NON-INTERCONNECTED ISLANDS SYSTEM & MARKET OPERATOR

Project Implementation of the Athens Central Energy Control Center (ECC) and the Local ECC for the Electrical Power Systems in Rhodes

TECHNICAL AND FUNCTIONAL REQUIREMENTS

PART B:
ENERGY MANAGEMENT SYSTEM

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List of Acronyms

ACE	Area Control Error
AGC	Automatic Generation Control
ATM	Asynchronous Transfer Mode
AVC	Automatic Voltage Control
AVR	Automatic Voltage Regulation
CA	Contingency Analysis
CCM	Control Center Model
CF	Constant Frequency
CHP	Combined Heat and Power
CIM	Common Information Model
CIP	Critical Infrastructure Protection
CNI	Constant Net Interchange
CPU	Central Processing Unit
DB	DataBase
DC	Data Concentrator
DCCB	Direct Current Circuit Breaker
DCN	Digital Communication Network
DCS	Digital Control System
DER	Distributed Energy Resources
DLP	Digital Light Processing
DMZ	Demilitarized Zones
DS	Dispatch Scheduling
DTS	Dispatcher Training Simulator
DW	Data Warehouse
ED	Economic Dispatch
EMS	Energy Management System
FAT	Factory Acceptance Tests
FG	Full Graphics
FTP	File Transfer Protocol

GDF	Generation Distribution Factor
GPO	General Purpose Outlet
GPS	Global Positioning System
GUC	Generating Unit Controller
HDR	Historical Data Recording
HIS	Historical Information System
HMI	Human Machine Interface
HV	High Voltage
ICCP	Inter Control Center Protocol
IED	Intelligent Electronic Device
IHR	Incremental Heat Rate
I/O	Input/ Output
IT	Information Technology
ITS	Interchange Transaction Scheduling
LAN	Local Area Network
LED	Light Emitting Diode
LFC	Load Frequency Control
LTO	Linear Tape-Open
MMI	Man Machine Interface
MMS	Market Management System
MV	Medium Voltage
NII	Non-Interconnected Island
NII SMO	Non-Interconnected Islands System and Market Operator
NTP	Network Time Protocol
OEM	Original Equipment Manufacturer
OLTC	On-Load Tap Changers
OLTP	Online Transaction Processing
OPF	Optimal Power Flow
OS	Outage Scheduler
PAGC	Predictive Automatic Generation Control
PF	Power Flow

PI	Proportional-Integral
PIC	Plant Incremental Cost
PLC	Plant Logic Controller / Programmable Logic Controller
PMU	Phasor Measurement Unit
PSM	Power System Model
PV	Photovoltaics
P-V	Power-Voltage
RAC	Real Application Cluster
RDAS	Rolling Day-Ahead Scheduling
RDBMS	Relational Database Management System
RES	Renewable Energy Sources
RM	Reserve Monitoring
RMAN	Recovery Manager
RTD	Real-Time Dispatch
RTDB	Real-Time Database
RTU	Remote Terminal Unit
SAT	Site Acceptance Tests
SCA	Short Circuit Analysis
SCADA	Supervisory Control and Data Acquisition
SE	State Estimator
SNMP	Simple Network Management Protocol
SOE	Sequence of Events
SOL	Secure Operation Limit
SVC	Static VAr Compensator
SW	Software
TLB	Tie-Line Bias
TFD	Time-Frequency Device
TM	Tele-Measurement
TS	Tele-Signal
TSA	Transient Stability Analysis
UI	User Interface

UIC	Unit Increamental Cost
UPS	Uninterruptible Power Supply
VoIP	Voice over Internet Protocol
VPN	Virtual Private Network
VSA	Voltage Security Assessment
XML	EXtensible Markup Language

1 Introduction

The monitoring, operation and control of the NII Electrical Systems will be implemented from the Energy Control Centers (ECCs) of the NII (Rhodes in this Tender) by the use of the Energy Management System (EMS) infrastructure.

In this part of the document the minimum technical and functional EMS requirements are presented. Deviations from the minimum technical and functional EMS requirements will not be accepted.

This Part of the Technical Tender is organized as follows:

Section 2 presents the high-level architecture of the EMS.

Section 3 presents general requirements.

Section 4 lists requirements for the SCADA.

Section 5 presents the requirements for the Automatic Generation Control (AGC) application.

Section 6 lists the requirements for EMS Services and Applications, including the Power Advanced Applications.

Section 7 lists the requirements for the Historical Information System (HIS).

Section 8 presents the main requirements for the Dispatcher Training Simulator (DTS).

Section 9 lists the main charateristics for the EMS development system.

Section 10 presents the migration requirements.

Lastly, Sections 11, 12, and 13 list the specifications for Remote Terminal Units (RTUs), Display Wall, and Time-Frequency Devices (TFDs), respectively.

2 EMS Architecture

This section presents the high-level EMS architecture.

Section 2.1 describes the organization of the ECC.

Section 2.2 provides a brief description of the EMS.

Section 2.3 presents the architecture of the main EMS subsystems.

2.1 Energy Control Center Organization

The organization of the NII SMO ECCs is as follows:

- Central ECC;
- Local ECC.

2.1.1 Central ECC

The Central ECC will be spatially located in two places, the premises of HEDNO's Information, Technology and Telecommunications Department, where the core ICT and Corporate systems infrastructure will be hosted, and the premises of Islands Network Operation Department, where the operation department will be hosted. The Central ECC will basically have a monitoring role with respect to the NII system operation; hence only remote displays will be installed in the Central ECC (not actual EMS systems).

2.1.2 Local ECC

The Local ECC shall be hosted in a dedicated space at the existing premises of the Energy Control Center in Rhodes. A Main EMS shall be installed in the Local ECC, which will be backed up by a Backup System.

2.2 Description of the Energy Management System (EMS)

The Main and Backup EMS should operate as complementary systems for the NII (only one should be active at a specific point in time while the other should be in monitor status). They should be always updated with the status of the electrical system and synchronized to each other in order to be ready to change their operational status when needed.

The EMS should directly communicate with the Electrical System Infrastructure (network, customers and power plants), through a centralized data exchange infrastructure of a Data Concentrator (DC) and a Time Frequency Device (TFD). Both DC and TFD will be located in the Local ECC. The EMS is also communicating with the MMS.

The EMS should be compliant with related international standards and the ENTSO-E Region Continental Europe Synchronous Area (RGCE ex UCTE) Operational Handbook adapted where necessary to meet the NII size of the electricity network, generation capacity and special conditions.

2.3 EMS Subsystems

In this Section, the architecture of the main EMS subsystems is presented. The EMS infrastructure will be hosted in the Local ECC of Rhodes.

The EMS subsystems infrastructure is presented in the following Figure.

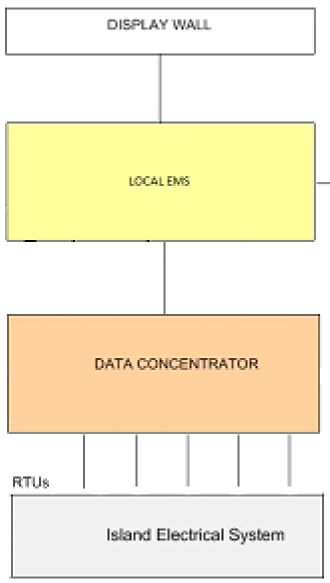

Figure 2-1. EMS Subsystems Infrastructure in the NII Local ECC

The Figure does not show the main/backup configuration, which is described below.

2.3.1 Architecture Overview

The EMS will be fully integrated with the NII IT Systems.

The EMS architecture consists of a main and backup structure located on the island. Both the Main and Backup EMS consist of fully redundant hardware and software infrastructure that hosts the Applications of the EMS; the applications are summarized as follows:

- SCADA;
- Automatic Generation Control (AGC);
- Power Advanced Applications:

- State Estimator (SE);
- Power Flow (PF);
- Optimal Power Flow (OPF);
- Contingency analysis (CA)
- Short Circuit Analysis (SCA);
- Outage Scheduler (OS);
- Automatic Voltage Control (AVC)
- Load Shedding.

- HIS;

It shall also include a Dispatcher Training Simulator (DTS).

The Main EMS is fully duplicated with the Backup EMS.

The Main and Backup EMS is directly communicating with the DC to exchange real time data and to issue controls to the NII Electrical System.

The Main and Backup EMS are always in full synchronization. The EMS is also communicating with the MMS.

2.3.2 DC - TFD

The DC or the port server infrastructure implements all data exchange between the EMS and the Electrical System of the NII through the RTUs, IEC protocols, Protocol converters, and Digital Control Systems (DCSs) installed in the assets (Substations, Powers Plants Renewable Generation).

The purpose of the TFD is to synchronize all island functions and to calculate the NII time deviation that has to be considered for correction by the AGC application.

The DC implements all data exchange between the EMS and the NII Electrical System through the RTUs, IEC protocols, Protocol converters, and Digital Control Systems (DCSs) installed in the assets (Substations, Powers Plants Renewable Generation). The DC directly communicates with the Main EMS, and with the Backup EMS, for the exchange of real time data. The DC communicates through the telecommunication network to be implemented by the contractor with the RTUs, protocol converted or DCSs which are installed in Substations, Power Stations, Wind Farms, PV and other RES.

The DC should be redundant, in active-active configuration, in order to avoid any single point of failure. The DC configuration shall allow for failure of a single DC without loss of communications to any RTU.

2.3.3 Remote Terminal Units (RTUs)

RTUs should be installed where necessary.

Within the scope of this Project the Contractor shall provide and install 7 RTUs in Rhodes.

The connection of the RTUs to the Data Concentrator (DC) should be implemented through the IEC 60870-5-101 or the 104 protocol. The Contractor will provide the appropriate equipment for the modification of a IEC60870-5-101 protocol data flow to IEC60870-5-104, where necessary Time synchronization of the new RTUs will be achieved by individual GPS receivers at the each RTU location.

2.3.4 Existing SCADA Infrastructure

Existing SCADA infrastructure shall remain operative.

2.3.5 Control Center Failure Scenarios

The EMS should be able to operate with all respective functionality under the following failure scenarios.

2.3.5.1 Main EMS Failure

In case of a Main EMS failure all functions should be transferred to the Backup EMS.

2.3.5.2 Data Concentrator (DC) Failure

The DC will be fully redundant. In case of a DC failure, all island functions will be assigned to the respective power plants that should act according to a defense plan agreed between the NII SMO and the power plants.

As this is the worst case scenario, the Contractor should provide a robust solution for the DC by considering and enhancing the design principles in order to diminish or minimize the interruption of the DC. At a minimum, the design should ensure that there will be no single point of failure.

3 EMS General Requirements

The Contractor based on the NII Code provisions, will design, implement, test and put in operation a modern EMS able to meet all requirements for the monitoring, operation and control of the autonomous NII Electricity System, in accordance with the detailed description of the Tender technical and functional requirements.

The Contractor should consider that the EMS is a critical infrastructure and the Project implementation robustness and availability requirements should be appropriate for such an infrastructure.

The Contractor should provide its latest technical solution (software, hardware and architecture) and make all necessary adaptations, configuration and customizations, to implement and put in operation the EMS.

The Contractor should also properly organize the implementation of maintenance services so as to fully comply with maintenance requirements, as presented in Part H - Maintenance Requirements of the Technical Tender Technical and Functional Requirements

This Section lists the following general requirements, with which the Contractor is obliged to comply:

- EMS Design Principles (Section 3.1);
- IT Infrastructure and Related Services (Section 3.2);
- EMS Human Machine Interface (Section 3.3).

3.1 EMS Design Principles

This Section includes the following:

- General Principles (Section 3.1.1);
- EMS Minimum Software Requirements (Section 3.1.2);
- Security Settings of Applications (Section 3.1.3);
- Software Licenses (Section 3.1.4);
- Operating Software (Section 3.1.5);
- System Level Software (Section 3.1.6);
- Time and Calendar Function (Section 3.1.7);
- Antivirus Software (Section 3.1.8);
- Firewall (Section 09);
- Backup Software (Section 3.1.10);
- Remote Administration Software (Section 3.1.11);

- Software Corrections (Section 3.1.12);
- Redundancy (Section 3.1.13).

3.1.1 General Principles

The objective of this section is to specify a set of attributes, in addition to the functional requirements, that the software architecture should possess in order to meet the business goals of the NII SMO.

In particular, the solutions offered by the Contractor should have the following features:

- **High efficiency:** Efficiency is critically important for real-time applications. The system performance should not degrade even under peak processing conditions. Typical metrics used to assess system performance are: system time responses, throughput rates, processing times, resource utilization and capacity. The Contractor should respect the system performance metrics defined in Part G- Testing, Availability and Performance of the Technical Tender Technical and Functional Requirements or any other part of the Technical Tender.
- **High availability:** High availability is a characteristic of a system that is continuously operational, without loss of service. Probably the most important mechanism to assure high availability is redundancy. The Contractor shall apply redundancy policies (active-active or passive-passive, server load balancing, failover, etc.) and practices defined in this document to achieve high availability.
- **Security:** Security refers to the degree to which a system protects information and data so that all users with access to the system do so according to their types of level and authorization. Hence, the offered systems shall be designed so as to prevent unauthorized access and to promote accountability (i.e., enable the administrator to trace actions uniquely to a particular identity a user or a different system).
- **Reliability:** Reliability refers to a system being fault tolerant and mature. The system should operate as intended even in case of a hardware or software fault.
- **Application enhancement, scalability, modularity and upgradeability:** In addition to ease of maintenance and low operating costs, the IT systems architecture must boost scalability through allowing enhancements and upgrades. This is a mandatory requirement in order to meet evolving business, technical, economical and legal requirements. The system should have a modular architecture. In other words, if a system component is modified it should have minimal impact on the other components of the system.

- **Increased agility:** The IT architecture will minimize the time required to adapt to new or modified processes or technology changes, which are extremely likely in the light of the evolving regulatory environment, as well as the aging physical / technological infrastructures.
- **Mature technology, robustness:** Building an IT architecture based on mature open systems, will enable the competitive procurement of products and services.
- **Advanced management functionality and security features:** The integration specifications will enable integrated administration of large scale deployments comprising IT systems.
- **Fostering innovation** through flexible composition of business services based on a set of underlying web services.

3.1.2 EMS Minimum Software Requirements

The software supplied should provide all required functions for EMS operation, maintenance, test and diagnostic for all supplied equipment, components and functions. This Section specifies the required general characteristics applicable to all software provided with the EMS system. It specifies the minimum requirements of the software and the software features.

The Contractor shall provide all software necessary to satisfy the EMS system functional requirements described in the respective parts of this document.

3.1.2.1 Conformance to Standards

The software provided shall comply with industry standards produced by national or international organizations, such as the IEEE, ISO or OSF. Specific standards are stated where applicable. The application programs and software servers shall use industry standard programming languages and shall run under operating systems using industry standard interfaces to the applications.

All software shall conform to coding standards. The Contractor shall establish and enforce coding standards for software.

Standard protocols shall be used to exchange information between the equipment in the substations and the SCADA facilities.

IEC60870-5-101 as minimum requirement;

IEC60870-5-104 where ever possible and supported by the communication network.

The interconnections between Control Centers as well the data exchange with other Control Centers, if applicable, should be implemented according to the following standards:

- IEC60870-6-TASE.2 (ICCP) protocol with capability of encryption of the data exchanged between the different sites of the EMS Systems and with other Control Centers of i.e., Distribution Control Centers.

- For the exchanges of historical data and other data, a File Transfer Protocol (FTP) shall be available.
- For interconnections with other NII SMO computer systems software, XML/IP, SQL, ODBC should be used.

In addition to the above, the EMS Systems shall comply with the IEC Security Standards for “Power Systems Management and associated information exchange.”

3.1.2.2 Common Information Model

For the purpose of supplying data to external systems like off-line calculations or other applications, the data shall be exportable in a CIM compliant format. CIM is defined in IEC-61970 and IEC-61968, and its purpose is to allow the exchange of information related to the configuration and status of an electrical system. Both export and import of CIM is supported. The contractor is bound to support future modifications of CIM during the maintenance period of the project and develop any adapters that implement CIM suitable to interface with HEDNO solution on Enterprise Service Bus (ESB).

3.1.2.3 Expansion

All software shall be easily expandable to accommodate the anticipated EMS system growth. The sizing and configuration of the software are to be specified by easily modified parameters contained in centralized system parameter files. All EMS system software shall be expandable beyond the initial system expansion planned and described in specification.

Bidders shall clearly identify with their bid all EMS software sizing and address limitations for future expansion beyond the specified sizing.

3.1.2.4 Modularity

All software shall be modular so as to reduce the time and complexity involved in making a change to any program.

3.1.2.5 Maintainability

The NII SMO experts, using the software services and the documentation provided with the EMS system, should be able to maintain and expand the EMS Software to a certain extend which will be agreed between HEDNO and the Contractor. Based on the aforementioned agreement, tools and documents used to develop and maintain the EMS software are expected to be delivered.

Simple changes such as addition of new signals, new reports, etc., should not require major upgrades, compilation and linking of the EMS software.

3.1.2.6 Interruptability

Software that requires long execution times to perform complex calculations or extensive data processing shall be interruptible and shall recognize and process a user request to abort the calculation or processing.

3.1.2.7 Security

The software shall provide a security mechanism for supporting at least the following requirements:

- Protection against unauthorized access and intrusion;
- Check of utilization rights;
- Check of access rights;
- Check of registration;
- Check on user- and group- passwords;
- Attack detection and prevention.

3.1.3 Security Settings of Applications

The results of the security checks shall be alarmed and documented in a detailed security protocol.

The system shall have the capabilities to disable any process/service at any time.

For interconnection between Process LAN and other networks, firewall systems shall be used.

The purpose of these firewall systems is to provide an additional layer of security (in addition to the security and access control mechanism provided by the EMS software system).

By default the firewall shall deny any network traffic from other networks destined to the EMS network. Only traffic which has been explicitly allowed in the firewall configuration shall pass the firewall.

3.1.4 Software Licenses

Contractor should provide all necessary software licenses (its own licenses as well as third party licenses) for the entire System and for the lifetime operation of the system.

3.1.5 Operating Software

It is preferable for the EMS System to utilize a UNIX or Linux operating system. UNIX or LINUX operating software will be preferred for the Main Application Functions. MS-Windows operating software could be utilized under the condition that licenses costs and maintenance per year costs are included in detail in the financial offer.

The MS-Windows operating software should be used for HMI applications because of the wide spread knowledge of the MS Windows' "look and feel".

For communication between the computers within the control center hardware configuration, standard communication protocols and procedures such as ETHERNET, TCP/IP shall be used.

3.1.6 System Level Software

The provided system-level software shall include real-time capabilities and device input/output control programs.

The Operating system software shall be based upon a standard virtual memory operating system. Upgrades shall be implemented without requiring modifications to hardware, application programs, support programs, or operating system interfaces. Upgrades shall not require the whole system to shut down.

On-line facilities shall permit adding and deleting programs from the list of periodic or scheduled programs. The scheduling of periodic programs shall be automatically corrected for manual and automatic adjustments of time.

3.1.7 Time and Calendar Function

The time of day and date shall be maintained for use by other specific software. Leap years, century rollover, and holidays shall be recognized. The handling of daylight saving shall be included. Specifically, the time of day and date and the frequency will come for the system HOPF.

3.1.8 Antivirus Software

In order to protect the EMS System from malware such as viruses, Trojans, spyware etc., all incoming traffic shall be scanned by a suitable antivirus software. The definition files of this software shall be updated automatically on a daily basis.

FirewallFirewall configuration detailed requirements are described in Part E Deliverables of the Technical and Functional Requirements – Chapter 6 Telecommunications Requirements.

3.1.9

3.1.10 Backup Software

The Backup Software shall be suitable to store images (real time) of all servers and workstations on the mass storage media (e.g., disk array) for rapid system restoration. It shall also be suitable to backup automatically the complete system on the tape drives (fully and incremental). The backup software shall be a state of the art standard software product.

3.1.11 Remote Administration Software

The Remote Administration Software shall enable the safe remote access of system administrators. The system shall provide all state of the art mechanisms to prevent any unauthorized access, such as callback, VPN, etc.

Independent from the type of access, the additional identification by an RSA secure ID shall be used.

For each remote session, a detailed log, containing all actions shall be recorded.

Bidders shall indicate with their bid type and make of the offered software product as well as the features provided.

3.1.12 Software Corrections

The Contractor should provide and install all software patches and updates and other improvements to increase the robustness, the security and functionality of the EMS system as well as to solve problems that may appear.

The Contractor should provide solutions to all discovered problems. Until the solution of the problems, the Contractor should provide temporary solutions to resolve the problem. The solution to problems should be provided, tested in the Development System and installed in the production System without additional charge.

As a general requirement, the System shall provide capability and tools for configuration, controlling and monitoring of the various redundancy stages in a way to ensure optimal availability. In addition, a scenario configuration management tool shall be included for easy determination and parameterization of configuration scenarios under different operational states and failures. In case of disturbances of the system environment, the authorized user shall be able to easily select between the pre-configured scenarios.

The EMS shall be built on the redundancy principle of no single point of failure. Specifically, all the devices, including the hardware and software infrastructure and all the critical applications shall be designed in a redundant way that shall ensure that no single point of failure can disrupt its normal operation.

3.1.13 Redundancy

3.1.13.1 Internal Redundancy

The EMS system shall provide internal redundancy. Thus the equipment EMS systems shall be realized by applying a redundant “hot standby” concept for hardware and software.

This is to ensure the taking over of functionality in case of outage of crucial components by redundant components, such as servers or communication links.

For the Data Concentrator (DC) both systems should be active.

Transition from the outaged to the redundant component must take place automatically without any hampering of the Power System operation and without any loss of information or data.

Time for transition to and taking over by the standby component are contained in the Tender G. In the end of this transition time, the active component shall have fresh and validated data and the System shall be ready to execute a control command initiated by an operator after this period.

3.1.13.2 Operator Console Redundancy

The Operator Consoles shall be redundant in such a way that each of the installed Operator Consoles shall be capable to cover the entire functionality of the SCADA/EMS System.

Each Operator Console shall be capable to use the full system redundancy, internal redundancy.

There shall be no restrictions in redundancy required by either the hardware nor the system (no single point of failure.)

The redundancy described above shall be supported by a facility for the arrangement and assignment of System areas and responsibilities to dedicated Operator Consoles and/or Operator Identifications.

3.1.13.3 System-wide Redundancy

The required redundancy as described in this Section shall be applicable system-wide to all components of the production EMS.

3.2 IT Infrastructure and Related Services

3.2.1 General

The effective operation of the EMS infrastructure and of the Control Centers depends on the hardware components that comprise it and all the related services and policies. In particular, the hardware components of the infrastructure can be classified into the following categories:

- Servers;
- Networking Equipment;
- Storage Area Networks;
- Backup systems;
- Security Equipment;
- Network Management System;
- Data Centre Infrastructure (Racks & cabling);

- All supplementary equipment needed.

