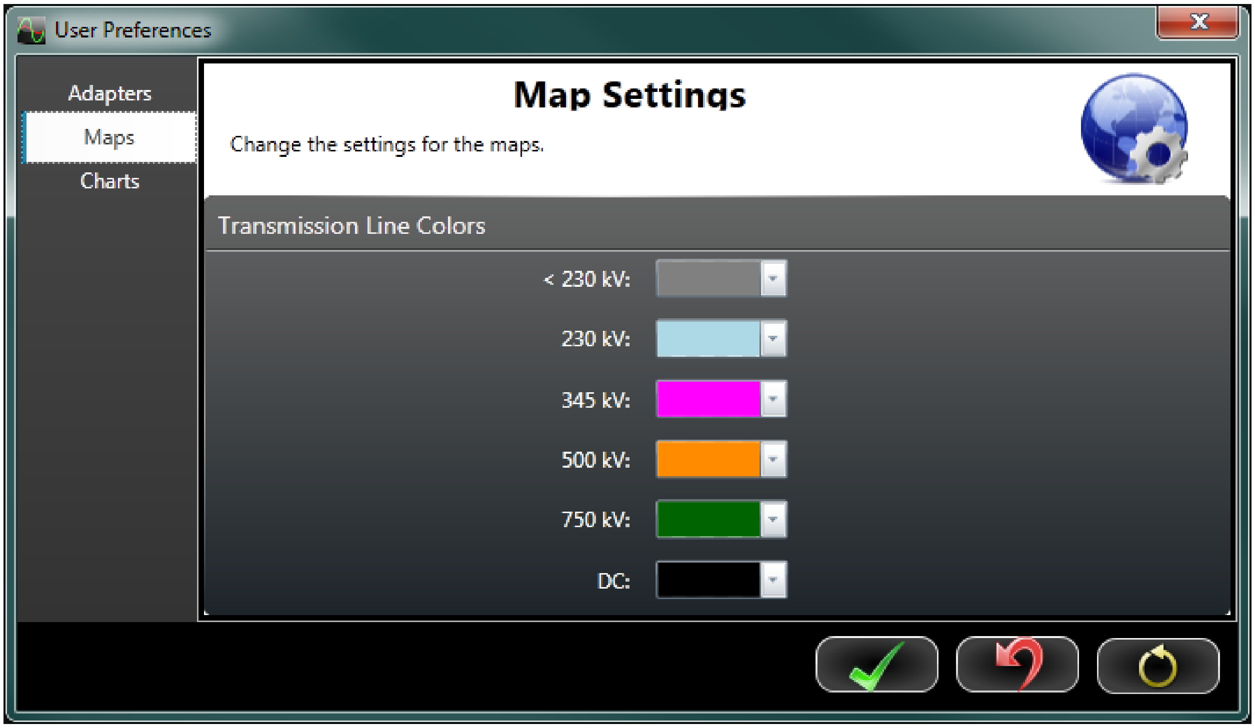
Note : Change in this value will be applied on reset of profile or restart of application.



14.2 Map Settings

This tab allows user to change the map's transmission line colors <230 kV, 230 kV, 345 kV, 500 kV, 750 kV and DC .

Note : Change in this value will be applied on reset of profile or restart of application.



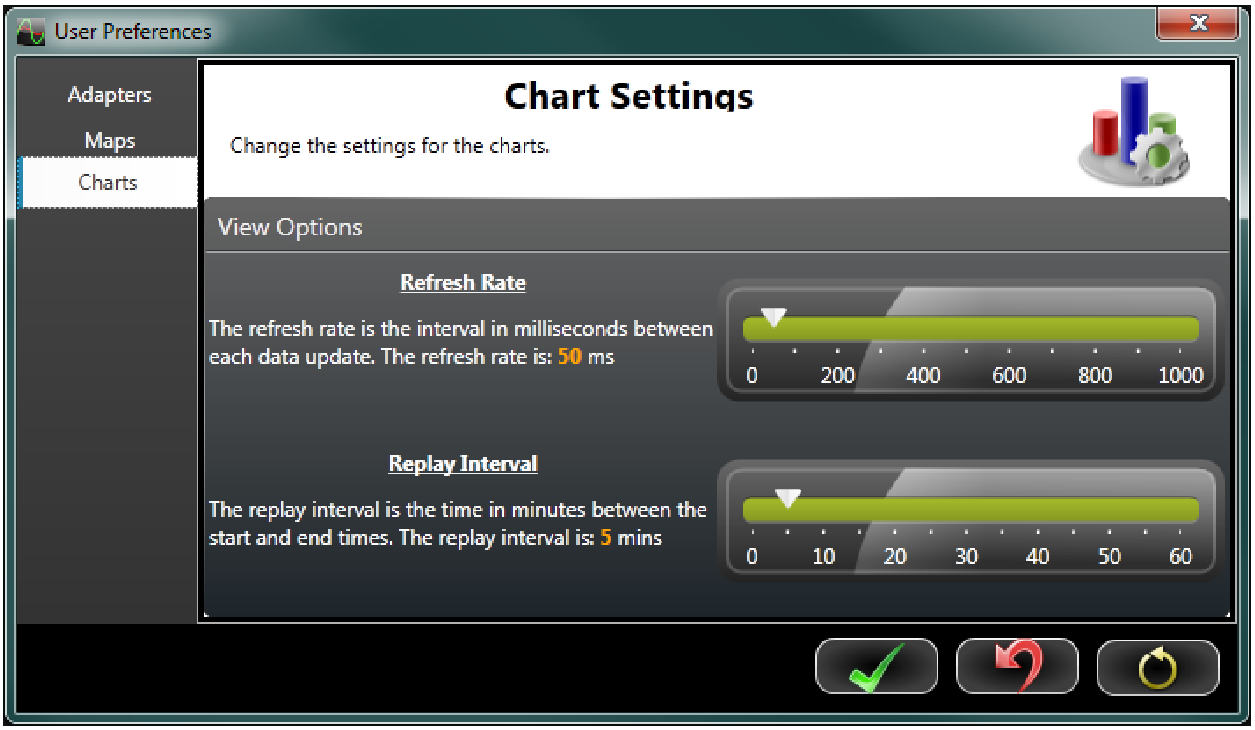
14.3 Chart Settings

This tab allows user to change the following chart settings :

Refresh Rate : The rate at which the charts paints can be controlled using this settings. The value is in milliseconds.

Note : Change in this value will be applied on reset of profile or restart of application.

Replay Interval : This setting value is to control the default time span set in Reply Control, default is 5 minutes. The value is in minutes.

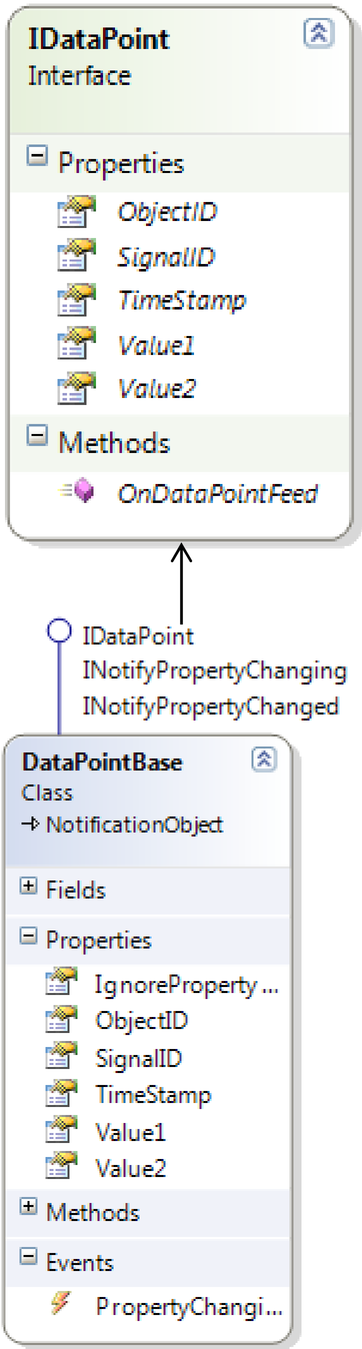


15. Class Diagrams and Package Diagrams

This section describes the UML diagrams for key classes and organization of classes.

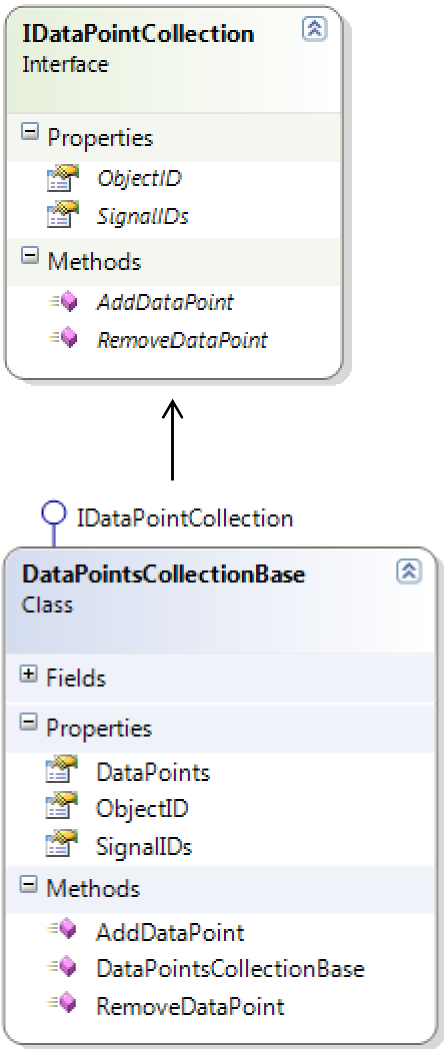
15.1 Class Diagram

DataPoint interface defines the data element to be transferred and displayed.

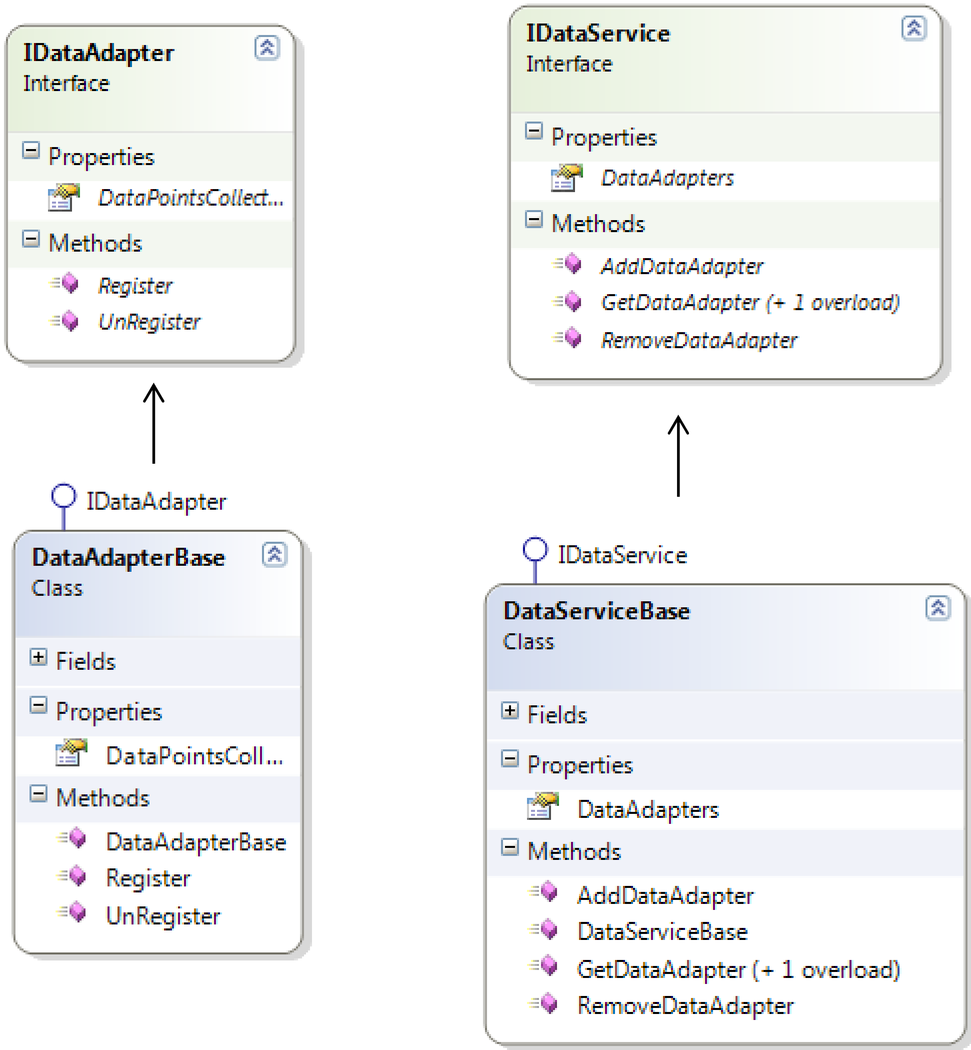


DataPoint Collection

Container of data points.

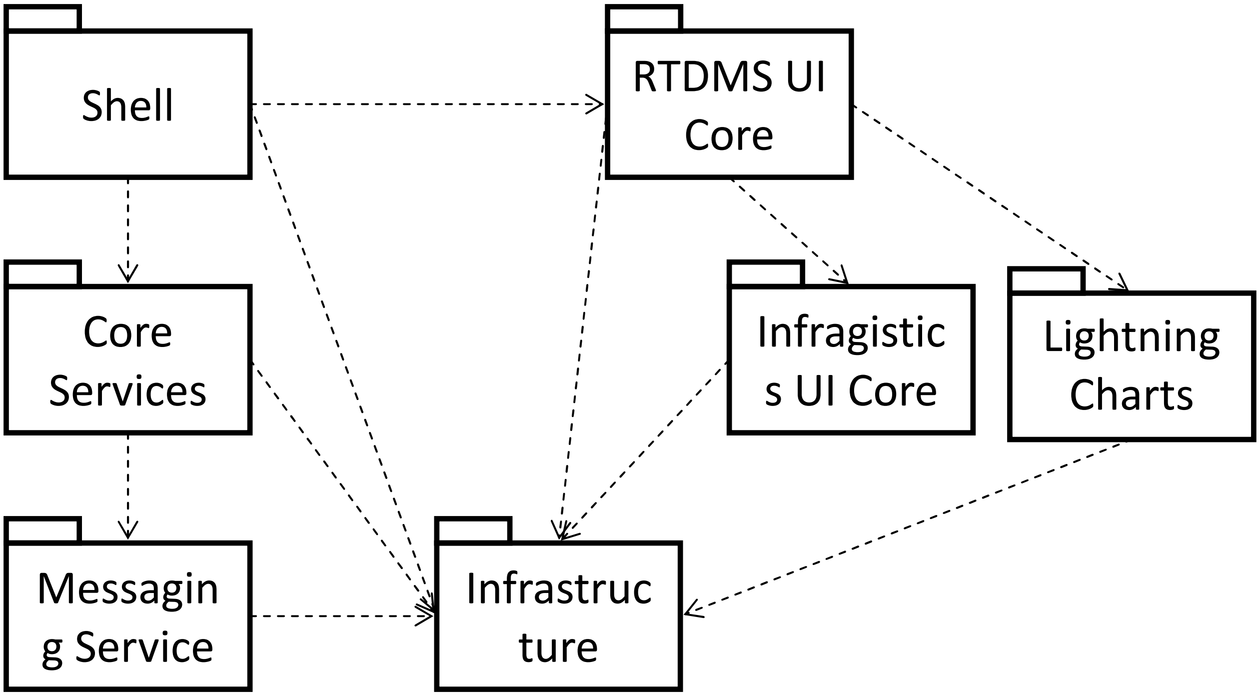


Data Adapter and Data Service are the interface between ISG and View Model.

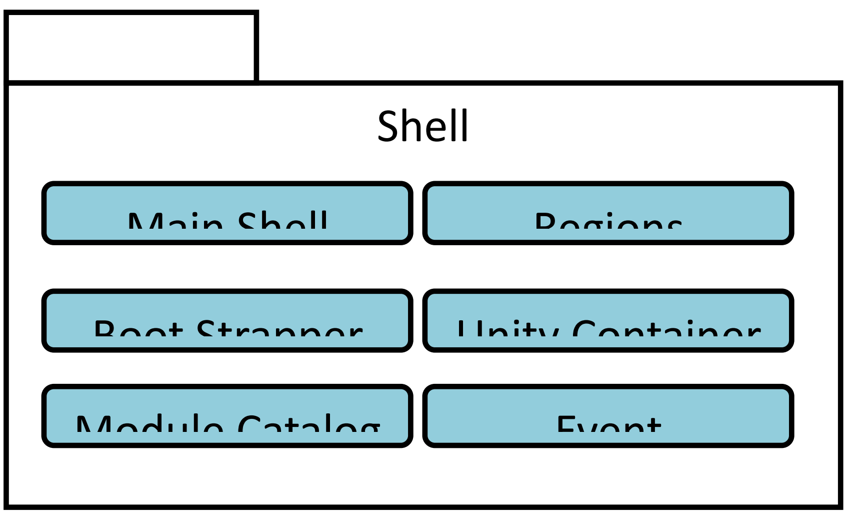


15.2 Packaging Diagram

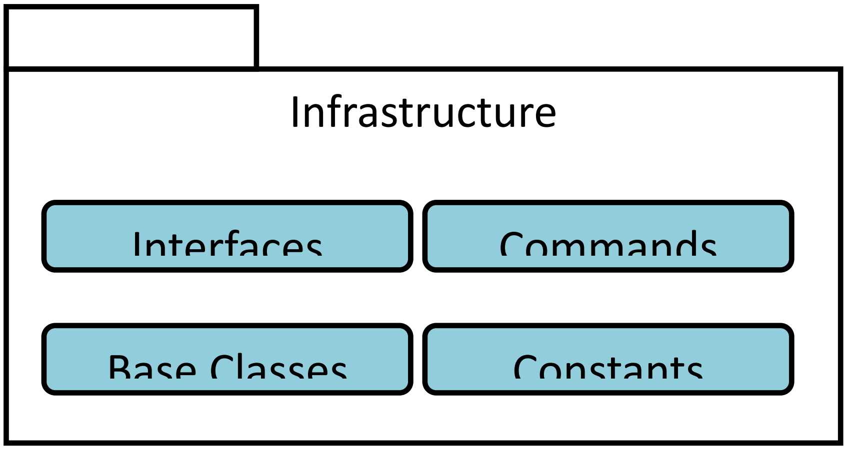
Overall:



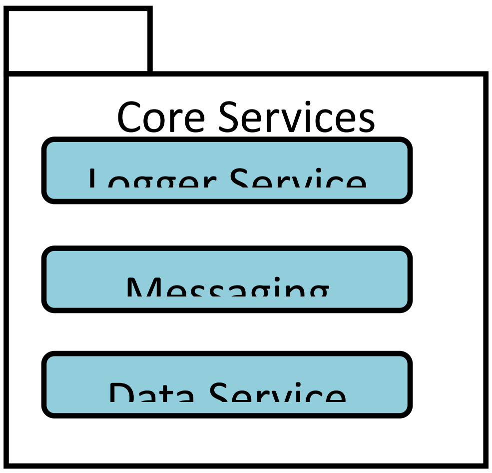
Shell:

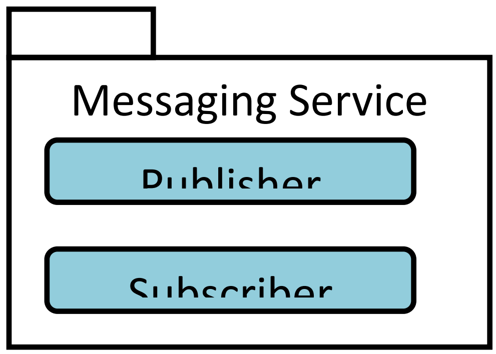


Infrastructure:

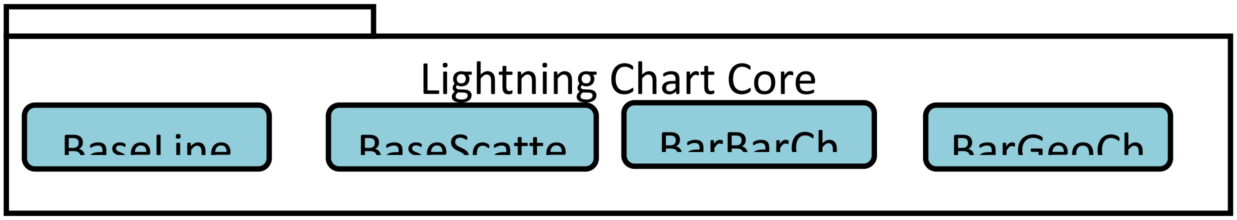


Core Services and Messaging Services:

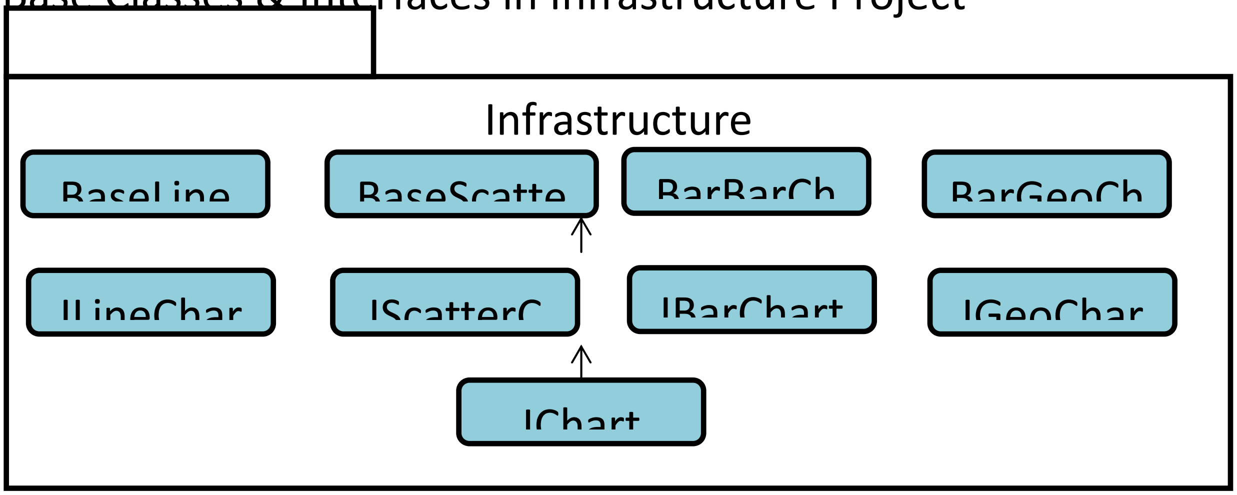




Charting:



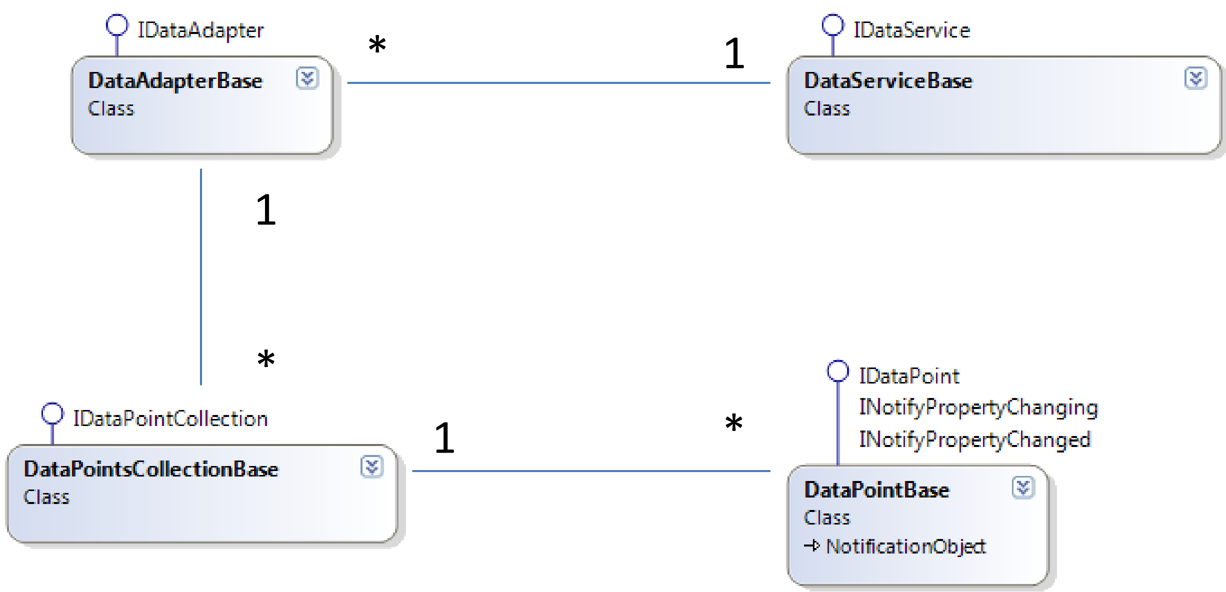
Base Classes & Interfaces in Infrastructure Project



16. Interaction Diagrams

This section describes the UML interaction diagrams among key class for critical procedures.

16.1 Real-time Data Flow



APPENDIX E:
CALIFORNIA ISO Phase Angle Baselining Study, Phase 1 – Data Quality Report

CAISO Phase Angle Baselining Study

Phase 1 - Data Quality Report

Prepared by
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Romulo Barreno
Ajay Das
Iknoor Singh
Mark Woodall

Electric Power Group

April 30, 2013

Submitted to:
California Independent System Operator
Jim Hiebert, JHiebert@caiso.com

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1.0 Executive Summary

The California Energy Commission has funded research in synchrophasor technology at the California Independent System Operator (CAISO) through Grant Award No. PIR-10-068. The Project consists of six (6) tasks. The goal of Task 6 is threefold, (1) review and compare the phasor data being received at the CAISO with the CAISO's state estimator data; discrepancies will be discussed with the appropriate Transmission Owner (TO), for their resolution; (2) to perform an initial phase angle baseline analysis for the CAISO's portion of the Western Electricity Coordinating Council (WECC) grid; and, (3) to document the entire analysis process and determine the feasibility of developing an annual automated process. The sections of this report will discuss Electric Power Group's (EPG) findings relative to data quality of the phasor data being received from the CAISO. Appendices 2 and 3 of this report show examples of the data quality issues.

EPG's Process - EPG conducted a data quality analysis by comparing the phasor data based results with the state estimator data-based results. The phasor data received consisted of voltage phase angles for 22 substations. The state estimator cases received from the CAISO were solved and the resulting solved cases used as sources of information to calculate phase angle differences.

EPG developed computer programs to calculate phase angle differences from the phasor data and from the state estimator solved cases. Angle differences were obtained for 18 pairs of substations equipped with phasor measurement units. The list of 18 pairs developed based on current availability of phasor measurement units is shown below.

Table 1: Angle Pairs for Phasor Based Analysis
(CAISO agreed with list on 12/14/12)

1. John Day-Malin

2. Malin-Tesla
3. Tesla-Los Banos
4. Los Banos-Midway
5. Midway-Vincent

6. Vincent-Lugo
7. Eldorado-Lugo
8. Mohave-Lugo
9. Lugo-Mira Loma
10. Lugo-Serrano
11. Devers-Valley
12. Valley-Serrano

13. Vincent-SONGS 230 kV
14. Serrano-SONGS 230 kV
15. Mira Loma-SONGS 230kV
16. Big Creek-Magunden 230 kV
17. Magunden-Vincent 230 kV
18. Kramer-Lugo 230 kV

For purpose of comparison EPG selected two days: July 28 and August 9, 2012. Phasor data was extracted and processed to develop curves for each of the listed pairs. Similarly, angle differences data was extracted from the state estimator (SE) solved cases and data extracted to produce angle difference curves for each of the 18 pairs listed above. The two curves, one from phasor data and the other from state estimator data, were plotted on the same graph for comparison. Appendix 2 shows phasor vs. state estimator comparison plots for the 18 pairs for July 28, 2012, and Appendix 3 shows phasor vs. state estimator comparison plots for the 18 pairs for August 9, 2012.

Below is a summary of the EPG's findings:

1. Of the 18 angle pairs analyzed, EPG finds that phasor data from 19 PMUs appear to be adequate.
2. Phasor data from three PMUs, Tesla, Los Banos and Midway, in the PG&E area are unusable invalidating phasor-based results for four pairs.
3. Southern California Edison's Mohave substation no longer has an operable phasor measurement unit; negating results for the Mohave-Lugo pair.
4. For the John Day-Malin pair, CAISO phasor data results do not match CAISO SE data results. EPG obtained phasor data for July 28 and August 9, 2012 from Bonneville Power Administration (BPA). BPA and CAISO phasor data results match but BPA and CAISO data results do not match CAISO SE results. See Appendix 4. Jim Hiebert for CAISO is working with Nick Leitschuh and Greg Stults from BPA to resolve this issue.
5. Phasor data is missing for Big Creek for July 28 and August 9, 2012 but upon review of all the phasor data received from CAISO, EPG found that overall phasor data for Big Creek is available for 75% of the time. EPG will include the Big Creek-Magunden pair for baselining analysis.
6. Four pairs in the PG&E area will not be included in the baselining analysis due to bad data; the Mohave-Lugo pair will not be included in the baselining analysis due to the PMU at Mohave not being available. EPG will have reasonable data to conduct phasor-based baselining for 13 pairs.
7. State estimator based data is adequate to conduct baselining analysis for the 18 pairs.