Furthermore, the following policies should be prepared and provided by the contractor:

- Security Policy;
- Backup and Restore Policy;
- Disaster Recovery Policy.

3.2.2 Control Center Infrastructure

The applications of each Control Center are hosted in dedicated hardware. The applications and the infrastructure are described in detail in the respective parts of this document.

All critical infrastructure and functions should be redundant and all servers, routers etc., and power supplies should be fully redundant.

The authentication process of the EMS users shall take place at dedicated authentication servers. The central implementation of this process will allow end-users (Operators and support users) to securely access and use the applications and services through a single login credential while they are connected to the corporate network. The actions of the EMS users will be logged by the system and be accessible by the EMS administrators.

The Archiving server will be attached to a tape library based on the LTO (Linear Tape-Open technology), for backup and restoration purposes. Full backups of the Operating Systems along with the applications they host will be obtained. Backup of the Historical Information System (HIS) database will be obtained using the RMAN Oracle Recovery Manager.

Several DMZs (Demilitarized Zones) will be implemented to add layers of security to the organization's LAN. Firewalls will be used for decoupling the different zones and enhance security against intrusion and hacks.

The EMS system will be operated and maintained via Consoles (workstations) which will be at the Control Centers.

A time and frequency facility to determine the system wide coordinated time, power system time, time deviation, power system frequency, and power system frequency deviation shall be provided in each Control Centre. The reference time shall be obtained from receivers using Global Positioning System (GPS) satellite signals.

For clock synchronization of the servers with the network, Network Time Protocol (NTP) will be used. The NTP would maintain time to within tens of milliseconds. The reference point of the clock would be taken by the GPS equipment.

3.2.3 Software Requirements

The Contractor's application software as well as the third party software (operating systems, databases, utilities applications, etc.) that will be used to meet technical and functional requirements should be the latest mature version release from the Contractor and the third party vendor.

All the third party software and Engineering Tools should be provided and used according to the policy of the third part vendors. All necessary licenses should be provided.

The Contractor should use standardized internal and external interfaces (networks, protocols) and will provide all the editors and drivers, all the facilities and utilities necessary for the Power System Operation, maintenance, parameterization, test, putting into service as well as for the compilation and maintenance of documentation.

3.3 EMS Human Machine Interface

The Human-Machine-Interface (HMI) is the interface between the control system and the users / Operators. This HMI interface covers the visualization and the user interaction. The HMI is a software application the purpose of which is to present information to a user about the state of the system and to allow the user to implement and convey control instructions to the system.

This Section presents EMS HMI requirements as follows:

- General HMI Requirements (Section 3.3.1);
- User Interactions (Section 3.3.2);
- Full Graphics Displays (Section 3.3.3);
- Display Types (Section 3.3.4);
- Printing (Section 3.3.5);
- Trend Displays (Section 3.3.6);
- Operator Notes (Section 3.3.7);
- Graphic Display Editor (Section 3.3.8);
- Operator Consoles (Section 3.3.9).

3.3.1 General HMI Requirements

The HMI should be capable to intreract with each of the island's applications but also to provide global overview and summaries in different levels of detail.

The principal interface between the user and the EMS will be realized by the operator consoles. The consoles shall be implemented through workstations defined in this Section. Printing devices, display color printers and display walls shall augment and enhance the user's ability to interact with the EMS.

The fundamental interface between the Operator and the System are representations of the Power System, its surroundings and the Control System equipment presented on workstation monitors and on the Display Wall.

A complete and flexible windowing mechanism shall be provided to allow a user to keep track, independently, of several network control tasks. It shall be possible to display a picture in a window on any of the console monitors.

The HMI Subsystem of the EMS shall be able to keep Versioning of the System, ensuring that all history and changes of the respective data including displays are kept safe and accessible.

3.3.1.1 Standards

The HMI shall be compliant with the widely recognized X-Windows standard (compliant with OSF/MOTIF) or Windows standard, associated with a Graphical User Interface (GUI) designed from de facto standards, such as OSF/MOTIF. Additional HMI capabilities such as Web FG technologies should be used.

Displays shall be used to accomplish the main following tasks:

- View the state of the monitored power system;
- Monitor and control power system equipment;
- Monitor and control the system configuration.

The other HMI equipment, such as printers, loggers, hard copy devices, digital displays and projection screen shall be used to enhance the user's interaction with the power system.

Hardware requirements for various HMI subsystems are detailed in Part E Deliverables of the Technical and Functional Requirements.

3.3.1.2 Language of HMI

The HMI delivered under this Project shall be capable to support Greek and English languages.

This requirement also applies to the respective input/output devices such as keyboards, printers etc.

Interaction of operators with the system shall be both in English and Greek language; this requirement particularly applies to:

- Alarm and event lines;
- Pop-up windows texts;
- Dispatcher online help.

3.3.1.3 User Interface Design

The following general principles and features shall be included in the SCADA system user interface:

- Design for usability;
- Avoid deductive designing;
- Ensure consistent design;
- Ensure consistent performance;
- Simplify navigation;
- Use of meaningful symbols;
- Use appropriate presentation;
- Hide details;
- Use color effectively (with dynamic coloring);
- Reduce mouse movements;
- Minimize typing by the user;
- Support user preferences;
- Provide immediate feedback for actions.

The visualization possibilities shall not be restricted by limitations such as:

- Number of pictures / displays;
- Number of objects included in the pictures / displays;
- Extent of pictures / displays (height / width ratio).

The Contractor will work with HEDNO during the Detailed Design Phase of the Project to ensure consistency of signs and colors with the ones currently used and to comply with the migration needs of HEDNO.

3.3.1.4 Window Features

Each window shall have the features described below. The Contractor's standard features and alternative approaches may be considered provided the functional requirements of the Specification are fully met.

Multi-Window Technique

Each screen shall support multiple windows. It shall be possible to use each window independently. Several windows shall be viewable on the screen at the same time. At a given time, only one window shall be active. All operator actions shall be performed in the active window, such as display call-up, panning and zooming, dialogue interactions. The active window shall be easily recognizable by an indicator such as the color of the window border.

Window Heading, Time and Date

Each window shall include a heading at the top of the display consisting of a title showing the unabbreviated name of the window. On multi-page windows, a full page numbering description such as PAGE n of m shall be provided.

Updated time and date values shall be displayed on each console screen. These time and date values shall only appear once on a screen. Representation and resolution of time values shall be unique and time synchronous with those shown on the Large Scale Displays supplied by Time and Frequency Facilities.

Window Navigation Aid

When a window that is larger than the screen is being viewed, a navigation window shall appear with the display. In this window, an indicator shall show the position in an overall network representation of the window currently in use. Movement, using the pointing device, of this indicator in the navigation window shall cause a corresponding change in the contents of the window currently in use.

It shall be possible to iconify windows. The operations of resizing, moving and iconifying windows shall be done with cursor and minimum number of keystrokes.

Window Scratch Pad

A means for the user to enter messages related to a window shall be provided. The messages or an indication of appended messages shall be displayed each time the window is called. The scratch pad shall be callable using a cursor target.

Help Displays

Every Window shall have an associated help display. The software engineer shall be able to modify and create help displays.

Shortcut Keys

The user shall be able to define and assign Shortcut Keys to specific actions.

User Guidance Message Area

A means for presenting system-generated user guidance messages on a window shall be provided.

User Specific Settings Saving

Specific settings or profiles chosen by any operator individually (e.g. arrangement of windows, extent and contents of windows etc.) shall be possible to be saved and altered by the operator. The settings shall be applicable after renewed log-in of the corresponding operator.

3.3.1.5 User Operation General Features

The operator communicates with the control system by means of the dialog system.

Differentiation is to be made between:

- Selection and control of HMI objects, e.g., types of representation or lists;
- Selection and control of technological objects, e.g., entire switching stations, lines, bays, equipment, etc.;
- Updating or replacement of values and statuses.

The mouse shall be used exclusively for all operator inputs and dialogs. All common interaction opportunities with the mouse should be feasible.

- drag & drop functions;
- snap functions;
- Zoom functions;
- scroll functions (with scroll wheel).

A complete and flexible windowing mechanism shall be provided to allow a user to keep track, independently, of several network control tasks. It shall be possible to display a picture in a window on any of the console monitors. It shall also be possible, through the windowing mechanism, for a user to access applications external to the network control system.

The operator in the case of a problem in a specific area of the power system requires a feature in order to help him focus quickly on this specific problem. The operator needs to get data from multiple sources in a very short time, but with the minimum navigation effort.

Appropriate tools shall be provided to help operators in the navigation issues through the multiple sources of data in short time, and at the same time help him not to lose context among the different source of information.

The following features shall be included in the EMS user interface. Alternatives may be offered but the alternatives must be functionally equivalent to the features specified.

User Guidance / On-line Help

The EMS shall respond to all user input actions indicating whether the action was accepted, was not accepted, or is pending. For multi-step procedures, the EMS shall provide feedback at each step. Indications such as text messages, color changes, and blinking shall provide this feedback.

A means shall be provided for displaying user guidance messages. User guidance messages shall be unabbreviated text and shall not require the use of a reference document for interpretation.

A context sensitive on-line help facility shall be provided to assist operators in the operation of the system.

As a minimum, on-line help shall be provided by selecting:

- Help from the window menu bar;

- Help button in a dialog box;
- Topics from a help window menu.

The on-line help shall enable the user to search a topic by providing the search engine keywords. The user shall also have the ability to refine search.

The help menu shall present a list of topics available for reference.

The topics shall be listed alphabetically and refer to areas in the User's Manual.

The ability to scroll through the topic's explanatory text shall be supported. The help button in a dialog box shall present the text of the Operating Manual where use of the dialog box is explained.

The user shall be able to scroll through this text.

The associated windows shall be retrieved for review by clicking on the icon and selecting restore or by double clicking directly on the icon.

Display Selection

Rapid, convenient, and reliable selection of displays shall be provided.

A function shall be available to search an element e.g., substation, OHV lines etc. The system shall guide the operator to the place where the respective element can be selected for display of this element on the screen, sized in the respective layer.

Panning, Zooming and De-cluttering

Network displays shall be variable sized pictures with pan and zoom functions and shall be used to represent and display the corresponding Island's Network network as a two-dimensional map.

Zoom refers to the action where part of a selected graphical display is diminished or enlarged.

Panning refers to the selection of a certain area of the display without changing the zoom level.

A dynamic network coloring function shall be provided with color and other picture attributes used to indicate the electrical connectivity and status of individual items of plant and network elements.

It shall be possible to structure network pictures into several layers, each of which, for example, will contain the network information to be displayed at a specified level of detail. For use with the zooming function, a magnification range shall be associated with each layer, and this shall cause decluttering changes in the displayed information as the zooming function crosses range boundaries.

The Contractor shall configure and apply the maximum number of layers that will be agreed in the Detailed Design.

For the display of variable value information in network pictures, HMI functions shall be provided to allow a user to alternate between the displays of various – at minimum two – sets of values at the same position in the picture.

Cursor Position Selection

Multiple methods of rapid and convenient cursor positioning shall be provided including a cursor positioning device (pointing device), forward and backward tab keys and normal cursor control keys. Cursor positioning techniques shall be consistent for all displays. To position the cursor on any screen, the EMS shall provide a means for moving the cursor from screen to screen on multiple screen consoles. Acceptable methods for moving the cursor to another screen include movement of the cursor positioning device, selection of a cursor target and functions keys. The keyboard shall be assigned automatically to the screen containing the cursor.

It shall be possible for the operators to adjust the acceleration, the speed of the cursor as well as the double click speed.

Data Entry

Data entry fields shall be defined when a display is generated. All enterable data fields shall be highlighted. The user shall be able to enter the desired value anywhere within the data entry field. The user will initiate data entry by selecting the value to be changed on a display. The value shall be highlighted and the value's identification shall be displayed.

Manual data entry of a calculated parameter shall cause termination of the calculation and the value shall be marked as manually entered on all displays and reports. Full page data entry shall be provided which allows users to make multiple data entries before requesting that the data be entered into the database. All valid entries shall be accepted unless an EMS function requires all entries to be correct.

In that case, the user shall not be required to re-enter valid entries. When the user successfully completes a data entry, the previous and new value shall be reported to the user.

For enhanced security along with critical manual entries, the user shall have the ability to receive confirmation dialogues from the system. The Confirmation dialogues feature shall be selectable (enable/disable) by the operator.

It shall be possible to prohibit manual data entry by the operator for specific values such as telemetering data.

In the case that the operator decides telemetering data to be manually overwritten, he has to follow a two step procedure. First he characterizes this telemetering data as “NOT In Service”. Then he can enter manually a new value for this data. The operator decides to overwrite a telemetering data.

User Entry Error Checking

The EMS shall verify user entries and detect errors. Invalid entries such as entering an invalid point identifier or an illogical sequence of actions shall be detected and reported to the user. Invalid entries shall be highlighted. The error message shall not require the use of a reference document for interpretation. The user shall not be required to repeat steps that were correctly executed prior to the erroneous action.

User inputs shall be subject to a time limit. If the user fails to respond within the required time, the EMS shall cancel the action in progress and report the cancellation. If the user performs any action other than that required, the original action shall be aborted and an error message shall appear on the screen. Time limits shall be adjustable. It shall be possible to inhibit a time limit for functions that have long data input sequences.

Modifications to the system model should be subject to twofold verification: on the client, upon data entry, and the server, before making the model online.

Element Highlighting

Highlighting techniques shall direct the user to critical data on displays. The display attributes of color, color intensity, blinking, line texture, and appended symbols shall be provided. These attributes shall be used to highlight alarms, data entry locations, data quality, error conditions and to convey power system information such as breaker states, limit violations, and line voltages to the user.

Quality Code and Tag Indication

All displays and reports containing telemetered analog values, device status, or calculated values shall have a data quality indicator associated with each data field. A separate indicator shall identify the devices which have supervisory control inhibit tags.

With different data quality indicators it shall be possible to identify the exact state of the data (e.g. NOT In Service by the dispatcher of specific site, manually overwritten by local site, manually overwritten by remote site, bad communication quality, etc.)

Furthermore the source of data origin shall be indicated, such as SCADA value, AGC Value, State Estimator value etc.

3.3.2 User Interactions

3.3.2.1 General User Interactions

Displays shall be used by the user to interact with the system. For this purpose, displays shall contain elements which can be selected to perform two types of actions:

Selection for specific action

This selection shall be performed by placing the pointer on the object and pressing a functional key (F-Key) or mouse button. The specific action shall be executed as soon as the object is selected. This method shall be used, for example, to call up a pop-up menu associated to a device, to request an action for the selected device (remote control, tagging, etc..) or to execute a specific program (state estimation, etc.) associated to a poke-point.

Selection for data entry operations

The data entry operations are described below. This type of selection shall concern fields and objects in database.

The following selection techniques shall be provided:

- Selecting individual items: By placing the pointer on the item and pressing a functional key or mouse button ;
- Selecting a group of items;
- Selecting all items in a window: By setting the window active and pressing a functional key or mouse button.

In addition of the selection operations, two more basic functions used for data entry operations shall be provided:

- Marking a location in a display used for insert and copy operations;
- Cancelling the selection of items before a data entry operation is performed.

3.3.2.2 Specific User Interactions

The following actions shall be available to the operator through the user interface. Whether the operator shall use display poke points, function keys or others will be subject of detail engineering phase. But in any case it shall be possible to restrict access to these actions. This shall be done by using the permissions that the operator has with respect to the data he wants to operate.

Supervisory Control Procedure

The operator shall be provided with interactive procedures for performing supervisory control. Cursor targets menu items or function keys to be pointed on with the pointing device shall be provided for control functions appropriate to the device selected.

The operator will initiate a supervisory control sequence by selecting the device to be controlled on a display. The selected device shall be highlighted and the device's identification as well as its actual state shall be highlighted as well.

The EMS shall validate whether the operator is authorized to perform control actions (including checks on control areas and areas of responsibilities etc.) and whether the selected device is controllable. A user guidance message shall inform the operator of the reason why any attempted control action is rejected.

For a device that passes the control validation, the operator will select the desired supervisory control action. Selection of the supervisory control action shall be acknowledged by a message stating the device identification and supervisory control action selected.

If the operator selects a control action which is not permissible for the selected device or the control action is violating interlocking rules, the action shall not be allowed and a user guidance message shall be presented to the operator.

After verifying that both, the correct device and control action have been selected, the operator shall select and execute operation.

The EMS shall execute the supervisory control, provide appropriate feedback to indicate the initiation, the success or failure of the control action, and record the results of the control action. All event messages shall be time tagged with the real time and shall be recorded in a log file to be easily accessed by the operator.

If the device fails to respond to the control action, the control sequence shall be cancelled by the EMS. An event message shall be displayed and recorded.

Operator entries shall be verified by the EMS. Invalid entries, such as an invalid item number or an illogical control action, shall be detected and reported to the operator. If the operator performs any action other than the one allowed or expected, the control sequence shall return to the last successful step and a user guidance message shall appear directing the operator to request a different action.

The operator shall be able to cancel the supervisory control action any time before initiating the execute step. The operator shall be able to end a control sequence by selecting cancel or requesting a different display. These actions shall cause the process to be terminated and the state of the selected device shall remain unchanged.

Set Point Procedure

The typical operator set point procedure shall involve selecting a point to be controlled, entering the expected value for the set point control, performing of validity check by the system to check on permissible limits and actually issuing the control command. The operator shall be able to cancel the sequence at any step before issuing the execution command.

Alarm Acknowledgement

Alarms that require operator acknowledgement can be acknowledged from any display showing the source data base object. Individual and multiple objects as well as whole page display acknowledgements shall be available through a single user's action.

Regarding alarm occurrences, the operator shall have the ability to obtain detailed info regarding the alarm. The operator shall have the option to ask from the Network Overview Display to navigate him directly to the source of the alarm.

Measurement in Service

It shall be possible to remove/restore from service, an entire substation, an RTU or an individual data base object.

Manual measurement entries shall require that the point be removed from service. A measurement that is not in service shall continue to be scanned, converted to engineering units and stored with its data quality in the data base.

Operator Limit Entry

Individual limit values shall be enterable on-line by the operator (i.e., manual thresholds). The entered value shall be checked for validity. When a new limit value is entered, the associated analog value shall be checked for any transition into or out of the violated state with respect to the new limit value.

Operator Manual Entry

Individual digital status points and analog values shall be enterable from any display that shows the values. The manual value shall be checked for validity. The value shall not be accepted if it is considered an illegal state for a digital status point or if it is unreasonable for an analog value. When the new value is entered, the digital status or analog value shall be checked for any transitions into or out of a violated state because of the new value.

Tag Placement or Removal

The operator shall be able to place, remove or modify tags on the devices of the power system from any display showing the device. The dialogue shall allow the operator to choose among all the tag types available in the system.

Device Status Entry

Displays shall show the state of power system devices whose status is non-telemetered or that have been removed from scan. To change the status indication of these devices, the operator will follow the procedure for data entry. The EMS database shall retain the manually-entered status of these devices. Devices which are not telemetered or have been removed from scan shall be indicated by special symbols and/or unique colors.

3.3.3 Full Graphics Displays

3.3.3.1 Display Rules

Single Line Diagrams and Tabular Displays

For each tele-measurement (TM) and tele-signal (TS) appearing on single line diagrams and related tabular displays, the following information shall be indicated using adequate colors and symbols:

- Validity;
- Manual invalidation;
- Automatic invalidation with associated origin (e.g. data acquisition system);

- Manual / automatic replacement value.

In particular, automatically invalidated TMs having a manual replacement value shall be distinguished from manually invalidated TMs having a manual replacement value.

It shall be possible to block/de block the state estimator output from updating certain workstations by automatic overwriting the measured values.

When the replacement values are estimated values, they shall be renewed as soon as and each time that the state estimation shall be processed.

When a TM is invalid without a replacement value, the corresponding value display shall be replaced by an asterisk (*), a colored information or another symbol.

When a TM overshoots a threshold, the value shall blink until the acknowledgement of the corresponding alarm.

Calculated values shall be distinguished from telemetered values.

Display of Alarms

Alarm occurrence, such as switching device change of state, no voltage on busbar, threshold overshoot, shall lead to the blinking of related information on images as long as the operator has not acknowledged the corresponding alarm.

Alarm markers (i.e. display poke points) associated to each priority level shall be shown on a particular window (e.g. basic signaling window). A special color associated to each alarm priority level shall be defined for the different alarm markers and associated alarm list messages. It shall be possible to access the alarm lists by clicking on the respective alarm marker.

Display of Alarm and Event Messages in Lists

The most recent alarm / event message shall appear on the first relevant list page which is displayed by default and successive messages shall be written underneath one another.

Some information may disappear automatically at the end of the corresponding event (to be defined at the data base configuration).

All alarm appearance and disappearance shall be displayed in the chronological event list.

For most of the alarms, alarm messages shall disappear from all alarm lists after acknowledgement of the disappearance of the associated abnormal condition (to be defined at the data base configuration).

3.3.3.2 Display Navigation

The operator shall be able to move quickly and easily between different displays, using poke-points or menus. Navigation shall be simple and self-guiding for the inexperienced user and powerful (productive and efficient) for the professional expert user.

The HMI system shall support the following navigation mechanisms:

- **Display Directories**

  Hierarchical directories of displays shall be available to the operator in order to allow navigation in one of two following ways:

  - Using a list of tasks: with this approach, the user only needs to know which system function he wants to perform and does not need to know the name of the desired display;
  - Using a list of displays: in case the user knows the name of the display he wants to look at.

- **Menu Bars**

  It shall be possible to associate a menu bar to a display. The menu bar shall be located on top of this display, and be composed of various menu items. Upon selection, each menu bar item shall give access to a pull-down menu.

Pull-down Menus

These menus shall consist of a list of items which either invoke sub-menus or commands.

Pop-up Menus

These menus shall appear at the cursor location where they are defined in the display.

Pop-up Windows

Pop-up windows shall be separate windows, which are temporarily presented to the operator, as a means to enter data, send commands and/or provide additional information.

The pop-up window shall remain until the operator has entered respective data, or until he closes the pop-up window.

Poke-points

It shall be possible to predefine areas that are sensitive to the cursor location in conjunction with either mouse clicks or keystrokes. Resulting action can be call-up of a new display or execution of a specific function.

Paging

Tabular displays shall support multi-page displays. Use of buttons (page up /page down) or pull-down menus shall allow rapid positioning to a specific page. The window title bar shall indicate the current and total page number of the display.

Finding Specific Locations in Displays

A text entry field accompanied by a dedicated button shall be available to specify the name of an access key (such as substation name) to allow rapid positioning to the corresponding page number of a large tabular display, or to the specific location (such as a substation) in a local map diplay.

Previous Display Capability

The HMI system shall retain at least the two previously viewed displays for each window, not taking into account the paging sequence. A recall function shall cause these displays to be recalled at the previous level of zoom and decluttering.

Rubber Band Selection Capability:

It shall be possible, from an overview window, to define (with a rubber band rectangle) an area which will be used as a navigator window.

3.3.3.3 Display Layers

It shall be possible to define multiple layers in e.g., a single-line diagram.