Recommendations

1. Obtain usable phasor data from phasor measurement units in the PG&E area; California-Oregon intertie, Path 15 and Midway-Vincent paths are important transmission paths to monitor in this area.
2. Develop a computer tool to convert IEC 61850 format PG&E phasor data to IEEE C37-118 format used by everyone else.
3. Resolve phasor-SE discrepancies for the John Day-Malin pair; CAISO to work with BPA to resolve discrepancy.
4. Continue saving phasor and state estimator data for 2013 to complete one year worth of data.
5. Ensure phasor data saved is accurate; periodically compare it with SE data.

2.0 Background

One of the goals of the California Energy Commission Grant Award No PIR-10-068, Task 6 is to review and compare the phasor data being received at the CAISO with the CAISO's state estimator data and discrepancies to be discusses with the CAISO and the appropriate TO, for their resolution. To accomplish this goal, EPG determined one year worth of phasor data and state estimator data would allow making a comparison that captures the different condition of the cycle. Previously, as part of another CEC project (Contract #500-08-048); Electric Power Group (EPG) received archived synchrophasor data recorded by the California Independent System Operator (CAISO) for the period of February 2 to July 30, 2011. Initial processing of the data showed that the majority of the synchrophasor measurements received were unreadable. EPG spent a significant amount of time identifying data recording errors and developing a software tool to recover the faulty dataset. After recovering the files, and while analyzing the phasor data, EPG encountered a number of data quality issues. These data quality issues were documented in the document shown in Appendix 1 and presented to CAISO staff in a meeting in Folsom, California on May 10, 2012.

Subsequently, EPG and CAISO agreed to collect a new set of data free of errors. To this effect, CAISO saved phasor data for the May 24 to December 31, 2012 period using COMTRADE format and provided it to EPG for analysis. This data was readable but voltages for the Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) substation were zero due to phasor data concentrator (PDC) to PDC transfer deficiencies. However, angle differences were free of transmission errors and such data is useable for the second goal of this contract which is to perform an initial phase angle baselining analysis for the CAISO's portion of the WECC grid.

3.0 Quality of Data Received

3.1 Data Received for the February 2 to July 30, 2011 Period.

EPG analysts encountered a number of data quality issues: some data did not make sense and had to be adjusted prior to using it; other data was not useable at all because it defied logic. No reasonable fix was identifiable. A description of some of the phasor quality issues encountered by EPG is provided below.

3.2 Incorrect status flags prevents adequate filtering

Phasor-based graphs should be clear lines that changes over time with system conditions. When extracted and plotted, the phasor data received resulted in numerous data dropouts as shown in Figure 1 below that provide a meaningless graph. Filtering using status flags was not successful for most of these points because no faulty data indication was recorded. A lack of reliable status flags indicating faulty data points makes software-based signal filtering difficult and significant time is lost in manually filtering the data.

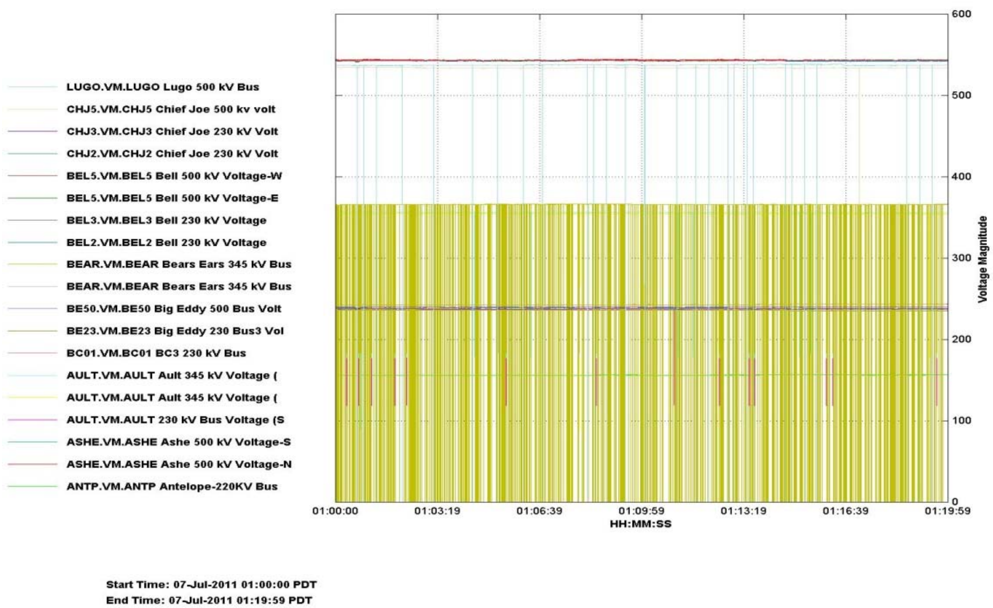


Figure 1: Data snapshot after status flag filtering enabled (vertical bars are dropout points)

3.3 Scaling Factors (CT & PT ratios)

Data, when plotted, showed inaccurate and/or unrealistic values. For example data for May 27, 2011 onwards, a change in voltage and current phasor scaling factors for a number of Bonneville Power Administration (BPA) phasor measurement units (PMUs) were not accounted for in the dst config files prior to distribution to users of the data; as a result, data values for power (a calculated value), appeared greater than what they really were. Initial examination of power flows across the California Oregon Intertie (COI) showed more than a dozen periods where the total transfer rose significantly above 4,800 MW, including one where the transfer rose to 5,500 MW (see Figure 2 below). Ultimately, an accurate curve was obtained by adjusting the scaling factors based on a comparison of the extracted phasor values with corresponding EMS results. A more realistic power transfer for this event (a DC block) is shown in Figure 3.

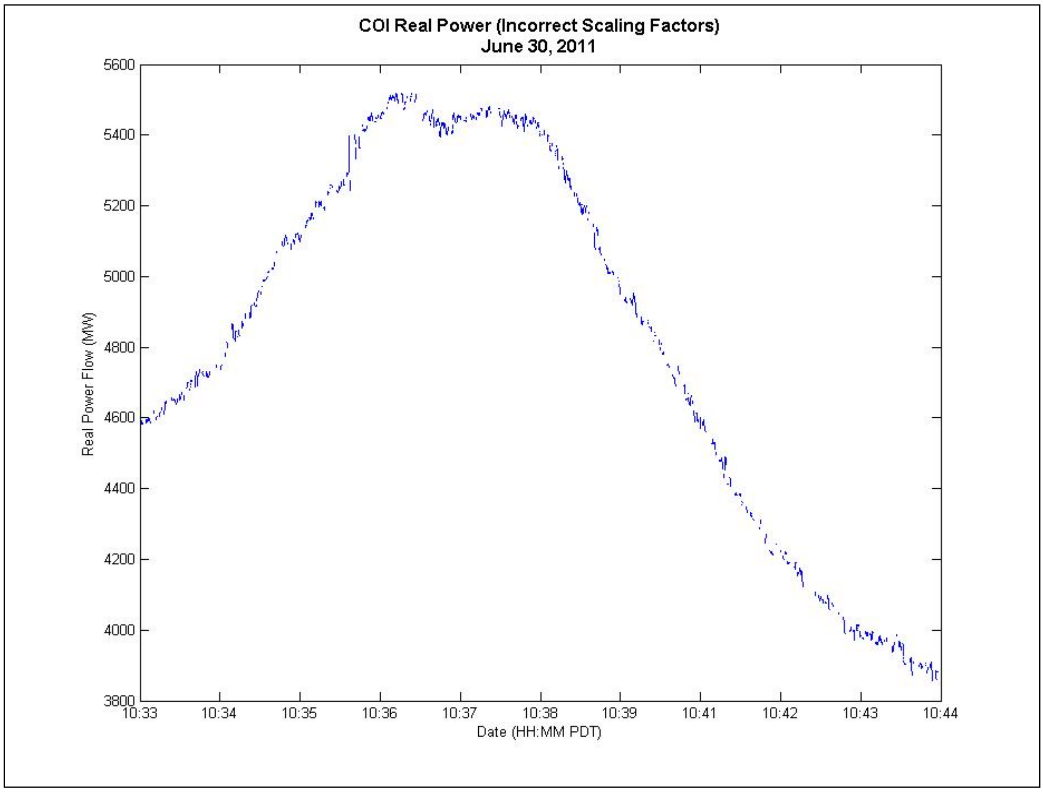


Figure 2: Incorrect scaling factors result in COI real power peaking at 5,500 MW

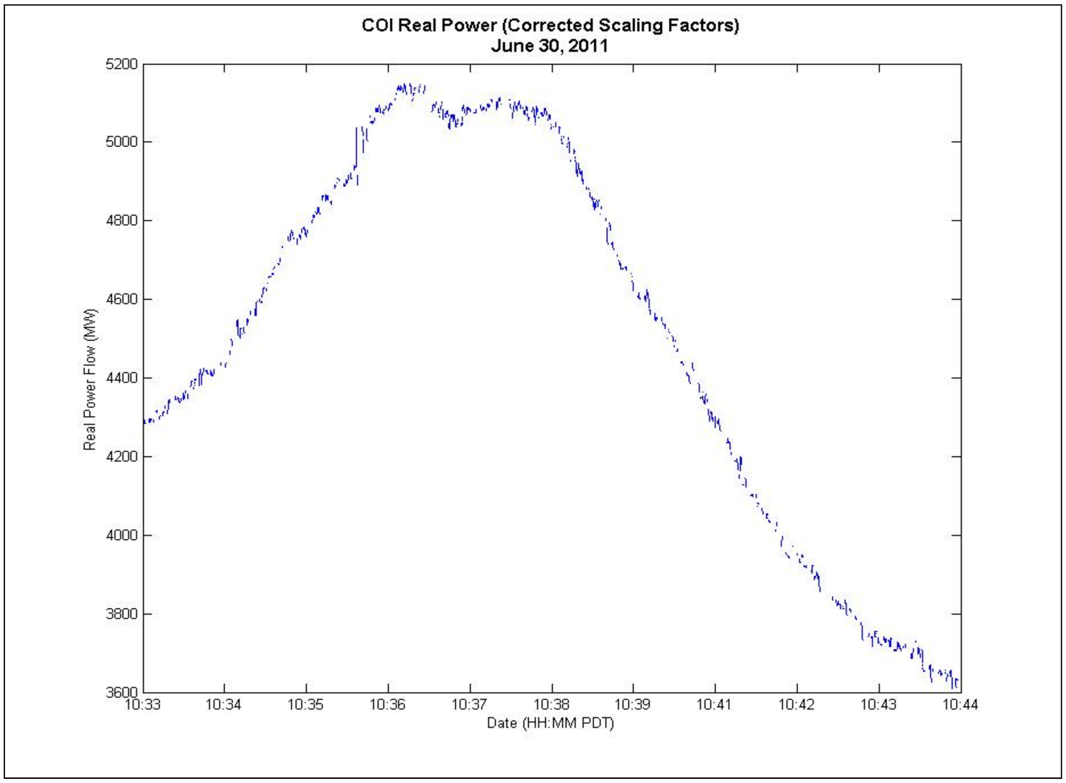


Figure 3: After correcting scaling factors, COI flow shows peaking at 5,100 MW, with less than 5 minutes over 4,800 MW

Correcting the scaling factors for COI (based on EMS data) reduced the number of periods where transfer exceeded 4800 MW to three.

3.4 Phase angles in the PG&E area

3.4.1 Inconsistency between phase angles and power flows

Angle data for PG&E PMUs had questionable accuracy. The angle difference between Malin and Los Banos, for example, showed inconsistency with the corresponding COI power flow. Despite high north-to-south power flows, the angle difference for Malin and Los Banos appeared partially negative (i.e., reflecting power flowing from Los Banos to Malin), as seen in Figure 4.

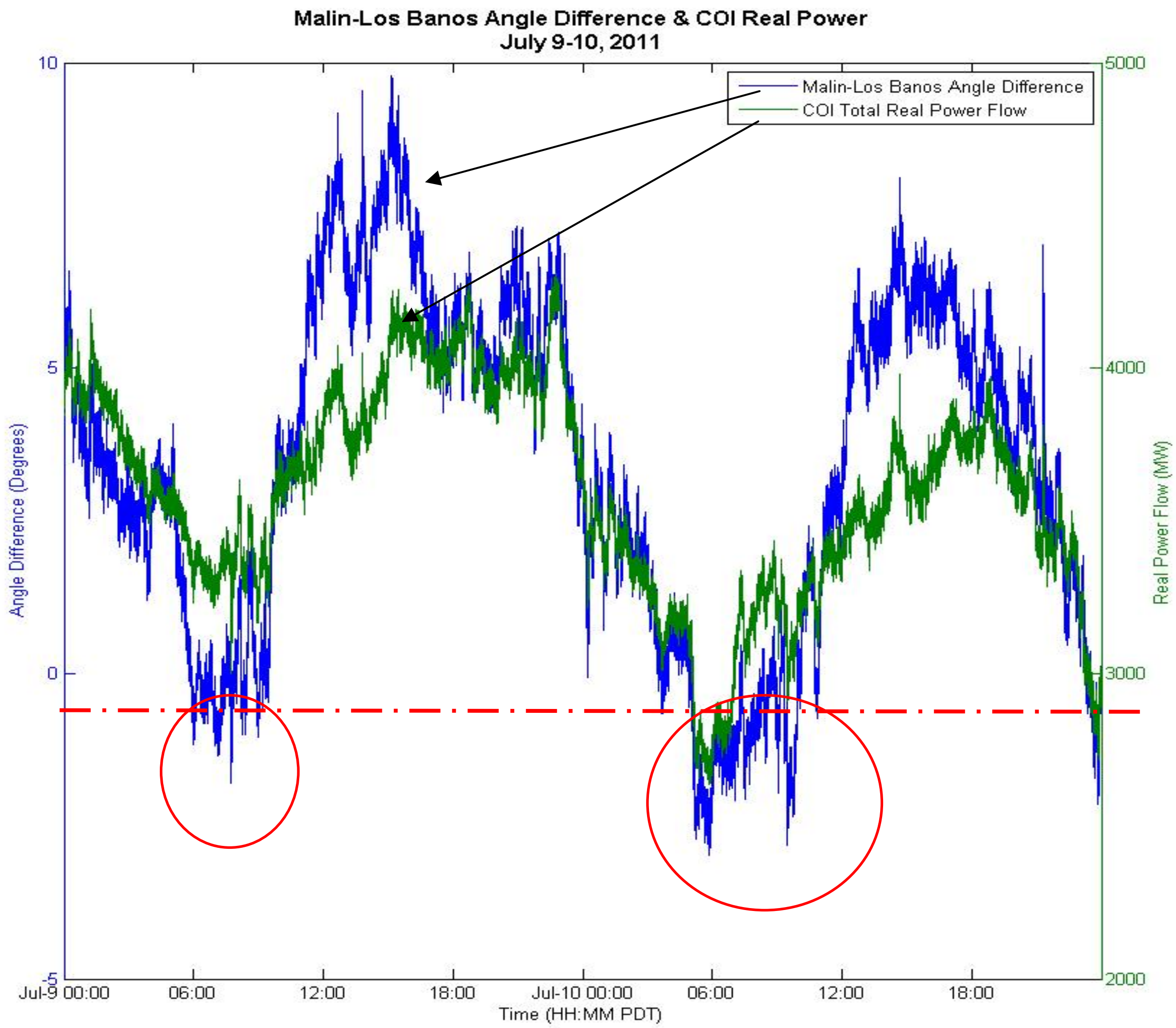


Figure 4: Negative Malin-Los Banos angle difference despite high North-South transfer

3.4.2 Angle plots for several paths in the PG&E area were out of expected order.

In general, the angle difference pairs for PG&E buses obtained from the phasor data received from CAISO (using PG&E PMUs) were not consistent with simulation results for the PG&E area; Figure 5 below shows the angle difference plots for Tesla, Los Banos, Midway, Moss Landing, and Malin relative to Vincent, a bus south of all five of these substations.

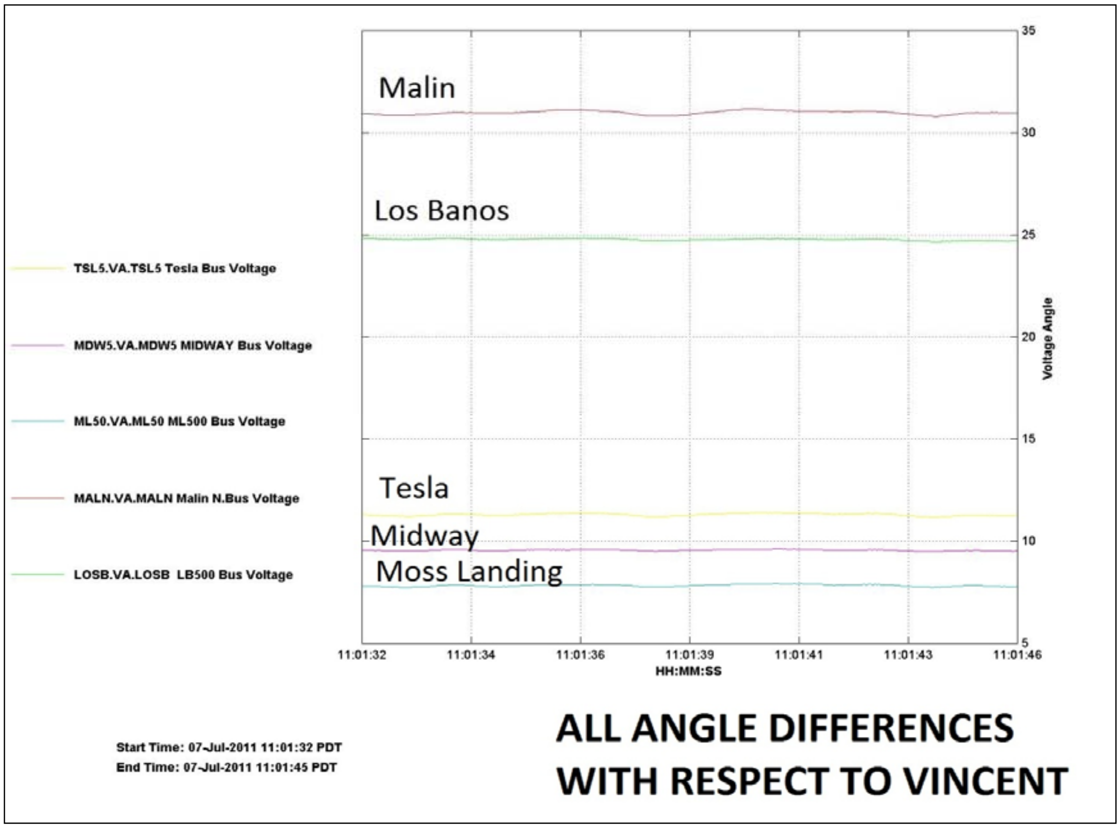


Figure 5: PG&E angle difference ordering problem

The Malin bus, in the BPA data stream, is included to provide perspective on the scale of angle differences; as expected the angle for this bus compared with Vincent is greater than the others. However, the angle differences for the buses in the PG&E area are significantly different from what one would expect. Geographically, Midway, Los Banos, and Tesla are sequentially north of Vincent when the power flow was in the north to south direction from these buses to the reference bus Vincent. From the angle perspective, Tesla should be greater than Los Banos, Los Banos should be greater than Midway, and Midway should be greater than Vincent. Instead, angles plotted based on the received phasor data shows a different order: Los Banos being the greatest at about 25 degrees, Tesla significantly lower at about 11 degrees, and then Midway at about 10 degrees. Moss Landing, roughly the same distance away from Vincent as Los Banos, appears to be the closest of all.

This voltage angle reference problem appears to be specific to the PG&E data. Further confirmation was provided by comparing the results of PSLF simulations for the 2011 heavy summer, non-contingency cases with the recorded PMU data. Selected results are shown in Table 1: PSLF Angle Difference Table for PG&E Buses below.

Table 1: PSLF Angle Difference Table for PG&E Buses

Angle Pair Names		COI Heavy Summer 2011 (COI MW _ %NCH)				
Bus 1	**Bus 2**	**c4800_h60**	**c4800_h70**	**c4775_h80**	**c4750_h90**	**c4500_h100**
Malin	Vincent	30.5825	30.8339	31.1779	32.916	32.2626

Moss Landing	Vincent	12.3704	12.2164	11.8943	12.5969	12.0609
Tesla	Vincent	10.8000	10.651	10.4799	11.5259	11.3355
Los Banos	Vincent	8.5733	8.4995	8.4155	8.9131	8.7458
Midway	Vincent	4.8792	4.8747	4.8693	4.8878	4.8811

Note Table 1 shows the angle differences in the Malin, Tesla, Los Banos and Midway order as expected.

3.5 Improper or inadequately documented PMU signal configurations

3.5.1 Incorrect, dead, or missing voltage phase references

While PMUs can produce values for voltage, current, and frequency, at a fundamental level, all of these values are calculated based on measurements of potential differences (voltage waveforms). PMUs typically require a single voltage phasor to be configured to be used as a reference to calculate frequency. Several voltage phasors are defined which appear to be dead throughout the data set. This in turn leads to a static 60 Hz frequency reading for that PMU (see Figure 6). The faulty signals should either be removed from the system or repaired on location.

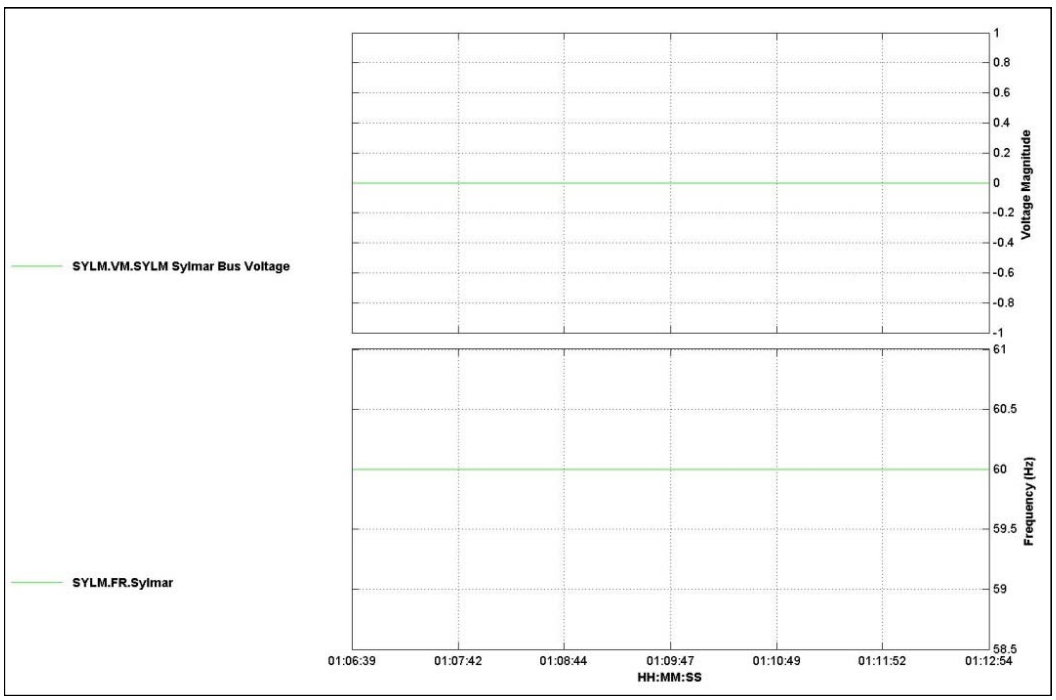


Figure 6: Dead voltage phasor and frequency at Sylmar bus

3.5.2 Phase to Phase vs. Phase to Neutral configurations not reported

Related to the scaling factor problem, in the past, signals have been observed to have voltage magnitude values that differed from the expected value by a factor of 1.7321 (square root of 3). This suggests that the PMU is in the opposite configuration from what the configuration file indicates.

3.5.3 Signing (direction) of current – CT Orientation

The typical signing convention for power flow signals at substations calls for positive values to represent inbound flows and negative values to represent outbound flows. EPG analysts experienced inconsistent signing within the data sets received even for two parallel lines such as Los Banos-Gates. For example, at Los Banos substation, the PMU-based power flows on Los Banos – Gates Line 1 and Los Banos – Gates Line 3 were in opposite directions relative to each other, as shown in Figure 7 below. Moreover, the power flow in these two parallel lines should be approximately the same magnitude, yet the PMU data does not reflect this. The actual flows (based on EMS and PSLF data) on the two lines are in the same direction, north-to-south, and the same magnitude.

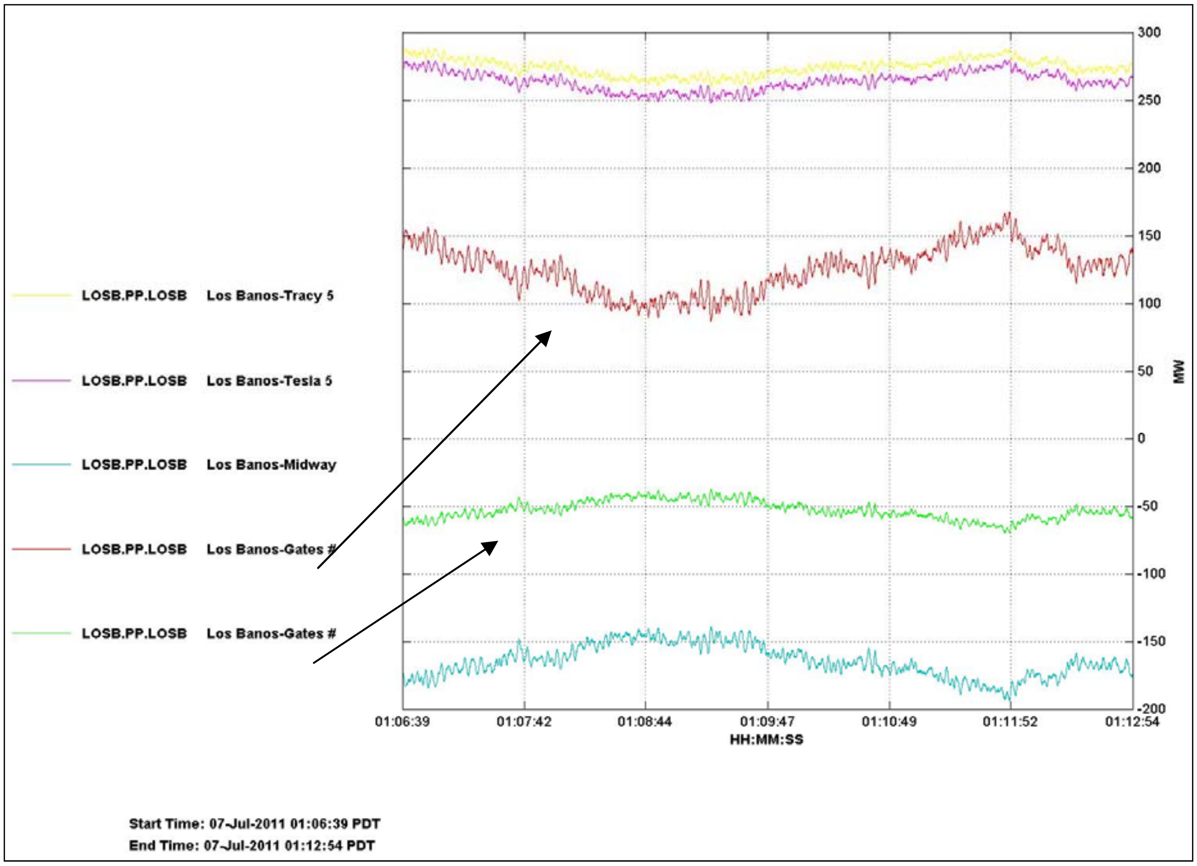


Figure 7: Inconsistent power flows at Los Banos

Power flow direction and magnitude should be validated for every monitored transmission line when the associated PMU is added to the data stream at CAISO.

3.5.4 General current / power flow signal configuration problems and inconsistencies

Comprehensive power flow analysis using phasor data requires that the PMU data be accurate, since there are not yet sufficient PMUs installed in the system to provide a comprehensive view of the system. It becomes a challenge to use phasor data that does not match expectations based on system data such as impedances (e.g., for parallel transmission lines, higher power flows are expected on lower impedance lines and, conversely, lower power flows on higher impedance lines).

Figure 8 illustrates one situation that does not match these expectations. The power flow on Midway-Vincent line 3 appears to be approximately half of the power flow on lines 1 and 2. However, according to the PSLF cases provided by the ISO, each of these two lines has higher impedance than the #3 line, and, consequently should have *lower* flows.

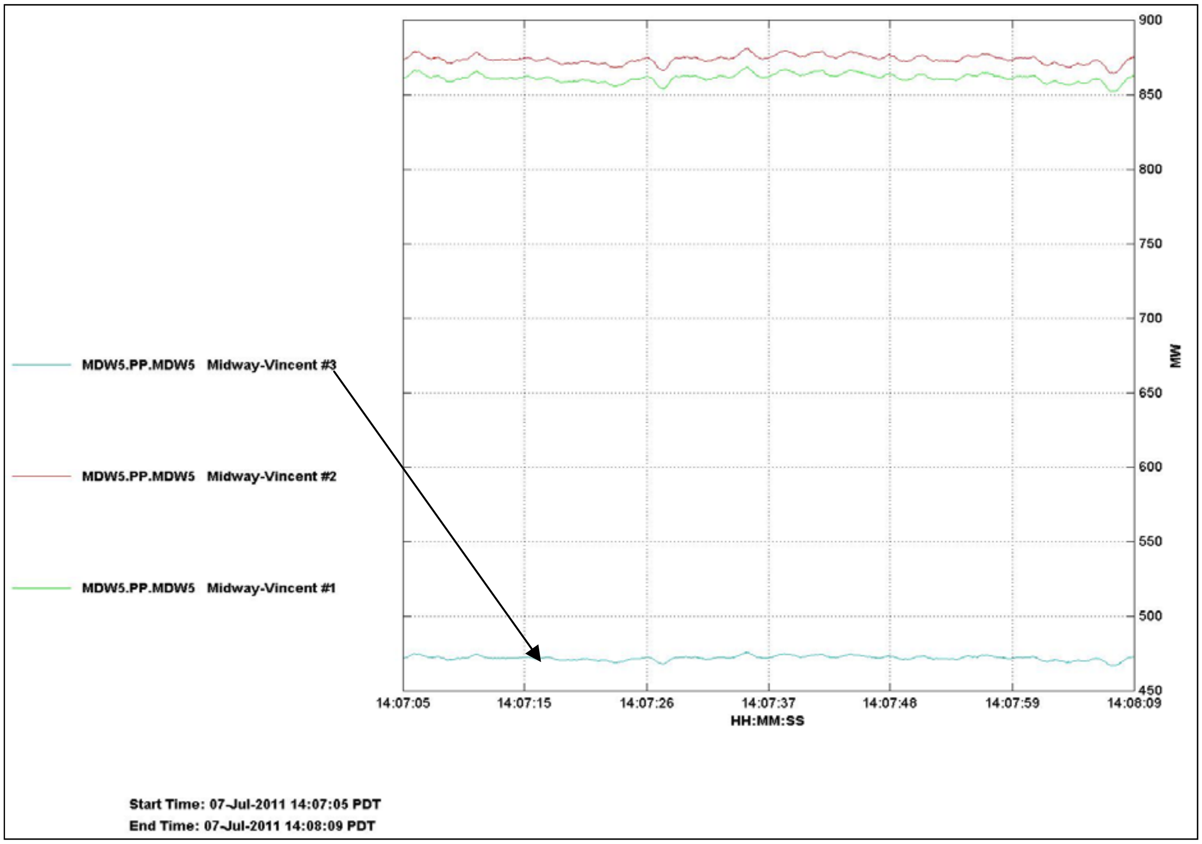


Figure 8: Midway-Vincent power problems

CONCLUSION

The above examples of data quality show that the February-July, 2011 phasor data for the PG&E area as received by EPG from CAISO does not have the quality needed for use in system analysis. The problems described above elevate the need to collectively validate and correct the data from the source (from CTS and PTs) to the CAISO *enhanced* Phasor Data Concentrator (*e*PDC). The phasor data received came from old PMUs installed in the PG&E area. PG&E has an ongoing project to install new PMUs in its area; these PMUs follow IEC 61850 standard. Since everyone else in the WECC system currently uses IEEE C37-118 standard, a conversion program is required to obtain data from the new PMUs being installed by PG&E.

4.0 Data Received for the May 24 to December 31, 2012 Period

This phasor-SE comparison analysis was completed using 2012 phase angle data provided by CAISO. The phasor data was collected by CAISO from their *e*PDC via COMTRADE into a storage disk and provided to EPG. The CAISO *e*PDC receives the phasor data from the PDCs at BPA, PG&E and SCE. Recently CAISO began receiving phasor data from Salt River Project (SRP) as well, but there was not enough data from SRP to be included in this analysis. EPG analysts had no problem reading the phasor data received however upon analysis of the downloaded phasor data, EPG found the zero values for voltages at the PG&E and SCE substations. Upon research, the cause was identified as lack of proper reading files from the SCE and PG&E PDCs to the CAISO *e*PDC. This deficiency has since been corrected. Voltage phase angles, however, were not affected and are available for angle difference baselining, the second goal of this Task 6.

State estimator cases were received for the June 18 to December 31, 2012 period at 5-minute intervals for a total of approximately 55,000 cases.

4.1 Process Used in Data Quality Analysis of the May to December 2012 Data

EPG conducted a data quality analysis by comparing the phasor data based results with the SE data based results. The phasor data received consisted of voltage phase angles for 22 substations. The state estimator cases received from the CAISO were solved and the resulting solved cases used as sources of information to calculate phase angle differences.

EPG developed computer programs to calculate phase angle differences from the phasor data and from the SE solved cases. Angle differences were obtained for 18 pairs of substations equipped with PMUs installed. The list of 18 pairs developed based on current availability of PMUs is shown below in Table 2.

Table 2: Angle Pairs for Phasor data Analysis
(CAISO agreed with list on 12/14/12)

1. John Day-Malin
2. Malin-Tesla
3. Tesla-Los Banos
4. Los Banos-Midway
5. Midway-Vincent

6. Vincent-Lugo
7. Eldorado-Lugo
8. Mohave-Lugo

9. Lugo-Mira Loma
10. Lugo-Serrano
11. Devers-Valley
12. Valley-Serrano

13. Vincent-SONGS 230 kV
14. Serrano-SONGS 230 kV
15. Mira Loma-SONGS 230kV
16. Big Creek-Magunden 230 kV
17. Magunden-Vincent 230 kV
18. Kramer-Lugo 230 kV

Phasor data was extracted and processed to develop curves for each of the 18 pairs. Similarly, angle differences data was extracted from the SE solved cases to produce angle difference curves for each of the 18 pairs listed above. The two curves, one from phasor data and the other from SE data, were plotted on the same graph for comparison. Appendix 2 shows phasor vs. SE comparison plots for the 18 pairs for July 28, 2012, and Appendix 3 shows phasor vs. SE comparison plots for the 18 pairs for August 9, 2012.

4.2 Data Quality Analysis

Analysis of the graphs in Appendices 2 and 3 produce the following results:

The curves, phasor-based and SE based, for 11 pairs have enough similarity to consider them consistent. The minor differences can be attributed to assumptions made in the state estimation process. The graphs for the Kramer-Lugo pair, July 28 data, show a difference of about 2 degrees in the middle of the day. Further investigation indicates the PMU may have been producing zero data for that period of time. The graphs for August 9 appear to be usable. The 11 pairs are:

1. Vincent-Lugo
2. Eldorado-Lugo
3. Lugo-Mira Loma
4. Lugo-Serrano
5. Devers-Valley
6. Valley-Serrano
7. Vincent-SONGS 230 kV
8. Serrano-SONGS 230 kV
9. Mira Loma-SONGS 230kV
10. Magunden-Vincent 230 kV
11. Kramer-Lugo 230 kV

b. John Day – Malin pair: the two curves, phasor and SE, for this pair are similar in shape for both days but separated by about 4 degrees. In attempt to resolve this difference, EPG obtained phasor data from BPA for July 28 and August 9, 2012. The phasor data from BPA match the phasor data from CAISO. BPA claims that their phasor data match their SE data (Nick Leitschuh-BPA). As a result, the focus of further investigation is the state estimator data from CAISO. Jim Hiebert-CAISO will work with Nick-BPA to resolve this issue.

c. The graphs for the four pairs involving substations in the PG&E area appear to be good state estimator curves. However, the curves obtained from phasor data contain much noise and are not suitable for baselining because either the phasor data is inadequate (Tesla and Midway) or missing (Los Banos). EPG learned that PG&E is implementing a plan to install PMUs in many substations that are intended to meet the new PMU communication IEC 61850 standard. CAISO or EPG or WECC for that matter, have no way at this time to read data in this format until a reader is developed and implemented to convert PG&E phasor data to C37-118 format.

d. Mohave-Lugo pair: the phasor data for Mohave is missing but the SE based angle difference curve for this pair appears usable. Upon consultation with SCE, operator of Mohave, we learned the PMU at Mohave was removed from service on April 9, 2011.

e. Big Creek-Magunden pair: the phasor data for Big Creek is missing for the two days analyzed (July 28 and August 9); the SE based angle difference curve for this pair appears usable. Upon consultation with SCE, operator of Big Creek, we learned the PMU at Big Creek is operable and producing good data. EPG reviewed all data received from CAISO for Big Creek and found an availability of 75% which is acceptable to include it for baselining purposes.

5.0 Summary and Conclusions

a. Of the 18 pairs analyzed, EPG finds that phasor data from 19 PMUs appear to be adequate.
b. Phasor data from three existing PMUs, Tesla, Los Banos and Midway, in the PG&E area are unusable and negate four pairs for baselining.
c. SCE's Mohave substation PMU is no longer operable negating one pair.
d. CAISO is working with BPA to resolve the phasor-SE discrepancy for the John Day-Malin pair.
e. EPG found that overall phasor data for Big Creek is available for 75% of the time. EPG will include the Big Creek-Magunden pair for baselining analysis.
f. EPG will have adequate data to conduct phasor based baselining for 13 pairs.
g. SE based data is adequate to conduct baselining analysis for the 18 pairs.

6.0 Recommendations

a. Obtain usable phasor data from PMUs in the PG&E area; California-Oregon intertie, Path 15 and Midway-Vincent paths are important transmission paths to monitor.
b. A "reader" should be developed to access 61850 PMU data from PG&E and convert it to usable C37-118 format.
c. Resolve discrepancies for the John Day-Malin pair.
d. Continue saving phasor and state estimator data to complete one year worth of data (2013).
e. Ensure phasor data saved is accurate; periodically compare it with SE data.

APPENDIX F:
Data Quality Report Phasor-State Estimation Comparison, 7.28.12

Appendix F of the PIR-10-068 Final Report

AKA Appendix 2 of Task 6 Deliverable

CEC PIR-10-068 –Task 6_State Estimator vs. Phasor Comparison _ Angle Differences for July 28, 2012

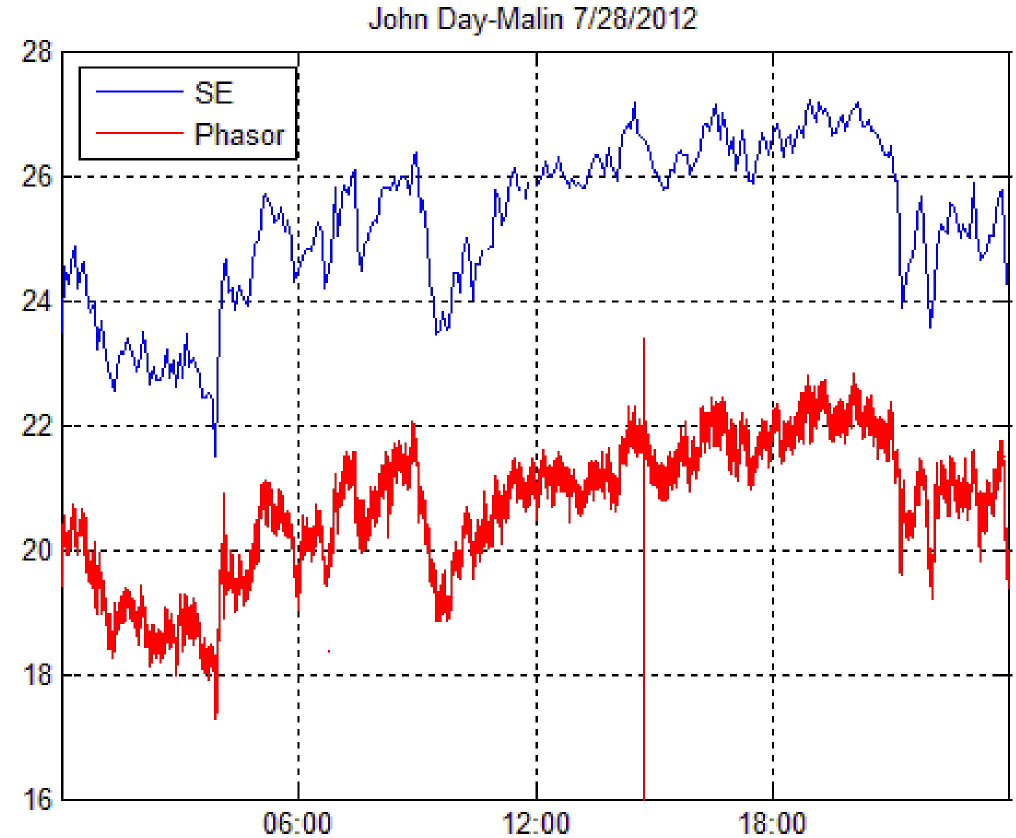
Angle Pairs Compared

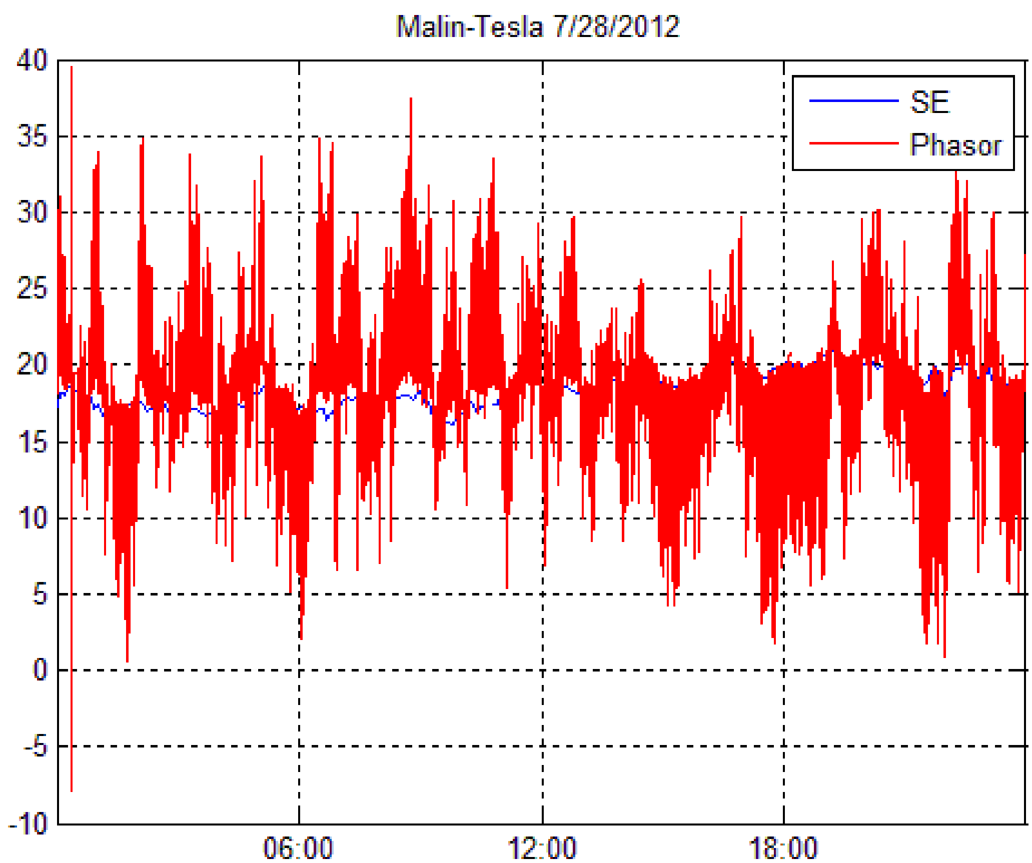
1. John Day-Malin

2. Malin-Tesla
3. Tesla-Los Banos
4. Los Banos-Midway
5. Midway-Vincent

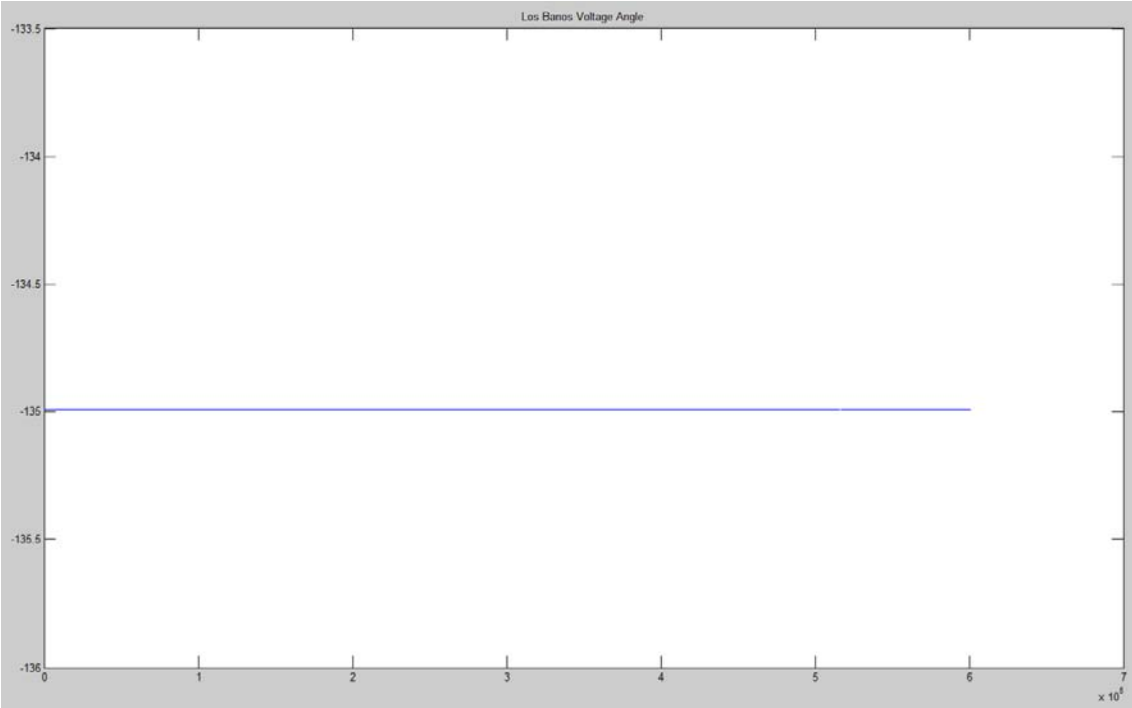
6. Vincent-Lugo
7. Eldorado-Lugo
8. Mohave-Lugo
9. Lugo-Mira Loma
10. Lugo-Serrano
11. Devers-Valley
12. Valley-Serrano

13. Vincent-SONGS 230 kV
14. Serrano-SONGS 230 kV
15. Mira Loma-SONGS 230kV
16. Big Creek-Magunden 230 kV
17. Magunden-Vincent 230 kV
18. Kramer-Lugo 230 kV

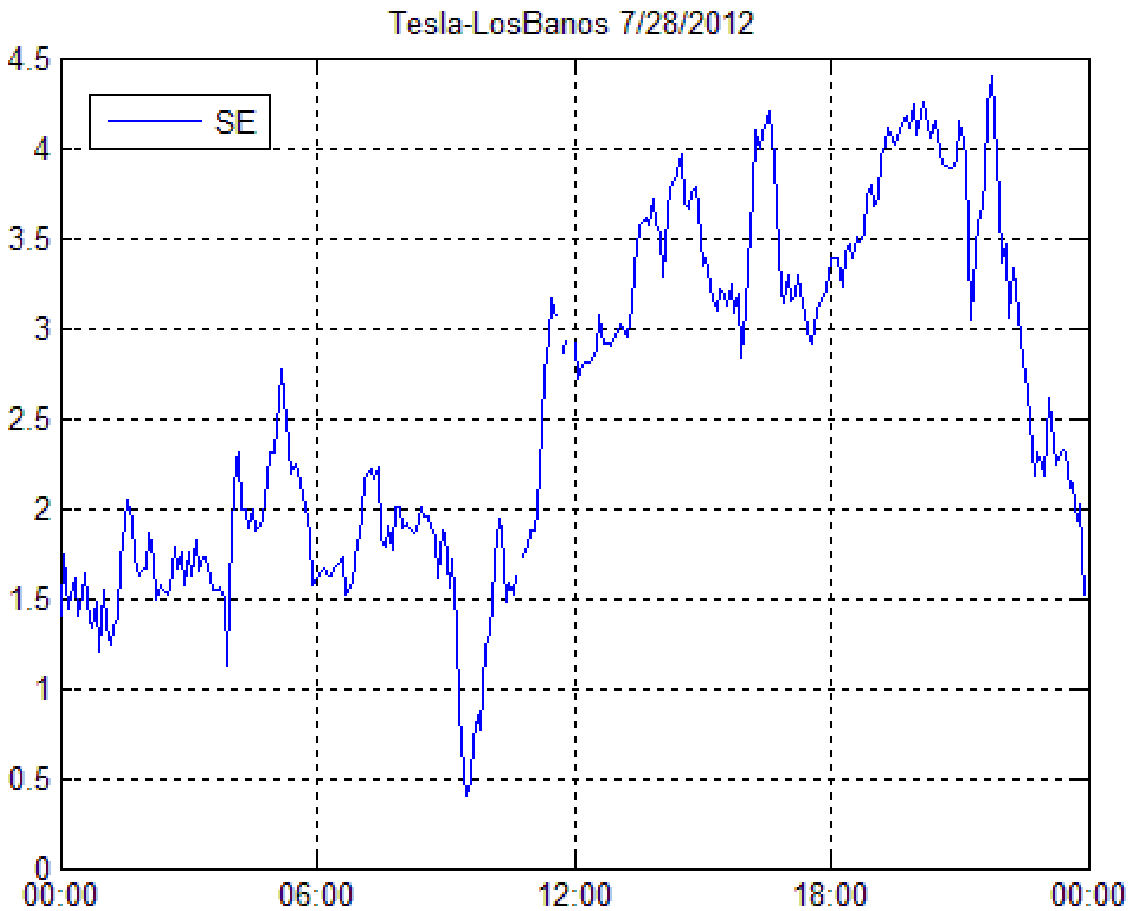

John Day-Malin 7/28/2012
28
26
24
22
20
18
16
06:00
12:00
18:00
SE
Phasor

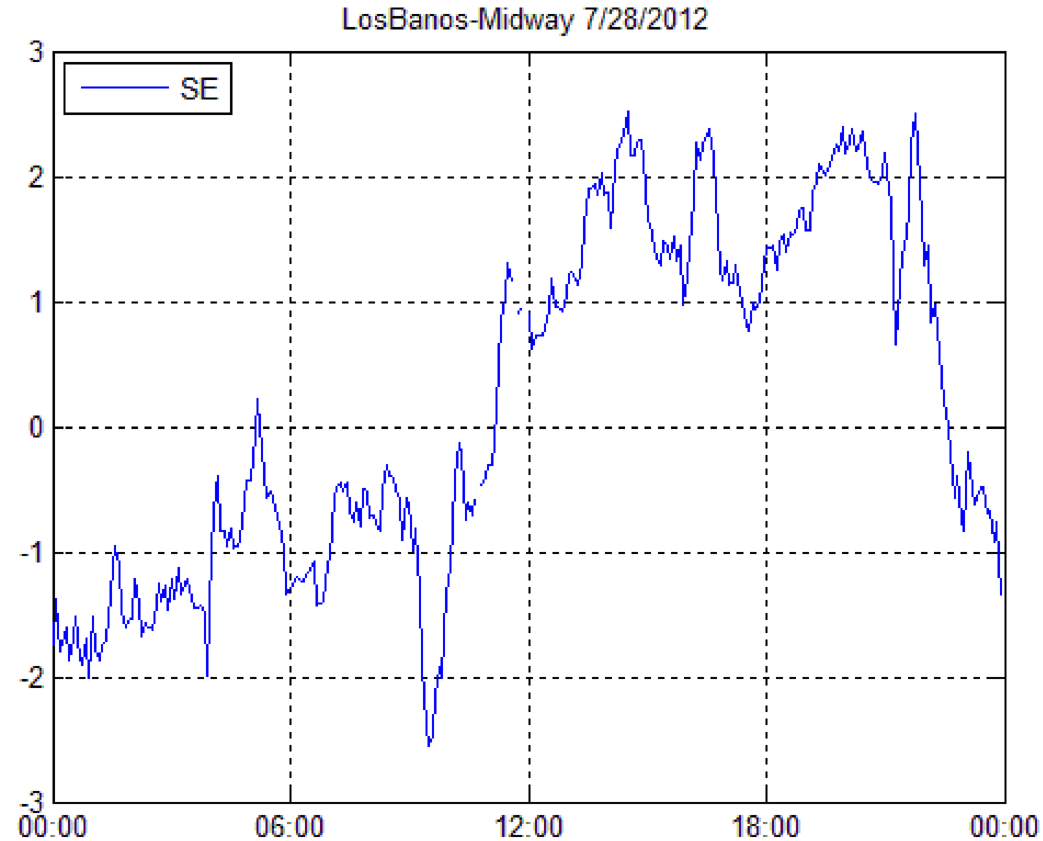

Malin-Tesla 7/28/2012
40
35
30
25
20
15
10
5
0
-5
-10
06:00
12:00
18:00
SE
Phasor

Tesla – Los Banos (Phasor)



NOTE: Los Banos Voltage Angle value (Phasor) is constant (-134.99), unusable




LosBanos-Midway 7/28/2012
SE
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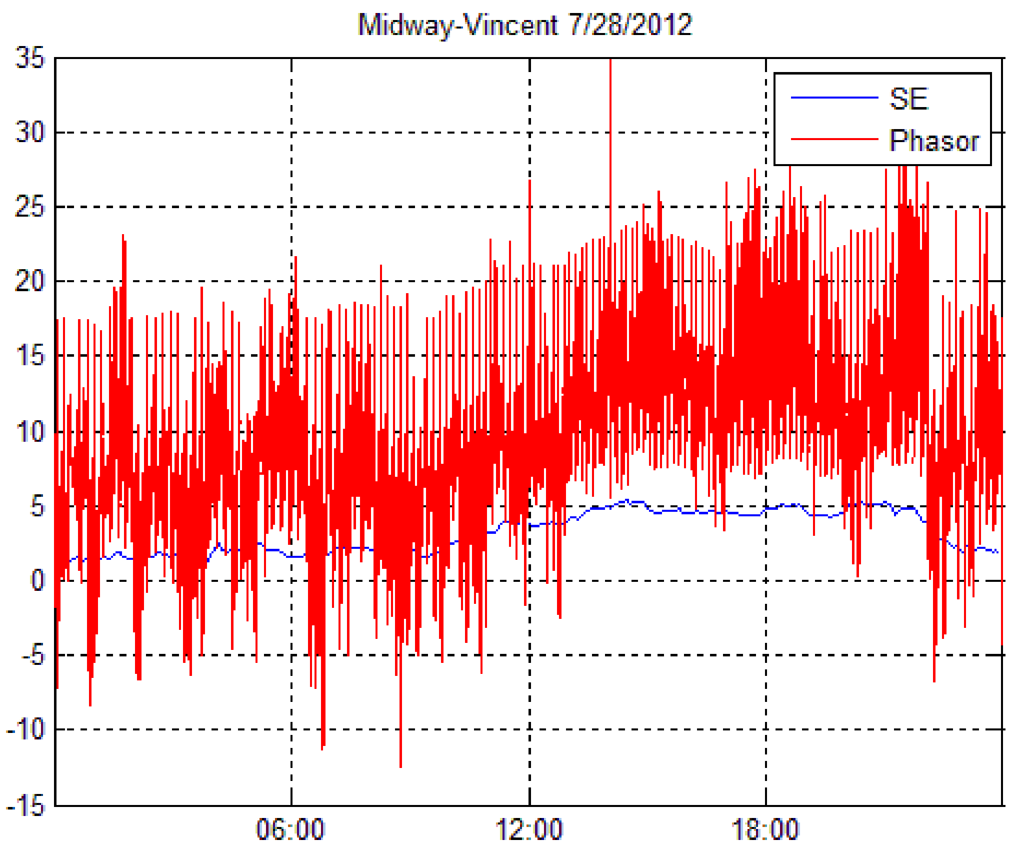
2
1
0
-1
-2
-3
00:00
06:00
12:00
18:00
00:00