The layering feature shall be useful for hiding data that needs not to be permanently shown, such as Ampere and MVA calculated values.

It shall be possible to dynamically set or reset each layer visibility attribute.

3.3.3.4 Panning

The operator shall have the ability to smoothly navigate around a very large display by:

- Using scroll bars;
- Using a mechanism based on the cursor location in the display.

Using Scroll Bars

Scroll bars shall be used to position horizontally or vertically within any large display.

Scroll bars, applied to any window, shall allow scrolling in one direction as follows:

- With small incremental steps;
- With large incremental steps, and
- By grabbing the scroll bar element and position it directly to desired location.

Cursor-driven Panning

Single step panning and continuous panning are required.

Continuous panning shall perform a move in a series of small steps, in the requested direction, until stopped by the operator. The speed at which panning is performed shall be proportional to the distance separating the mouse cursor from the centre of the window. It shall be possible to define the panning step on a console basis.

During a continuous panning operation, the display refresh should be kept active.

3.3.3.5 Zooming

The Contractor should configure and apply the ability to zoom in/out on displays. Generally, three different types of zoom in/out facility are available:

- Predefined zoom level;
- Single step zoom;
- Rubber-band zoom.

Predefined Zoom Level

This procedure shall allow the user to select a predefined zoom level from a menu.

Single Step Zoom

This procedure shall change the size of the display by applying a zoom factor.

Rubber-band Zoom

The rubber-band procedure shall allow magnification of a selected area in the display.

3.3.4 Display Types

3.3.4.1 General

The visualization concept for the EMS comprises of world map displays as well as fixed displays.

Different types of displays shall be realized and provided by the System. For this reason the structure of displays shall be hierarchically organized, giving detail information to the operator at the lower levels of displays, but consolidating the information at the higher levels of displays.

The structure of displays outlined in the following sections shall be understood as a recommendation for an approach on display hierarchy, which shall be discussed during the Detailed Design Phase.

3.3.4.2 Displays for Network Overview Level

The main functional requirements for this level of displays is the Dynamic representation of the network topological state with automatic coloring according to the status of the switching devices and network (on – off, voltage levels, etc.).

Displays should support:

- Customizable filters for selection / suppression of element types to be displayed;
- Poke points for selection of network detail displays and substation displays.

3.3.4.3 Displays for Network Detail Level

Displays for Network Detail Level will be designed for pre-defined areas of the network, but can also be selected by infinitely variable zooming.

The functional requirements for this level of displays are:

- Selection of Network Detail Level by clicking a poke point in either Disturbance Level, Network Overview Level or Substation Level displays;
- Selectable fade in of telemetered, estimated or calculated currents, voltages, loadflows and MW / MVAr values with indication of limit violations;
- Display of all Substations with full names;
- No consolidated but single device switching states and network coloring;
- Poke points for transition to neighboring Network Detail Level displays;
- Possibility for initiation of Control Commands e.g., in the form of a list of possible actions, whereof the operator can select specific permissible actions by using push buttons, etc.;
- Measurements including indication of limit violations.

3.3.4.4 Displays for Substation Level

Displays for Substation Level will be designed for all Substations or other parts of the equipment, including power stations, which require overview or are remotely controlled.

The functional requirements for this level of displays are:

- Single device switching states and network coloring;
- Set and removal of all respective tagging information;
- Display of telemetered, simulated or calculated currents, voltages and MW / MVAr values with indication of limit violations;
- Display of all feeders, sections, busbars with full names in clear text;
- Display of substation related alarms and events;
- Poke points for transition to neighboring Substation Level displays;
- Menu for initiation of Control Commands.

3.3.4.5 Displays for Disturbance Overview Level

The functional requirements for this level of displays are:

- View of Group Alarms of network equipment;
- View of changed switching states (e.g. state changes without command);
- View of alarms on deviation from normal switching conditions;
- View of system security violations.

3.3.4.6 Other displays

In addition to the aforementioned displays, the Contractor shall include the following displays:

- Menu directory display (Master display);
- SCADA system directory display;
- Network system directory display;
- Generation system directory display;
- Substation directory display;
- Summary displays for alarms / events;
- Summary displays for off-normal status;
- Summary displays tagged data;
- Summary displays manual entry;
- Summary displays alarm inhibit;
- Summary displays limit override;
- User access assignment display;
- System configuration monitoring and control displays;
- State of Telecontrol systems displays;
- State of Telecommunication systems displays;
- Communication statistics displays;
- Report review and editing displays;
- Application program displays;
- Notes display;
- System dialogue display;
- Help displays.

Every display shall have a prominent cursor target so the user can select to request the associated Help Display. Authorized HMI users should have the ability to modify and create Help displays.

3.3.4.7 Databases Population, Display and Report Generation

The Contractor shall provide all necessary equipment and work for the:

- Population of all necessary data bases;
- Generation of all necessary displays;
- Generation of all necessary reports.

The displays and reports to be created under this Project shall satisfy the requirements as specified in the above sections.

Necessary displays and reports, that have to be developed by the Contractor comprise, but will not be limited to:

- Island's Network System Overview Displays as world maps;
- Substation / Power Station Overview Displays as world maps;
- Island's Network Circuit and Inter-bus Transformer One-Line Diagrams;
- Substation Single-Line Diagrams;
- Substation Tabular Displays (each of the substation single line diagrams should have at least 6 tabular displays such as analog list, status list, alarms of the substation, control list, tag list, station summaries including inhibited, not in service analog and digital summaries);
- EMS Overviews showing configuration and control displays;
- Telecommunication equipment overviews showing configuration and control displays;
- Overview Alarm Matrixes;
- Summary displays;
- Miscellaneous displays;
- AGC schemes;
- Load flow schemes;
- Diisplays Power Flow and Optimal Power Flow;
- State Estimator's displays;
- Display for DS;
- Daily Report diplays per island and overall:
  - Daily Gross Generation report per Unit and per type (oil, wind, solar);
  - Daily Voltage report by selected busbars;
  - Daily Reserves report;
  - Graphical dailly, weekly and monthly reports load availiability.
- Other schemes for visualization of the EMS functions per Island and overall:
  - Gross Generation Overview;
  - Voltage Overview;
  - Overall Production and Generation per island;
  - VAR Generation Overviews;

- Displays for the RES;
- Displays with meteorogical measurements collected by renewables substations;
- Real Time Dispatch (RTD) related displays for monitoring of the real time market data residing in the EMS database;
- Displays of Load and RES Forecast curves;
- Other attached displays.

The Gross Generation Overview is an important display for the NII System Operation. In this display histograms present the actual production of units per generation type. Additional information is the capacity of the units, the status of the telemetered values, the market set points, the status and mode for each unit, the ACE, the regulation reserves, the total load, the frequency of the control island, the aggregated production per generation type, the total generation, the AGC status and mode, the last time that it has run, the RTD status.

Displays must be capable to present information from different databases of the EMS.

3.3.4.8 Display/Report Review, Approval, and Generation Responsibility

The Contractor shall be fully responsible for the population of the databases, generation of displays and reports, the testing and the putting in service thereof.

The NII Engineers shall have the right to review the format and content of all displays supplied by the Contractor. In addition, the NII Engineers shall have the approval rights for the displays developed by the Contractor.

During the development of the databases population and display/report generation performed by the Contractor, the NII SMO personnel shall be trained in these tasks on the new system, in order to be able to manage the maintenance of the system after implementation.

Thus, a development system of the EMS, as specified in Section 9, shall be delivered at an early stage of the Project for training, data base population and display/report generation.

3.3.5 Printing

The HMI shall provide printing capability on operator’s request for at least:

- Hardcopy of the entire screen;
- Hardcopy of any displays within a window;
- Printouts of any tabular or lists.

The printed display shall reflect the presentation shown on the screen at the time of the capture, provided that the used printer is a color printer.

If a printer is not a color printer, it shall be possible to print out color prints in different shades of black.

It shall be possible to request a hardcopy of a display not currently viewed in a window in order to print the entire display.

In addition, the printing facilities shall provide the following capabilities:

- Print to files;
- Data export in ASCII format.

As a general requirement, all print facilities shall consequently apply the WYSIWYG principle, i.e., the screen shall look exactly as the final document is, when it is printed out.

The HMI shall support page sensitive printing, with user selectable pages for all printing functions.

Hard copy requests shall be possible to be buffered in print queues, to be printed out as soon as the associated print unit is available.

Since the content of the displays and reports will consist of Greek language and English language or a mixture of both, printers shall include the necessary tools and the necessary fonts.

3.3.6 Trend Displays

The HMI shall provide a trend display facility to the operator for selecting data from the databases and send them to Workstation for graphical presentation.

It shall be possible to display trends for the following data:

- Real - time data collected from data bases; this type of data shall be sent to the display device as it is sampled;
- Stored data read from a file and sent to the display device;
- Dispatcher training simulator data.

It shall be possible to overlay real time, archived and forecast data trends simultaneously for comparison purposes. For instance, the operators shall be able to compare the load flow of past days with the one of the present day and with load flows based on forecasts.

For objects such as transformers, feeders, it shall be possible to open a trend window, showing the relevant current and historical analog values as trend.

It shall be possible to export the trend window itself in graphical formats, such as .png, .gif, .jpeg, .svg etc.

The user shall be able to select the indicated chart type, such as line chart, bar chart, pie chart etc.

The real time data requested for trending shall be selected by the operator from full graphic displays. Any numeric or Boolean data from any data base may be selected for trending. Once selected for trending and assigned to a specific display device, the data shall be sampled from the relevant data base and sent to the display device (workstation).

The sample rate and the display device shall be defined, on a point basis, using the trending facility user interface.

For real-time data, the user shall be able to select a trend rate different than the scan rate.

The following graphical features shall be provided:

- Drawing areas, where curves are presented, shall be displayed in a dedicated window. Within each drawing area, each curve shall be displayed using a different color. The name of each curve shall appear in the corresponding color.
- The operator shall be given the possibility to modify the graphical presentation of trended values. The four following presentation types shall be available:
    - Traces: a basic X-Y plot or graph, similar to the trace of a strip chart recorder
    - Bar graphs: one or more points plotted from a common base line,
    - Pie charts: graphics showing the relative percentage of point values versus the "whole"
    - Meters: graphics showing a point value in relation to a minimum and maximum scale for a single instance in time.

In addition:

- It shall be possible to display curves horizontally or vertically;
- An automatic scale adjustment option shall be offered, that adapts the min and max values to the sampled data; min and max values shall also be manually enterable;
- Scale numbering shall be done in reasonable rounded values (5, 10, 15, ...);
- It shall be possible to define at least two threshold levels (high and low) per sampled point; portions of the curve beyond the high level and below the low shall be shaded in a different color;
- It shall be possible to hide / display any one or more curves within an area, zooming and scrolling features shall be available;
- Designating a point on the curve shall result in displaying accurate Y-axis value along with time of occurrence;

- A print option shall be available in order to print currently displayed trends (preferably in Postscript format);
- A save and restore function may be proposed; this would allow the operator to save trends of interest in a file and recall them for display (as static data) later on.

3.3.7 Operator Notes

The HMI system shall provide a tool to allow operators or management staff to make notes on displays so that they can communicate information with each other. Notes shall be used by the operators i.e., in the form of "yellow post-it" on a display screen flagging something that requires attention.

This note facility shall provide for ways to capture displays or portion of displays, add text and graphics, and store the marked-up display as a note.

A note work area shall be available; it shall be a scrollable window that shall provide the operators drawing primitives (lines, rectangle, circle, etc.), text, and a color palette that shall be used in conjunction with primitives and text.

From the note work area it shall be possible to perform the following:

- Select all or portion of a display and paste it into the note;
- Add text to the note;
- Add graphics to the note;
- Move elements in the work area;
- Save the notes.

It shall be possible to declare a note as being attached to a display. When the display has at least one note associated with it, a note menu associated to the display shall provide the following capabilities:

- Obtain a list of notes: this list shall provide ways to filter the notes according a type of operator and/or their creation date;
- View the display with note attached (for example highlight rectangle) or not;
- Move from one note to the next one in the display;
- Delete notes;
- Call a note for consultation or modification;
- Print notes.

The Contractor shall provide its standard approach for note facilities as well as the functionalities provided with its solution to meet the requirements outlined above.

3.3.8 Graphic Display Editor

The HMI system shall include an editor for creation and modification of graphic displays.

The display editor shall be a graphical tool which provides an off-line display building facility. It shall provide an interactive environment in which users can build graphic objects and displays, and define the linkage of graphical objects in the displays to the application data base.

Displays shall be composed of graphical objects that contain both static and dynamic information linked to a specific class of data base object. Once a graphical object is defined, instances of this object may be placed several times on different displays. Displays shall provide the context in which to view those objects.

The display editing subsystem shall provide at least the following features:

- A user interface based on a direct manipulation philosophy; the user's on-line means of interacting with the system shall be by selecting and manipulating visual objects on the screen instead of typing commands;
- The ability to manipulate multi windowing user interface techniques;
- An interactive graphical editor which allows the user to create and modify displays using direct manipulation; this editor shall allow the user to create and modify libraries of shared objects and displays;
- In addition, the user shall be able to create and modify private objects and symbols;
- Access to several standard fonts that vary in size, style and boldness;
- The ability to create displays and objects regardless of the availability of the data bases containing the displayed data;
- The ability to modify and view displays and objects in an off-line mode which does not affect the on-line displays;
- The possibility to dump display and object definitions into human-readable flat ASCII files; once compiled, these files shall be made available to the on-line system.

The display editor shall support the following concepts:

- Graphic primitives (line, circle, rectangle, arc, ellipse and polygon);
- Video attributes: It is desirable that these attributes be gathered into a special generic and reusable type of object. Attribute bundle shall encompass at least the following items:
  - Color;
  - Blink;
  - Visibility;

- Font identifier;
- Line thickness;
- Line style;
- Fill pattern.

- Interactors: This kind of objects are used to interact with the user. Interactors supported shall include, but not be limited to:
  - Menus (pop-up, pull down),
  - Label/action pairs - labels to be displayed in the menu and the action to occur when that label is selected.
- Sensitive area (poke points) that can be bound to a part of an object, an entire object or a portion of a display; for a sensitive area, one shall be able to associate an action that shall be executed when the user hits a predefined key;
- Data entry windows that allow the user to enter data into application database fields;
- Function keys/action pairs - although function key are defined at the console level, the display builder shall be able to redefine the action that results when the user strikes the key;
- Scroll bars (horizontal/vertical);
- Attribute modifier: these are objects that modify attributes bundles depending on the result of a test using data fields in the application database;
- Facility to import text file(s) to picture display with scrolling facility;
- Facility for alignment function to adjust the drawing (e.g. grids);
- Facility to put two static/dynamic elements overlap and to pop up one over the other.

Attribute modifiers shall be used to modify the graphic bundles of primitives, formatted data base fields, scaled primitives.

In addition to use attribute modifier features, the builder shall be able to specify the visibility of an entire object based on:

- Data fields in the application data base;
- Console permission assignment;
- Scaled primitives: the builder shall be able to define primitives that are scaled according to user specified values; these values can be data base fields or constants;
- Whenever the value is a data base field, the primitive shall be dynamically scaled as the value changes.

When editing displays, the operator shall be able to specify:

- static background information;
- single line type display where each object in the display shall be placed and linked to a data base object using a record key;
- or tabular display for which the operator shall be able to specify particular portions of the data base record to be used.

At any point in the display editing process, if the data base exists, the user can request a compilation of the display and a check of the link to the data base objects.

Once compiled, the display can be brought on-line.

At last, one display shall not be modified by more than one user.

All related equipment and tools shall be capable to handle HMI features arising from the necessity of supporting Greek language as well as English language.

Optional Requirements for Graphic Display Editor

In addition to the above, the Graphic Display Editor shall provide the following facilities:

- Facility to create new keys for display objects;
- Facility to create quality code and tag indicators and the ability to attach them to display objects (CB, Isolators);
- Facility to create quality code that takes into account the state of more than one database object (e.g., if CB1 in substation1 and CB2 in substation2 is open make the interconnection line invisible) or support such functionality by another equivalent way;
- Facility to create quality code that can use summarization or subtraction functions between different data base objects. (e.g., if MW of CB1 and MW of CB2 greater than value1 then highlight both CB1 and CB2) or support such functionality by another equivalent way.

The Contractor shall provide a description in the Detailed Design of how the facilities mentioned above will be realized in the new EMS.

3.3.9 Operator Consoles

3.3.9.1 Dispatchers' Workstations

Dispatchers will be provided with operator consoles that will support the HMI requirements described in this document. Different system display levels will include:

- Semi-geographical system representation for areas, including network overview and network status information as well as system security related information;

- Single-line substation representation for detailed information on power flow and voltage profile for the different voltage levels and also representation of circuit breaker and isolator status;
- Individual object (element/type) representation for status and loading condition indications;
- Plots, lists, matrixes, etc. to display events, alarms, reports, trends;
- Implementation of auxiliary functions such as manual data entry, integrated user handbook for network operation and control system handling, on-line help, etc.

There shall be no limitations for assigning different groups of windows and activities to a certain screen. Cursor operations by pointing device movements between the 4 Screens of a console and also the Display wall (when existed) shall be possible without requiring any further action by the operator. All activities to be performed by the operator shall be handled via interactive dialogues using the keyboard and/or pointing device.

3.3.9.2 Support Workstations

Support workstations shall be located in the computer rooms of the Control Centers and in the offices of the EMS Support team. They are to be used mainly for system configuration, maintenance work and for the supporting of all EMS applications.

The support workstations shall be connected to a separate redundant DMZ/LAN of the EMS System.

In order to achieve a uniform and homogeneous system concept, the hardware and software of the support workstations shall be of identical type and performance characteristics as that of the operator workstations. However, the support workstations shall be equipped with only two monitors.

3.3.9.3 Thin Client Interface

The thin client interface shall enable access to EMS (any diagrams including single-line diagrams, displays, historical data, reports, demand, etc.) through the web. In other words, the use of a thin client on an operator console should not require installation of the client application to the console and the client software should be automatically updated. The client application will be provided via web, either as a standalone application or as an application running in a web browser.

3.3.9.4 System Access Security

The EMS shall be provided with implemented advanced security in all levels: operating system level, static and real time database levels as well as EMS applications level in such a way to prevent unauthorized access to the system resources and to control/audit user access to the system resources and the controlled process.

3.3.9.5 System Administration

It shall be possible for authorized persons to add or modify the list of identifiers (such as operator name and/or mode of operation) and its assignments in order to supervise the access to functions, displays and data for each console.

It shall be possible to authorize any task from any workstation (i.e., all workstations shall have complete functional capabilities).

Access control shall be based on permissions and area of responsibility.

System Operation

It shall only be possible to access to the predefined functions, displays and data for the console and the identifier.

The system shall allow several identifiers for each workstation.

Only one identifier shall be active at a time on each workstation.

Password Security

A password security feature shall be provided that permits only authorized users to access the EMS through the consoles. The system shall encourage the authorized users to be security conscious, for instance by suggesting users to modify passwords at regular intervals. If the users are not allowed to change their passwords but receive them from the administrator, the system should encourage the administrator to change passwords and distribute them to users at regular intervals. No logins should be allowed without passwords.

Short passwords are easier to guess and hence are susceptible to brute-force and dictionary attacks. Thus, the system shall be configurable to require a minimum number of characters and be able to evaluate the password strength.

After a number of unsuccessful tries to login into the system (the number specified by the administrator) the system should lock the user out from the particular terminal.

A user shall log on to the system at a console by entering an identifier and a password. Passwords shall be encrypted using one-way encryption. The vendor shall specify the network authentication protocol used by the device doing the authenticating process .Each user shall have a dedicated identifier. The specific functions, areas of responsibility and permissions shall be controlled through log-on operation.

Each log-in and log-out shall be reported as an event. The event message shall indicate the date and time the procedure was executed, the name of the console and the identification of the user. The log-in / log-out status of the user shall be unaffected by any failure recovery procedure in the EMS.

A secure method shall be provided for the NII SMO designated authority to administer passwords, user identifications and the corresponding user access rights.

User Access Criteria

User access to the EMS shall be assignable on a console basis using an access control display. It shall be possible to define user access to the data base, displays and report selection as well as the ability to modify their structure and content.

In particular:

- It shall be possible to restrict a specified user's access to specified consoles;
- It shall be possible to restrict the EMS functions and displays accessible to a specified user;
- It shall be possible to restrict the EMS functions and displays accessible from a specified console.
- It shall be possible for users with proper authentication credentials to monitor the system via mobile phones.

Area of Responsibility

The monitored Power System shall be divided into several areas of responsibility for the purpose of limiting access.

The concept of area of responsibility shall be defined during the detail engineering phase of the project and shall also be used for alarm routing, alarm acknowledgement and supervisory control.

Each point of the monitored network shall be assigned to a single area of responsibility. Any console assigned to this area of responsibility shall have responsibility for controlling that point.

An attempt to perform an action from a console that does not have the proper assignment shall be rejected and an error message shall appear at the console.

Any area of responsibility shall have one or several consoles assigned to it, permitting more than one operator to control points in that area. In addition, any console could be assigned to more than one area of responsibility.

Permissions

In order to restrict the operator’s actions to specific functions, permissions shall be assigned to each identifier by the administration.

A permission console's assignment shall determine which sets of functions a console shall have access to and what type of access the console shall have to those sets of functions.

For example, a set of functions shall be:

- Dispatching functions;
- Supervisory functions;
- Generation functions;
- Study analysis functions;

- Maintenance functions;
- Programming functions;
- Training functions.

At least, three types of access shall be provided:

- Read permission shall allow an operator to view all displays associated with a set of functions
- Write permission shall allow an operator to enter data into data base using displays associated with a set of functions
- Execute permission shall allow an operator to execute control from displays associated with a set of functions.

Several operators may have the same permissions.

If an operator has no permission to access to an application, the displays of this application shall not be presented to him.

4 SCADA

This section presents the technical and functional requirements for SCADA. It is structured as follows:

- SCADA Functional Specifications (Section 4.1);
- Data Processing (Section 4.2);
- Supervisory Control (Section 4.3);
- Tagging (Section 4.4);
- Switching Management Facility (Section 4.5);
- Dynamic Network Coloring (Section 4.6);
- Historical Data Recording (Section 4.7);
- SCADA Telecommunication Daily Statistics (Section 4.8);
- Data Presentation and Reporting (Section 4.9)
- Inter Control Center Protocol (Section 4.10);
- Data Exchange with Substations and Plants (Section 4.11).

4.1 SCADA Functional Specifications

The functions to be performed by SCADA are described in this section.

4.1.1 General Requirements

All parameters in the SCADA system shall be defined in the database and shall be adjustable. Adjustments made to parameters by the operator or the software engineer shall become effective without having to reassemble or recompile programs or regenerate all or portions of the database. It should be a fully configurable system without reassemble programs.

All input data and parameters, whether collected automatically by the SCADA system or being the result of an operator action, shall be checked for reasonability and rejected if they are unreasonable. All intermediate and final results shall be checked to prevent unreasonable data from being propagated or displayed to the operator. When unreasonable input data or results are detected, diagnostic messages, clearly describing the problem, shall be generated. All calculations using the unreasonable data shall either be temporarily suspended or continue to use the last reasonable data as designated by the user.

Access to the functions shall be limited to authorized users. Users that do not have access to a function may view displays associated with the functions.

The SCADA software shall fulfill functions for ensuring a reliable and safe operation of the system as stated in the following sections.

SCADA heartbeat should be configurable from 100 ms up to 1 second.

4.1.2 SCADA Sizing

The SCADA should shall be sized to meet the data acquisition, processing and archiving of the NII expansion in the next 10 years. The above data should include the amount of data to be collected from RTUs or DCSs or imported from other systems as well as calculated values inside the SCADA system. At a minimum the SCADA should support the amount of signals described in Part - A General for the current condition and future expansion (substations mentioned) in Rhodes, plus an extra 50%. The exact size requirements for the future number of stations, number of signals, etc., will be determined during the Detailed Design Phase of the Project.

4.1.3 Data Acquisition

The SCADA system shall be able to acquire and handle the following types of data:

- Tele-metered data received from RTUs located at the various substations and power plants, through the data Island's Network;
- Sequence of Events (SOE) data;
- Data received from other control centers via "Inter Control Centre Communication";
- Calculated data (analog values and digital status values) generated by programs;
- Non tele-metered data (analog values and digital status values), i.e., manually entered data.

In the following, the types of data presented above are further defined.

4.1.3.1 Telemetered data

Tele-metered data comprise but are not limited to:

- Device status represented by a pair of digital inputs (double pole indications) i.e., for switching devices like circuit breakers, disconnectors, etc.;
- Device status represented by a single digital input;
- Alarms represented by a single digital input;
- Tele-measurements (analogs) e.g.: kV, A, MW, MVar, phase angles, temperatures, frequency, etc.;
- Accumulator values from energy meters.

4.1.3.2 Sequence of Events (SOE) Data

Specific status information is provided by RTUs including a time stamp indicating the actual time when the information was acquired. The time stamp is transmitted within the telegram containing the status information.

The SCADA system of the Control Center is in charge of processing the SOE data received from substations or power stations and of presenting them to the operator in the sequence of occurrence in a chronological order.

4.1.3.3 Data Exchanged with other Control Centers

The SCADA system shall be able to collect and handle various types of data from other Control Centers acquired via Inter Control Centre Communication utilizing the standard communication protocol IEC 60870-6 TASE.2.

4.1.3.4 Calculated Data

It shall be possible to define, in the database, calculated data generated either by SCADA software or EMS software (e.g., data issued from state estimation).

The associated database values shall be updated either on a cyclical or non-periodic basis. The calculated data may correspond to analog values, statuses, alarms or energy values.

All the requirements, described in the following paragraphs, concerning the tele-metered data shall also be applicable to calculated data, such as monitoring of values, tagging and data quality attributes. It shall also be possible to show these values on any display.

4.1.3.5 Manually Entered Data

Some data are used by the system although they are not acquired by the data acquisition subsystem. These data may correspond to analog values, status indications or energy values. The corresponding values are entered and updated manually by the operators/engineers.

These manual data entries shall be time tagged by default by the system or by the operator.

The auto checking of the manual data entries shall be provided, e.g., values entered out of limits.

These manually entered data shall be integrated in the same way as tele-metered data in the database. It shall be possible to show these values on any display.

4.1.4 Data Acquisition from RTUs

4.1.4.1 Basic Requirements

The new SCADA system shall be equipped for data acquisition with RTUs via the following protocols:

- IEC 60870-5-101;
- IEC 60870-5-104.

The new EMS shall be designed and prepared in a way to ensure that SCADA through the above mentioned protocols will provide all the necessary data for safe and reliable functioning of all the relevant applications for monitoring and control.

4.1.4.2 Supervisory Modes

At least two modes shall be implemented in the new SCADA:

Supervisory mode: The Control Centre acts in supervisory mode and is responsible for supervision and control of the respective substations. Each substation of the Island's Network System shall be tagged properly by a tag, showing which Control Centre supervises this substation.

Local mode: The Control Centre acts for the respective substation only in monitoring direction – not in control direction. Control commands are initiated locally at the substation. Control commands from the Control Centre to the respective substation shall be prevented.

A third mode is optional.

Test mode: The test mode will be applied during test phases (e.g. during commissioning or extension works at the substation) in order to discriminate the information transmitted by the respective substation from the rest of the information, so that the operators are not disturbed while supervising the remaining Island's Network.

4.1.4.3 Monitoring of RTU - Communication links

The data acquisition subsystem of the SCADA system shall monitor the on-line status of the communication links with RTUs.

At least the following information shall be possible to be monitored on displays:

- Current status of the communication with each of the RTUs i.e. in service, out of service, failed, actively connected to channel etc.
- Communication statistics for each RTU indicating communication quality i.e., number/percentage of failed telegrams.

Communication error reports from the RTU data communication subsystem shall allow SCADA software to indicate and alarm poor communication links/paths on relevant displays.

4.1.4.4 Test Mode

The operator shall be able to declare any RTU in the test mode for purposes of calibration, maintenance, or testing. When an RTU is in the test mode, the real-time database shall retain the last value from all points collected via the RTU before it was placed in the test mode. The discrete input points shall be marked in the database with a quality code indicating that their source RTU is in the test mode. Supervisory control of points that are in the test mode shall not be possible. The ordinary alarm processing of the respective input points (audible alarms, entry in dedicated alarm lists) shall be suppressed. The analog and accumulator data shall also be marked with the respective quality code and the value shall be set to a special sign.

The operator shall be able to substitute a value in the database for any data point. When telemetry returns from test mode to normal, the SCADA system shall automatically resume updating the database with the scanned data.

Test displays which show the actual values being received from an RTU in test mode shall be provided. The displays shall include data from all input cards installed in the RTU, including spares. It shall also be possible to control all outputs installed in the RTU, including spares. Spare I/Os shall be marked as such in the database.

4.1.4.5 Telemetry failure and deletion from scan

If valid data are not received from an RTU in response to a scan command, another scan request for data from that source shall be issued. If valid data are not received from a data source after an adjustable number of retries, each point affected shall be marked "failed" and an alarm shall be generated.

If an entire RTU or its communication channel fails, only a single alarm shall be generated. In the event of telemetry failure, the last good status shall be retained in the database for each affected point along with a tag identifying lack of telemetry. The analog and accumulator data shall also be marked with the quality code.

The operator shall be able to substitute a value in the database for any point that is experiencing telemetry failure. When telemetry returns to normal, the SCADA system shall automatically resume updating the database with the scanned data.

The operator shall be able to delete any point from scan processing and substitute values for the data. When the operator restores a point or source to scan processing, the SCADA system shall automatically resume updating the data base with the scanned data.

4.2 Data Processing

The SCADA system shall process all data it acquires by use of the display, control, and application functions.

This section will address the directly process-related information only. Some of the most important procedures will be described in the following sections.

4.2.1 Analog Input Data

Each analog point scanned by the SCADA system shall be converted to engineering units before being stored in the database.

The following conversions shall be supported as a minimum:

- Linear conversion;
- Non-linear conversion (e.g. by piece wise linear conversion technique with multiple breakpoints such as changer position).

4.2.1.1 Quality Markers

The system shall provide a number of quality markers for each item of input data such as, but not limited to the following:

- Not renewed;
- Not reasonable;
- Out of service;
- Manually substituted;
- Not updated;
- Limit violated;
- Invalid;
- Out of Scan;
- State Estimator data.

It shall be possible to add new attributes if necessary.

The quality markers shall be applicable to modify the display of the respective data on the displays and in the reports (e.g. change of colors, tags, symbols etc.)

For calculated data, the presence of a quality code on any of the component data values shall not disrupt the calculation using that value. The quality of the calculated value shall be the quality of its "poorest" constituent.

4.2.1.2 Zero Range

The system shall provide an adjustable zero range for each item of measurement data. Should its value fall within this range, the system shall set the value to zero.

4.2.1.3 Sign Conventions

The following sign conventions for real and reactive power flow shall be used universally throughout the SCADA system:

- All active and reactive power flowing into a busbar shall be negative;
- All active and reactive power flowing out of a busbar shall be positive.

4.2.1.4 Reasonability limits

All analog values shall be compared against high and low reasonability limits. The comparisons shall be performed at the scan rates of the analog values. The reasonability limits shall represent the extremes of valid measurements for the point's value. An alarm shall be generated the first time a reasonability limit violation is detected. The last valid value of the variable shall be maintained in the database and marked with a quality code indicating the reasonability limit violation. When data returns to a reasonable value, the new value shall be accepted.

Reasonability limits shall be adjustable by the software engineer.

The unreasonable value of the analog point shall be kept in a separate field in the database.

4.2.1.5 Limit Monitoring

Not only all telemetered analog points, but calculated, estimated and manually entered values as well, shall be compared against two upper and two lower limits. The limits shall be adjustable by the operator. Violation of the adjustable limits from either direction shall be alarmed utilizing an adjustable hysteresis dead-band to prevent multiple alarms when a value oscillates around the limit value.

When an analog value violates the predefined limits, the following events shall be executed, depending on the respective parameterization:

- Updating the chronological list;
- Updating the relevant displays (i.e. single line diagrams and lists) with the associated value and coding related to the change of the value;
- Processing of the associated alarm if relevant.

This monitoring shall be performed either by default or upon operator's request as described here after.

Monitoring by Default

Limits monitoring by default shall be defined in the data base configuration and shall be available for each selected tele-measurement.

This monitoring shall be performed on the tele-measurement scanning frequency basis.

An alarm priority level shall be assigned to each defined limit during data base configuration.

The operator shall be able to disable the monitoring of any selected tele-measurement on line, by default.

Monitoring upon Operator's Request

The operator shall be able to introduce manual thresholds for any tele-measurement.

Seasonal Limits

Facilities shall be provided for selected analogs (e.g. MW and MVAR) to be allocated at least two sets of supervisory and urgent limits (corresponding to the seasonal limits for winter and summer).

Seasonal limits shall be individually defined for each analog.

It shall be possible for the user to manually update the active limit checking values from one of the seasonal sets on a system wide basis.

Amendment to the active limit values shall not update any of the defined seasonal limits.

Overrides

Facilities shall be provided for overriding analog values with fixed values entered via the User Interface.

All analogs shall be eligible for overriding.

Overridden values shall not be updated by values telemetered from RTUs or calculated by the system.

The appearance of analogs on displays shall be modified when an override has been applied.

Upon removal of an override, the analog shall be marked “suspect” until the value has been updated from the telemetered source or recalculated.

Overrides shall be possible to be entered and removed wherever the value is displayed.

4.2.2 Discrete Input Data

All discrete input data acquired shall be processed to detect any change of state further to spontaneous events or after a control order sent from the Control Centre.

Each acquired discrete input data shall be checked to see whether transition into that state is to be alarmed. If so, and if no control action is pending on the status point, then an alarm action shall be triggered.

Suppression of transient signals due to intermediate positions of slow switching devices (e.g., disconnectors) is a task which is normally performed by the associated RTU equipment. However, in case the RTU equipment would not be able to perform such functionality (e.g., old equipment), it shall be possible to define a dead time in the SCADA system via data engineering to delay the alarm generated by the related change of state.

4.2.2.1 Quality Markers

All discrete information shall be marked with quality markers such as but not limited to the following:

- Out of service;
- Manually substituted;
- Not updated;
- Invalid;
- Out of Scan.

The quality markers shall be applicable to modify the display of the respective data on the displays and in the reports (e.g. change of colors, tags, symbols, etc.)

For calculated data, the presence of a quality code on any of the component data values shall not disrupt the calculation using that value. The quality of the calculated value shall be the quality of its "poorest" constituent.

The priority of these quality markers shall be defined in the Detailed Design Phase of the Project.

4.2.2.2 Event Generation

Each identified change-over that will update the Real Time Database will be classified according to the associated "event".

Events are, for example:

- All dispatchers' manual entries;
- Acknowledgement of a control;
- Spontaneous change of state;
- Missing message in a general interrogation;
- Fault position;
- Intermittent message;
- Additional information in the telegrams.

The basic change-over processing is updating the system's Real-Time Data Base (RTDB). Any change in the RTDB will update all objects related to the change in:

- Process displays;
- Lists;
- Special displays.

The event-generation defines how the received data will be further processed (updating of state lists, logs, archives and alarm generation).

Normally, the events should be classified in types or classes such as:

- Switching state (on; off; fault position; in-transit);
- Transformer tap position;
- Protection indication;
- System indication generated by diagnostic function for the Control Centre and communication devices;
- Indication of application software (SE, CA, etc.).

4.2.2.3 State Names

Each state of a discrete input point shall be able to be associated with any state of a device according to the following examples:

- Open/closed
- Tripped/closed
- Alarm/normal
- On/off
- Auto/manual
- Remote/local
- On control/off control.

4.2.2.4 External Changed Status

The SCADA system shall provide for the following types of external changed status:

- Switch status represented by a pair of digital inputs (double pole indications) is given by two contacts characterizing two determined states (0 | 1 and 1 | 0) and two undetermined (invalid) states (0 | 0 and 1 | 1) of an operational equipment, in general circuit breakers and isolators;
- Status represented by a single digital input;
- Persistent alarm status;
- Fleeting alarm status.

4.2.2.5 Internal Changed Status

Internally created status changes are:

- Certain tagging notes applied to network elements, e.g., lines and transformers in the network;
- Limit traversal by measurement and counter data processing;
- Changed status relating to the control equipment itself.

4.2.2.6 Alarm Processing

For every changed status, the system shall determine whether an acknowledgement is required from a user and, if so, it shall lead the user through an appropriate sequence of menus and pictures to the point at which the acknowledgement can be made.

For a switch status change, the system shall proceed as follows:

- Uncommanded changes in switching state, changes in telemetered and calculated discrete points shall be alarmed; the alarm message shall include:
    - Time of detection;

- Station name;
- Complete identification of respective device;
- Current state.

- Commanded changes initiated by supervisory control shall not be alarmed, but shall generate an event message. The message shall include the same information as an uncommanded change-of-state message, except that the event shall indicate that the change is the result of a supervisory control.

4.2.2.7 Sequence of Events (SOE) Processing

Regarding real time information with time stamps acquired from RTUs, the SCADA system shall process the information in the correct sequence of events, sorted by the acquisition time included in the telegrams.

If the time stamps added to the information in the substation only contain the relative time, the SCADA system shall assign the exact time and date to the information.

SOE data shall be presented to the operators in special SOE lists according to the sequence of their occurrence in a chronological order.

The resolution of the occurrence time in the SOE lists depends on the quality of the time information (synchronized / unsynchronized) and the resolution of the time stamps provided by the equipment in the substations.

The SCADA system shall be capable of sorting real time events with a resolution of +/- 1 msec.

4.2.3 Pulse Accumulator Data

Pulse accumulator data shall be collected on a quarter of the hour period. A freeze command shall be issued on the quarter-hour to ensure consistency of accumulator readings gathered from the RTUs.

Quarter-hourly accumulator data shall be converted to engineering units. The calculation shall accommodate accumulator rollover.

If quarter-hourly accumulator data cannot be acquired due to a failure in e.g., a counter, a communication channel or other failure, the missed quarter-hourly accumulator value(s) shall be assigned either the integrated MW values or the invalid value sign and marked with a telemetry-failure quality code.

When the quarter-hourly scan is finally successful, the total accumulation since the last successful quarter-hourly scan shall be re-partitioned among the intermediate quarter-hours according to one of the following methods selected for each point:

- Assignment of the latest flawless accumulation value to the quarter-hour it was obtained, with a "questionable" data quality code;

- Re-partition of the total accumulation since the last successful quarter-hourly scan equally among the intervening quarter-hours, with a "questionable" data quality code.

4.2.4 Counting of Operation Hours and Number of Operations

The system shall make provision for counting the number of operating hours and the number of operations, as appropriate, for Circuit Breakers. It shall be possible to set limits for these and, when the limits are exceeded, the system shall raise an internal changed status.

4.2.5 Generalized Calculations

A number of calculations are performed by the SCADA system. In order to perform these calculations a number of standard and custom made functions are used.

As standard functions, we consider the following:

- Arithmetic operations (addition, subtraction, multiplication, division, equation, exponentiation, square root, absolute value, logarithmic logic, etc) with analog, count and constant record operands;
- Trigonometrical operations (sin, cos, tan, etc) for analog, count, and constant records;
- Logical operations (and, or, exclusive or, not, etc) for point records;
- Comparative operators (Less Than, Greater Than, Less Than or Equal To, Greater Than or Equal To, Equal To, and Not Equal To);
- Statistical operations (max, min, average, sum, weighted sum, etc.) for analog, count and constant records;
- Most commonly used calculations (MVA from MW and MVAR, MVA from AMPS and KV, etc.

Within the calculation, the operator must be able to apply suitable rules or operators (such as multi-level parentheses) in order to indicate the sequence of functions in the calculation. The execution of a defined function or portion of a function may, if so chosen, be conditional on the state of a telemetered or calculated discrete value, or the comparative relation of two values.

The calculations shall be performed at the indicated rates and the results shall be incorporated into the database as calculated data. The database variables to be used for arguments and the mathematical functions to be used as operations shall be definable interactively at a console as well as by the software engineer using database creation and maintenance procedures.

The quality markers associated with the value of each of the data items shall be used during the calculation and shall determine the quality markers associated with the result.

All the calculations shall be executed either on an exception basis, whenever the inputs of the calculation change, on a periodic basis, definable within a range from 1 second up to 1 month, or upon request by the operator.

At least 500 generalized calculations shall be performed at the fastest scan rate of the component data without affecting SCADA system performance. Each calculation may consist of up to 25 arguments.

The result of all the calculations shall be treated in the same way as analogs/counts/points regarding the storage in the SCADA/EMS Archives.

4.2.6 Alarm and Events Processing

An intelligent alarm system is of great importance to manage the island power system. It shall guide the operator using a top down hierarchy of signaling to the most important starting place of the disturbance.

The SCADA system shall allow defining at least the following occurrences as either alarms or events:

- Single and double tele-signal change of state;
- Tele-measurement threshold overshoot;
- Failure of control action;
- Protection relays operation;
- Failure of Control Centre equipment (i.e., RTU data communication subsystem, servers, workstations and peripherals);
- Failure of software processes;
- Failure of RTU and telecommunication paths;
- For each above mentioned occurrence, the attributes defining alarm and event conditions shall be configurable in the SCADA database.

Any user and system action shall be classified as an event (e.g., alarm acknowledgement, inhibition, redirection of a printout). Each event based on user action shall be stamped with the user identity.

In order to limit information flow and to help operators select information according to its importance (i.e. emergency level), at least the following alarm attributes shall be defined:

- Priority;
- Area of responsibility;
- Category;
- Origin (or location).

4.2.6.1 Alarm Presentation

Basic Signaling Window

A basic signaling window shall be presented on every screen during real time operation.

The buttons in the display shall be symbols of alarm summaries. The basic signaling display shall be configurable and shall, in general, contain only a small number of buttons to select functions or displays such as:

- Power system overview displays;
- SCADA system configuration displays;
- Network overview diagrams.

The flashing buttons shall indicate the affected areas. Starting at this point the operator shall be guided to the displays containing detailed information about the alarms.

Each alarm shall be presented in a way that the following alarm states can be distinguished:

- Alarm is active and not acknowledged;
- Alarm is active and has already been acknowledged;
- Alarm has gone but was not acknowledged;
- Alarm has gone and has been acknowledged.

Audible Alarms

An audible alarm with a minimum of two distinct tones or sounds shall be provided for each console.

The alarm type shall define the selection of an audible alarm sound. The audible alarm device shall sound only for a limited period of time which should be configurable, e.g., 10 to 15 seconds or shall be single sounds e.g., gong when an alarm is raised. If an alarm is not acknowledged, an alarm sound shall be initiated again after a selectable period of time (1 min) which should also be configurable.

It shall be possible to disable the audible alarm function at a console and silencing shall then remain in effect until the operator restores the audible alarm function. All actions related to disabling and restoring the audible alarm function shall be recorded as events.

Alarm and Event Messages

Alarm messages shall be single line messages describing the alarm that has occurred and the date and time of occurrence. For device alarms, the name of the substation and the device or circuit shall be included. If the alarm relates to a data value, the value at the time of the alarm and the limit violation shall be included. The alarm message shall be a comprehensive text and shall not require the use of a reference document for interpretation. The same message format shall be used for displaying and printing.

It shall be possible to modify alarm message formats and add new formats by Data Engineering.

Alarm messages shall be stored and archived in chronological order. It shall be possible to retrieve, sort and print alarm messages from any console.

Events shall be recorded in the form of an event message. The event message shall be a single line message of a comprehensive text that describes the event. The message shall include the time and date of the event.

The same message format shall be used for displaying and printing events. When the event is the consequence of a manual data entry, both the old and new value shall be included in the message.

Event messages shall be displayed in an events summary. Event messages shall be archived in chronological order. It shall be possible to retrieve, sort and print event messages from any console.

Alarm Condition Indicators

Each graphical symbol or numeral representing a device of the power system, a value or parts of the SCADA system shall be able to correspond to an alarm.

It shall be possible to highlight each representation using alternative figures, colors, intensity, and flashing. An alarm condition indicator shall be displayed adjacent to the device or value in alarm. The alarm condition indicator shall show whether the alarm has been acknowledged. The alarm condition indicator shall include at least one printable character so unacknowledged alarms for devices or values can be identified on black and white alarm hard copies.

Alarm and Event Structure

Alarms or events shall appear when the status of an item in the power system or in the SCADA system changes, for example:

- A value changes from normal to limit violation;
- A breaker status changes from “close” to “open” without a command from the Control Center;
- An application program detects violation of the regular status;
- A device of the SCADA System changes e.g. from status “normal” to “failure”;
- Events shall include:
    - User actions including data entry, supervisory control and application function control;
    - Conditions detected by application functions that do not require immediate operator notification, but should be recorded.

In each Control Centre the full format of an alarm or event shall consist of at least 4 attributes:

- Timestamp: it shall be assigned by SCADA;
- Location: In most cases a substation, but it may be an application function, SCADA system equipment, etc.;
- Device Type: Circuit Breaker, Disconnector, Grounding, Switch, miscellaneous devices of a Substation;
- Device Name: For example the name of the specific breaker P130.

The time of appearance is a fundamental part of an alarm or event message.

4.2.6.2 Alarm Processing

Each alarm or event shall be subject to a series of processing functions. An item's alarm condition shall be assigned to an alarm category. All alarms shall be assigned to an alarm type that determines how the alarm will be processed. Details of these functions are specified below.

Alarm Types

Each alarm shall be assigned to an alarm type. The alarm type assignment shall determine how the alarm will be presented, acknowledged, recorded and deleted. Alarm interactions will only be allowed at consoles assigned to the category containing the item in alarm. For each alarm type it shall be possible to independently select any of the following actions:

- Audible annunciation;
- Visual annunciation;
- Alarm deleted when return-to-normal alarm occurs;
- Alarm deleted when return-to-normal alarm is acknowledged.