Midway-Vincent 7/28/2012
SE
Phasor
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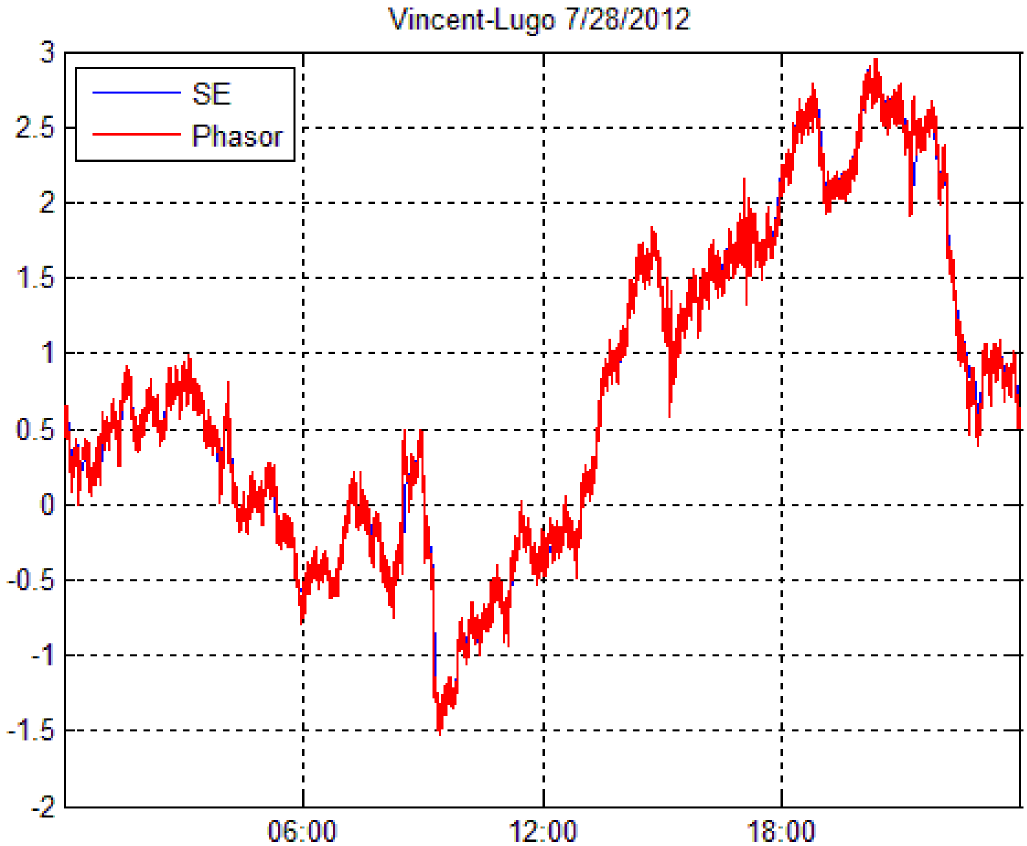
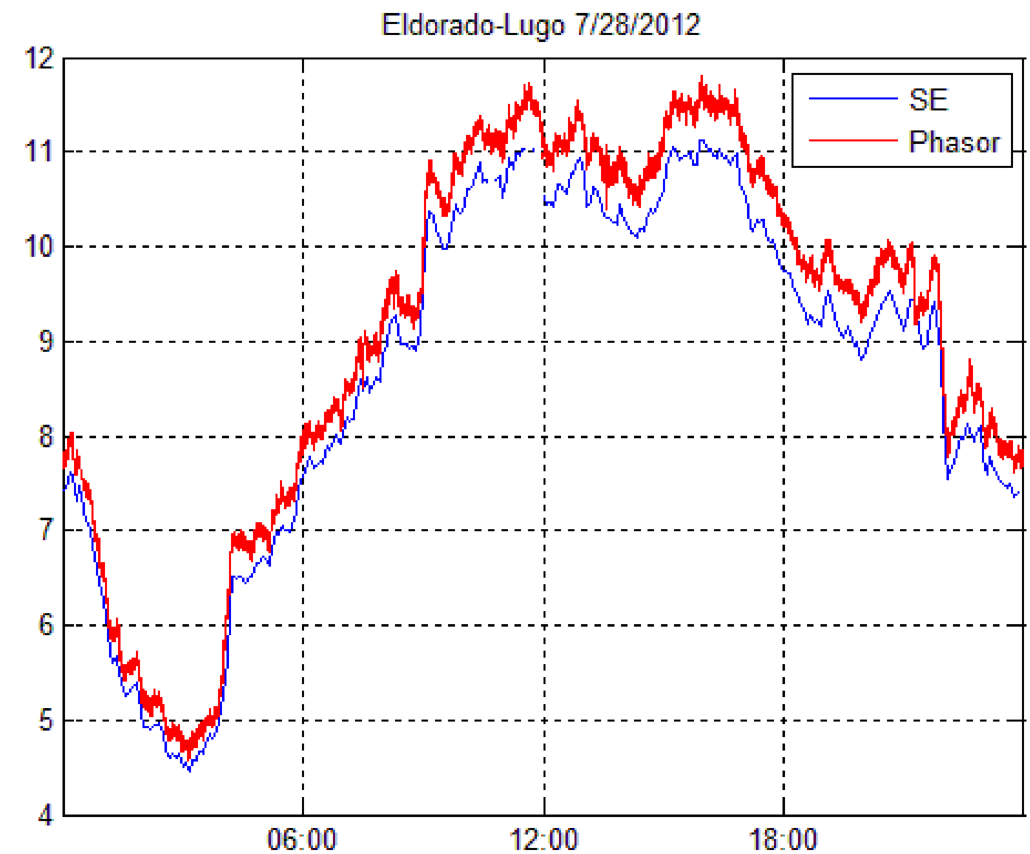
30
25
20
15
10
5
0
-5
-10
-15
06:00
12:00
18:00

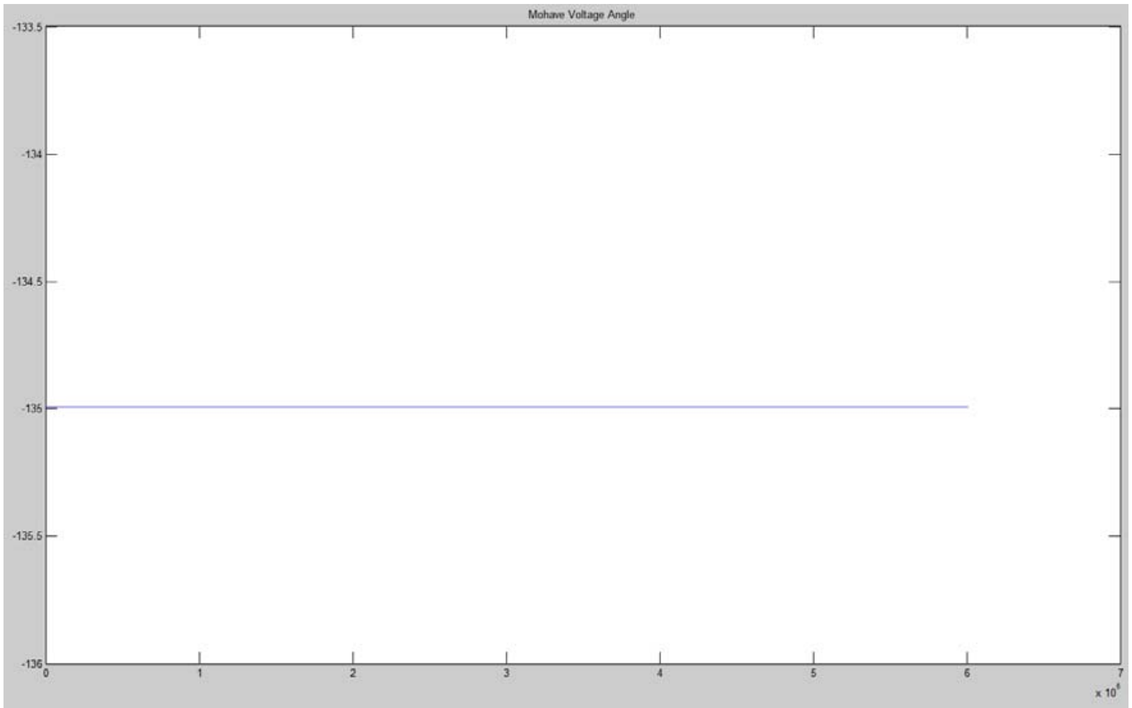


Vincent-Lugo 7/28/2012
SE
Phasor
3
2.5
2
1.5
1
0.5
0
-0.5
-1
-1.5
-2
06:00
12:00
18:00

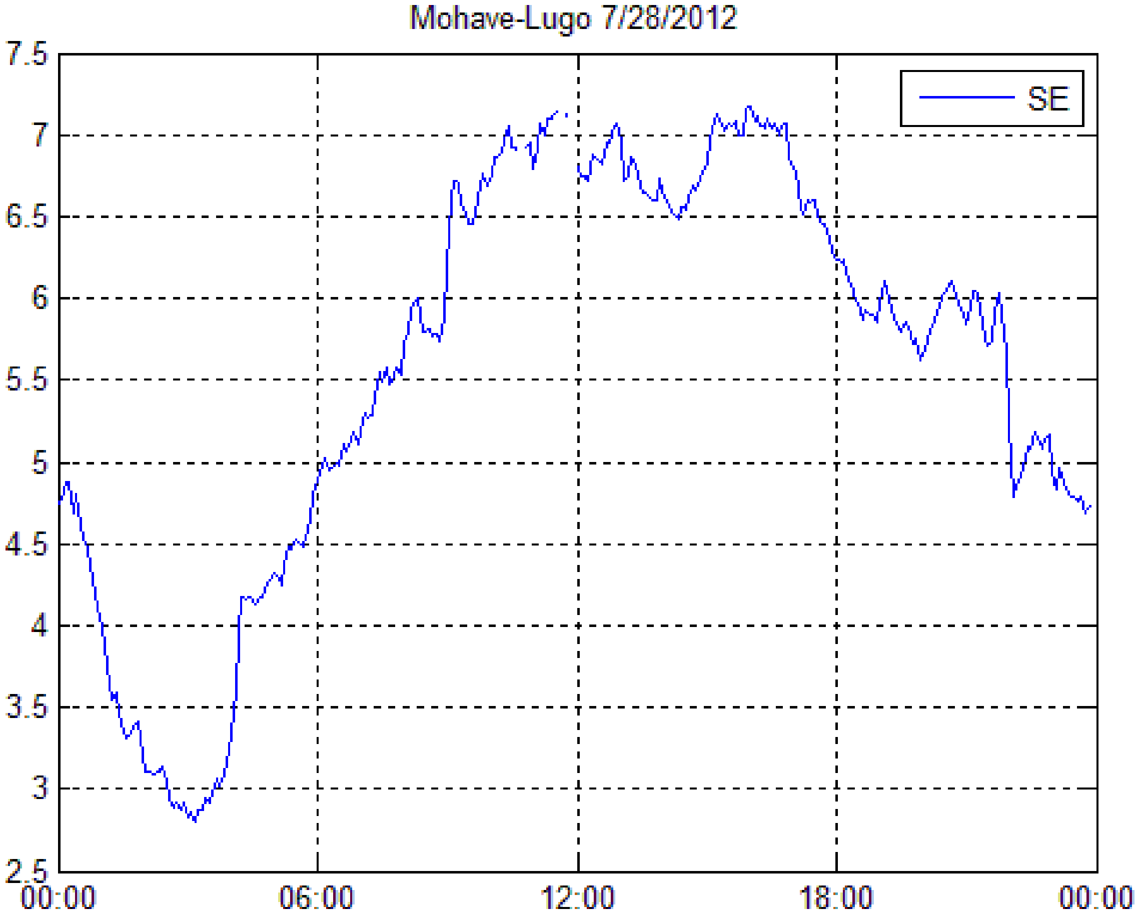


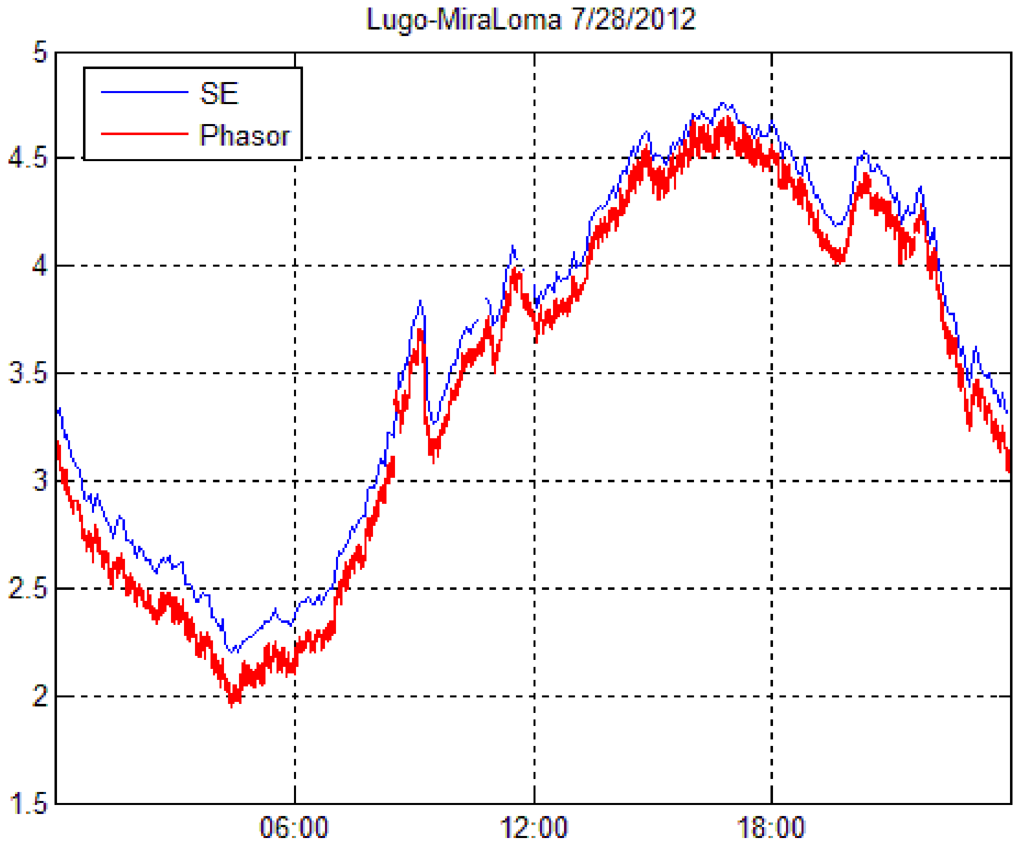
Eldorado-Lugo 7/28/2012
SE
Phasor
12
11
10
9
8
7
6
5
4
06:00
12:00
18:00

Mohave – Lugo



Note: Mohave Voltage Angle value (Phasor) is constant (-134.9950), unusable




Lugo-MiraLoma 7/28/2012
SE
Phasor
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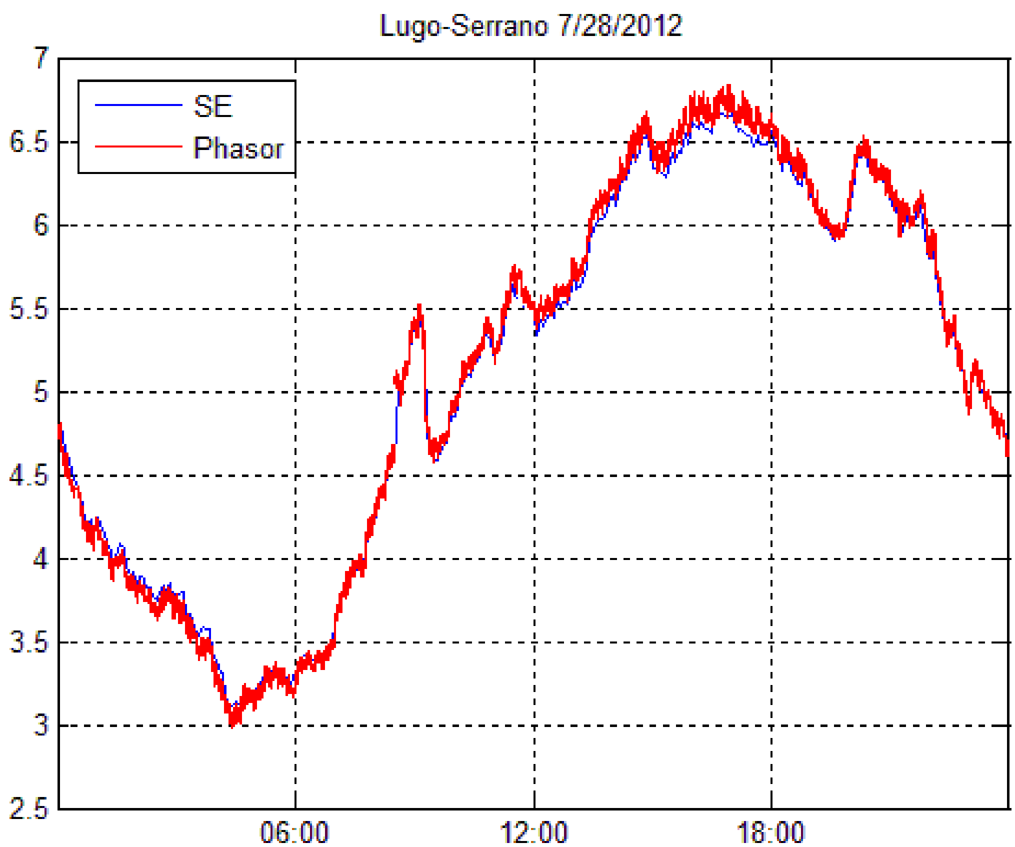
4
3.5
3
2.5
2
1.5
06:00
12:00
18:00


Lugo-Serrano 7/28/2012
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Phasor
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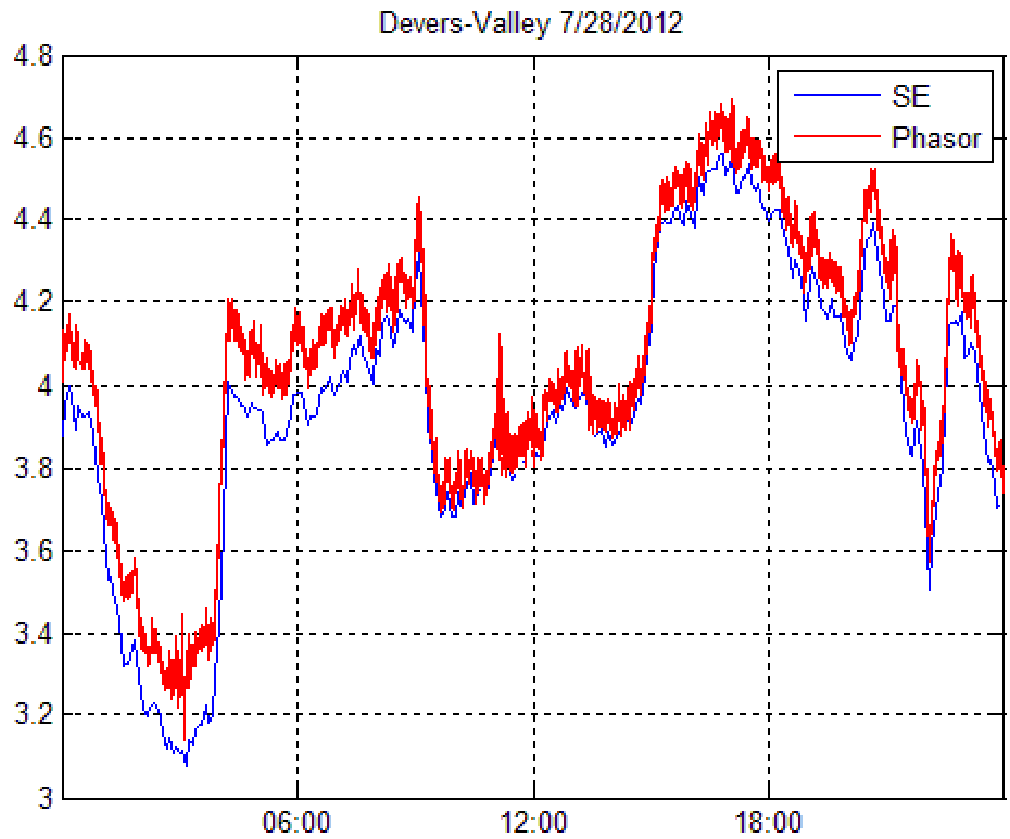
06:00
12:00
18:00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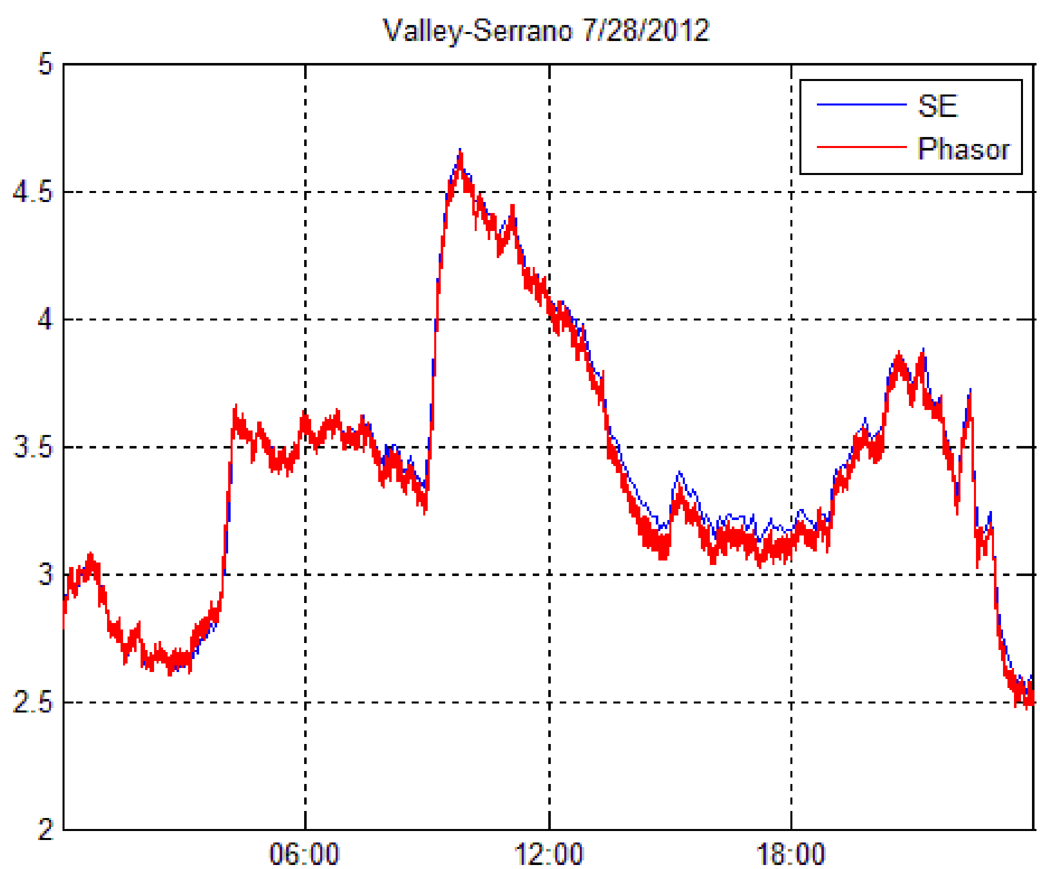
12:00
18:00
SE
Phasor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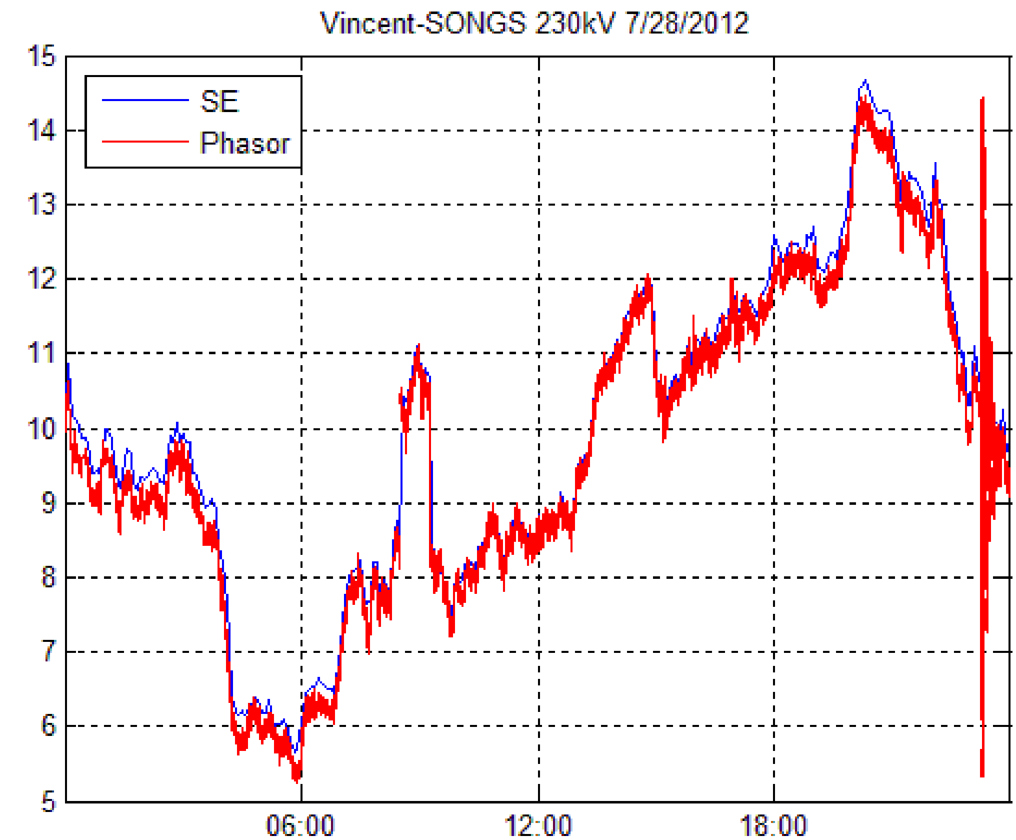
SE
Phasor


Vincent-SONGS 230kV 7/28/2012
SE
Phasor
15
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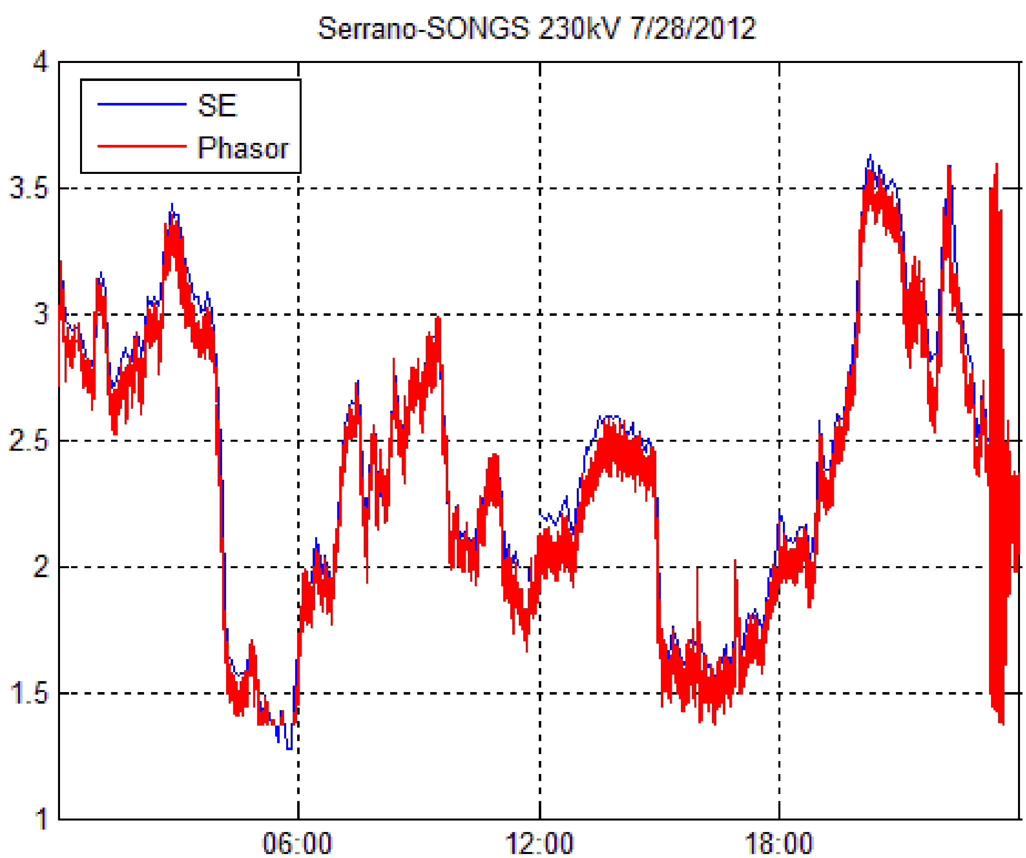
12:00
18:00


Serrano-SONGS 230kV 7/28/2012
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Phasor
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1.5
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06:00
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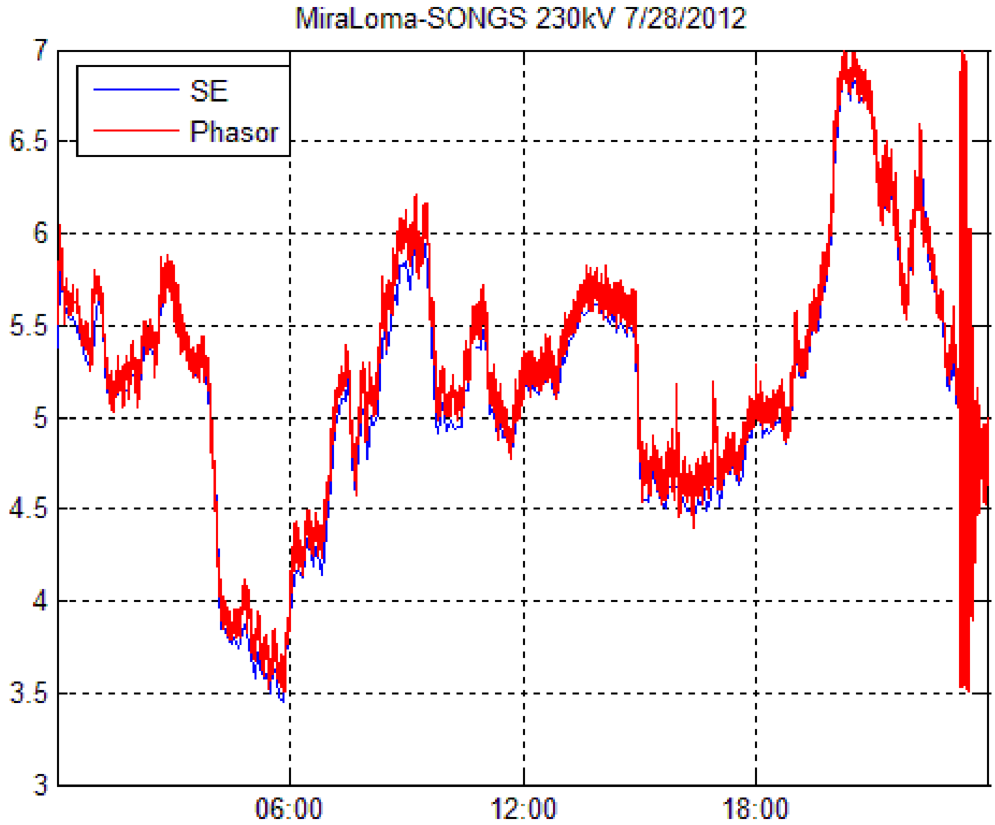
18:00


MiraLoma-SONGS 230kV 7/28/2012
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Phasor
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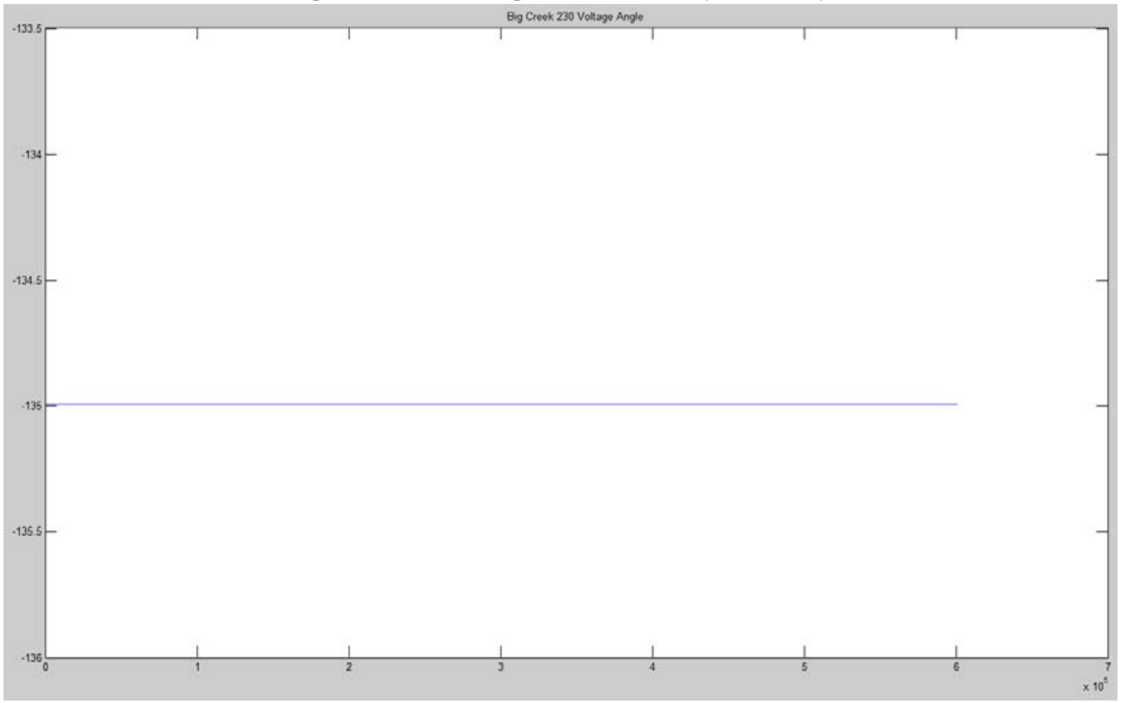
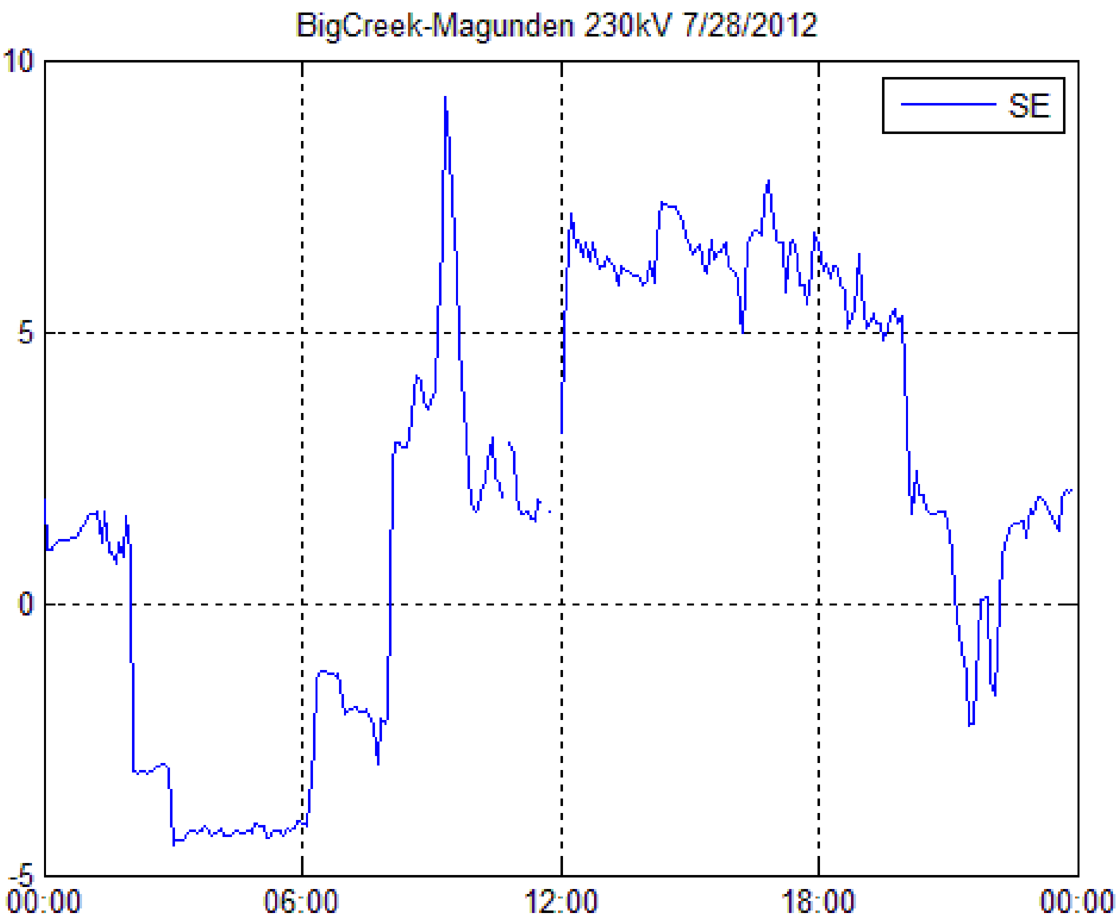
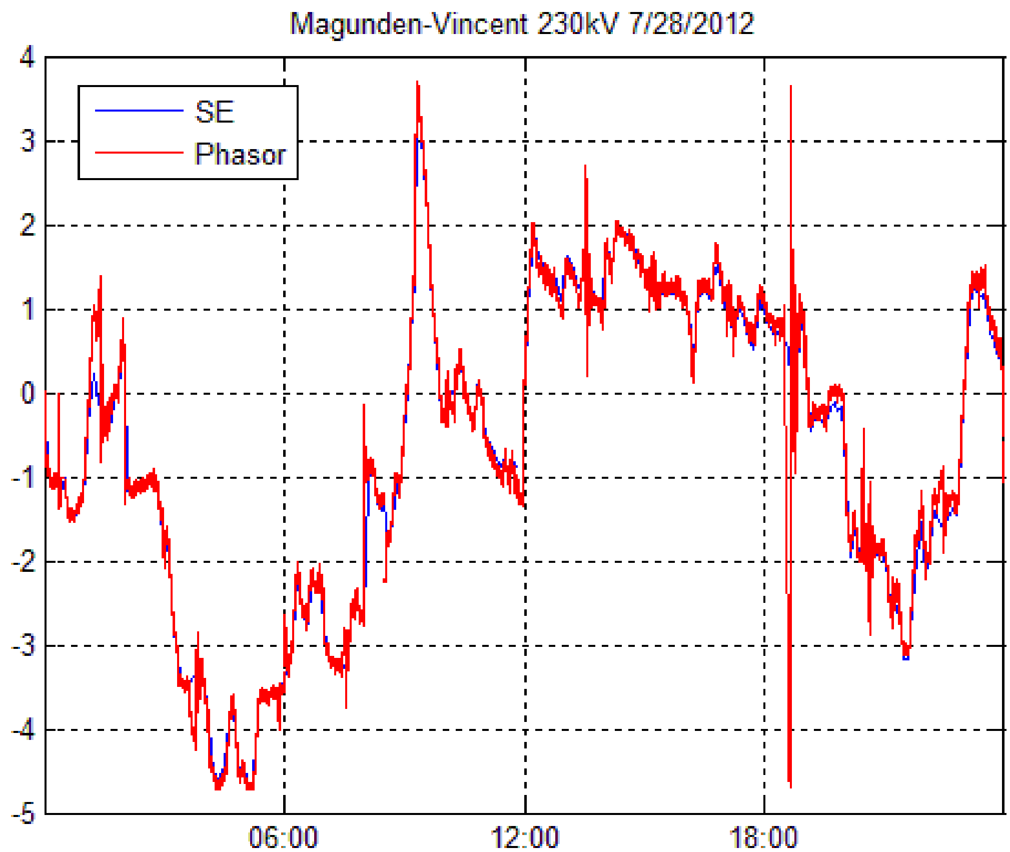
06:00
12:00
18:00

Big Creek – Magunden 230 (Phasor)



NOTE: Big Creek 230 Voltage Angle value (Phasor) is constant (-134.99), unusable




Magunden-Vincent 230kV 7/28/2012
SE
Phasor
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-2
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-4
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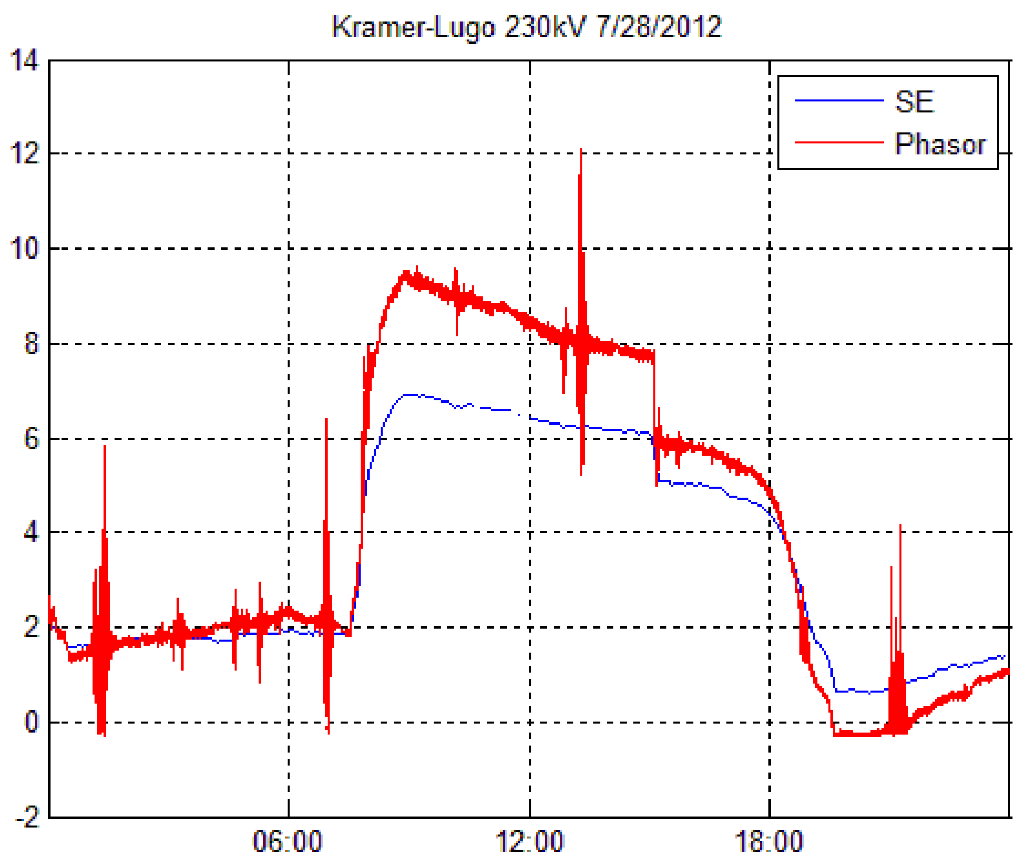
06:00
12:00
18:00


Kramer-Lugo 230kV 7/28/2012
SE
Phasor
14
12
10
8
6
4
2
0
-2
06:00
12:00
18:00

APPENDIX G:
Data Quality Report Phasor-State Estimator Comparison, 8.9.12

Appendix G of PIR-10-068 Final Report

CEC PIR-10-068 –Task 6 (Appendix 3)_ State Estimator vs. Phasor Comparison Angle Differences for August 9, 2012

Angle Pairs Compared

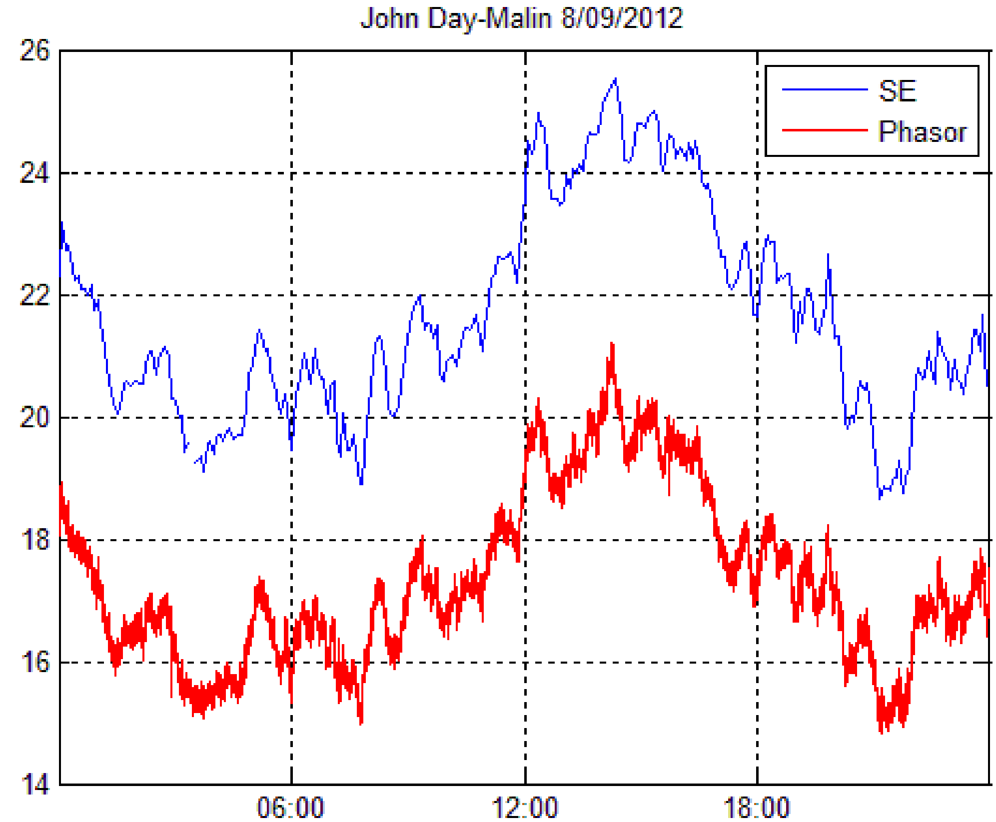
1. John Day-Malin

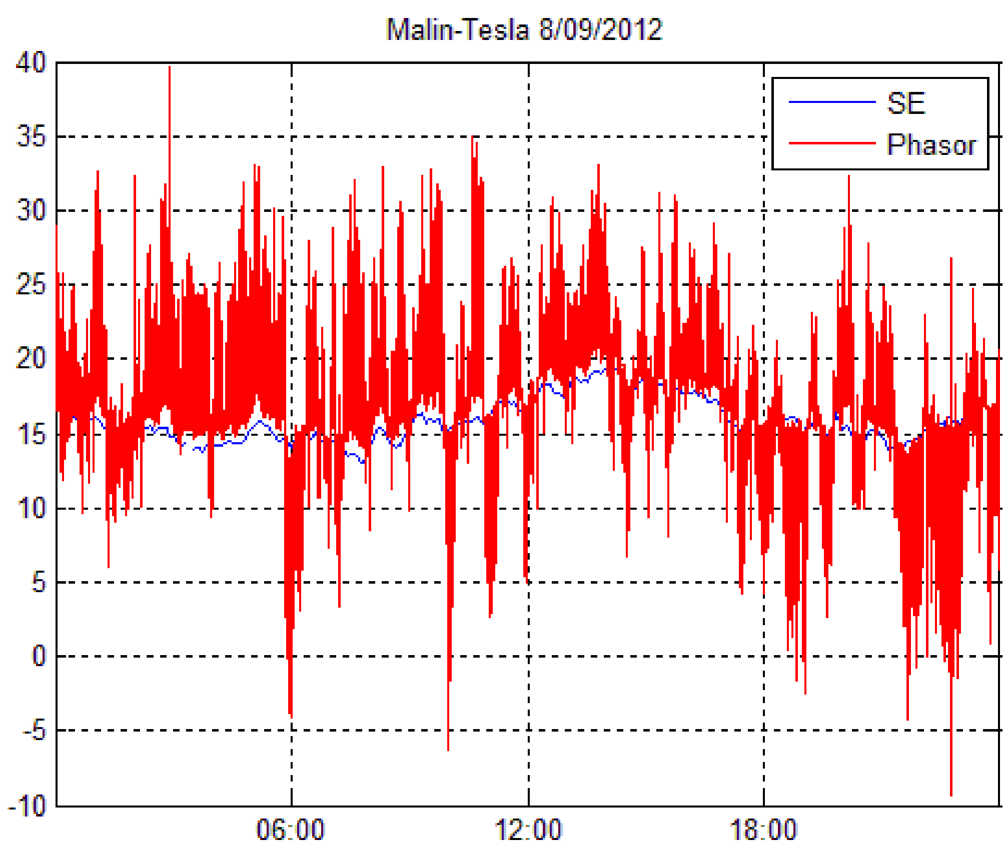
2. Malin-Tesla
3. Tesla-Los Banos
4. Los Banos-Midway
5. Midway-Vincent

6. Vincent-Lugo
7. Eldorado-Lugo
8. Mohave-Lugo
9. Lugo-Mira Loma
10. Lugo-Serrano
11. Devers-Valley
12. Valley-Serrano

13. Vincent-SONGS 230 kV
14. Serrano-SONGS 230 kV
15. Mira Loma-SONGS 230kV
16. Big Creek-Magunden 230 kV
17. Magunden-Vincent 230 kV
18. Kramer-Lugo 230 kV

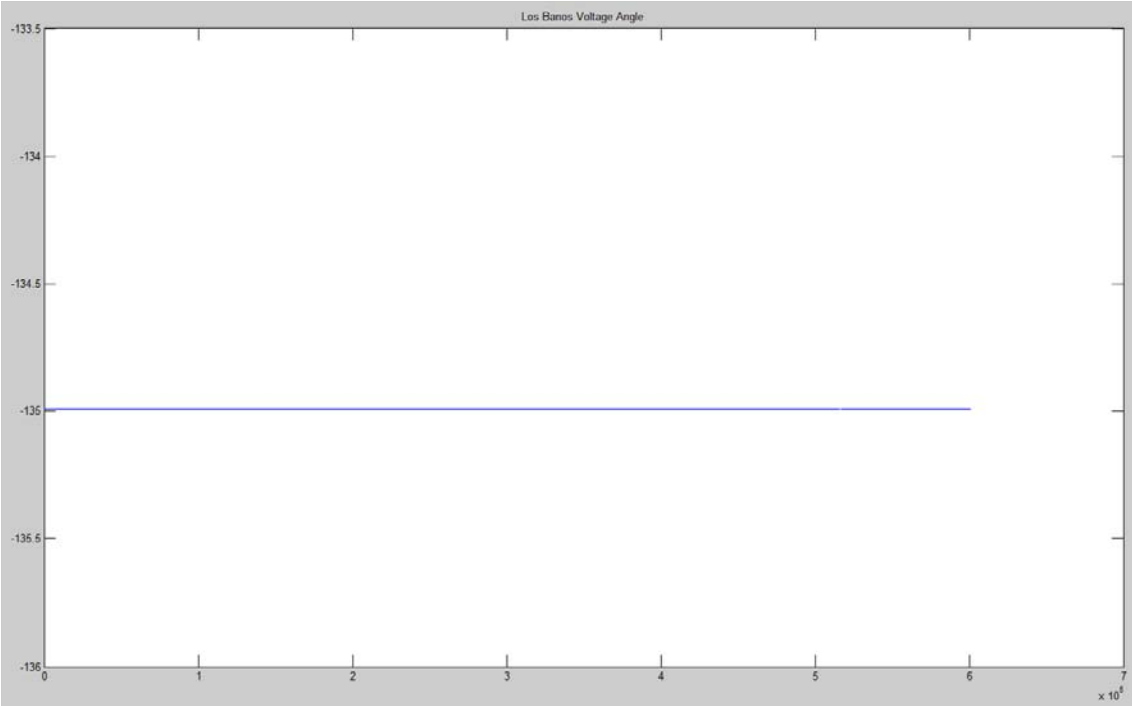
CAISO Comparison Aug 9



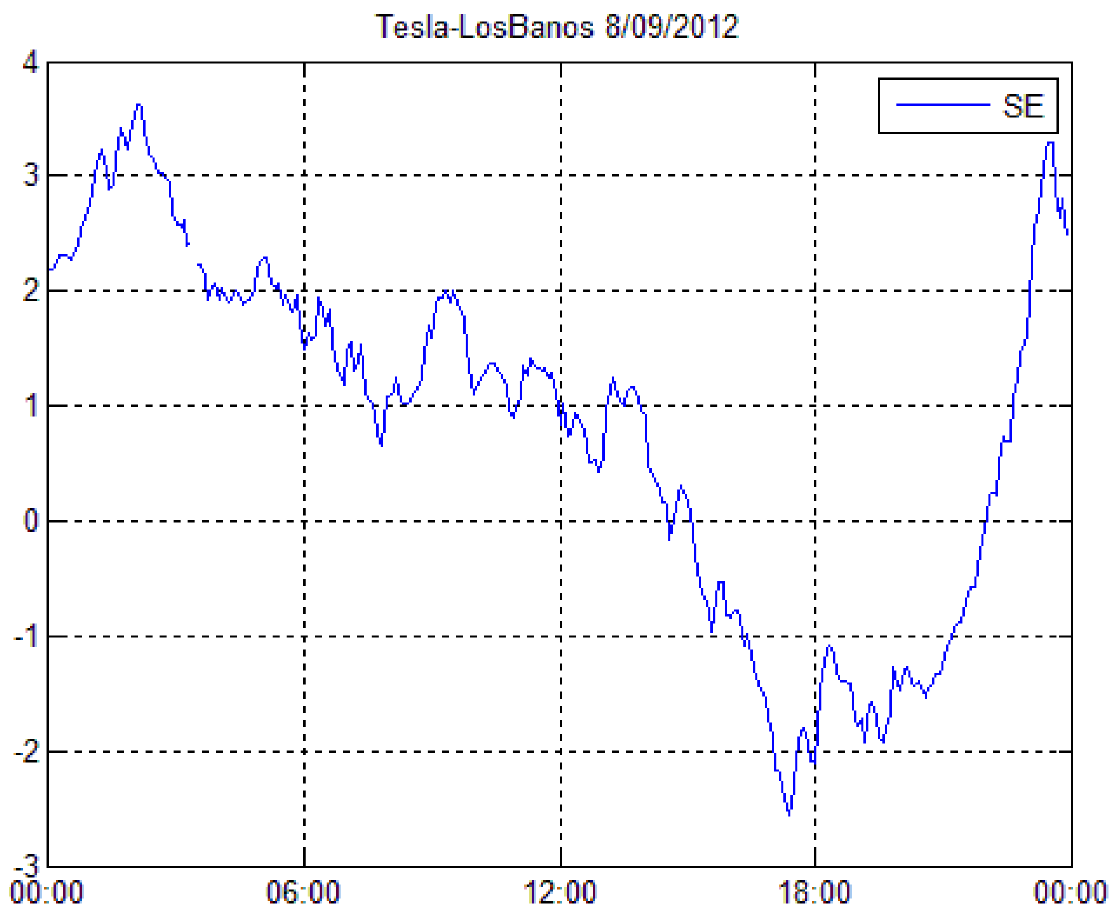


CAISO Comparison Aug 9

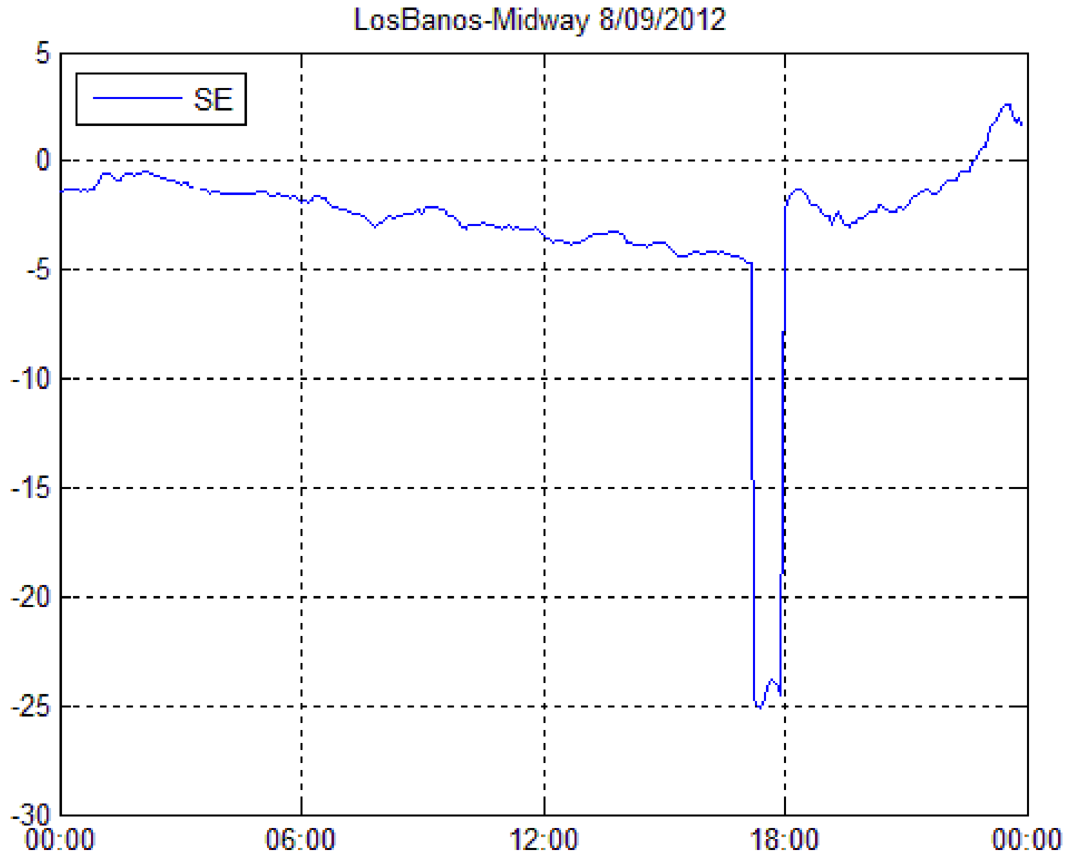
Tesla – Los Banos (Phasor)