Alarm Priorities

Based on the importance, alarms shall be prioritized with user-attributable color and sound for each level of priority and shall be filtered based on the area of responsibility.

Based on equipment, alarms shall be grouped (when more than one alarm is pending on an equipment) and the alarm with the highest priority shall be displayed in the summary-window against a node. The warning sound played shall be that of the highest priority among the pending alarms.

Events

Events are conditions or actions that shall be recorded by the SCADA system but do not require immediate operator notification. Events shall include:

- User actions including data entry, supervisory control and application function control;
- Conditions detected by application functions that do not require immediate operator notification, but should be recorded.

Events shall be recorded in the form of an event message. The event message shall be a single line of comprehensive text that describes the event. The message shall include the time and date of the event. The same message format shall be used for displaying and printing events. When the event is a data entry, both the old and new value shall be included in the message. Event messages shall be displayed in an events summary.

4.2.6.3 Alarm Interaction

The operator shall be able to inhibit and enable alarm processing, acknowledge alarms and change an item's alarm limits. The operator shall be able to perform such actions for telemetered, calculated and program-generated alarms.

Alarm Acknowledgment

An alarm shall be acknowledged by selecting an alarm acknowledge operation on the item in alarm from:

- Any display showing the device or value in alarm;
- Any display showing the alarm message.

It shall be possible to acknowledge all or individual alarms on a display page. When an alarm is acknowledged, flashing of the alarm condition on displays and console visual indicators shall stop. The key alarm indicators shall be turned off when all alarms in the categories have been acknowledged.

When a return-to-normal alarm is acknowledged, both the return-to-normal alarm message and its associated alarm message in an alarm summary display shall be removed (not from data base). The remaining messages in the display shall be realigned to present a continuous listing of alarms.

Alarm Inhibit / Enable

Inhibiting alarms for a value or device shall cause all alarm processing of that value or device to be suspended. However, scanning of the value or device shall continue and the database shall be updated.

Alarm inhibiting for each item shall include at least the following three flags: unacknowledged, log and abnormal that shall be managed by the system administrator in order to fine tune the inhibit action.

Alarm inhibiting shall cause the SCADA system to:

- Cease all or partial further alarm annunciation for the value or device including symbol flashing or highlighting;

- Present a quality code next to the value or device on every display and hardcopy containing the item in alarm;
- Add a message to the alarm inhibit summary along with the time alarming was inhibited;
- Alarm messages generated prior to the alarm inhibit shall remain and shall require operator acknowledgment and deletion.

Alarm enabling shall cause the SCADA system to:

- Resume normal alarm processing and annunciation;
- Remove the inhibit message from the alarm inhibit summary display;
- Remove the alarm inhibit quality code from the value or device;
- Record the time alarming was enabled.

4.2.6.4 Event and Alarm Lists

Several alarm and event lists shall be available. Thus, it shall be possible to present alarms and events classified according to:

- Priority;
- Area of responsibility;
- Category;
- Location;
- Status of the alarm (i.e. unacknowledged, acknowledged or inhibited);
- Chronological order;
- Other NII SMO criteria defined during the Detailed Design Phase.

In order to facilitate system maintenance, all the alarms related to special equipment (e.g. RTUs, Telecommunication equipment, Control Centre equipment etc.) shall be presented in specific alarm lists dedicated to this equipment.

Furthermore, the SCADA system shall provide for additional event/alarm lists such as:

- All items being in abnormal state;
- All items being inhibited;
- All items being manually overridden.

It shall be possible for the system administrator to create new lists with special features.

System Message Log

All alarm and event messages shall be gathered in a general system message log.

The system message log shall consist of the chronological listing of all SCADA system and power system alarm messages, event messages and user messages. Each entry shall consist of the time tag (field time tag wherever available), dynamic information, user identification and text that is displayed in the Alarm Summary or Event Summary display.

Facilities to sort and selectively display and print the contents of the system message log shall be provided. The user shall be able to select the display of system message log entries based upon the following sort keys and combinations of these keys:

- Alarms;

  The user shall be able to select a subset of alarms based on alarm category and class.

- Events;

  The user shall be able to select a subset of events based on user action and application function detected condition.

- User message line messages;
- Station;
- Device type;
- Device;
- Time period.

A display shall be provided to permit the user to define the selection criteria. The user shall be able to direct the selected subset of system messages to a specific monitor or printer from this display.

4.3 Supervisory Control

Supervisory control is the function of issuing control commands to field equipment. Supervisory control may be used to change the state of switching devices or to send a specific digital or analog value to field equipment.

The operator shall be able to request digital status control, raise/lower control and set point control on selected elements.

The control orders shall consist of the following – not exhaustive:

- Circuit-breaker open/close command;
- Disconnector open/close command;
- Tap changer raise/lower command;
- Auto-recloser on/off command;
- Start/stop or on/off commands;

- Set-points for regulating equipment.

The operator shall be able to control the operation of switching devices connected to the Control Centre. The switching devices that can be controlled from any particular console shall be determined by the access rights assigned to that console and to the respective operator.

As a general requirement, all control actions initiated by any operator shall be logged as events and shall be possible to be retrieved allowing different searching and filtering levels.

This is to provide historical views of control actions in order to provide evidence from which console a control action or an acknowledgement has been issued.

4.3.1 Security

The system shall provide a comprehensive range of mechanisms designed to prevent or minimize the risk of damage to personnel and network equipment.

4.3.1.1 Select before Operate Sequence

A control action shall require a confirmation-of-selection-prior-to execution response. Initiation of the control execute step shall occur after the operator confirms that the correct point and control action have been selected. Raise/lower control action shall be monitored by a similar select before operate sequence, except that the operator may carry out multiple control orders without having to reselect the device.

Any control action for which execution fails to complete, due to communication errors, faults in the RTU, switchgear failures, etc., shall be presented to the operators through appropriate alarm messages. This shall be accomplished by means of a time out feature which shall be adjustable on a per point basis.

Furthermore, several conditions shall be checked before a requested control action is actually allowed to be sent from the Control Centre. For example:

- The control point must be in service and the corresponding status information updated in the Control Centre;
- The control point must not be tagged against operation;
- Interlock conditions must be satisfied;
- The RTU to which the control will be sent must be in service;
- The associated digital status point must not already have a control pending;
- The RTU “LOCAL/REMOTE” control switch must be set in “REMOTE” mode.

4.3.1.2 Interlocks

For the execution of controlling operations, interlocks shall be provided to prevent operations which endanger personnel or material or violate the company’s rules. Although the Operators are aware of the interlocks and the conditions to be met for each control action, the automatic interlock checking is used to help the operator in stress situations and to allow complex switching operations to be carried out. Except for the parameterized interlocks, no additional data entry shall be needed. The rules shall be automatically available for all switching operations. Network calculations shall be integrated into the interlock checks, if available.

- The interlocks shall be definable by the SCADA System Administrator. They can comprise of the following (not exhaustive): Access interlocks. Only logged-in operators with the adequate permission can activate control action.
- Area of authority. The selection of any object is checked with the appropriate setting of the Area-of-Authority.
- Selection interlocks. Once an element is selected, no object in a defined area can be selected by another Operator.
- Status interlocks. Status interlocks are based on tags and/or the current object states of the elements in the network. RTU “Local/Remote” control switch status.

User Definable Interlocking Rules

The SCADA System shall provide the capability for user definable interlocking rules.

User definable interlocking rules shall only apply to specific network elements, according to NII SMO´s modeling.

If an interlock condition is recognized, the Operator shall be alerted by a special Interlock-Message Window, which lists the object which has caused the interlock.

4.3.2 Single Controls

The operator shall be able to select and operate any controllable switching device.

For a single control operation it shall be possible for a user to use the pointing device to select the item to be controlled.

The system shall guide the user by control windows and messages relating to possible control operations.

Prior to prompting a user to confirm his requirement for execution of a control operation, the system shall execute all relevant security functions.

If, after selecting a point for supervisory control, the operator does not execute the control action within an adjustable period, or if the operator performs any console action other than completing the control action, the selection shall be cancelled and the operator shall be informed.

The operator shall not be prevented from requesting other displays, performing a different supervisory control action, or performing any other user interface operation while the SCADA system waits for a report-back on previously executed control actions.

4.3.3 Raise / Lower Commands

Controls for raise or lower of e.g., tap positions of On Load Tap Changing (OLTC) transformers shall be provided. The OLTC automatic / manual status and supervisory / local status shall be monitored together with the tap position and high and low tap alarm position limits.

Supervisory control of OLTC transformers shall only be permitted when it is in manual and supervisory mode, parallel and stepping mode. All attempted invalid control actions shall be rejected.

For supervisory operations, the initial selection and control of the OLTC for a raise / lower operation shall follow the confirmation of selection-prior-to-execution technique. Upon receipt of the raise / lower command, the RTU will immediately execute the control action. For subsequent raise / lower operations the operator shall only have to repeat the desired raise / lower command, which shall be executed immediately.

The SCADA system shall confirm that the control has operated correctly or that the control has failed before subsequent controls are allowed. Normal scanning function shall not be suspended during the time repeated raise / lower commands are issued.

The operator shall be able to cancel the operation or have it automatically cancelled by the SCADA system after a software engineer adjustable time period elapses after the last raise / lower command.

4.3.4 Set Point Controls

The system shall provide for set point control. Set point control shall be possible by selection of a controllable device, manually entering the set point value, and executing the control. Feedback of this action will be the relevant measured value.

AGC as well as other applications shall be able to issue set point controls through SCADA towards Power Stations, Wind Parks, or others.

4.3.5 Control Action Monitor

The response to all control actions shall be verified by monitoring the appropriate feedback variable. A report-back timer (the duration dependent on the type of device) shall be initiated when the command is issued. The report-back timers shall be adjustable for each controlled device independently.

The operator shall be provided with an indication that a control action is in progress and a report of the result. If the control is unsuccessful, an alarm shall be generated.

4.4 Tagging

The system shall allow tags to be attached to and removed from a specified device or section of a network.

Tagging Definition

The tagging definition function shall enable the user to define tag types. A tag type defines the effect that tags have when placed on a device.

It shall be possible to define the following tag types:

- Control inhibit;
- Removed from operation;
- Grounded;
- Permit to work;
- User defined tags.

The SMO software engineer shall be able to define the tag symbol to be displayed for each tag type as well as the function of the tag.

Tags shall be able to be placed on any technological level such as Substation level, Bay level, equipment level and device level.

Tags shall apply in hierarchical order for the subordinated technological levels; this means that tags set in the bay level shall imply the tagging of all the elements included in the respective bay.

A priority shall be assigned with each tag type in order to uniquely identify it on the SCADA single-line diagram.

Tag Placement and Removal

The tag placement function shall allow the operators to place tags on devices to prevent them from closing or opening or to inform the operators of any special condition. It shall be possible to place multiple tags on a device. Only the tag with the highest priority shall be displayed.

The system shall keep track of tag placement and removal (i.e. associated date and time) along with the name of the operator who issued the request.

Operators shall be able to enter informational texts associated with the tags.

Operators shall be allowed to remove tags. Placement and removal of tags shall be permitted only for devices which respect the authorization conditions assigned to the operator. All actions on tags shall be recorded as events.

Facility for listing of all tags on the system in each category with all recorded information shall be offered.

It shall also be possible to provide/print a report on each tag that will include all information entered by the operator and information related to the tag (i.e. at least: Date/Time of Tag Placement, Tag Level, Substation Identifier, Device Identifier, Comment Field, User or console who placed the tag).

When a control order is rejected because of a tag placement, a clear explanation message shall be shown on operator displays.

4.5 Switching Management Facility

The SCADA System shall include a Switching Management Facility to assist the operators in the creation and the management of Switching Procedures.

A Switching Procedure may consist of single controls or a list of control operations to be directed by the Operator when carrying out a pre-defined Control Sequence for switching elements of the Power System.

The Switching Management Facility shall provide convenient capabilities for the management of Switching Procedures such as manual creation, automatic creation, display, sorting, copying, saving, restoring, removing, selecting and printing of Switching Procedures.

Moreover it shall support the approval, modification, supervision and execution of Switching Procedures.

It shall be possible to execute previously defined Switching Procedures in real-time.

Switching Procedures shall be displayed and stored in the SCADA System for retrieval, according to the following attributes indicatively:

- Title/Name of Switching Procedure;
- Number;
- Type (e.g., normal/daily/weekly/on disturbance/on request/scheduled etc.);
- Scheduled start and end dates;
- Time of creation;
- Version/Modification history;
- Status (notified/planned/approved/active/rejected/closed etc.);
- Work Crew for execution;
- Author (Operator ID);
- Approved by (Operator ID);
- Areas of responsibilities;
- Notes.

The attributes should be defined and customized during the Detailed Design Phase of the Project.

Creation of Switching Procedures

The SCADA System shall include an interactive tool to assist the user with the creation of Switching Procedures.

Manual preparation of the Switching Procedures shall require as little data entry as possible. This shall include the ability to start from an existing Sequence.

Each Switching Procedure shall include a header and a main body.

The header shall contain general information according to the attributes as listed above for management and retrieval.

The main body of the Switching Procedure shall include multiple entries defining the switching actions to be taken.

The user shall be able to define time delays, waiting steps and breakpoints between steps as part of Switching Sequences. Each entry shall have an entry number.

The System shall provide for check routines on topological and interlocking conditions.

Maintenance of Switching Procedures

After a Switching Procedure has been created, the user shall be able to save it for future use. The SCADA System shall maintain a directory of Switching Procedures. The user shall be able to use the directory to review, copy, rename, print, and delete Switching Procedures and to call them up for review and modification.

Appropriate functionality shall be provided by the Facility for authorization and approval of Switching Procedures according to NII SMO's organizational and operational regulations.

Switching Procedure Execution and Checkout

The user shall be able to execute Switching Procedures in real-time. Execution shall take place in proper sequence automatically or in manual step-by-step mode based on assigned breakpoints. All built-in time delays and breakpoints shall be recognized. Alternatively, the user may temporarily assign new time delays and breakpoints.

After successful completion in real-time mode, the Switching Procedure shall be indicated as completed and further stored in the SCADA System.

Event processing and reporting of the Switching Procedures shall be performed according to the provisions stipulated in the respective earlier paragraphs of this section.

4.6 Dynamic Network Coloring

The SCADA system shall include a Network Topology Processor function.

The Network Topology Processor shall analyze the status of network switching devices, such as breakers and disconnectors, in order to define the configuration of the network.

The status of the network shall be determined and highlighted according to parameterizable colors by a dynamic network coloring facility.

The network coloring facility shall be suitable to give Operators a clear presentation and view of the network status on operational displays.

The dynamic network coloring facility shall be designed in a way to make it exploitable in order to assist Operators in special disturbance scenarios, such as restoration of the Power System after a blackout.

The dynamic network coloring shall fulfill the following requirements:

- Fast performance for changes in network coloring as a result of changed status in the network;
- Flexible choice of colors for individual coloring of respective sub-networks.

In addition to alternative colors, it shall be possible to dynamically assign different line widths to the corresponding sub-networks according to their status.

The energization of lines, transformers, and generating units shall be determined so that the overview displays will correctly show, in different colors, the status of these power system elements as energized, de-energized, or grounded.

In case of electrical islanding, the topology processor shall identify each island.

The configuration shall be re-evaluated and updated after an adjustable time delay following a change-of-state of a switching device and shall also be executable on demand.

There shall be no limitation on the number or configuration of network switching devices required to define the energization status of lines, transformers, and generating units.

Coloring according to the Electrical Status of the Network

The system shall provide for topological network coloring according to the electrical status, showing the state of switching devices and the interconnection of sub networks and substations.

The following states shall be distinguished:

- Energized;
- Load flow possible;
- De energized;
- Grounded;
- Inconsistent / not plausible;
- Out of service;
- Undefined.

Detailed requirements for network coloring according to tags shall be defined during the Detail Design Phase of the Project.

Coloring according to Load

Alternatively to the topological network coloring, it shall be possible to choose coloring according to the load.

Coloring shall be possible to assign to multiple percentages of load by parameterization.

Coloring according to Voltage Levels

It shall be possible to choose coloring according to voltage levels. Operating equipment of the same voltage level shall be indicated with a unique color.

Coloring according to Electrical Nodes

Nodes are defined as the ensemble of impedance-free connected network elements. All nodes shall be colored correspondingly.

Nodes shall be segregated by lines, transformers and open switches.

Coloring according to Disturbances

In order to have a clearly arranged overview of the network, in case of disturbances and to facilitate localization of operational malfunctions, the network shall be possible to be visualized in "disturbance coloring mode" on request by the operator.

The Contractor shall describe the facilities provided by the new EMS for covering this item in the Detailed Design Phase of the Project.

4.7 Historical Data Recording (HDR)

Disturbance data collection and presentation for Post Mortem Review and Historical Data Recording (HDR) functionality shall be provided.

The SCADA system shall offer a tool for Historical Data Recording (HDR) of all SCADA analogs and points. The selection of the data that should be recorded shall be user definable on a per item basis.

The user shall be able to perform the following functions on the HDR data:

- Load user selected HDR data for a user defined time period into text files or EXCEL files or into any other user friendly presentation format for reviewing and exporting them from EMS.
- Reconstruct HDR data in a different DB than the real-time EMS DB (same structure), where the One-line displays (substation displays) can represent a replay of the past situation of the Power network, for short-term detailed analysis.
- Store the HDR archives as files, facilitated and efficiently managed by a fast and large offline-storage media system e.g., LTO library.

Formats and storing of HDR files shall be defined in detail during the Detailed Design Phase of the Project.

4.8 SCADA Telecommunication Daily Statistics

The SCADA system shall include a software tool that will run automatically every day at the end of the day (just after midnight) and it will collect and present with an hourly analysis the complete statistical performance during the previous 24 hours period of both communication paths of all the RTUs of the island. The report shall include for each communication path and for every hour at least the following attributes:

- Name of the communication path;
- Number of hourly communication attempts through this path;
- Number of hourly no reply errors;
- Number of hourly CRC errors;
- Number of hourly any other errors (beyond the above two categories).

The same tool shall produce a second brief statistical report with the same information as the above. The brief report will present the daily performance of each communication path on a single line containing the above attributes showing the accumulated numbers for the whole 24 hour period.

Both reports shall be in an ASCII table-like format (MS Word document, EXCEL worksheet, etc.) and shall be stored in two separate files.

4.9 Data Presentation and Reporting

4.9.1 Trend Displays

For presentation of data in curve diagrams, trend diagrams shall be available.

Basic requirements for Trend Displays refer to those already been set forth in Section 3.3.6.

4.9.2 Single Line Diagrams

Archive data shall also be possible to be displayed in Single Line Diagrams. Basic requirements for Single Line Displays refer to those already set forth in Section 3.3.3.

For the presentation of value archive time series within Single Line Diagrams, the EMS shall provide facilities for tape-recorder like controls to play, fast-forward, rewind and stop playback data replays of archived time series.

4.9.3 Area of Responsibility

The Local ECC will fully cover all the functions of controlling and monitoring the Island.

The Athens Control Center will monitor the Island remotely via WebUI displays.

4.10 Inter Control Center Protocol

The NII SMO´s new EMS shall be able to exchange real-time SCADA data with other Control Centers utilizing the standard communication protocol IEC 60870-6 TASE.2.

Such TASE.2 connections shall be used for data exchanges with Distribution Control Centers for the NII. The synchronization should either be implemented through IEC 60870-6 TASE.2 protocol and only though proprietary protocol in case it provides clear advantages to the system communication and on the condition that it should be fully documented and licensed to be used for the NII SMO IT system expansion.

The Contractor shall provide a redundant infrastructure of ICCP servers for both the main and backup systems. The TASE.2 servers shall be equipped with a complete application environment that shall manage in an efficient and user friendly way at least the following tasks (by offering an HMI similar to that of SCADA):

- TASE.2 connections and TASE.2 data modeling and verifications;
- TASE.2 operation parameters tuning;
- Bringing online new TASE.2 models;
- Operating the real-time TASE.2 connections and data;
- Switching over between the redundant TASE.2 servers.

The TASE.2 time database that will be hosted in NII SMO's TASE.2 servers should be capable to exchange the anticipated within 10 years real time data with Distribution Control Centers.

It is assumed that all other relevant TASE.2 database records and necessary infrastructure shall be sized accordingly.

The TASE.2 database and application offered by the Contractor shall be capable to manage at minimum the above numbers maintaining a good performance and a user friendly HMI.

4.11 Data Exchange with Substations and Plants

In order for the EMS functions at the Control Center to operate properly, they must receive primary data from the Power Plants, Wind Farms, Solar Farms, future RES and Storage Stations, and Power System Substations of the Island.

The RTUs installed in the Substations, will collect data from the electric system of the island and will send them to the Control Center.

The Control Centers will be able to collect data concerning the Power Plants either from the existing systems at Power Plants after suitable modifications e.g., communication hardware supporting IEC 60870-101 or 104 depending on the communication lines, or from new RTUs which will be installed at the Power Plants.

For data exchange with RES, respective RTUs should be used, or if local systems for controlling and monitoring are available they should be modified with the installation of proper equipment in order to communicate with the Control Centers.

The exchange protocols will be determined during the Detailed Design Phase of the Project.

4.11.1 Data Exchange with Power Plants

4.11.1.1 Telemeasurements and Setpoints

The SCADA/EMS should receive the following tele-measurements and set-points:

- Gross production (MW, MVAR) from every unit, current (Amps) and voltage (kV) and the same values for Net production;
- Auxiliaries (MW, MVAR) for every unit and station auxiliaries;
- Current and Voltage excitation;
- Set-point feedbacks;
- High and low limit production for every unit, fuel measurements and maximum daily capacity for every unit.

This is an indicative list. The exact list will be determined during the Detailed Design Phase of the Project. The SCADA/EMS should be able to send set-points with values in order to regulate the units. These set-points should be for Active Power (MW) regulation and for Reactive Power (MVAR) or Voltage regulation.

4.11.1.2 Telesignals and Controls

The EMS should receive the following tele-signals and controls:

- Status of switching devices i.e. circuit breakers, disconnectors and grounding switches of the units represented by double pole indications;
- Alarms and trips protection of units;
- Signals for every unit indicating its regulation mode, e.g., ON AGC Control, Voltage Control, etc.;
- Signals of every unit indicating if the unit is ON production or not;
- Signals of every unit indicating if a unit must re-declare the technical limits.

This is an indicative list. The exact list will be determined during the Detailed Design Phase of the Project.

The SCADA/EMS should be able to send Emergency Trip to a unit in case there is a major problem in the electric system.

4.11.2 Data exchange with Substations which are Under the NII SMO Control

From the substations that are under the NII SMO supervision there will be the following data exchange between the substations and the SCADA EMS at the minimum:

4.11.2.1 Telemeasurements

- Active and reactive power, current, voltage and frequency for every switching device of power lines;
- Voltage and frequency for every bus-bar;
- Active and reactive power, current voltage and oil temperature of every transformer in the substation.