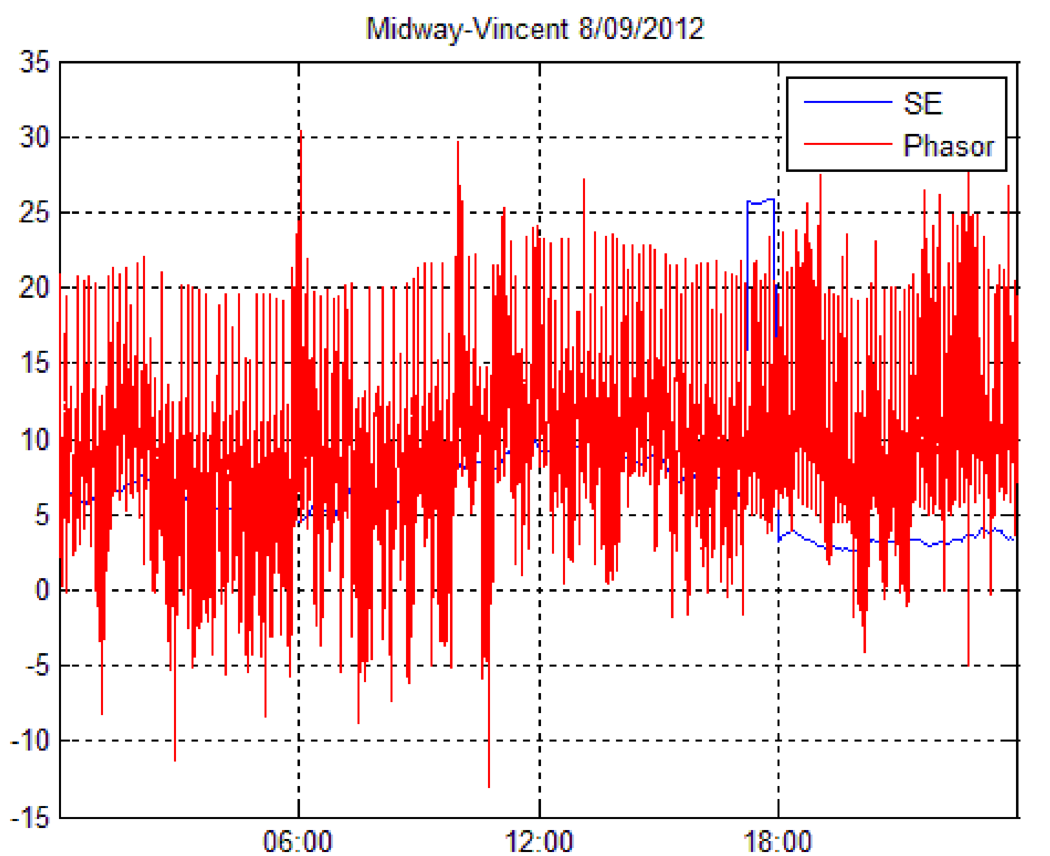


NOTE: Los Banos Voltage Angle value (Phasor) is constant (-134.99), unusable

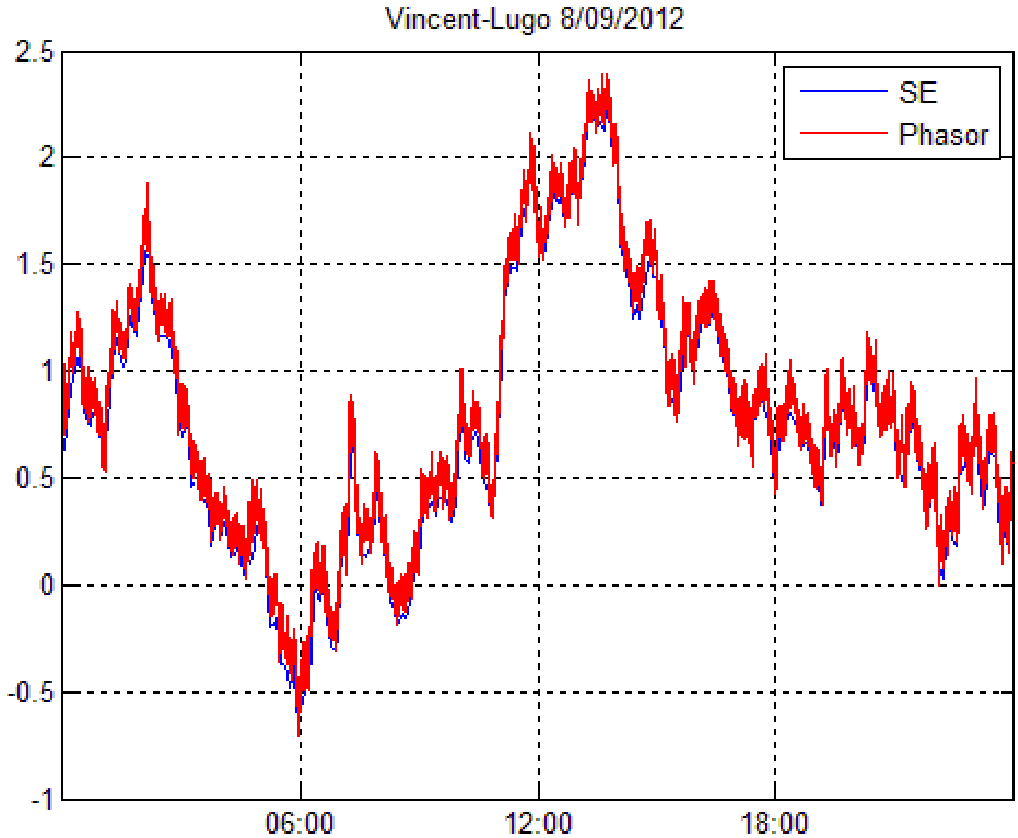


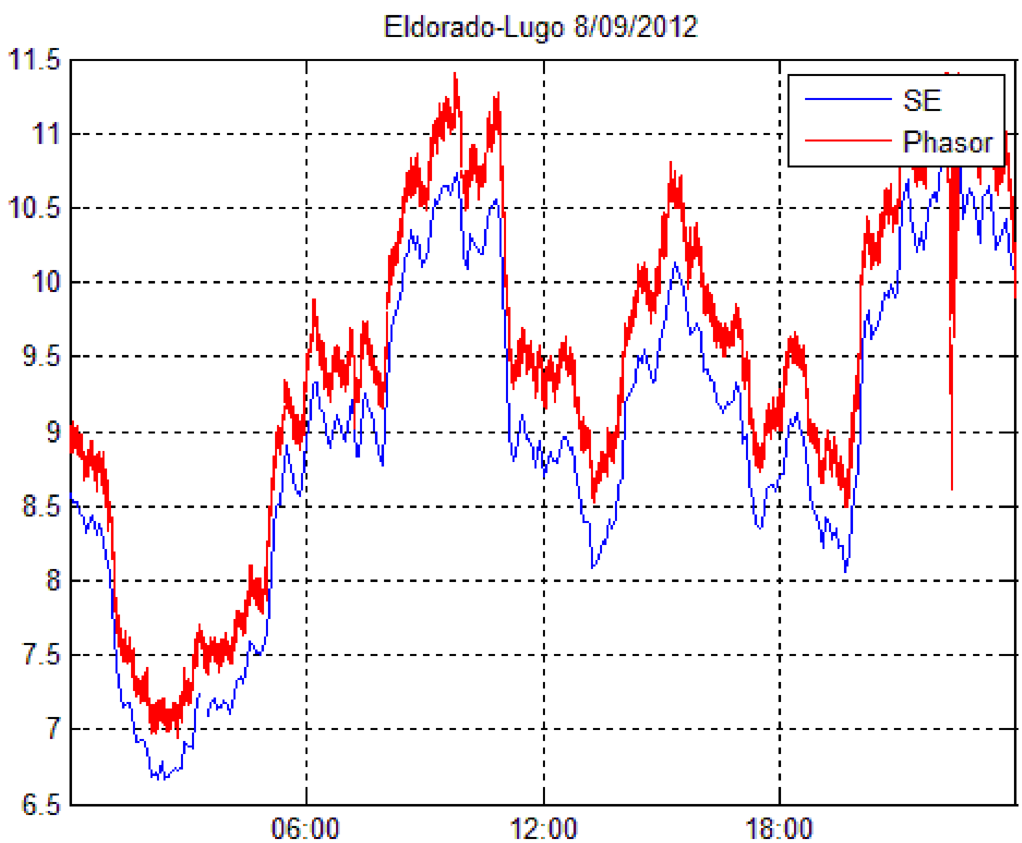
CAISO Comparison Aug 9





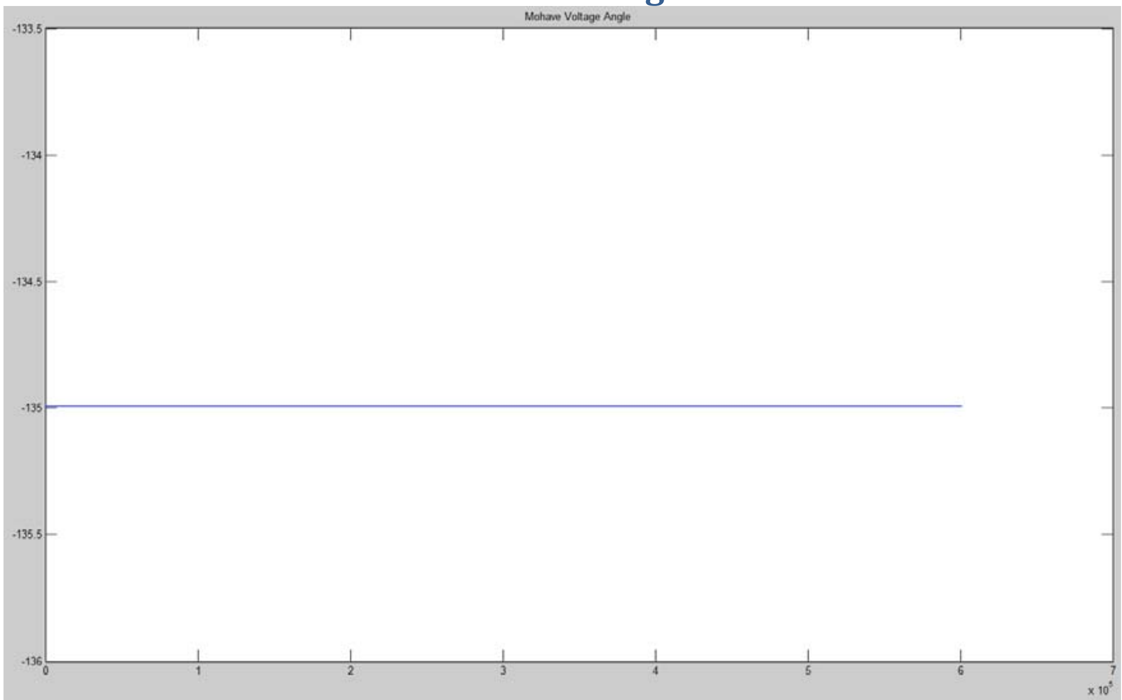
CAISO Comparison Aug 9



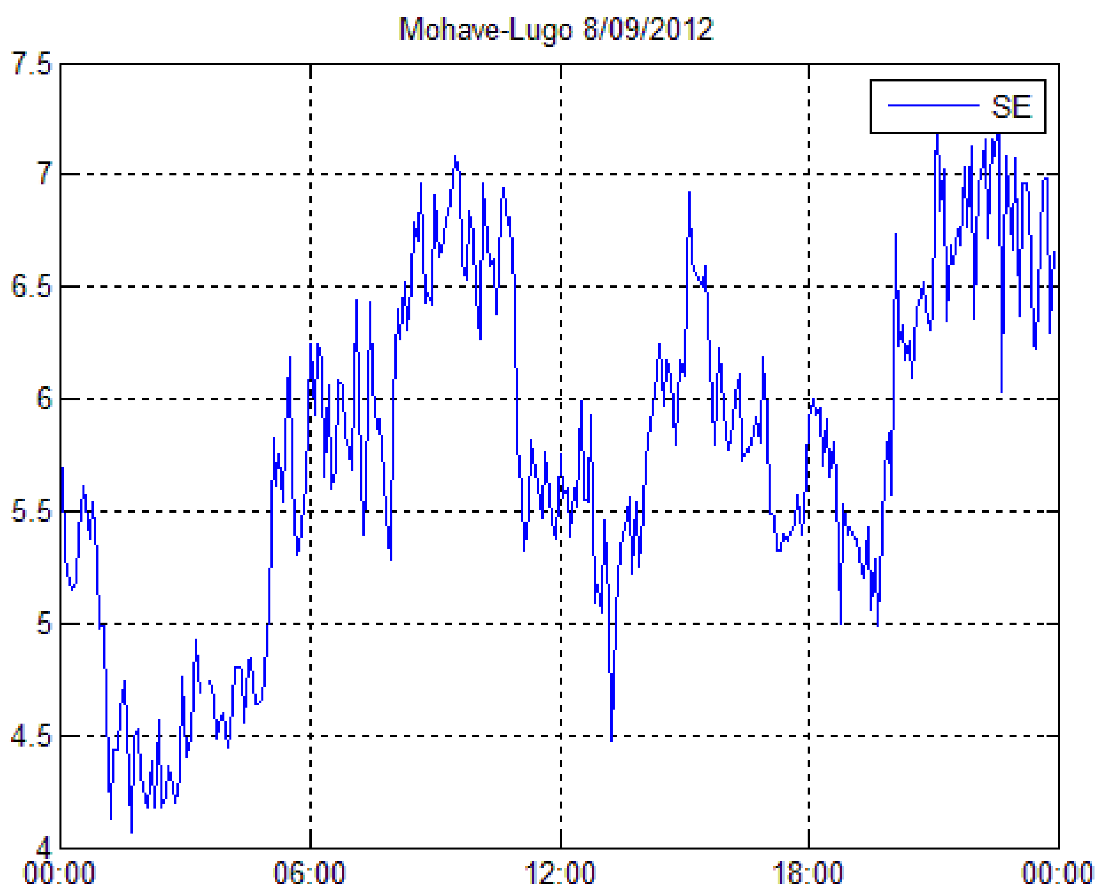


CAISO Comparison Aug 9

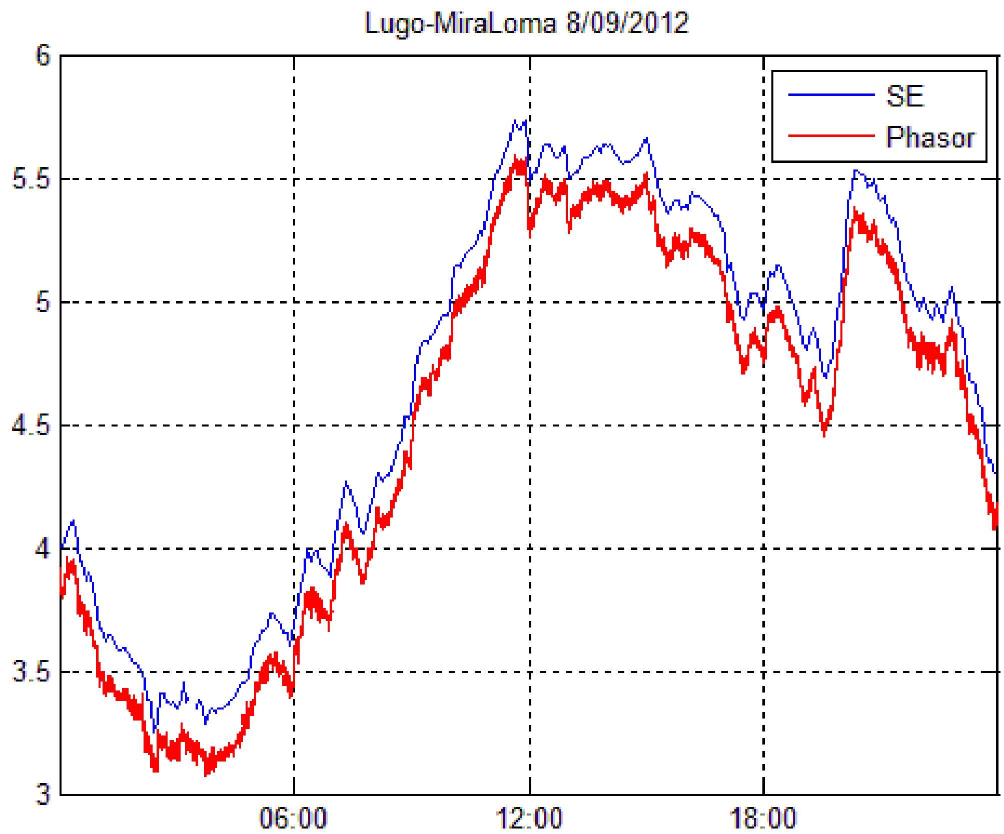
Mohave – Lugo

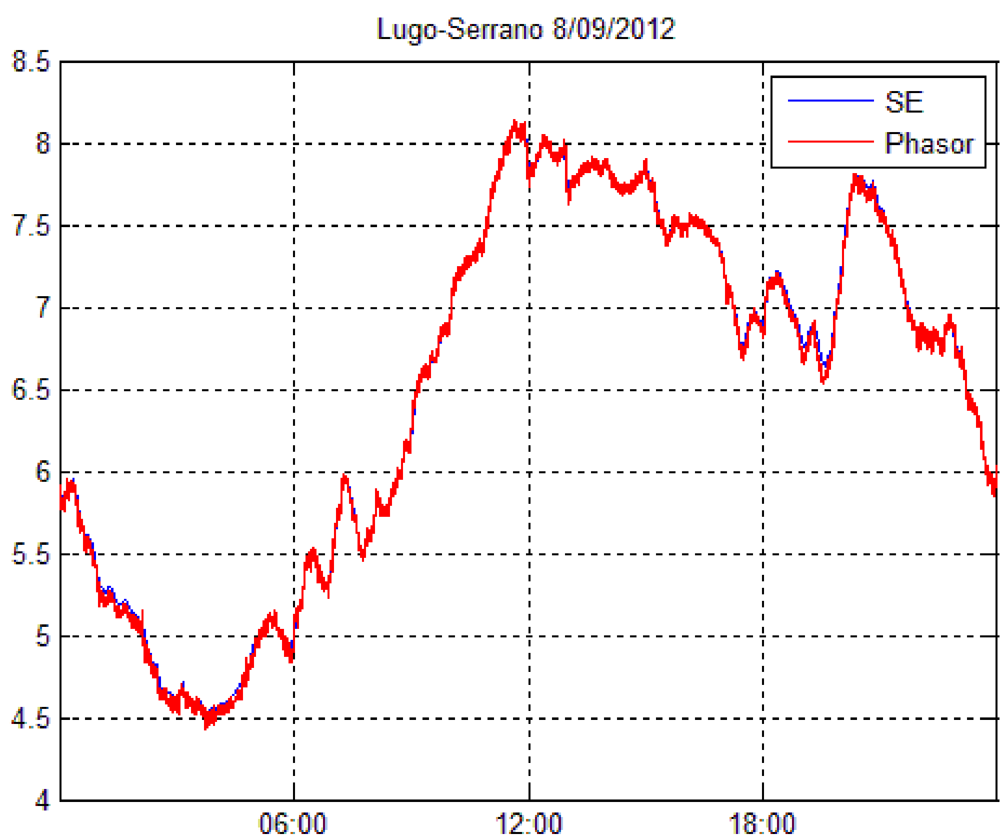


Note: Mohave Voltage Angle value (Phasor) is constant (-134.9950), unusable



CAISO Comparison Aug 9





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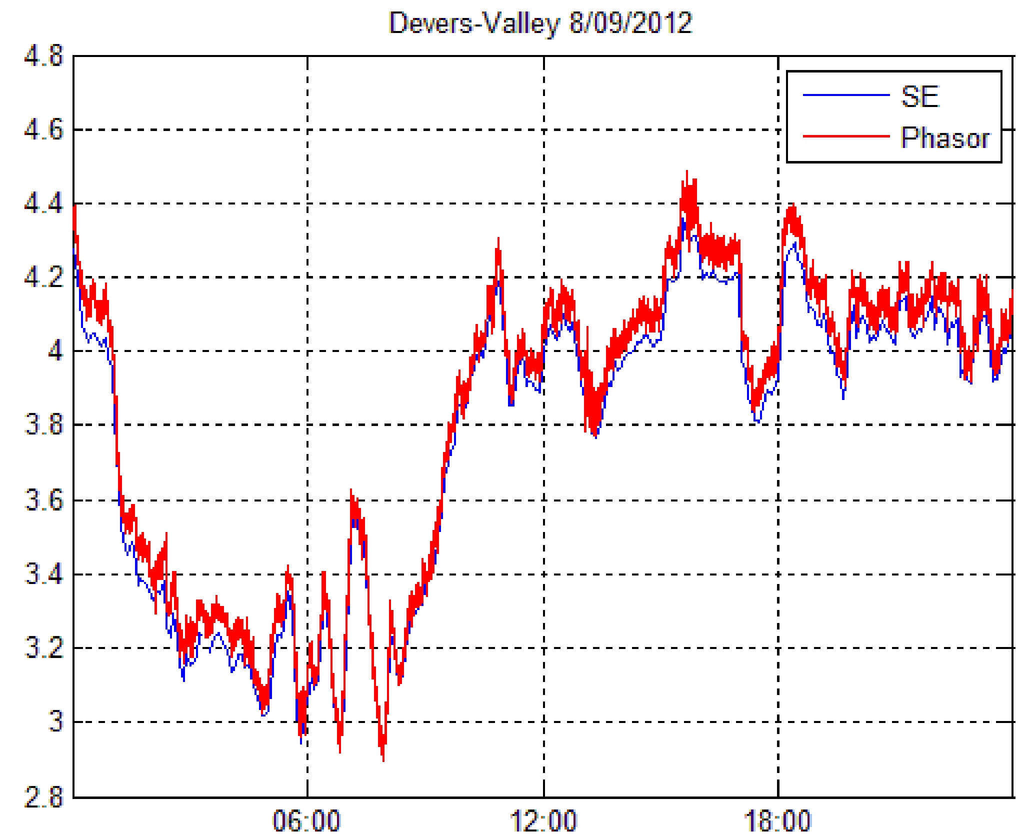