4.11.2.2 Telesignals

- Status (OPEN/CLOSE) of every switching device like circuit breakers, dis-connectors and grounding switches at the substation that is under the NII SMO control – lines, transformers, capacitors, reactors;
- Double pole indication for every auto-reclosure switching device at the substation (ON/OFF);
- Double pole indication for every tele-control device at the substation that indicates if the device can be tele-controled by the Control Center (LOCAL/REMOTE);
- Alarms and trips from relays such as protection relay, overcurrent relay of lines devices and transformers;
- Alarms from substation communication devices, batteries, chargers etc.

4.11.2.3 Controls

The SCADA/EMS should be able to send the following controls:

- Controls (OPEN/CLOSE) for the lines' switching devices;
- Controls (OPEN/CLOSE) for the transformers' switching devices;
- Controls (OPEN/CLOSE) for the capacitors' switching devices;
- Controls (OPEN/CLOSE) for the reactors' switching devices;
- Raise/Low of Tap Changers.

4.11.3 Data exchange with RES

From the RES there will be the following data exchange between the RES facilities (current and future RES, e.g., solar thermal, hybrid, biomass) and the SCADA EMS at the minimum:

4.11.3.1 Telemeasurements and Setpoints

- Active and reactive power, current, voltage from the renewable farm and system connection switching device;
- High and low limit production;
- Wind speed and direction from Wind farms;
- Measurements of insolation from Solar farms;
- Set-point feedbacks (from dispatching renewable farms);

The dispatching renewable farms should be able to receive set-points for reducing or regulating production.

4.11.3.2 Telesignals and Controls

- Status of switching devices i.e. circuit breakers, disconnectors and grounding switches of the renewable farms, represented by double pole indications;
- Double pole indication that a renewable farm can be controlled (LOCAL/REMOTE);
- Alarms and protection trips from the switching devices of the renewable farms;
- Emergency trip of the switching devices of the renewable farms;
- Digital set-points for immediate or predetermined time interval reduction of the production to zero in cases of emergency situations.

5 Automatic Generation Control

5.1 Introduction

Following the introduction of the Electricity Market, the economic functions that were previously embedded in the traditional AGC and performed by Economic Dispatch (ED), are now performed by the Real Time Dispatch Application. AGC still performs the system control but according to the Real Time Dispatch (RTD) Application results.

After this separation of the economic function from AGC, when AGC operates in an Electricity Market environment it has to closely co-operate with RTD, so that AGC can implement the system control based on the RTD results.

RTD performs the economic function based on techno-economic data and AGC performs the reliability function to keep the system in a reliable state based on the input received by the RTD.

To achieve this cooperation a new module (AGC RTD module) was added to the AGC that is communicating with the RTD Application to exchange real time information and to receive base-points and other economical information needed for the AGC operation.

The LFC module of AGC that performs the system regulation and control is not affected and still remains unchanged. Both AGC RTD and ED modules in AGC are tightly connected with the LFC module.

The RTD application considers the generation costs and provides the RTD results to the AGC as a reference. It does not use priced bids from Market Participants. So in this project, this is a cost-based RTD application.

The following diagram presents the typical AGC diagram and its communication with units / plants adapted with the new RTD module for illustration purposes only.

Even though the RTD in its current form is not a market function since it is not deploying offers from the Market Participants, instead is using generation cost data, in the diagram below we use the term "Market Base Point" and RTD Market application to signify the fact that in the future an RTD market application can be implemented which can produce market results.

In the next sections, the following requirements are listed:

- AGC Main Requirements (Section 5.2);
- AGC Co-operation with RTD (Section 5.3);
- AGC Interfaces (Section 5.4);
- AGC Main Components (Section 5.5);

- Load Following (Section 5.6);
- AGC PI Controller Requirements (Section 5.7);
- AGC Operation and Status Modes (Section 5.8);
- Unit/Plant Control Status (Section 5.9);
- Unit/Plant Limits (Section 5.10);
- Plant Logic Controllers in AGC (Section 5.11);
- Alarm Processing for AGC (Section 5.12);
- Outages and Derates (Section 5.13);
- Predictice AGC Functionality (Section 5.14);
- Aggregate Resource Modelling (Section 5.15);
- Instructions Recording and Associated Calculations (Section 5.16);
- AGC Wind Monitoring and Control Function (Section 5.17).

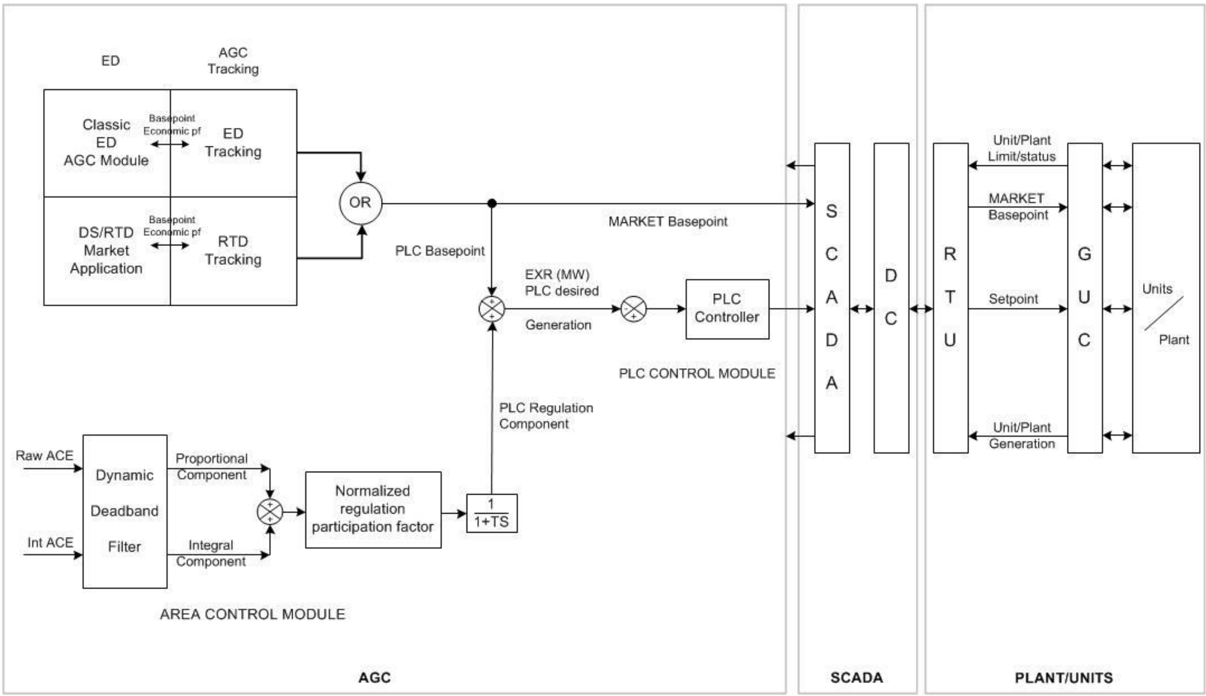

Figure 5-1. Typical AGC diagram

5.2 AGC Main Requirements

The AGC application should meet the following main requirements:

- AGC should be able to operate in an Open Market Environment and when necessary without market, based on cost-based RTD algorithm.

- AGC should be able to be customized to meet the control of autonomous systems in the NII, but it should also have capabilities to operate a group of interconnected islands.
- AGC will issue all Real-time instructions to dispatch all resources reliably and to monitor their response.
- AGC main responsibility is the reliability and security of the power system operation and control.
- AGC should cooperate with the RTD application and exchange the information needed to perform the real time control based on the RTD solution through an appropriate interface.
- RTD co-operates with the AGC application by exchanging appropriate information.
- AGC should be able to operate and issue control commands even in cases of RTD failure or break of its connection with RTD.
- AGC should be able to operate either in Market environment or in an environment without Market with the activation of the cost-based RTD module.
- AGC will communicate through SCADA with all generating resources and tie-lines (if they are available in the future) to collect, all real-time data and to issues the dispatch instructions of all resources.
- AGC should be fully compliant with the principles of the ENTSO-E Operational Handbook requirements and where necessary should be adapted to meet the special requirements for the NII.
- The AGC program shall be configurable and easily adaptable to meet the technical requirements of the NII SMO.
- AGC should have appropriate extension for the management of over generation conditions by issuing max permissible generation commands to non-dispatchable renewable generation.

5.3 AGC Co-operation with RTD

Although the cost-based RTD function is described in the MMS Tender Part C, it is briefly presented here in order to make clear the AGC functionality and its cooperation with RTD.

The RTD calculates, periodically or upon AGC trigger, base-points for all units (re-dispatches generation) by minimizing cost objective based on the techno-economic generator cost data and prioritizing RES absorption as per Code Requirements. The RTD optimizes the generation dispatch considering the actual data and conditions (measured production, actual capacity limits, synchronization and control status of the units and the ramping capabilities of the on-line units, etc.) as well as the very short term load and RES generation forecasts within the next 5 minutes.

Typically the RTD executes automatically every five (5) minutes but under certain conditions AGC or a system operator request can trigger its execution. The AGC should trigger the RTD to run (for an “out of sequence” execution) upon the occurrence of a specific system conditions, such as a significant change in power system load, a change in any generating unit’s operational status, a system emergency or a change in the control mode, etc. The RTD re-optimizes the energy production while meets primary and secondary reserves, according to the current system conditions. The operator will also be able to specify manual dispatch instructions or constrain the dispatch of any unit. These manual instructions and constraints must be classified and recorded for auditing purposes and for settlements.

The RTD provides the base-points for the units/plants to the AGC RTD module. Then the base-points are processed by the AGC by considering respective regulation component of the units and dispatch instructions are calculated and issued to all dispatchable units/plants. For the units that are not automatically controlled by the AGC but participate in the market, the RTD notifies each unit, through the SCADA subsystem of EMS, the respective base-point as a manual instruction. These manual instructions (unfiltered base-points) are communicated and presented to the station Operators in appropriate displays in the control rooms of the power plants and the operators should execute even manually these dispatch instructions. There are 3 control rooms for the power plants in Rhodes.

The RTD considers the problem as a constrained linear optimization problem, consisting of an objective function (operational cost minimization with maximum possible RES absorption), a set of decision variables (quantity to be allocated for each unit), and a set of linear constraints (equality or inequality constraints). It uses a Linear Programming model that allows the inclusion of properly linearized energy and security type constraints directly into the problem formulation. It includes in the solution the units that are detected actually as on-line and it acquires upward and downward secondary reserves from the units that are at that time in AGC mode.

The RTD re-optimizes the dispatchable unit’s base-points to minimize the objective function while meets the secondary reserve requirements provided by the units that actually participate in AGC regulation in real time. These units are automatically recognized by RTD through the information coming from EMS. The RTD can dispatch base-points to a unit in its secondary reserve range and it has constraints related to the total system secondary reserve requirements. In case reserve requirements are not met appropriate alarms are issued to alert dispatchers to take necessary actions.

The RTD requires a load and RES forecast for the next 5-min intervals in its time horizon. This forecast will be derived from the Very Short Term (5 minutes) Forecasting Application.

5.4 AGC Interfaces

AGC should be fully integrated to the EMS platform and it should be able to exchange information with all EMS real time aplications.

AGC uses EMS telemetry data as well as external data from other external systems. The AGC interfaces are with the other EMS applications such as SCADA, Network, Reports, HIS, etc., and with the MMS and exchanges appropriate data either through direct DB access or .xml file exchange.

AGC exchanges data with the market system through a communication interface by direct access to the databases or .xml file exchange or other robust data exchange technologies such as web services. Data exchange between EMS and MMS systems are presented in this document.

The communications with the new units will be made based on the IEC protocol 101-104 while the communications with the older units will be made based on display terminal with alarms. Unit limits and availability will be communicated from the units to the RTD system.

5.4.1 Telemetry Data

The data exchange that should be implemented for the AGC operation is based on telemetry data. The minimum telemetry data needed include the following:

- Tie line MW (may be in the future);
- Unit gross MW and station auxiliary MW or unit net MW;
- Breaker status;
- Unit local/remote control status;
- System frequency measurement;
- System accumulated time error measurement;
- Unit limit settings.

All the LFC telemetry values shall be filtered in order to be used by the AGC application for control purposes. Separate filtering constants shall be used for each of the individual points being smoothed. It should be possible for the AGC analysts to change the setting of filtering constants and even to eliminate the filtering. Moreover, data for the scheduled exchanges through interconnection lines will be handled by AGC with proper function of the module ITS (Interchange Transaction Scheduling) described in the respective section of this document.

Redundant measurements shall be available for the critical data associated with the AGC operation such as frequency and tie line power flows (if available). Both the primary and the backup measurements shall be compared. An alarm shall be issued if the deviation exceeds a predefined limit (if this alarm function is enabled with a use of a specific flag or with an appropriate use of an offset).

Primary telemetry source measurements shall be used by the LFC function unless a primary measurement is determined to be invalid, in which case the alternate measurement, if it exists, will automatically be used. For a measurement to be concluded as invalid it must be in the telemetry error condition and/or deactivated. Manually entered values are considered as good values except for frequency telemetry and the time errors.

5.4.2 Data Exchange between AGC and RTD

The data exchange between the RTD and AGC will be implemented using XML encoding. The data exchange mechanism should be robust to meet the security of operation based on the actual or latest data with appropriate confirmations between senders and recipient for the data handling and for data validation. Appropriate time stamping should be used in order to be sure that the correct data are exchanged. In case a file is invalid or the process that is responsible for the file retrieval fails to execute a warning message should be displayed to the corresponding EMS screen.

Data to be transferred from the RTD application to the EMS (AGC) are transferred either at plant level or at unit level considering the type of units (depending on modeling of aggregated resources, if any).

Indicative set of data that will be exchanged from RTD to AGC are as folows:

- Base-points (MW) in gross and in net values;
- Regulation Limits used in RTD;
- Indication flag that unit can follow RTD instructions;
- Regulation Ramp Rates of units;
- Costs of units to be used by AGC for calculating economic participation factors;
- Declared technical minimum and maximum and low and high limits of the units forbidden zone (if exists).
- Hourly production declarations of dispatchable RES units.

Indicative sets of data that will be exchanged from AGC to RTD are as follows:

- Telemetered gross power output (MW);
- Telemetered quality flags associated to the quality flag of respective telemetered values from plant (e.g. generation, limits);
- Resource Regulation flag (Y/N);
- Regulation Paused Flag (Y/N);
- Regulation Suspend Flag (Y/N);
- High operating limit (MW) from plant to be respected when re-declared in real time;

- Low operating limit (MW) from plant to be respected when re-declared in real time;
- High regulating limit (MW) per unit and per plant (for cases of aggregated resource modeling e.g hydro plants).

It is reminded also that it is required in other Sections of this document, that in addition to the above described data, other information should be transferred from MMS to EMS, that will not be transferred with the above described XML messages that are communicated normally every five minutes for the co-operation of RTD and AGC.

Such information includes:

- The declared fuel cost, including the cost of emissions, for each unit by the producer (available on daily basis in MMS database to be used by RTD and OPF);
- The schedules in interconnection lines (future item when interconnections are available);
- The system reserve requirements (available in a market platform database normally every day for each one hour for primary, secondary up and down and tertiary reserve to be used by Reserve Monitor function).

The Contactor has the responsibility to create a mechanism to retrieve these files and make the related information available to be used by the EMS applications.

5.4.3 RTD/AGC Conflict Management

The AGC should always abide by the RTD dispatch instructions except when the reliability of the system is jeopardized.

In cases of a conflict between RTD and AGC the AGC should ignore the RTD base-points and should issue a trigger for the RTD (to run an “out of sequence” run) and produce new base-points. Additional capabilities to face emergency situations, with automatic activation or by manual intervention of the operator should be provided. This includes, forcing the AGC to ignore the base points and by default replace them with actual generation.

5.5 AGC Main Components

The main AGC Components are:

- Load Frequency Control (LFC) function;
- Economic Dispatch (ED);
- Time – Error Correction;
- Reserve Monitoring;
- AGC Performance Monitoring & Analysis; and

- Adaptation of AGC for Multi-Area Control.

These functions are analyzed in the following sections.

5.5.1 LFC function

The AGC is used to automatically run, typically every two (2) seconds, to balance a control area.

This balancing is performed through the LFC, which is the main AGC module, that calculates and sends control data to units on regulation based on based points calculated by the ED adapted with the regulation component.

The Regulation component is calculated for each unit according to respective units / plants regulation participation factors.

5.5.1.1 Calculation of ACE

The imbalance of a control area is represented by the area control error (ACE) that is calculated as follows:

$$\mathbf{ACE = \Delta P + K * \Delta f}$$

where:

ΔP: interconnections exchange power control error (P measured – P total exchange program where the power transits are considered positive for export and negative for import). <u>This term is not applicable in the current configuration of the NII</u>.

Δf: frequency control error (f measured –f setpoint).

K: K factor (in MW/Hz) corresponds to the slope of power-frequency control characteristic line of the power system. Its value is calculated for each control area.

The AGC shall regulate the power output of generators in response to changes in system frequency and tie-line loading, real-time system load, or the relation of these to each other, in order to maintain the scheduled system frequency and/or the established net interchange with other Control Areas within predetermined limits (scheduled).

In other words, AGC will automatically use regulating units to minimize the magnitude of ACE (keep frequency to the nominal value and interconnection schedules to the schedules) and to follow the load.

The LFC module uses as input base-points (either calculated from RTD or from ED module representing the economic dispatch instruction or manually entered or calculated values (as average between certain limits, scheduled values, etc.) and telemetry data to calculate the setpoints for the units in regulation needed to minimize the ACE.

The ACE is distributed to the regulating units according to the regulation participation factors that are calculated according the respective unit response rate along with additional economic parameters.

The amount of “regulation” for each regulating unit should be within a regulating margin equal to the respective secondary reserve range and it is summed up to the base-point to build up the respective “set-points”, that is issued to the regulating units / plants as a dispatch instruction that has to be automatically implemented.

It is noted that for a unit that is regulating in any way the base-point and set-point will not be necessarily the same.

The AGC program shall be executed every two (2) seconds, and compute and process the Area Control Error (ACE) and sends commands every four (4) seconds. The issuance of commands every 4 seconds should be a parametric value. The relevant ENTSO-E requirement is “the cycle time for the automatic SECONDARY CONTROLLER should be between 1 second and 5 seconds”.

The AGC ACE calculation mode shall be selectable by the System Operator, via an appropriate Operator display, and at a minimum shall include the following three control modes depending on ACE calculation formula:

CF: Constant Frequency control.

The Constant Frequency mode is used to keep the frequency at a constant (50 Hz) by having a frequency bias. This mode is used for autonomous systems or automatically switched to when the system becomes an electrical island.

CNI: Constant Net Interchange control.

The Constant Net Interchange mode is used to keep Actual Net Interchange to the Net Scheduled Interchange. This mode is used in special cases that need to minimize interchange error or switched automatically when the system frequency telemetry fails or the system is unable to calculate the frequency deviation correctly and/or it has an error.

TLB: Tie-Line Bias control.

Tie Line Bias mode will regulate the control area using the normal calculation of ACE of both interconnection and frequency components. This is the default control mode.

The Programmed (scheduled) Values for Secondary Control (e.g., for power exchanges and frequency set-points) must be entered as time-dependent set-point values based on schedules.

According to the above convention ACE greater than zero indicates that the system generation must be decreased while ACE less than zero indicates that the system generation should be increased and always the ACE should be controlled to zero on a continuous basis.

The AGC system should be able to easily change the desired mode of operation seamlessly and without complicated procedures.

In order to maintain time control an offset in the set point value of frequency in Secondary Controller must be foreseen in the AGC system. A facility should be provided so that the frequency program values could be scheduled in a scheduler who provides the capability to define the frequency programs for at least seven days on hourly basis.

Moreover, the AGC system should have a Time Error Correction mechanism of the AGC system (enabled by flag) in which the time error is monitored and a time error bias (in MW/sec) or other equivalent bias factor is used.

When in the CNI and TLB mode the AGC shall have provisions for the dispatchers to update the interchange schedule values that are provided by the ITS function. The inadvertent interchange corrections should also be supported by the AGC application. Further details about the functionality of ITS and for calculation of inadvertent payback are presented in the relevant section of this document.

5.5.1.2 Calculation and Use of Regulation Participation Factors

The regulation participation factors are used to distribute the ACE regulation to the regulating units / plants. The unit regulating participation factor calculation is part of the AGC internal design and methodology to divide up the regulation signals amongst all regulating units. This calculation should take into account the change of production that can be achieved by each regulating unit in the next AGC cycle considering the ramp rate and available secondary reserve in the desired direction. The ramp rate for units on regulation should be the declared or registered regulating ramp rate (different values for upward and downwards direction should be available). For aggregate resources the unit regulating participation factors, that are required to divvy up the signals amongst the physical units of the aggregated resource, should consider the units, comprising the generating entity (power plant in this case) that are in operation during real time operation. There must be also an option to use the telemetry ramp rate for the resources, when this kind of measurement is available for the units in regulating mode. Moreover, the calculation of the regulation participation factors should be flexible enough to be modified to adapt it in future could be used depending on the market model for ancillary services.

5.5.2 Economic Dispatch

The AGC Economic Dispatch should be able to operate in two different modes by activation of respective ED modules.

The two AGC ED modes are:

- Cost-based RTD (or Classical ED) Mode;
- Market-based RTD.

5.5.2.1 Cost-based RTD (or Classical ED) Mode

This is the classical mode of AGC operation and should be the normal mode of ED operation in this project. This is the only function which will be developed in the project.

The ED program shall be executed periodically to allocate total generation among available dispatchable units in such a manner as to optimize a selected system variable and shall provide the economic participation factors for each unit. The respective base-points calculated by the cost-based RTD between the successive RTD executions should be used by the RTD ED module. Between the successive RTD executions, the RTD ED module will periodically, typically at the cycle of LFC module, adapt the base-points through the RTD tracking module, to follow the current conditions. This adaptation is based on the economic participation factors that are communicated from the cost-based RTD application along with the base-points.

The basic cost-based RTD algorithm shall minimize the incremental cost of power delivered to meet power system load using unit incremental heat rate (IHR) curves, fuel costs and Island's Network loss penalty factors. The cost-based RTD should correctly model Combined Cycle units and the operating range of a unit. In this mode, the cost-based RTD should take into account heat rate curves, fuel cost and constraints. All rules in the Code about RES management apply.

The cost-based RTD program shall have the capability to optimize other parameters when expressed in economic terms such as Island's Network losses.

The cost-based RTD program shall be executed typically every five (5) minutes (it will be a configurable value) or upon the occurrence of certain conditions (enabled by respective flags) such as:

- Significant change in power system load;
- Change in any generating unit operation status or control mode;
- Change in any generating unit limit;
- When a new IHR curve is selected for any unit;
- System Operator request.

In addition to calculating the incremental cost for each unit, the cost-based RTD program shall calculate a generation plant incremental cost. The unit incremental cost (UIC) or plant incremental costs (PIC) shall be available for Operator displays, calculating variables and for producing logs.