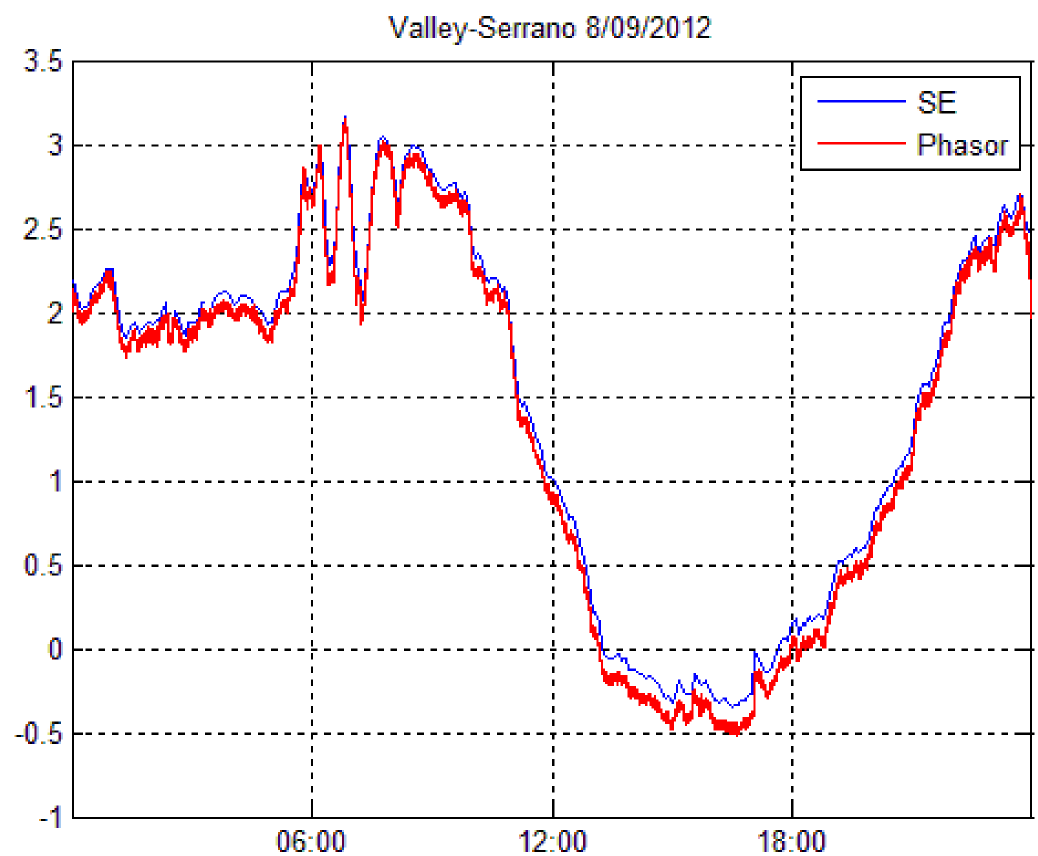

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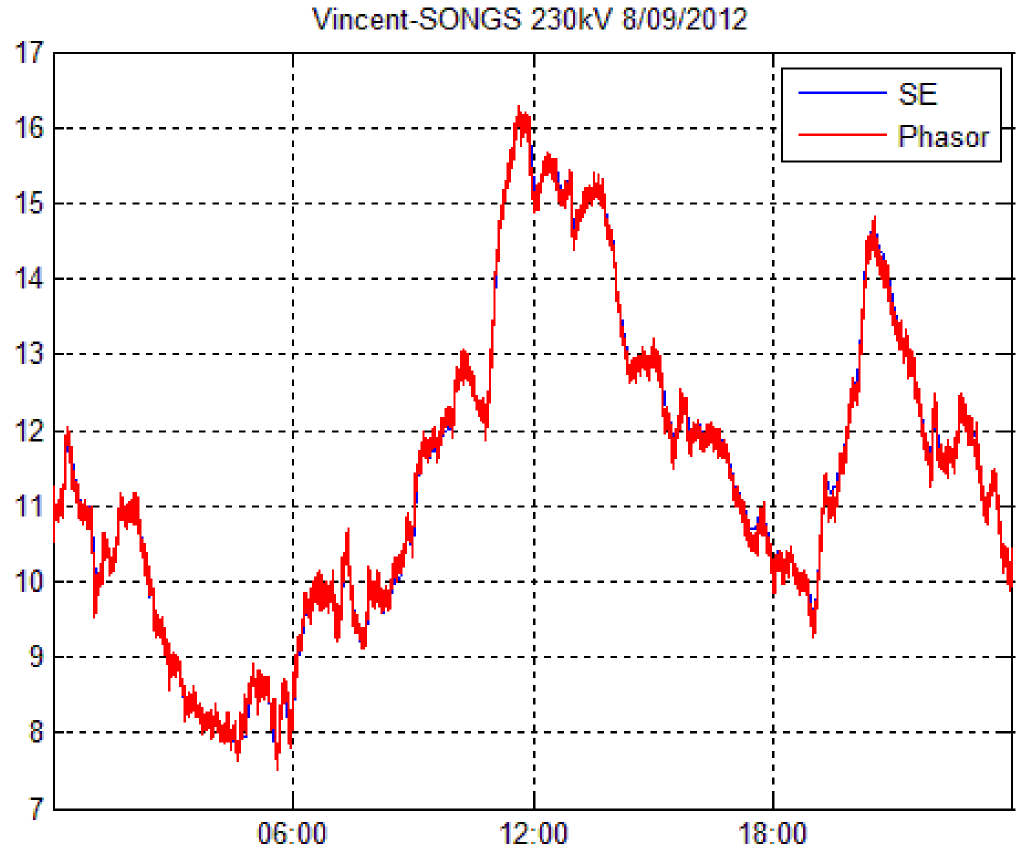
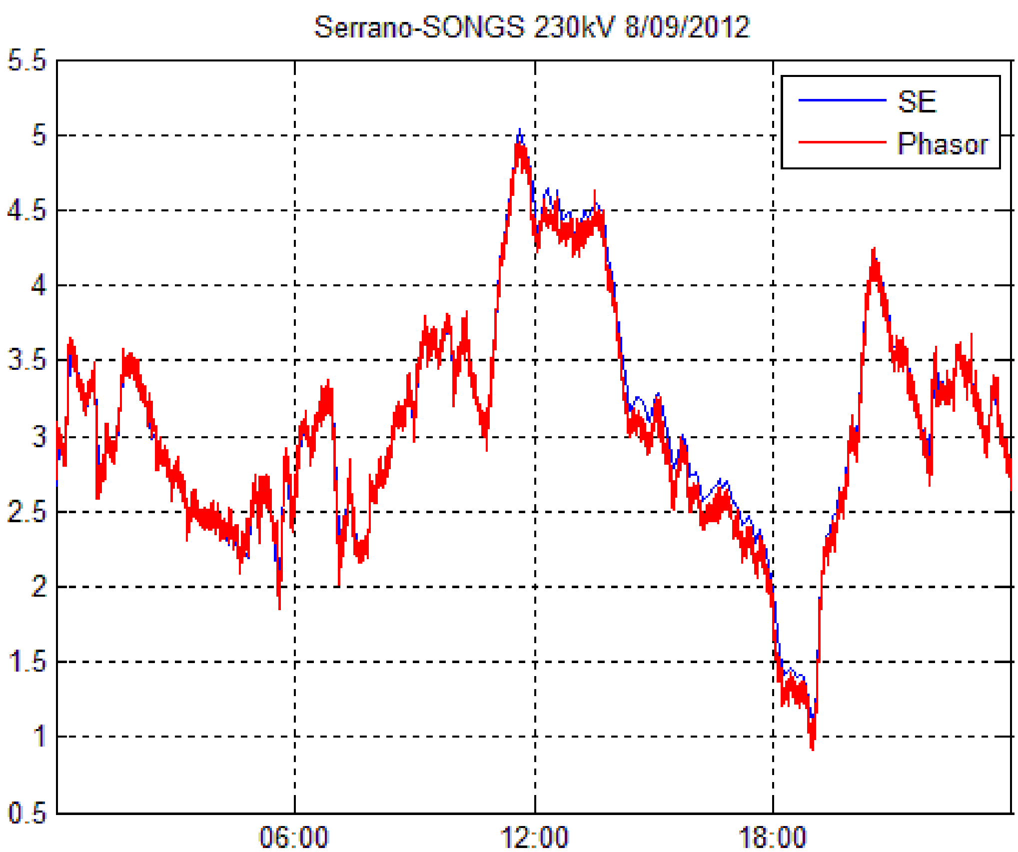
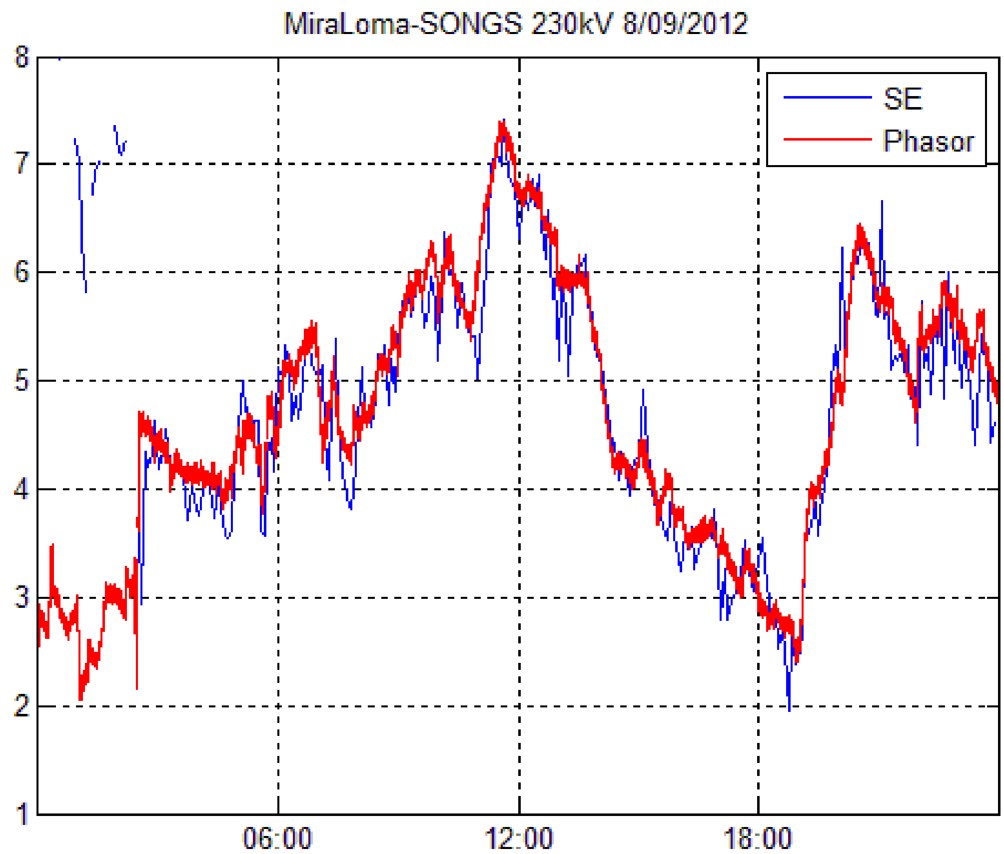


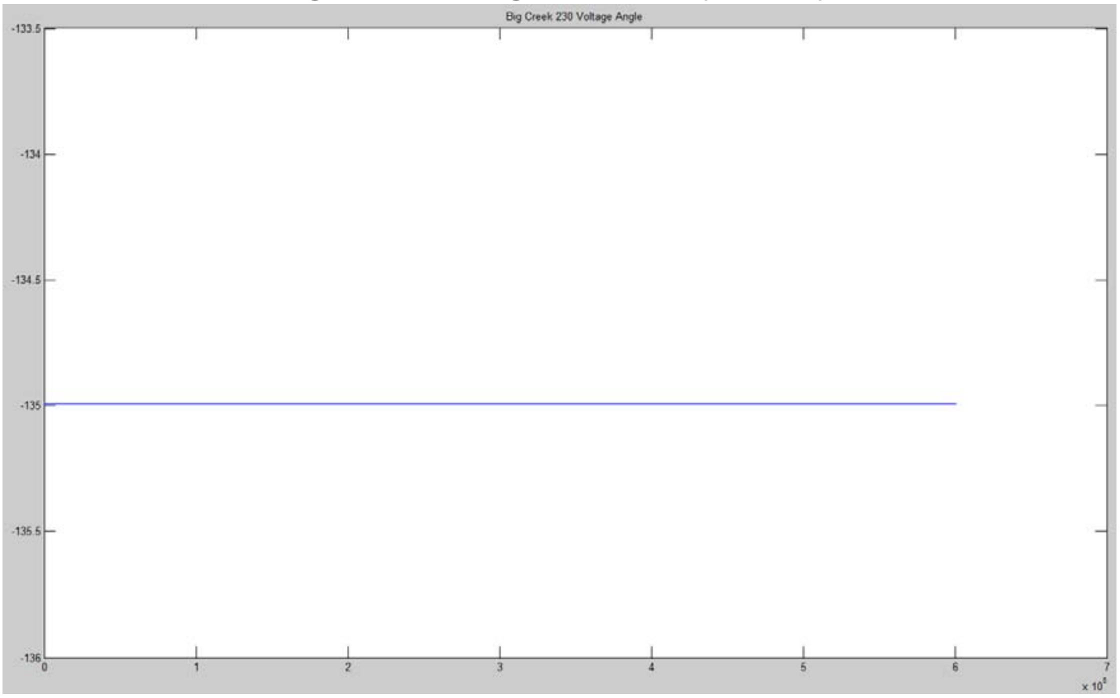


CAISO Comparison Aug 9

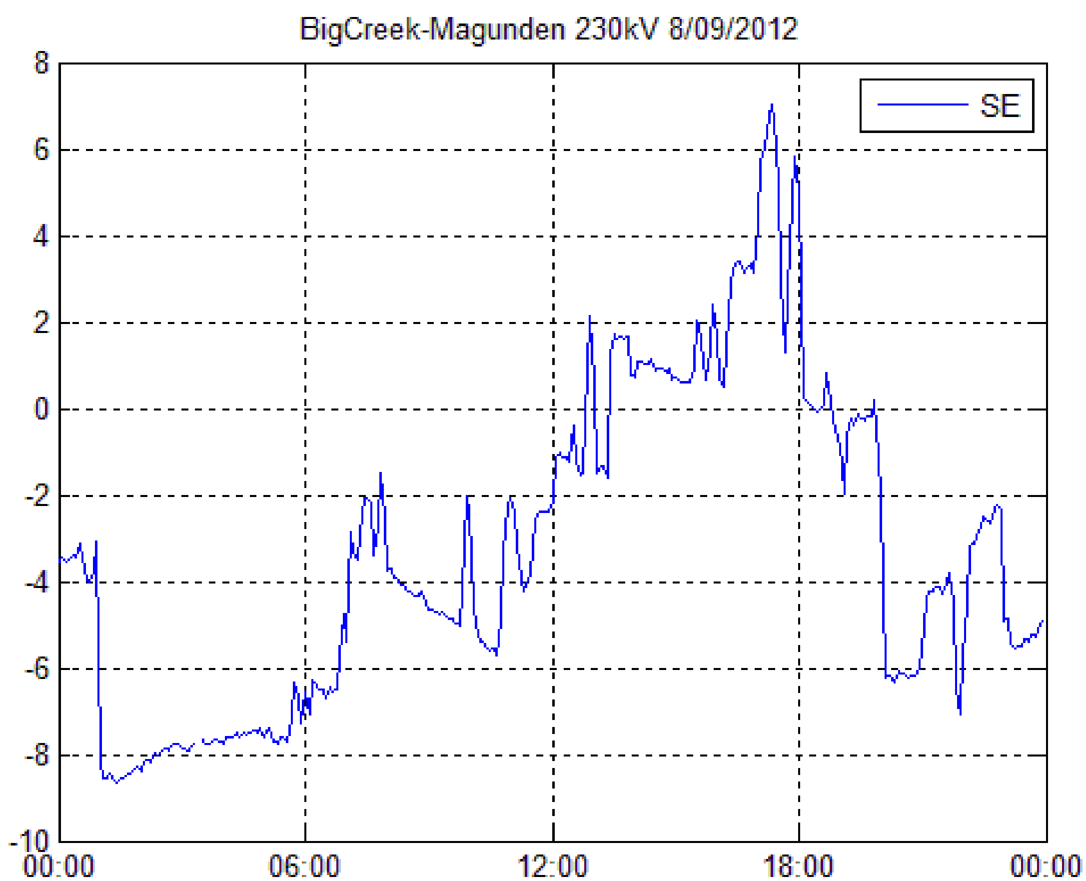


CAISO Comparison Aug 9

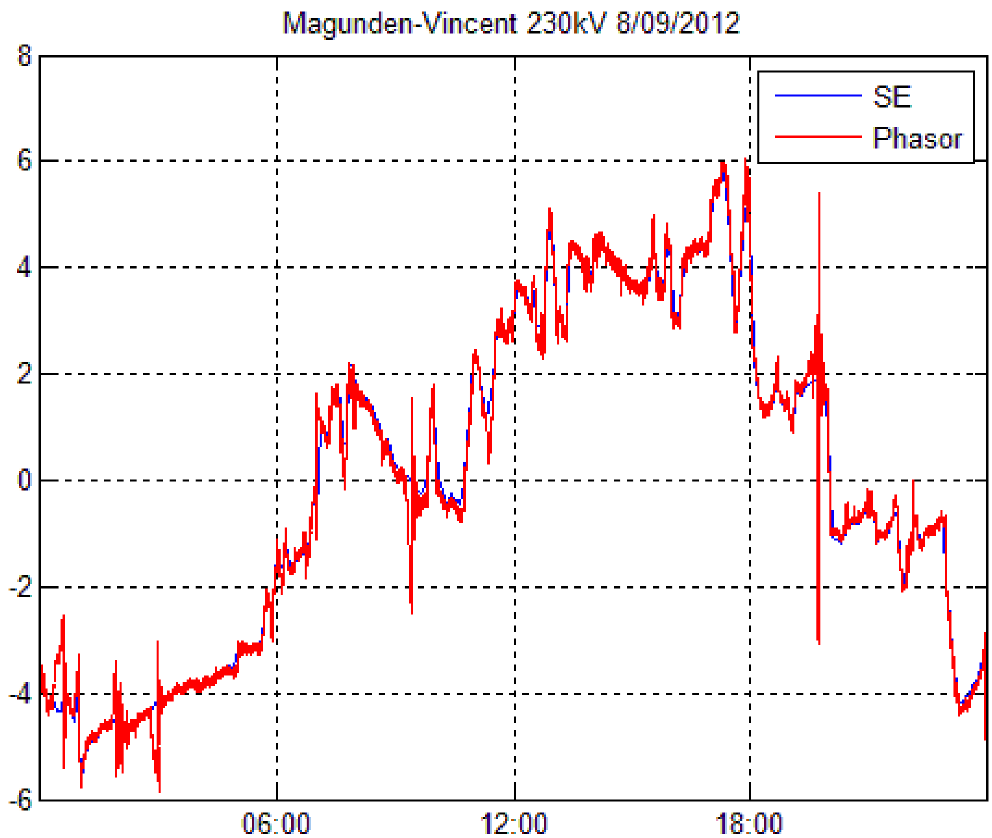
Big Creek – Magunden 230 (Phasor)

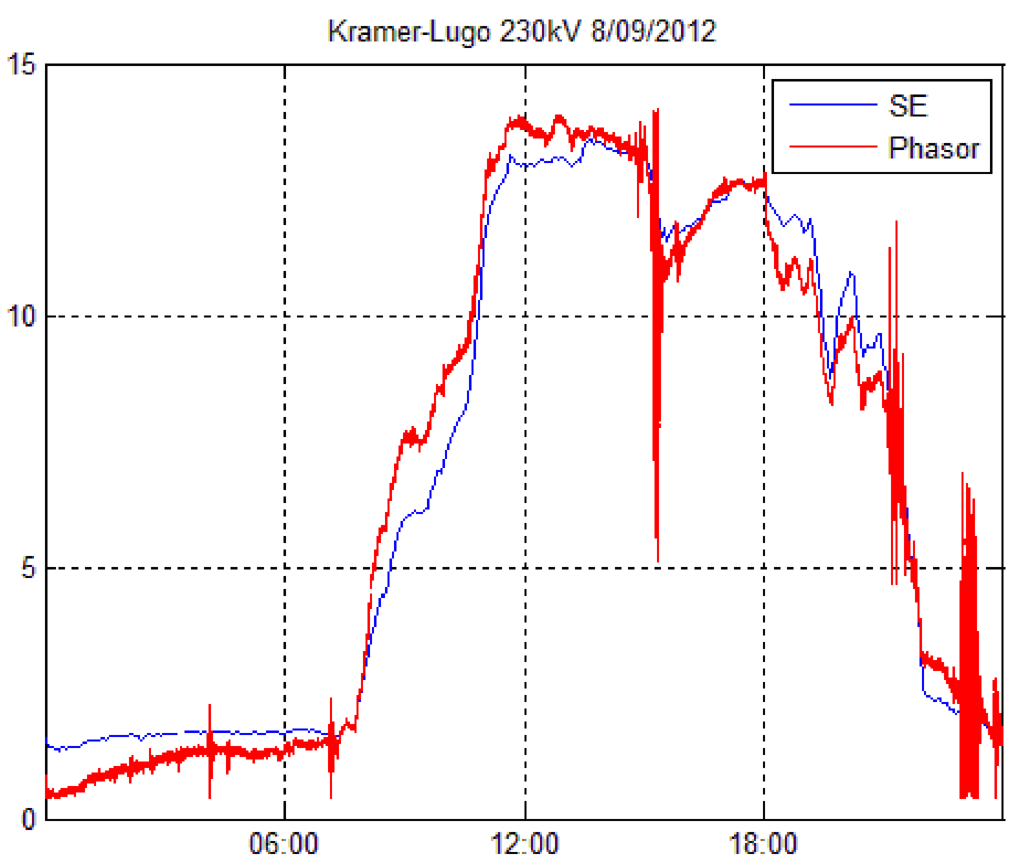


NOTE: Big Creek 230 Voltage Angle value (Phasor) is constant (-134.99), unusable



CAISO Comparison Aug 9





APPENDIX H:
Statistical Analysis of Large Synchrophasor Datasets, Functional Specification: Automation of Baselining Analysis, May 22, 2013

Electric Power Group

Functional Specification: Automation of Baselining Analysis

CEC 10-068 Task 6, Statistical Analysis of Large Synchrophasor Datasets

May 22, 2013

Prepared by
Ajay Das
Electric Power Group

Document Change History

Version No.	Date	Author(s)	Description of Change
0.1	4/18/2013	A. Das	First draft version of the document
0.2	4/19/2013	A. Das	Final draft version of the document
0.3	5/11/2013	J. Dyer	Reviewed and posed questions/observations.
0.4	5/13/2013	R. Barreno	Addressed questions.
0.5	5/21/2013	J. Dyer	Reviewed and provided edits.
0.6	5/21/2013	R. Barreno	Reviewed and approved for finalization.
0.7	5/21/2013	L. Garcia	Edit for content, format, grammar.

Table of Contents

Objective

Statistical analysis of system data with time frame of one year or more is performed to identify the baseline behavior of the system which includes:

1. Identification of thresholds to set for identifying alarming conditions.
2. Seasonal variability analysis.
3. System behavior during daily on-peak and off-peak hours.
4. Sensitivity analysis of one system metric with another.
5. Data Mining (outlier analysis for identifying possible system disruptions).
6. Data quality and availability analysis.
7. Identification of stressed locations and flow gates.
8. Clustering analysis to identify data source units with similar behavior.
9. Data source comparison and validation (for example: Phasor and SE, Phasor and EMS).

Phasor measurement units (PMUs) produce a large amount of data at 30 – 60 samples per second which is essential to capture the grid dynamics for monitoring and event analysis purposes. When this data is used for long term analysis in the order of daily, weekly, monthly, seasonal, and yearly time frames, then the analysis process runs into a problem of dealing with a large amount of data. For example, it is necessary to have approximately 5 Terabytes of storage space available to archive one year of 30 samples/second data of a typical system with 50 PMUs. A typical baselining analysis requires at least one year of data to analyze effect of seasonal variations in system performance.

Processing these large datasets requires a considerable amount of computer system resources and time, which is the major concern during baselining analysis of synchrophasor data. This document provides a functional specification of automated methods and pre-analysis steps that can be taken to enable the user to get automated and on-demand statistical summary of the data without the frustration and time consuming activity of loading and processing of large sets of synchrophasor data at their maximum resolution.

1 Data Sources

The possible list of data sources used for baselining analysis can be divided into two broad categories:

1. Databases (examples: PI Database, RTDMS[1] Database, and MySQL Database).
2. Data Files (examples: CSV data files, COMTRADE data files, and DST data files)

Data files are more portable than databases and better suited for short-term data analysis. Use of data files for long-term analysis is inefficient as it involves individual processing of large amount of data files

[1] ®Electric Power Group. Built upon GRID-3P platform, US Patent 7,233,843, US Patent 8,060259, and US Patent 8,401,710. All rights reserved.

(each with its own metadata in the form of header row in CSV files and configuration files in the case of COMTRADE and DST files) to extract statistical summary information. While automatically processing these files, the metadata information of each file must be matched with the metadata previously processed files for calculating data summaries. The challenge of synchronizing metadata information across all the data files makes it harder to use data files for long term statistical data analysis. In addition, the extracted statistical summary information is highly specific to the particular analysis being conducted by the user at the time, and to change any analysis parameters would require repeating processing of each file all over again.

Databases in comparison are better suited for automated pre-processing of data, extracting summary analysis, and archiving the summary statistics for future analysis. This is due to the fact that all the metadata information is centrally stored in the database and changing any analysis parameters can be conveniently done while extracting summary information and generating analysis reports. This document focuses on automation of long-term statistical analysis using data stored in database format.

2 Data Preprocessing

Data preprocessing is an essential part of long term data analysis which must be performed on the data in the database prior to extracting statistical summary information. This process should ideally be performed daily after midnight (low system load conditions) to work on previous day's data and archive the summary results for later analysis. This process can be automated and would include the following steps.

2.1 Data cleaning

Data cleaning is the process of elimination of bad data from the dataset. Data is identified to be of bad quality by using the status flag information, relational operator filters, filters to detect and eliminate prolonged identical data values, and other customized filters. Data cleaning should be completed before any further statistical analysis is performed on the data to avoid including bad data in the analysis process.

1. **Apply Status flag if available**. Status flag is a part of the C37.118 data stream coming from the PMU and contains information regarding the quality and reliability of the data being transmitted from the PMU.
2. **Apply relational operator filters (>=, <=, ==) for known bad data**. The purpose of this is to eliminate any high and low extreme values that are known to be bad (through operational knowledge of power systems; for example, frequency values which are less than 55Hz or greater than 65Hz)
3. **Filters to eliminate prolonged identical data values**. It is observed that if the data values remain identical for a long period of time (few minutes); it is an indication of data dropout with a repetition of previous good value. The customized filter will identify repetition of data values more than configurable time duration and eliminate those data points.

4. **Filters to eliminate noisy data values**: Noisy data can be identified by checking standard deviation value of a sample dataset. This filter is used after data is cleaned and while calculating statistical summary variables during down sampling process.

2.2 Data down-sampling (1-sec and 1-min)

Data down sampling is essential to manage the data volume for long term analysis while preserving the information present in the high resolution data. This is achieved by using the sub-second data to calculate the following information during the time duration periods of 1-second and 1-minute: The method of down sampling proposed in this document is to keep all the relevant statistical information intact (such as, max, min, median, and standard deviation).

1. Max value.
2. Min value.
3. Median value.
4. Average (Mean) value.
5. Standard deviation value.
6. 90% data max value (to eliminate outliers).
7. 90% data min value (to eliminate outliers).

Table 1 provides an estimation of data volume reduction when data is down-sampled for long term analysis. Assuming a linear relationship between number of data points and analysis effort (time and system resources), the suggested down-sampled resolution aims to keep the effort comparable to analyzing one-hour of data at full 30-samples per second. From previous studies experience, analysis of 1-hour of sub-second data takes approximately 30-minutes to 2-hours depending on the number of PMUs and signals to analyze.

Long Term Analysis Duration	Number of data points per signal at 30 samples/sec	Recommended down sampled data	Number of down sampled data points	Analysis effort compared to analyzing 1-Hour of sub-second data
Hourly	108,000	Sub-Second	108000	100%
Daily	2,592,000	1-Second	86400	80%
Weekly	18,144,000	1-Second	86400 x 7	80% x 7
Monthly	77,760,000	1-Minute	43200	40%
Yearly	922,752,000	1-Minute	43200 x 12	40% x 12

Table 1: Comparison of analysis effort for long term analysis durations

It can be noted that weekly analysis can be then broken down to 7 daily analyses and yearly analysis can be broken down to 12 monthly analyses. Seasonal analysis will be a combination of approximately 4-5 monthly analyses.

2.3 Data availability analysis

Data availability analysis is done by calculating the percentage of missing data points compared to expected data points. For example, if in an hour instead of expected 108,000 data points there are 107,000 data points in the database then the data availability will be = (108,000-107,000)/108,000 = 99.07%. The analysis is performed for the down-sampled duration (1-second and 1-minute) and the results are archived for future analysis.

2.4 Data quality analysis

Data quality analysis is done after completion of the data cleaning process. This measures the percentage of good data available in a set of data points. Continuing with the example in section 2.3; if out of the available 107,000 data points, 5,000 data points were eliminated using combination of the data filters in the data cleaning process, then data quality analysis will result = 5,000/107,000 = 95.33% good data. To get an estimate of overall good quality data available for analysis, multiply the numbers from data availability and data quality analysis = 99.07% * 95.33% = 94.44% good quality data available. Data quality analysis is also performed for the down-sampled time durations at the end of the day and summary results can be archived for future analysis.

2.5 Summary database creation

The Figure 1 flowchart illustrates the preprocessing steps to be performed on the data in the database and the resulting summary statistics to be archived in summary databases for future analysis.

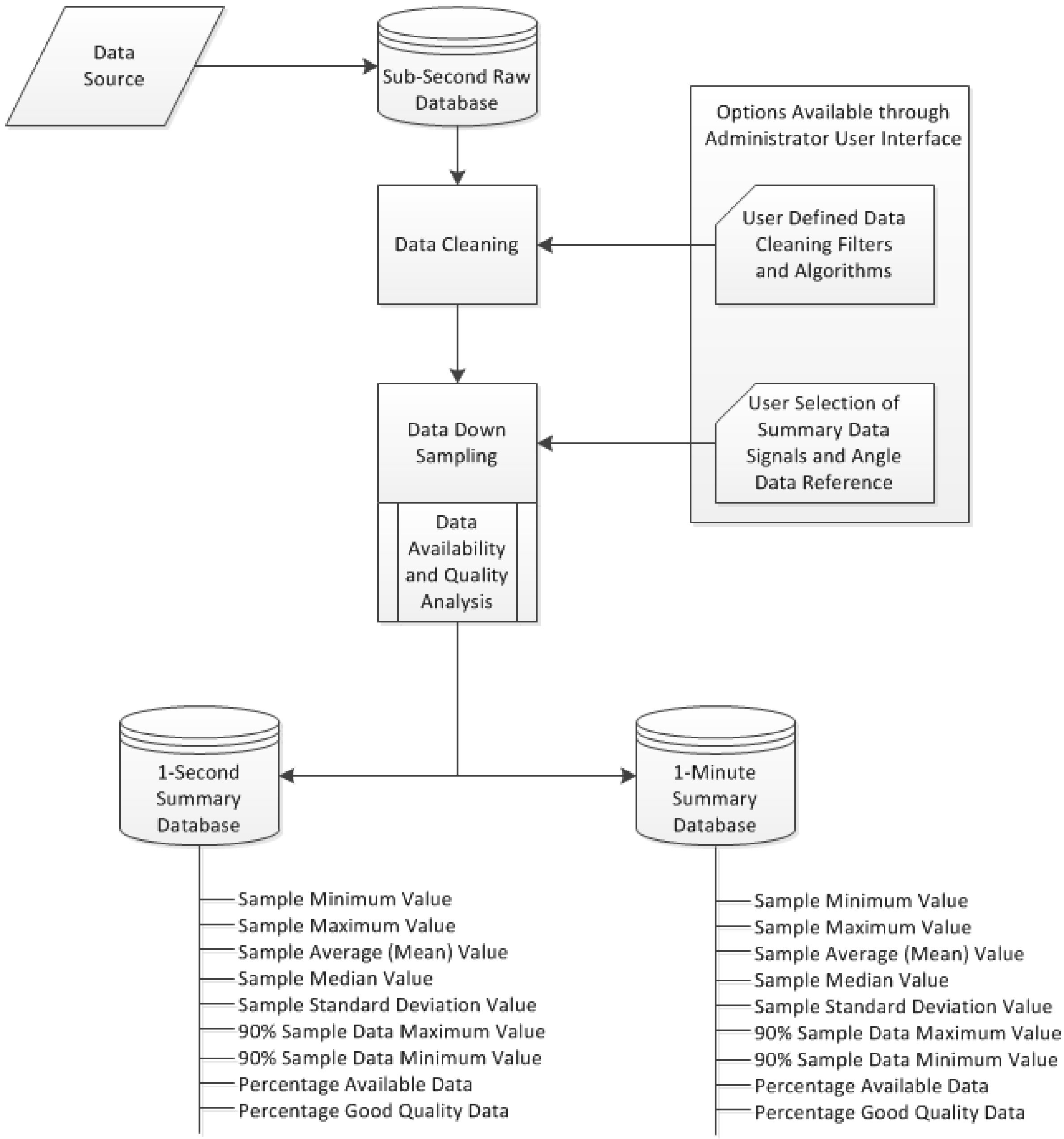


Figure 1: Statistical summary database creation flowchart

The Administrator user interface (The administrator user interface will be part of the proposed new baselining app to be integrated with the database) with options to create the summary databases is shown in the Figure 2 below. It is important to revisit this and tweak the settings as required. It is recommended to automatically add new PMUs and signals when available.