The cost-based RTD should be able to operate using the cost curve data that are submitted by the producers to the market platform (the heat rate curves are rarely changed since are considered to be static data while the costs like fuel cost may change every day for each unit). The cost-based RTD should have the ability to import these data to input tables and execute the cost-based RTD.

If in the future a market-based RTD is implemented, the switching from the cost-based RTD to the market-based RTD mode and vice versa will be accomplished in an easy and smooth way, e.g., without requiring a failover.

The cost-based RTD module shall also be available in a study mode in order to support studies for production cost etc, using and snapshots from real time operation. The real time operation with the cost-based RTD (or the market-based RTD) execution shall not be affected when study ED is operated.

The AGC will normally operate based on the base points calculated by the cost-based RTD and the market-based RTD function.

5.5.2.2 Market-based RTD Mode

This mode may be developed and implemented in the future. It is not part of the current project, but the system should be configured for a smooth transition to this mode when it is implemented in the future.

The RTD Market application shall be typically executed every five minutes or upon an AGC trigger to provide the base-points used by RTD ED module. Between the successive RTD executions, the RTD ED module will periodically, typically at the cycle of LFC module, adapt the base-points through the RTD tracking module, to follow the current conditions. This adaptation is based on the economic participation factors that are communicated from the market-based RTD Market application along with the base-points.

The RTD ED module should be able to continuously minimize the generation movements and energy imbalance around the base-points provided by the RTD. This optimization is implemented by the use of the economic participation factors provided by the RTD application for each unit.

The AGC should trigger the RTD Market application to run (for an “out of sequence” run) upon the occurrence of specific conditions such as:

- Significant change in power system load;
- Change in any generating unit operation status or control mode;
- Change in any generating unit limit;
- When a new IHR curve is selected for any unit;
- System Operator request.

The AGC shall trigger or not the RTD to run, taking into account and a respective flag (Trigger RTD enabled: Y/N) which will be available in an AGC analyst display.

Market-based RTD tracking

When AGC co-operates with Market-based RTD the Economic Participation Factors can be indicatively calculated according to the following rules. For all plant controllers (PLC) that are used by the tracking module (generating entities under automatic regulation receiving basepoints from RTD mode and not suspended), an adjustment component is added to value of desired generation using the following formula:

ADJUSTMENTPLC = TOTAL ADJUSTMENT * (ECOPFPLC / sum of ECOPFPLC that are taken into account by the tracking module)

where TOTAL ADJUSTMENT is the calculated difference between the generation demand (taking into account the ACE) and the sum of current basepoints of the regulating units and the current production of the others in the system (the calculation is done with appropriately filtered values for each component). The Economic Participation Factors (ECOPFPLC) can be indicatively calculated by the following formula:

- If λ1 PLC = 0 then ECOPFPLC = 0 for positive total adjustment (e.g. when unit is out of operation)
- If λ2 PLC = 0 then ECOPFPLC = 0 for negative total adjustment (e.g. when unit is out of operation)
- If Total Adjustment > 0 (i.e adjustment requires increase of generation): ECOPFPLC = λ1 PLC
- If Total Adjustment < 0 (i.e adjustment requires decrease of generation): ECOPFPLC = λ2 PLC

where λ1 PLC is computed by the RTD and is associated to the offer price of the unit in the market for increase generation (up) λ2 PLC is computed by the RTD and is associated to the offer price of the unit in the market for decrease generation (down) It is also noticed that in certain cases the RTD will produce loading values which have no respective price offers. In this case predefined values of λ PLC are transmitted to AGC. This special treatment in AGC will be described in detail to the Contractor during the detail design phase. An example of this special condition is when a unit is loaded at a mandatory level in the increase direction. In this case this unit takes the biggest priority among the others while in the decrease direction it takes the lower priority).

Finally, in case that an invalid λ value is received by AGC for at least one participating unit then automatically (if in AGC is still active in the mode for co-operating with RTD) the ECOPFs are calculated taking into account the difference of RTD basepoint and the current minimum regulating limit (LFCMIN) of the units as follows:

- IF (base PLC - LFCMIN PLC .eq.0) then ECOPFPLC = 0 for both positive and negative total base adjustment

For a positive total base adjustment:

ECOPFPLC = abs (basePLC - LFCMIN PLC)

For a negative total base adjustment:

ECOPFPLC =1/abs (basePLC- LFCMIN PLC)

If the values of all ECOPFs are zero then all ECOPFs are forced to take the value one in order to have an equal distribution of total base adjustment for all the participating units.

5.5.2.3 Penalty Factors

The ED shall use generator Penalty Factors derived by the Real-time Network Analysis function or a static set as entered in the database to account for the Island's Network losses (depending upon the setting of an appropriated flag).

5.5.2.4 Unit Incremental Heat Rate Curves

The variable costs (and startup costs) will be used in the calculations. These costs are calculated from the incremental heat rate curves of the units. The incremental heat rate (IHR) curve of each generating unit shall be represented by the heat rate curve and by the respective multiple straight-line segments (10 segments, minimum).

The ED function shall support a minimum of four (4) IHR curves for each generating entity and shall allow on-line System Operator selection of the curve as well as automatic switching of curves based on defined criteria (e.g., number of units in real time operation comprising a power plant that is represented as one generating entity, as in the case of hydro plants and combined cycle units).

5.5.2.5 Cost-based RTD Tracking

AGC and the cost-based RTD modules should be able to track (follow) the load for the period between their successive executions. This is implemented though their respective tracking functions that re-adjust periodically the set-points calculated by cost-based RTD and issues updated set-points to the units in regulation.

Simply the unit's desired generation shall be computed as the sum of the base-point and a regulation component plus a tracking component. Normally, the base-points are calculated at each cost-based RTD execution and in between the tracking function calculates the mismatch between the generation demand (considering the ACE) and the sum of current base-points of the regulating units and the current production of the others in the system (the calculation is done with appropriately filtered values for each component). The calculated difference (defined as TOTAL ADJUSTMENT) is distributed to the available regulating units according to a set of economic participation factors.

Economic participation factors are calculated by the cost-based RTD module.

In particular, when AGC co-operates with the cost-based RTD the calculation of economic participation factors will be done according to the following rules:

For all plant logic controllers (PLC) that are used by the tracking module (generating entities under automatic regulation receiving base-points from the cost-based RTD and not suspended), an adjustment component is added to value of desired generation using the following formula:

ADJUSTMENTPLC = TOTAL ADJUSTMENT * (ECOPFPLC / sum of ECOPFPLC)

The Contractor based on the above principle may be given additional requirements by HEDNO during the Detailed Phase of the Project (other than those already resulting from the Tender itself and in principle accepted by the Contractor) in order to comply with the regulatory framework. In the occurrence of such event, a common agreement should be pursued between both parties upon the necessary means to facilitate such modifications. However, the Contractor should beforehand take appropiate measures to enhance and provide a complete solution adaptable to system changes and to consider all exceptional cases such as invalid or zero system dispatch cost, unit at minimum or maximum etc., as well as data synchronization between the cost-based RTD and AGC applications.

5.5.3 Time Error Correction

The Time Error Correction mechanism of the AGC system should have the following functions:

5.5.3.1 Time Monitor

Time should be monitored using the frequency deviation and tracked for time-error correction when needed (which is derived from the integration of the common System Frequency in this zone of synchronous operation) and the actual time (universal time coordinated, UTC).

5.5.3.2 Frequency Set-Point for Secondary Control

For time control purposes, AGC is required to create and involve a displacement in the set-point frequency for control. The System Frequency shall be the nominal frequency value of 50 Hz, so that on average the time deviation results to zero.

5.5.3.3 Time Correction Offset

If the time deviation is within the frequency offset threshold for time correction, then it should be set to zero. If the deviation is outside the threshold of the offset and is behind the actual time, the offset is set to +10 mHz or to another value enterable by the user. If the deviation is outside the threshold of the offset and is ahead of the actual time, the offset is set to –10 mHz or to another value enterable by the user.

5.5.4 Reserve Monitoring

The AGC should be able to periodically calculate the system reserves in real-time (at the AGC cycle). The AGC will support through appropriate displays the monitoring of reserves and release alarms based on defined limits in case of deficiencies.

The Reserve Monitor (RM) function shall calculate and monitor the MW capacity available to satisfy user-entered or imported from market platform through XML reserve requirements. The RM function will track the reserves of each unit and the total system quantities according to relevant telemetered data from the power plants. These quantities should be displayed and checked against the requirements in order to inform the system dispatchers if there is a need for generation capacity to be activated (or de-activated in case of a surplus). This information should also be recorded in the HIS database.

Reserve categories shall include at a minimum the following. The detailed definition of the reserve categories will be determined during the Detailed Design of the Project:

5.5.4.1 Regulating Reserves

Upwards and downwards provided by units under AGC control in active regulation mode. These values are respectively calculated based on the differences between the LFCMAX and LFCMIN from the current production of units being in automatic regulation, selected to participate in ACE regulation and not paused or suspended.

5.5.4.2 Tertiary Spinning Reserves

These reserves are available from synchronized units within a few minutes (e.g., 15 minutes). It is computed taking into account the upwards reserve of synchronized units and a limit value that has been entered by an analyst for each unit (depending on the type and technical capabilities of unit long with the experience of NII SMO for the response of each unit). In this type of system reserve, the contribution of certain interruptible loads (pumps) can be included, if a respective flag for each pumping unit has been selected by the dispatcher.

5.5.4.3 Tertiary Non-Spinning Reserves

These reserves are available from non synchronized units that could be available in operation within a few minutes. It is computed taking into account the difference of the current generation from the technical maximum of the unit where the technical maximum could be either the telemetered capacity by the plant or the respective value received through XML by the RTD. The contribution of non synchronized units is taking into account for the system operating reserve if a respective flag for each unit has been selected by the dispatcher. The wind farms and other non-dispatchable RES units defined by HEDNO will not be considered to contribute to the system operating reserve.

The RM function shall maintain for display to the dispatchers on an appropriate Operator display, an updated summary listing of all RM flags and calculated data including unit control modes, unit generation output and unit limits. Moreover, in the reserve monitor screen it will be displayed the expected response rates of the entire system upwards and downwards (in MW/min) which are computed as the sum of respective declared rates of the units in regulation.

It will be displayed also the ON/OFF position of primary control status of the units (based just on respective digital signal telemetered from each power plant to SCADA). The RM function should have the ability to monitor primary control of units that have been indicated by the operators (with a flag) that are assigned to provide primary control, and track their capabilities to contribute when it is required. Specifically, the RM function will monitor if the scheduled primary reserves per selected unit is available taking into account the above described on/off signal, the actual loading of units and the operating limits as these received in SCADA. It is computed, for the selected units, taking into account the difference of the current generation from the technical maximum of the unit where the technical maximum could be either the telemetered capacity by the plant or the respective value received through XML by the RTD (as in operating reserve). Also, the total available primary reserve in the system should be tracked by the RM function against the defined respective requirement. When violations of primary reserve requirements occur, alarms are issued to the dispatchers.

5.5.5 AGC Performance Monitoring & Analysis

The AGC program shall provide control performance monitoring capabilities based on the current NERC and ENTSO-E Control Performance Criteria. In addition, the AGC program shall maintain statistics for an AGC performance report, according to the ENTSO-E control performance criteria. The AGC program shall have the capability to present at specific operators displays the performance indices on daily basis, at minimum, store the necessary data and calculation outputs in the HIS database. The statistics are associated to frequency, unscheduled exchange deviation and ACE and include at a minimum the following:

5.5.5.1 Statistics for Frequency Deviations (on Hourly and 15 Minutes Basis)

Average

$$\Delta f_{avr} = \frac{1}{n}\sum_{i=1}^{n}(\Delta f_i)$$

where n = number of samples in the reference period (e.g., 1800 in one hour in case that the sampling of SCADA for frequency is 2 sec).

Standard Deviation

$$\sigma_{\Delta f} = \sqrt{\frac{1}{n}(\sum_{i=1}^{n}\Delta f^2{}_t)}$$

where n is described above.

5.5.5.2 Statistics for ACE

ACE Average and Standard Deviation (on Hourly and 15 Minutes Basis)

- Average value of ACE over a time period (e.g., one hour) is calculated as follows:

$$ACE_h = \frac{1}{n}\sum_{j=1}^{n} ACE_j$$

where n = number of samples of computed ACE by AGC in one hour or fifteen minutes (e.g., in one hour and four sec AGC cycle, n = 900).

- The respective Standard deviation of ACE that is calculated over a period of one hour or fifteen minutes is calculated as follows:

$$\sigma_{ACE,h} = \sqrt{\frac{1}{n}\left(\sum_{j=1}^{n} ACE_j^2)\right)}$$

where n is described above.

Monthly Statistics of ACE values

It is performed with the averages ACE for each hour or fifteen minutes intervals of the month, as follows:

$$ACE_{avr,monthly} = \frac{1}{n}\sum_{i=1}^{n} ACE_{h,i}$$

where n = number of hours or fifteen minutes intervals in the month (720 hours or 2880 fifteen minutes intervals in a month having 30 days).

Standard Deviation of ACE

The standard deviation of ACE ($\sigma_{ACE,month}$) is calculated as follows:

$$\sigma_{ACE,monthly} = \sqrt{\frac{1}{n}\left(\sum_{i=1}^{n} ACE^2{}_{h,i}\right)}$$

where n is described above.

The indices σ_{90} and σ_{99} of ACE on a monthly basis should also be calculated.

It is also noted that in order to avoid the big influence that may have on the monthly results the fact that sometimes exceptionally large values of ACE can occur (due to rare unexpected events) it may be necessary to discard the worst values of ACE for each month in percentage of 1%, i.e., the 7 largest (in absolute value) hourly values and 28 largest (in absolute value) 15 minute values. Such details will be clarified with the Contractor during the detailed Design Phase of the Project.

Other statistical indices that should be calculated and displayed are:

- Hourly Mean Tie Line Power Flow (not applicable with the current NII network configuration);
- Hourly Mean Tie Line Power Scheduled Flow (not applicable with the current NII network configuration);
- Hourly Mean Tie Line Power Flow Deviation (not applicable with the current NII network configuration);
- the value of hourly accumulated integral of ACE;
- Hourly Peak ACE, peak load and time instances that occurred;
- Hourly Mean System Load.

Note: The system load shall be calculated by AGC and displayed also in real time and its computation will be completed according to the measurements of generating resources, flows in interconnection lines (not applicable with the current NII network configuration) and miscellaneous load and generation quantities entered by the dispatchers.

5.5.5.3 NERC Performance criteria

These criteria are enforced in the USA but they part of the standard EMS AGC vendor software. The values associated to A1 and A2 NERC Performance criteria (summarized in a one day NERC CRITERIA PERFORMANCE) will also be displayed:

A1 criteria:

Number of times each hour that ACE fails to cross zero in a 10 minute interval.

A2 criteria:

Number of times each hour that the 10 minute average of ACE was greater than a limit (enterable in engineer display).

- the total number of times per hour that criteria A1 and A2 were violated for each hour;
- the average number of times per hour that violations of the A1 and A2 criteria occurred;
- maximum and minimum number of times that criteria A1 and A2 were violated within one hour;
- the percentage of time where A1 and A2 criteria limits were not violated in the current day;
- one day summary of inadvertent interchange separated for on-peak nd off-peak times;
- averages of consecutive 10-minute periods for the best and poorest hours for the summation of absolute ACE for the current day.

Distrurbances

History of disturbances will be maintained (ACE disturbance summary) for the last ten disturbances with data as follows:

- Time, ACE, Frequency and Inadvertent Interchange (not applicable with the current NII network configuration) corresponding to the beginning of the disturbance (when ACE equals or exceeds an entered limit value);
- Time, ACE, Frequency and Inadvertent Interchange (not applicable with the current NII network configuration) corresponding to the maximum disturbance (when ACE reaches the maximum value during the disturbance);

- Time, Frequency and Inadvertent Interchange (not applicable with the current NII network configuration) corresponding to the end of the disturbance (when ACE crosses zero).

A monitoring tool for the performance of regulating units should also be provided in which there will be included data related to the usage of units regulation (e.g., number of changes in set points within a specified period) and indications for their response (e.g., cases in which some units have been detected by AGC as “not following” the set-points, etc.).

5.5.6 Adaptation of AGC for Multi-Area control

In order to fulfil future requirements, following the electrical interconnection of NII to the Greek Interconnected system at mainland the AGC should have the capability to support a scheme of co-operating secondary controllers operated at both areas of interconnection line. The proposed methodology requires that there will be a central optimizing solver which will co-ordinate the AGC applications in both areas. This central optimizer will exchange information with the involved AGC applications in real time (e.g., every 4 sec) via two redundant communication lines for n-1 security reasons while TASE.2 will be used for this purpose. Each AGC will send to the central optimizer the necessary data related to the secondary control demand and participation status of the respective control area while the central optimizer will send to each AGC a respective correction component of ACE. Therefore the AGC of each co-operating area should in this case eliminate the corrected ACE which can be obtained from:

ACE corrected = ACE measured + ACE correction

where ACE measured is the classical ACE (computed according to measured and scheduled values of frequency and interchanges) and ACE correction value is transmitted to the AGC by the central optimizer. In order to guarantee consistency of the entire operation sign conventions must be followed correctly. The co-ordination will be done so that the rest of AGC operation is kept unchanged in case that the AGC operator disables the participation to the co-operation scheme (On/OFF selection flag is foreseen). Moreover, the participation to this joint regulation would be automatically reset by several conditions including the following:

- Failure in communications with the central optimizer
- ACE calculation mode is changed to CF control mode
- ACE measured exceeded a pre-defined emergency level for a time period exceeding a predefined threshold (adjustable parameters)
- Flows in certain interconnections exceeded respective pre-defined limits for security reasons (adjustable parameters).

Furthermore, congestion values will be used in order to limit the correction signal and by doing so to keep the additional load-flows caused by the co-ordinated scheme within allowable margins. The proposed co-operation scheme, as described above, is based on the Grid Control Cooperation (GCC) approach which has been implemented by several TSOs in Central Europe.

5.5.6.1 Interchange Transaction Scheduling (ITS)

The current network configuration of the NII have no interchange capabilities with other systems. However, this software capability should be provided by the Contractor because in the future the Islands systems may become interconnected and the flow on the interconnections should be scheduled and controlled.

It is noted that the ITS is a standard functionality in EMS that is used for the management of interchanges with neigbouring Electrical Systems.

5.5.6.2 ITS Basic Requirements

The ITS function shall provide the NII SMO with the capability to enter and maintain schedules for power system interchange energy with neighbouring NII and for the periodic calculation of total scheduled net interchange for use by the AGC function. The interchange scheduling periods currently is in hours but in near future it may be smaller e.g., 15 minutes, depending on the evolution of the market. The ITS should have the flexibility to cope with the modifications in the periodicity of schedules. The ITS function shall provide an interface for schedule submission to the EMS. The key task of the ITS is to provide data to EMS for AGC operation and relevant reports. The ITS will also consider the defined quantities of compensation programs that should be taken into account at every defined period when calculating the control schedule for AGC.

The ITS should have the capability to provide an interface with the MMS platform in order to receive schedules encapsulated in XML files.

The data that will be communicated by the MMS platform to the ITS will include interchange schedules per border with neighbouring Operators. The compensation programs will be communicated also in XML files with data aggregated per type of interconnections (AC interconnections and DC interconnections). The ITS shall perform a structural validation of the XML according to a schema definition. In cases that the ITS will not receive timely valid XML files from the MMS platform, then respective warning messages will be released by the ITS to alert the dispatchers. The dispatchers should have the option to review, modify and finally notify as accepted the schedules, received through XML, for reasons related to unexpected problems in the real-time operation and even to enter new schedules (for example emergency schedules).

The ITS function shall also provide the capability for entry of interchange schedules and compensation programs with permissible start times from immediate to within 7 days of the current day. The function shall have the capability to define schedules with different types. Error checking, following simple rules, of all altered and/or newly entered data shall be provided.

For the AGC operation there is no need to define all schedules per market participant but it is sufficient to sum up and define the schedules per border with the neighbouring NII and per interconnection type (AC or DC) concerning the compensation programs. However, it is needed to consider separately the schedules that will be implemented through the interconnections that have been defined as Not Included in the calculation of ACE (i.e., interchange schedules through interconnection lines with neighbouring systems that are implemented by directly attaching as part of the network because these schedules do not affect the ACE calculations).

When changes of schedule programs occur each change should be converted to a ramp with a ramp period of 10 minutes, starting 5 minutes before the agreed time of the change and ending 5 minutes after the change. This requirement is imposed by the respective terms of ENTSO-E Policy 1 (the numbers of 5 minutes and respectively 10 minutes should be adjustable parameters).

The ITS function shall provide schedule file management features that maintain all schedules presently in progress and all transactions scheduled, but not yet started. Completed schedules shall be stored for use by the historical information storage and reporting software.

5.5.6.3 ITS Schedule Entry

Schedule entry default values, changeable by the user, shall be permitted in order to minimize the time required to enter or modify a schedule. In addition, the NII SMO shall be provided the capability to save a schedule action and, by changing the date of the save case, define a new schedule. The ITS program shall be able to accommodate switchover to/from Daylight Saving Time.

New transaction entries and modifications to existing transactions (not-yet-active and active) shall require the NII SMO inputs listed below. Default values and re-entry of save cases as described above shall be permitted in order to facilitate the following NII SMO input requirements:

- Schedule number;
- Transaction date (month and day);
- Neighbouring Operator name (sixteen character abbreviation);
- Transaction type (six character abbreviation);
- Import/Export indication;
- Transaction value in MW;
- Start time (format suitable for schedules of defined period e.g hour, 15 min);
- Stop time (format suitable for schedules of defined period e.g hour, 15 min).

It is noted that the above input data and their format is indicative. It is required to follow the ENTSO-E ESS format for cross border scheduling.

The dispatcher shall be able to setup and define schedules for submission through an appropriate user friendly interface for data entry. After entry of the schedules or transaction information using the ITS Schedule Entry display pages, the dispatcher should have the capability to notify as accepted the schedules e.g., by selecting a display screen poke point. The system should support a validation procedure before the activation of the schedules in order to help the dispatchers to avoid mistakes.

5.5.6.4 ITS Displays

The Contractor shall provide, at a minimum, the following ITS entry and review displays described in this section in order to provide the dispatchers with the capability to execute, in a user friendly man machine interface, the required ITS functions and features.

An ITS Index Display shall be provided that contains a tabular listing of schedules that have been entered in the ITS system. The entries shall be arranged such that only one page is required. The display should contain the summed up schedules per border, the compensation programs and total schedules for imports/exports in and from the Control Area of each Island respectively.

An ITS Display per neighbouring Operator shall also be provided that allows the display of all entered schedules with each neighbouring Operator. An "active flag" shall be attached to each schedule currently active.

An ITS Active Display shall be provided that presents all schedules currently active, grouped on the basis of borders with neighbouring Operators, ordered by schedule number.