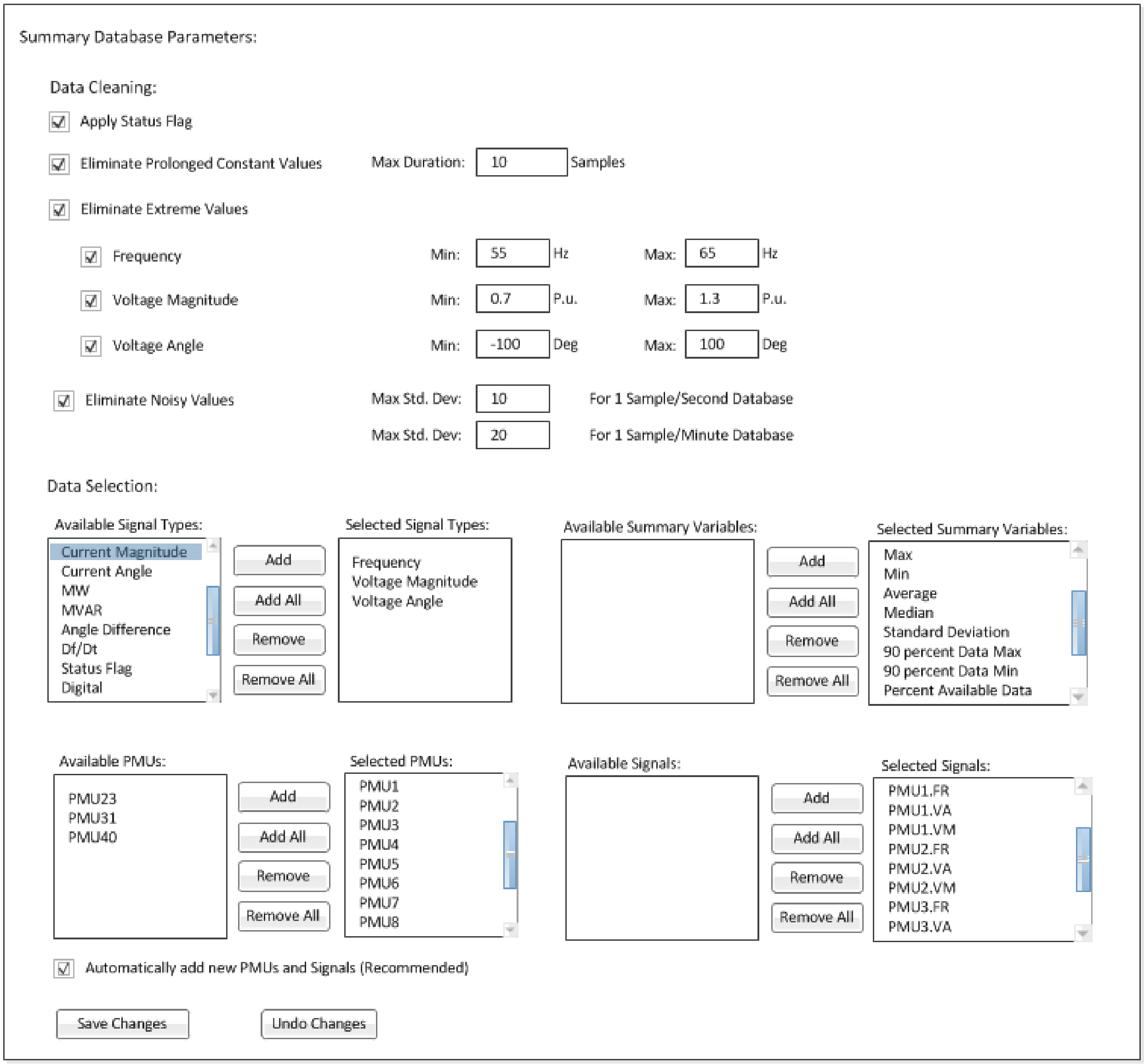


Figure 2: Administrative user interface to summary database

When starting on a brand new database, this process can be run continuously on all the available data to create the summary databases. When the process is completed, any future process is recommended to be run daily after midnight on the previous day's data.

3 Long-Term Data Analysis

Long-term data analysis can be performed on the two summary databases to extract statistical summary information. This information can either be automatically e-mailed to recipients based on a pre-defined report format or generated on-demand by the users using an interface to interact with the database variables and produce requested results. The 1-second and 1-minute summary data can also be downloaded and exported to perform custom analysis using other data analysis applications.

3.1 On-Demand Reports

An interface will be built as a windows application or a web page to be able to connect to the 1-second and 1-minute summary databases and generate charts and graphs based on the summary data variables. The interface will allow selection of Date and Time, Data Resolution, Signal Type, Signal Names, Data Summary Variable, and Chart Type. In addition, each chart type will have its own set of parameters to be selected.

3.1.1 Date and Time

By default the end date time is pre-selected to be the last hour of previous day. This can be changed to any day and hour in history which is not earlier than the earliest available data. The available date time range is displayed as a reference. The date selection will open a calendar for selecting required date and the time selection will be restricted to “Hour” selection from 0 to 23.

There will be pre-defined time range available as Last Hour, Last 24 Hours, Last 7 Days, Last 30 Days, and Last 52 Weeks. If the user wishes a custom date range selection then the custom button is selected which enables a “Start Date/Time” selection.

By default data resolution will be 1 sample per second, which will be automatically switched to 1 sample per minute for any date range greater than 7 days. This can be reverted back by user to 1 sample per second, which will result in a warning message to the user that the result will take longer time than usual. Sample interface is illustrated below.

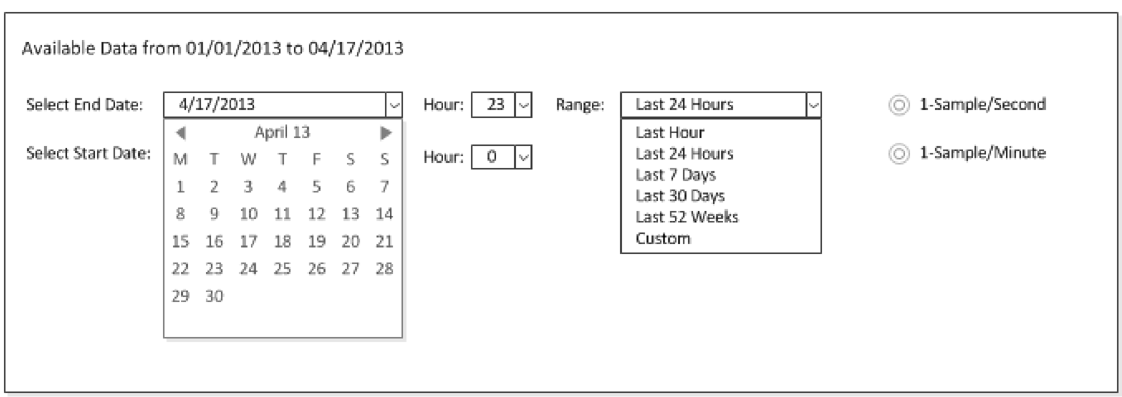


Figure 3: Date and time range selection interface

3.1.2 Signal Selection

Signal selection interface allows user to select signal types, signal names, and corresponding data summary variables to be used for creating charts. Signal types window will contain all the available signal types in the summary database. After signal type selection, the required data summary variables need to be selected from the available list:

1. Max.
2. Min.
3. Average.
4. Median.
5. Standard deviation.
6. 90 percent data max.
7. 90 percent data min.
8. Percentage available data.
9. Percentage good quality data.

Selecting the signal type and summary variables will display all the available signal names. Desired signal names need to be selected and moved to selected signals section. If voltage or current angles are selected then an angle reference selection is needed. The interface below shown in Figure 4 illustrates the interface for signal and summary variable selection.

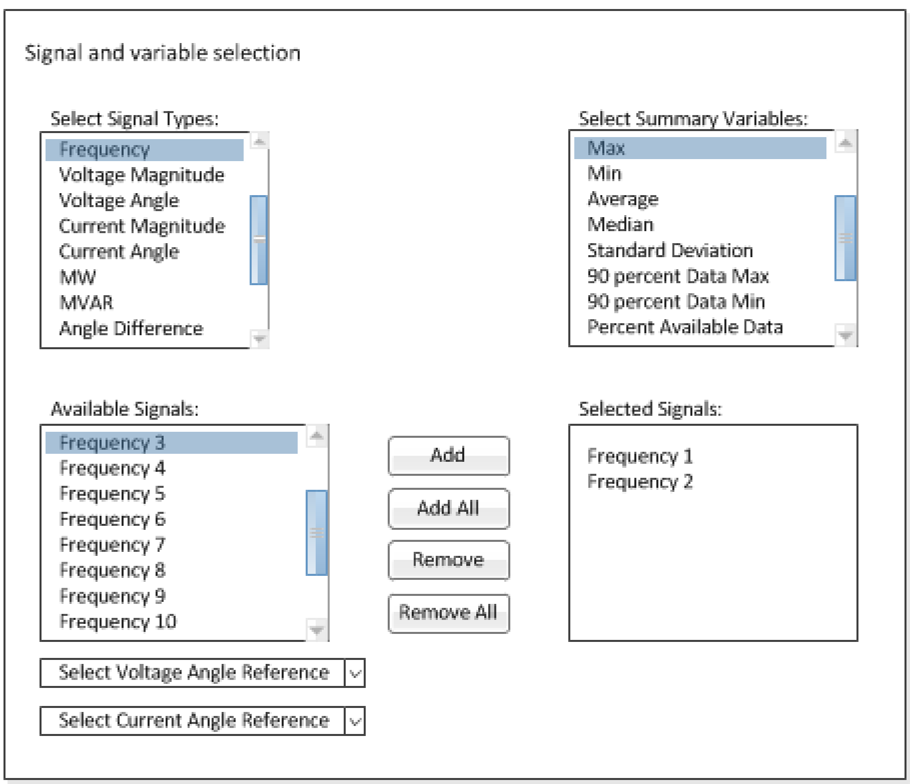


Figure 4: Signal and summary variable selection interface

3.1.3 Chart Display and Data Export

After selecting the desired signals and summary variables, there are two options available to the user to either display the result in a chart or export the data in CSV format for further analysis using other data analysis tools such as Excel or Matlab. User option of displaying data as charts needs selection of chart types and corresponding chart parameters.

3.1.3.1 Line Chart:

The default chart is the simple “Line Chart” which is automatically selected and generated when the “Display Chart” button is clicked. Line chart can be generated by “combining” all the signals of the same signal type in one chart or generating “individual” charts.

Line charts can also be plotted with periodicity groupings of Hourly, Daily, and Weekly. For example, if angle difference data for a week is plotted with daily periodicity then there will be seven line charts (for each day of the week) plotted on the same chart area. This will enable comparing data behavior of each day of the week with other days and identify baseline behavior and any unusual system behavior during different times of the day.

3.1.3.2 Time Duration Chart:

Time duration chart is generated by sorting the data and plotting as a line chart with x-axis as the percentage of data from 0 to 100. This helps in identifying the spread of data from maximum value to minimum value and also the percentage of any data range as shown below.

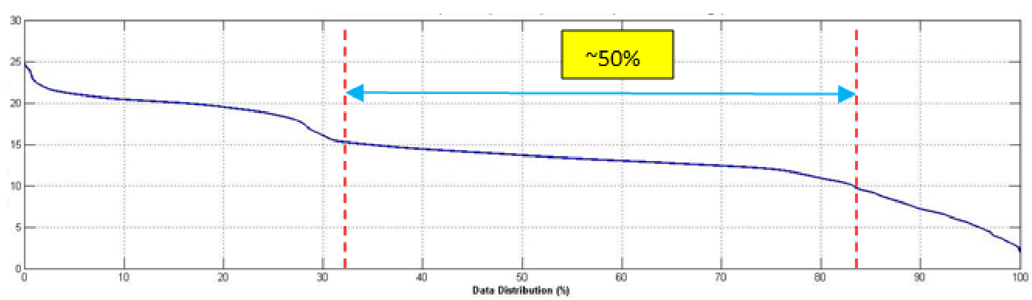


Figure 5: Sample time duration chart

3.1.3.3 Box-Whisker Chart:

Box-whisker chart is generated by first grouping the data and then plotting the box and whiskers over grouped time in the x-axis. The available groups are hourly, daily and weekly, which are available when corresponding selected time range exceeds one hour, one day and one week. Sample chart in Figure 6 explains some of the properties of the chart.

The box-whisker chart shows the data distribution (min, max, median) for each group (hourly, daily, and weekly) and its variation over the analysis duration. In addition to providing information regarding the spread of the data it also indicates missing data if any particular box-whisker is missing from the plot.

In addition to grouping, box-whisker charts can be plotted with daily periodicity (with hourly grouping) and weekly periodicity (with daily grouping). In these plots, all the data of the same hour of day (for daily periodicity) or same day of week (for weekly periodicity) are grouped together. This will provide further information on baseline behavior of any signal for any particular hour of day or day of week as desired.

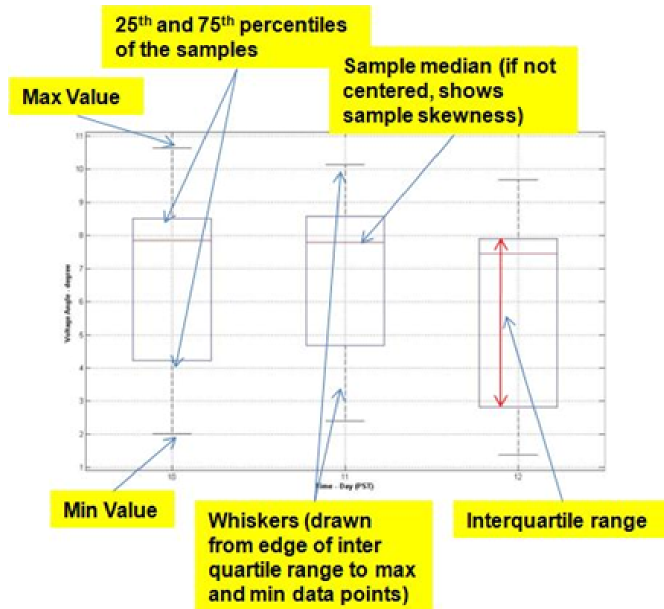


Figure 6: Sample box-whisker chart

Figure 7 illustrates the user interface for selecting chart type and available chart parameters.

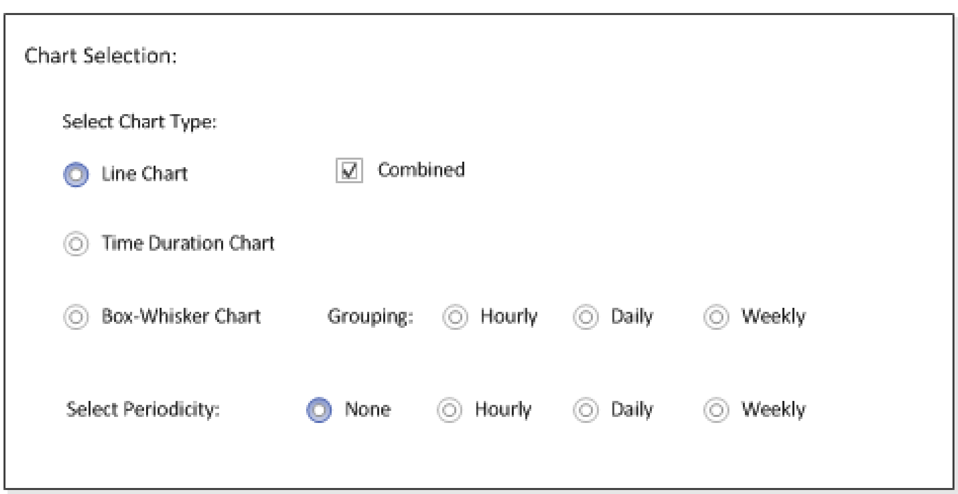


Figure 7: Chart type selection interface

The "Combined" option is only available for line charts and when checked it will generate line chart with all selected signal variables in the same chart area. Grouping is only available for box-whisker chart. Periodicity is available for all the chart types. For "Line Chart" it is enabled when "Combined" option is unchecked. For "Box-Whisker" chart when "Hourly" grouping is selected then only "Daily" periodicity is available, and when "Daily" grouping is selected then only "Weekly" periodicity is available.

3.2 Automated Daily Reports

Automated daily reports can be generated by an application which operates on the 1-second and 1-minute summary database and e-mails the results to listed recipients. This report will have summary statistics on data availability and data quality at the PMU level, daily statistical summary of the data of selected signals (user configurable) and also highlight any unusual system conditions in last 24-hours. The report contents and recipients can be configured using interface illustrated in Figure 8 below.

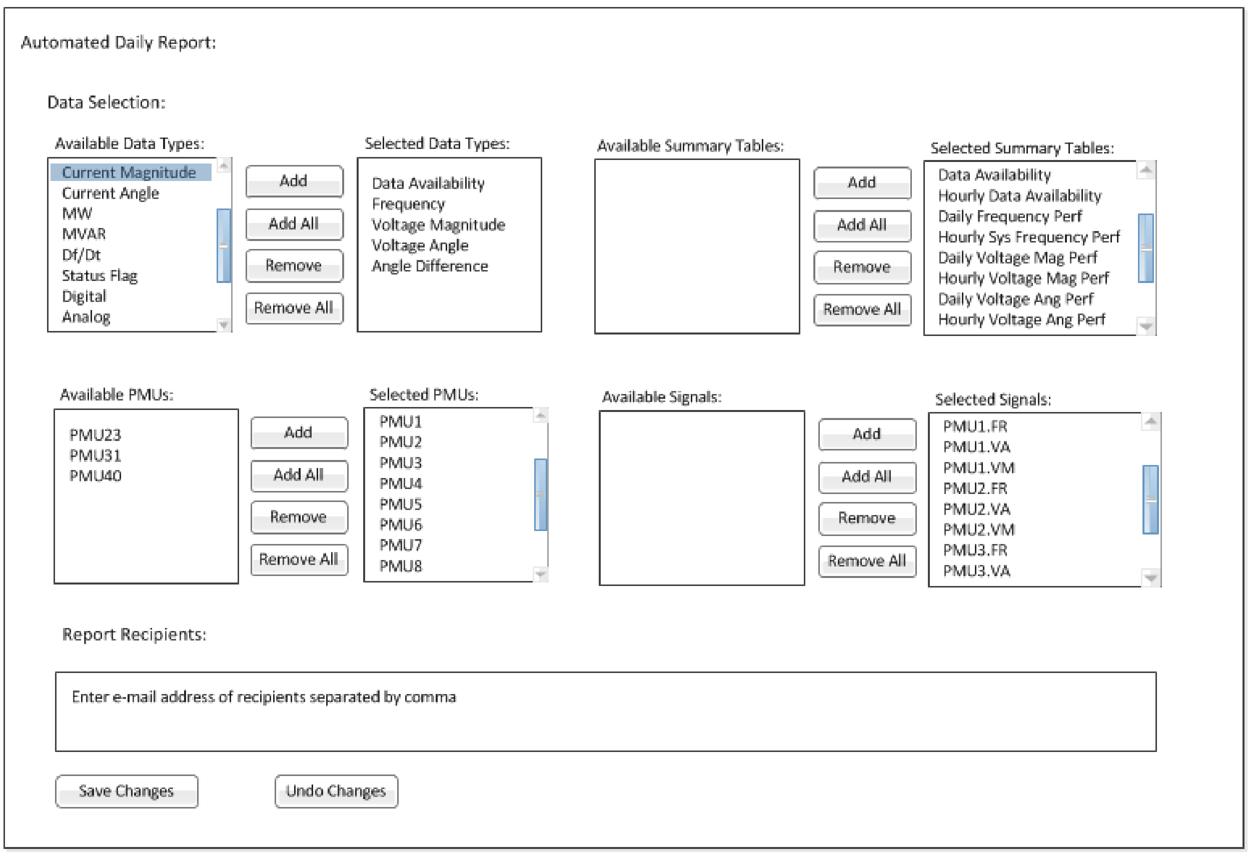


Figure 8: Daily report configuration interface

3.2.1 Data availability summary

Following sample Table 2 illustrates the summary data to be extracted and reported to highlight the severity of any data quality/availability issues:

	Last 24-Hours	Last 7-Days	Last 30-Days	Last 90-Days
PMU1	100%	99.97%	98.95%	97.25%
PMU2	60%	75%	80%	85%
PMU3	55%	48%	30%	28%
PMU4	95%	88%	NA	NA

Table 2: Data availability summary table

Each column is a rolling time window of 24-Hour, 7-days, 30-days and 90-days. The data in the sample Table 2 helps illustrate possible different types of data quality/availability issues with each PMU.

1. PMU1 has been consistently of good quality for data monitoring and analysis.
2. PMU2 historically had good data quality but has recently developed data quality problems.
3. PMU3 data quality has been consistently bad and needs attention to be fixed or removed from data monitoring and analysis purposes.
4. PMU4 has recently stated sending data in less than 30-days and has some data quality issues but overall acceptable.

Data availability hourly summary Table 3 below provides further granularity on the data quality/availability for Last 24-Hours. Each column represents hour from 0 to 23. The boxes are color-coded based on the data availability percentage values (user configurable)

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
PMU1																								
PMU2																								
PMU3																								
PMU4																								

Table 3: Data availability hourly summary table

The table provides at-a-glance information regarding the nature of problems with data availability. Following observations can be made:

1. PMU1 has overall good data quality.
2. PMU2 suffers from consistent bad data quality over the 24-hour duration.
3. PMU3 has random extreme data dropouts/ bad data quality.
4. Hours 5 and 6 have data quality issue across all the PMUs which indicate data quality issue independent of any PMU. This can be a system related issue at the receiving end and needs to be further looked at.

3.2.2 Frequency data performance

The frequency data daily performance Table 4 contains summary statistics of last day. The first row is for system frequency performance. System frequency is the average value of frequency from selected representative signals (user configurable). The frequency signals can be grouped into regions across the system to identify the location of any identified issue. The summary Table 4 includes following variables:

1. Daily Minimum: Minimum of 1-second minimum value table in last 24 hours.
2. Daily Maximum: Maximum of 1-second maximum value table in last 24 hours.
3. Daily Average: Average of 1-second average value table in last 24 hours.
4. Daily Std. Dev.: Standard Deviation of 1-second average value table in last 24 hours.
5. Max. Dev. (mHz): Maximum difference between 1-minute maximum and 1-minute minimum value of two consecutive minutes in last 24 hours. This provides information regarding any large sudden change in frequency values in last 24 hours.
   Max. Dev. = Max[abs(Max_t – Min_{t+1}),abs(Min_t – Max_{t+1})] for all minutes in last 24 hours
6. Max. Dev. 60 (mHz): Maximum difference between 1-minute maximum and 1-minute minimum value from nominal frequency in last 24 hours.
   Max. Dev. = Max[abs(Max_t – 60),abs(Min_t – 60)] for all minutes in last 24 hours

Region	Signal	Min	Max	Avg.	Std. Dev.	Max. Dev.	Max Nom Dev.
System	Sys Freq						
Region1	Freq1						
	Freq2						
	Freq3						
Region2	Freq4						

Table 4: Frequency data daily performance table

The system frequency hourly performance Table 5 provides further granularity of system frequency performance by providing at-a-glance color-coded deviation (in mHz) of 5-minute frequency average values from nominal frequency value for last 24-hours. The rows are Hours from 0 to 23. The first column is the deviation of hourly average value from nominal frequency. Columns 2 to 12 are the deviation of 5-minute average frequency values from nominal (in mHz) which are color-coded (user configurable) to identify any unusual system behavior.

	Avg	0-5	5-10	10-15	15-20	20-25	25-30	30-35	35-40	40-45	45-50	50-55	55-60
HR0	-1.5	5.5	3.2	2.6	11.0	-35.1	-30.2	1.0	2.3	5.6	7.8	6.4	2.3
HR1	-2.6	-30.9	-6.3	-5.2	-4.1	2.5	1.5	-2.3	8.9	7.5	-6.1	-5.3	8.4
HR2	-18.7	-52.3	-50.2	9.2	5.4	1.3	11.3	-9.4	-36.4	-38.5	-40.6	-32.8	8.1
HR3	3.6	2.0	-7.9	-9.4	36.5	32.8	33.2	5.7	14.0	-9.4	-11.6	-20.3	-22.6

Table 5: System frequency hourly performance table

3.2.3 Voltage magnitude performance

The voltage data daily performance table contains summary statistics of last day. The voltage signals can be grouped into regions across the system to identify the location of any identified issue. The summary table includes following variables:

1. Daily Minimum: Minimum of 1-second minimum value table in last 24 hours.
2. Daily Maximum: Maximum of 1-second maximum value table in last 24 hours.
3. Daily Average: Average of 1-second average value table in last 24 hours.
4. Daily Std. Dev.: Standard Deviation of 1-second average value table in last 24 hours.
5. Max. Dev. (kV): Maximum difference between 1-minute maximum and 1-minute minimum value of two consecutive minutes in last 24 hours. This provides information regarding any large sudden change in voltage values in last 24 hours.
   Max. Dev. = Max[abs(Max_t – Min_{t+1}),abs(Min_t – Max_{t+1})] for all minutes in last 24 hours
6. Max. Nom. Dev. (kV): Maximum difference between 1-minute maximum and 1-minute minimum value from nominal voltage in last 24 hours. Nominal kV is automatically assigned to be Base kV, which can be changed by admin during report configuration.
   Max. Dev. = Max[abs(Max_t – Nominal kV),abs(Min_t – Nominal kV)] for all minutes in last 24 hours

Region	Signal	Base kV	Min	Max	Avg.	Std. Dev.	Max. Dev.	Max Nom Dev
Region1	VM1							
	VM2							
	VM3							
Region2	VM4							

Table 6: Voltage magnitude daily performance table

Voltage magnitude hourly performance Table 7 below provides further granularity on the performance of voltage magnitude signals for Last 24-Hours. Each column represents hour from 0 to 23. The boxes are color-coded (user configurable) based on the “maximum nominal deviation” values as defined in item 6 of section 3.2.3 above.

Region	Signal	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Region 1	VM 1																								
	VM 2																								
	VM 3																								
Region 2	VM 4																								

Table 7: Voltage magnitude hourly performance table

3.2.4 Voltage angle performance

The voltage angle data daily performance Table 8 contains summary statistics of last day. The voltage angle signals can be grouped into regions across the system to identify the location of any identified issue. The voltage angle data is calculated based on a reference angle (user configurable). The reference is ideally selected to be centrally located in the system. The summary table includes following variables:

1. Daily Minimum: Minimum of 1-second minimum value table in last 24 hours.
2. Daily Maximum: Maximum of 1-second maximum value table in last 24 hours.
3. Daily Average: Average of 1-second average value table in last 24 hours.
4. Daily Std. Dev.: Standard Deviation of 1-second average value table in last 24 hours.
5. Max. Dev. (Degrees): Maximum difference between 1-minute maximum and 1-minute minimum value of two consecutive minutes in last 24 hours. This provides information regarding any large sudden change in voltage angle values in last 24 hours.
   Max. Dev. = $Max[abs(Max_t – Min_{t+1}),abs(Min_t – Max_{t+1})]$ for all minutes in last 24 hours

Region	Signal	Base kV	Min	Max	Avg.	Std. Dev.	Max. Dev.
Region1	VA1						
	VA2						
	VA3						
Region2	VA4						

Table 8: Voltage angle daily performance table

Voltage angle hourly performance Table 9 below provides further granularity on the performance of voltage angle signals for Last 24-Hours. Each column represents hour from 0 to 23. The boxes are color-coded (user configurable) based on the “maximum deviation” values as defined in item 5 of section 3.2.4 above.

Region	Signal	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Region 1	VA1																								
	VA2																								
	VA3																								
Region 2	VA4																								

Table 9: Voltage angle hourly performance table

3.2.5 Angle difference performance

The angle difference data daily performance table contains summary statistics of last day. Angle difference signals must be defined during report configuration. The summary table includes following variables:

1. Daily Minimum: Minimum of 1-second minimum value table in last 24 hours.

2. Daily Maximum: Maximum of 1-second maximum value table in last 24 hours.
3. Daily Average: Average of 1-second average value table in last 24 hours.
4. Daily Std. Dev.: Standard Deviation of 1-second average value table in last 24 hours.
5. Max. Dev. (Degrees): Maximum difference between 1-minute maximum and 1-minute minimum value of two consecutive minutes in last 24 hours. This provides information regarding any large sudden change in angle difference values in last 24 hours.
   Max. Dev. = Max[abs(Max_t – Min_{t+1}),abs(Min_t – Max_{t+1})] for all minutes in last 24 hours

Signal	Min	Max	Avg.	Std. Dev.	Max. Dev.
AD1					
AD2					
AD3					
AD4					

Table 10: Angle difference daily performance table

Angle difference hourly performance Table 11 below provides further granularity on the performance of angle difference signals for Last 24-Hours. Each column represents hour from 0 to 23. The boxes are color-coded (user configurable) based on the “maximum deviation” values as defined in item 5 of section 3.2.5 above.

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
AD1																								
AD2																								
AD3																								
AD4																								

Table 11: Angle difference hourly performance table