5.5.6.5 Emergency Net Interchange Schedule

During power system emergencies the NII SMO shall be able to override all interchange schedules with a single manually entered emergency net interchange schedule. The emergency schedule entry shall include an Emergency Net Interchange value, and a ramp rate. The AGC System shall ramp up to the emergency net interchange value.

5.5.7 Inadvertent Interchange

Inadvertent (unscheduled) net interchange, defined as the difference between actual net interchange and scheduled net interchange, shall be computed hourly. It is implied that this is only applicable for the CNI and TLB mode of AGC operations.

The Inadvertent Interchange program shall provide the following for display to the dispatchers:

- On-Peak and Off-Peak accumulations of net inadvertent interchange to the end of the last hour;
- On-Peak and Off-Peak net inadvertent interchange at the previous midnight;
- Net inadvertent interchange for the current day to the end of the last hour.

Each of the data described above shall be subject to modification by the System Operator. On-Peak and Off-Peak clock hours shall be user definable.

The Inadvertent Interchange function in the EMS will be consistent with other means and procedures compatible with ENTSO-E Policies. The Contractor should implement this tool consistent with the following requirements:

- It will calculate daily the hourly unintentional deviations;
- It will accumulate them per tariff (according to the ENTSO-E tariffs);
- The accumulation will be in daily basis and also per period (Summer/Winter) according to the ENTSO-E rules;
- The accumulation will respect to the special days of ENTSO-E. These special days follow the Sunday tariffication and are defined in the Appendix 2 of the ENTSO-E Policy 2 Operation Handbook;
- It will implement the compensation program;
- Specifically for a DC interconnection the tool should be able to calculate the unintentional deviations and issue a compensation program.

5.6 Load Following

The cost-based RTD should produce the optimal balance of generation and demand that can be forecasted and will produce the optimal base-points. The AGC should use that balanced energy and deal with all the deviations regardless of the reasons (forecast error, Unit tripping, Time error correction, etc.). In other words any deviation within the 5-minute interval will be the responsibility of AGC regardless of the condition that caused the deviation. It is expected that the MMS system will produce the right energy schedule and all the right Ancillary services awards to meet all the possible conditions the AGC system needs to resolve.

5.7 AGC PI Controller Requirements

In this section the requirements for the implementation of the AGC PI controller, that process the area control signal, are presented.

According to the Operation Handbook of ENTSO-E, each Operator needs to operate sufficient generating capacity under automatic control by the Secondary Controller to meet its obligation to continuously balance its generation and interchange schedules to its load for the Control Area /Block. In order to control the ACE to zero, Secondary Control must be performed in the corresponding control centre by a single automatic Secondary Controller with Proportional-Integral (PI) that needs to be operated in an on-line and closed-loop manner.

The PI controller must have a high availability and must operate highly reliable. In order to have no residual error, the Secondary Controller must be of PI type. The behaviour over time is desired to be in accordance with the following formula:

$$\Delta P_{di} = -\beta_i \cdot G_i - \frac{1}{T_{ri}} \int G_i \cdot dt$$

where:

ΔPdi: is the correcting variable of the PI Controller governing control generators;

βi: is the proportional factor (gain) of the PI Controller in Control Area i

Tr: is the integration time constant of the PI Controller in Control Area i

Gi: is the Area Control Error (ACE) in Control Area i

ENTSO-E recommends the following for the set up of the PI controller:

In case of a very large control deviation, the control parameters βi and Tr of the PI Controller should be adjusted automatically for a given period of time. The control parameters βi and Tr are closely linked. Values ranging from 0 to 50% may be set for the proportional term βi of the area controller. The time constant represents the "tracking" speed of the PI Controller with which the controller activates the control power of participating generators. Values ranging from 50 seconds to 200 seconds should be set for the time constant Tr. Measurement cycle times, integration times and controller cycle time must be coordinated.

The integral term must be limited in a certain value (entered in an analyst display) in order to have a non-windup control action, able to react immediately in case of large changes or a change of the sign of the ACE. Moreover, for the cases of a change in the sign of ACE, the values of integral term should be properly adjusted in order to smoothly minimize problems in regulating the current ACE, when ACE exceeds predefined limits.

It must be also possible to set to zero the current integral of ACE at the top of each hour if this option is activated by a flag (in an appropriate analyst display). There are also other cases in which the integral ACE has to be reset as in changes of AGC mode of operation, emergency conditions, serious frequency disturbances etc.

Finally, in order to prevent excessive deviations when changes of control programs occur, it is necessary that each change be converted to a ramp with a ramp period of 10 minutes, starting 5 minutes before the agreed time of change and ending 5 minutes later (10 and respectively 5 minutes are indicative and these numbers shall have configurable values). It is required that the ramping be performed in the same way by all controllers of the CESA (Continental Europe Sunchronous Area).

The AGC program shall determine how much, if any, control action should be executed based on the characteristics of ACE. AGC shall consider ACE random variations, integral of ACE, and feed-forward of known generation and interchange changes when AGC is operating permissively. Non-linear filtering techniques, which reduce control actions, are required. It is repeated that special attention should be paid so that the effect of integral ACE to not counteract the regulation needed to minimize the current ACE, when values of current ACE exceed pre-defined limits. Information concerning the values and parameters associated to the control actions will be displayed to dispatchers.

AGC application gains , time constrants, filtering etc should be properly tuned in real time environment with proporly tuned units / plants to meet the requirements of the NII.

5.8 AGC Operation and Status Modes

AGC operations and status modes are as follows:

5.8.1 AGC Operation Modes

The AGC system will support at minimum the following AGC operation modes, depending on ACE values:

Normal: This mode is the default mode and should ramp units assigned to regulate under when ACE is inside ACE predefined limits using normal ramp rates (registered physical values or offered by the generators in the MMS) at the required direction.

Assist: This mode should ramp units using all regulating units assigned to regulate in normal and in assist mode when ACE exceeds a predefined limit using normal ramp rates. This mode should be selected automatically based on ACE deviation.

Emergency: This mode should ramp all regulating units using emergency ramp rates (physical or offered) assigned to regulate in normal, assist and emergency mode using normal ramp rates. This mode should be selected automatically based on ACE exceeds a predefined limit higher that the respective Assist limit.

The type of AGC control utilized shall be determined by comparing the ACE magnitude with certain user definable limits. For small values of ACE, AGC shall utilize normal command control. For larger values of ACE, AGC shall utilize the assist command control. For large values of ACE, AGC shall utilize emergency action that will bypass economic considerations and cause all regulating units operating in the regulating mode to be moved in a direction to minimize ACE regardless of economic reserve limits (a flag will be available to enable such a regulation). These modes, while they might be internal to AGC, should be displayed to the operator.

5.8.2 AGC Status Modes

AGC system will support the following status modes:

On: This is the normal mode in which the AGC fully operates, i.e., it makes calculations and sends control signal to the generating units.

Suspend: This mode suspends sending signals to generating units. AGC enters this mode automatically after a period of time where telemetry failure persists. The suspend state is a transit state for a period of suspend time. The mode must switch to Off (Trip) mode upon expiration of the suspend time or recover back to on mode because telemetry was restored.

Off (Trip): This mode is either entered from the suspend mode or if requested by the operator.

Monitor: This mode is selected by the dispatcher when the AGC operates from the another site (not applicable in the project). In this mode the AGC is fully functional but the controls are not issued to the units / plants.

Moreover the AGC function shall provide automatic initiation of AGC Control Suspension for all units at least when excessive frequency deviations occur (magnitude of deviation shall be User adjustable) or when excessive ACE magnitude occurs (magnitude of deviation shall be User adjustable).

In addition, AGC Control suspension shall occur for telemetry failure of any tie-line (future condition, not currently applicable) (except in Constant Frequency control mode), or for failure of the primary frequency source (except in Constant Net Interchange control mode). The AGC program shall use a time-out limit for these failed telemetry values before suspending. The time-out limit shall be User adjustable. Automatic tripping shall be prevented and AGC control resumed (with appropriate messages describing all events) if the telemetry becomes valid prior to time-out, the System Operator enters a replacement value (with the exception of frequency), or the System Operator selects a redundant source for telemetry.

AGC should have the ability to detect telemetry failure and take appropriate action like pausing, resuming, suspending, or tripping with associated alarms. Disturbances in the system should be automatically detected and AGC should react immediately to contribute to the reliability of the system operation. AGC should be able to detect the difference between true disturbances on the system or telemetry failure. The AGC should be able to detect cases of serious disturbances of network (Island's Network) system such as system split (islanding of a part of a system in which exist units in operation and being under AGC control and then AGC should react immediately to contribute to the system security, e.g., at least with suspending of remote control for units which are measured to operate at different frequency than the main part of the system). The technical details concerning the AGC reactions when serious failure events appear in the Island's Network system will be discussed with the Contractor during the Detailed Design phase of the Project.

5.9 Unit / Plant Control Status

The control mode of a unit / plant is defined by the activation of appropriate flags from both the dispatchers (in AGC MMI) and plant operators (in unit / plant Controller

MMI) based on unit operation, participation in regulation, participation in the market according to operational requirements for each unit and the market declarations.

The minimum status of operation and control for the units under AGC should be as follows:

On Line /Off Line: The unit is On-line or Off-line for generation. This status is generated respectively from telemetry. When a unit's breaker is open, the unit control mode shall be automatically set to Off-Line in case that megawatt output is also less than a minimum threshold (e.g. 5% of the unit's nominal capacity).

Off Control: The unit is on-line and is being manually loaded by the plant Operator according to respective dispatching instructions. AGC will not send any set-points to this class of units, other than its current production (optional by user's selection for each unit). When a unit is in Off-Line then is automatically set to off-control and when changed from Off-Line to On-Line it remains in Off Control until the dispatcher changes it.

On Control: The unit is controllable by the AGC program within respective high/low regulating limit settings. This also implies that the power plant operator has set the unit interface appropriately so that the remote control to be allowed. Units cannot be actually on control without the plant giving them the option. This status is generated from telemetry and dispatcher settings.

The unit control modes shall be defined as combination of the type of source of the base-point for each unit and the type of priority in participation of the units to the regulation of the system, depending on ACE values.

The base-point could be derived with the following minimum options: A fixed value entered manually by the operator or an outcome of ED module or an outcome of a scheduler (programmed values in AGC) or an automatic outcome of RTD (or other external market solver) or as computed average of a regulating range.

The options for regulation priorities of units should have the following minimum options: fully regulation (participation to regulation in all values of ACE), assist and emergency (where in these cases the unit contributes to ACE regulation when AGC is in the assist mode and emergency mode respectively - when large and very large values of ACE appear).

All regulating units could have the same regulation priority mode in order to avoid discrimination among units but the assist and emergency regulation priority modes should be supported by the AGC in case that there will be a change in the future to the ancillary services market model. Finally, a unit can be assigned to not participate at all regulation. In this later case, when a unit is defined to not participate in the ACE regulation, then the set-point value that is finally sent by AGC could have the following two options (respective flag per unit shall be available for this purpose):

- The set point is equal to the base-point;

- The set point in some cases will not be always equal to base-point but equal to filtered values computed by AGC (AGC in this case tries to “push” the production of the unit to the base-point with respect to other criteria e.g., to not counteract with the elimination of current ACE when ACE is above one limit).

In addition to the above a Test Mode should also be provided to facilitate testing and tuning of the units or plants for regulation under AGC control. The System Operator uses this procedure to manually test the unit response to AGC signals and the associated interface of the corresponding unit. The AGC should have appropriate features and displays to facilitate the tuning of the plant controller parameters according to the unit’s type and the measurements of the unit’s response.

5.10 Unit / Plant Limits

5.10.1 Unit Limits

The following standard unit limits shall be supported at the minimum by the AGC program:

Total Capability - The total capability of the generating unit is the maximum maintainable output.

Regulating High Limit: This limit is the highest maintainable output with the equipment in service at the time. This limit is telemetered by each power plant but can be restricted by a manual limit entered by the dispatchers. The AGC shall recognize this limit as an absolute high limit. In addition, the AGC program shall pulse units into the region defined as, "Regulating High Limit minus Economic High Limit", only when power system conditions warrant additional generation for non-economic regulating purposes.

Economic High Limit: The AGC shall recognize this limit as a "soft" limit, representing the upper limit of generator output during power system "normal" conditions, when economic constraints dominate the AGC control output execution. The default value of this limit is maintained for each unit in the database (modeling value) while it can be transferred also by an external source (e.g. cost-based RTD) or the Real Time Security Enhancement application (real time OPF network application) depending on a respective flag.

Economic Low Limit: The AGC shall recognize this limit as a "soft" limit, representing the lower limit of generator output during power system "normal" conditions when economic constraints dominate the AGC control output execution. The default value of this limit is maintained for each unit in the database (modeling value) while it can be transferred also by an external source (e.g., RTD) or the Real Time Security Enhancement application (real time OPF network application) depending on a respective flag.

Regulating Low Limit: This limit is the lowest maintainable output with the equipment in service at the time. This limit is telemetered by each power plant but can be restricted by a manual limit entered by the dispatchers. The AGC shall recognize this limit as an absolute low limit. In addition, the AGC program shall pulse units into the region defined as "Economic Low Limit minus Regulating Low Limit", only when power system conditions warrant less generation for non-economic regulating purposes.

The AGC shall perform a reasonability check of above limits to ensure that the relationships of entered values to each other are the same as the order in which they are listed. If not, an alarm shall be generated and AGC control suspended for the unit until the limits are corrected.

Moreover, there will be Ramp Rate Limits which represent the maximum sustained rates-of-change for the unit output, upwards and downwards, and constrain the unit ramp rates that are provided by the Market Participant (via the MMS) or may be telemetered from the power plant.

5.10.2 Plant Limits

For power plants with more than one units the respective aggregated limits along with unit limits should be calculated.

5.11 Plant Logic Controllers in AGC

The AGC should be able to model and handle aggregate resources as well as physical resources.

In AGC each generation resource unit or plant is modeled by its respective Plant Logic Controller – PLC that is a module of AGC software used for the monitoring and control of each generation resource.

The PLC module models the respective unit's (or plant) response characteristics to anticipate the unit (or plant) response and feedback the full effects of control outputs. The units' capacity limits, ramp rates, primary control effects, time delays in the control procedure, fuel type characteristics, etc., should be considered for this purpose. Unit prohibited (forbidden) zones, if any, should be correctly accounted for the control action.

Power plants can be either modeled as single units or where necessary for technical or market reasons as plants.

In case of plants that are represented by a single PLC, the set-points issued are for the entire plant and in such cases single techno-economic data are submitted by the producers for the entire plant. The AGC should recognize the individual units of the plan that are synchronized and regulated in the plant and the respective production, Min and Max limits and the prohibited zone (if any) and the control status per unit.

Examples of plants with a single PLC are Combined Cycle plants that are comprised by more than one unit (e.g., 2 GT and one ST), etc.

The modeling of the units / plants in the PLC software should be consistent with the Power Plant Controller (installed locally in the plant) that implements the set-points by distributing them to the respective units in order to minimize the differences between set-points and actual generation and to achieve the best regulation results. It is emphasized here the importance of the AGC modeling to be consistent with the cost-based RTD that produces the respective base-points for the units or the power plants.

The power plant controller in the modern power plants is implemented by the DCS of the power plants and special functions are integrated in the control system of the plant in a way that it acts as a joint controller.

The older power plants or units don't have power plant controllers.

This is also important for accurately mapping resources between the AGC and the network applications (e.g., the State Estimator) which require the unit configuration at an individual level.

The AGC should be able by proper parameter tuning to reduce control action outputs for each unit (or plant), thus avoiding overshoot and undershoot conditions and the tear/wear of the units. In addition, it shall provide the means for determining when a unit (or plant) fails to respond. The model shall permit the AGC to utilize a unit's stored energy to move the unit faster than its rated response limit for short periods (e.g., with an appropriate boiler model). Special models for Combined Cycle plants should be developed. Unit dead-bands, and other logic shall be utilized to avoid output change request smaller than the control resolution of units, while ensuring that control errors do not accumulate.

Fully integrated plant and unit tuning tools will be implemented that recognize the specific features of each type of power plant and facilitate a fast and effective regulation. The plant logic controllers should be programmed to permit fast and effective regulation. At the same time the AGC software should be designed to minimize oscillations. For this purpose there will be co-ordination of control of the AGC main controller, the plant logic controllers of AGC and the controller equipment at the power plant level.

To this aim the following logic should also be included (this logic has to be enabled by a respective appropriate flag): Inhibiting of control commands during a defined wait time (specific control delay time expressed e.g., in AGC control cycles), before reversing the trend of commands that are issued to unit (i.e., from increase to decrease direction and vice versa), provided that the ACE remains in its normal range.

In addition, the AGC should have the ability to consider time delays due to communication problems and to detect telemetry failure with each plant and take appropriate action like pausing, suspending, etc., the control of the plant with associated alarms. The AGC function shall provide automatic initiation of AGC control suspension for a single unit when data cannot be collected from a unit or data indicates the unit is not responding for a period of time exceeding a User adjustable time limit for the unit. The control mode of the offending unit shall be automatically set to suspended and an alarm shall be generated.

All appropriate unit (or plant) modes will be available to recognize the different operation and control statuses of the unit (or the plant) as these are determined based on telemetry data, market declarations and manual entries from the dispatchers (e.g., fixed load with regulation, automatic, etc.) and unit attributes for supporting the AGC operation modes (e.g. economic, fast ramp, assist, emergency). Moreover, the unit (or plant) modes should consider the different alternative cases where the economic base-point is coming from the cost-based RTD or from the market-based RTD module (when available) or other source defined in the AGC software (see and section Unit Control Modes).

It is noted also that for the majority of power plants the set-points of AGC are expected to be in gross values, i.e., the AGC should send gross set-points to the plants but the AGC should have the capability to handle and cases where the AGC should control power plants in terms of net values (set points and measurements). It is very difficult to change this principle since the plant auxiliary loads cannot be measured reliably in real time on the power plant site unless there is a costly extended local SCADA at each power plant which should monitor also the substation that connects the generating units to the Island's Network system. This means that the base-points from the cost-based RTD (which are initially calculated in net values) should be transformed in gross values in order to be used by the AGC. Contractor should implement this transformation based on measurement.

It should be noted that AGC compares the reaction of the plant /unit, marks the unit's behaviour (not following, out of service etc.), considers accordingly its participation to the regulation and issues respective alarms to notify the dispatchers for the situation.

Additional AGC capabilities such as sending the set-points based on Generation Distribution Factors (GDFs) with the ability to recognize a physical unit child of the aggregate resource if it is off-line and normalize the GDFs accordingly should be investigated and provided. When the aggregate resource is de-rated then the AGC should be able to handle any de-rate on the physical or logical (aggregate) level and not exceed the capacity of the units.

5.12 Alarm Processing for AGC

The system shall have the capability of notifying operators of abnormal conditions that may occur and require operator intervention or informational system messages, including alarm acknowledgement. Alarms shall consist of but not limited to:

- Limit violations of telemetered or calculated values;
- Communication error detection;

- Improper unit response detection (unit is not responding to set-points);
- Abnormal condition detection;
- Excessive ACE;
- Excessive deviation between primary and back up telemetry;
- Reserve deficiencies; and
- Reasons to pause etc.

Moreover the AGC will have special alarms, related to the co-operation with the cost-based RTD. The major alarms are related to problems in the link with RTD and the reception of files from it (e.g., no communication, the data coming from RTD is not updated etc). In particular, when the AGC stops receiving files from RTD or files are received with a delay bigger than a defined time tolerance or files are received from RTD with old data or there is a syntax error in these files then a respective alarm is released in the EMS site. It is noted that in the case that AGC cannot not read the RTD file or could not work with the values received (not valid), AGC will continue to work with the last good data received from the market file from previous reads.

Besides to the major alarms listed above there will be and some alarms of minor importance that could optionally inhibited by an analyst display. This kind of alarms include cases in which the base-points, received by AGC, for some units could be out of the current operating or regulating range (e.g., a unit has got offline but AGC receives a base-point from RTD for this unit due to the time gap between the RTD snapshot of data for execution and actual status operation). More details about these alarms, which are not limited to the above described situations, and the behavior of AGC when abnormal situations are detected in the co-operation with RTD, will be elaborated with the Contractor during the Detailed Design phase of the Project.

The system shall have the capability of notifying operators of abnormal conditions that may occur and require operator intervention or informational system messages, including alarm acknowledgement. Alarms shall consist of but not limited to:

- Unit is not responding to set-points; and
- Limit violations of telemetered or calculated values.

When the AGC receives a set-point for a resource that is off-line it will generate an alarm to let the operator with true intelligence to make the evaluation and decide if an action is needed to start the resource manually or correct any mismatch between the RTD unit condition and the actual resource condition or to trigger manually the RTD to run taking into account the most recent system conditions.

5.13 Outages and Derates

The AGC should support scheduled outages and derates of generation and the Island's Network system element either entered manually on appropriate user displays or automatically imported from the MMS System. The AGC should fully respect derated capacity or dispatch a scheduled outage unit. In both cases a manual override, as a last minute correction, should be supported.

5.14 Predictive AGC Functionality

Although there is a predictive load change capability for the RTD, the AGC system should incorporate a Predictive AGC (PAGC) functionality that would be tuned and ready to be activated and put in operation with an appropriate flag. This capability can also be disabled by the Operator with an appropriate flag.

The PAGC should be configurable in such a way that the pre-filtered ACE be based not only upon the instantaneous raw ACE value, but also it will consider events that occur within the short-term.

AGC should consider and react to known changes that will occur in the near future (a configurable time period ahead by adding prediction component to the ACE equation. This predictive value consists of the following five components (which may be implemented as a whole or individually):

1. **Changes in wind generation:** the amount of MW change based on the output of a wind forecast application.
2. **Changes in the load forecast:** the load forecast “N” minutes from the current time is calculated through linear interpolation between the current and next hour load forecasts.
3. **Changes in unit output for generators in the RAMP[1] control mode:** the amount of MW change is based upon the unit’s sustained ramp rate and limited by the unit’s target MW value.
4. **A telemetered offset:** value which is read from a SCADA.
5. **Changes in scheduled interchange (not applicable in the current NII network configuration):** the scheduled interchange “N” minutes from the current time is determined from the AGC composite. The difference between the current scheduled interchange and the future scheduled interchange comprises the interchange component.

Individual gains are applied to each of the components. This enables some components to be weighed more heavily than other components. Also, the user can set components to be ignored by setting its gain to zero.

This collective Predictive (anticipated) value should be added to the ACE and it will modify accordingly the regulation component of ACE when ACE is not in the assist region. It is not included when the value of ACE is in the assist region.

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[1] RAMP refers to the units that are ramping to their minimum after synchronization or from their minimum to their shut down state, etc.

5.15 Aggregate Resource Modeling

AGC should be able to model and handle aggregate resources as well as physical resources. The base-points received by the cost-based RTD can be sent to a physical or aggregate resource. In the following we present specific modeling for various Aggregate Resource cases.

A type of aggregate resource is the hydro plants, in case such plants become available in the future. Specifically for hydro plants, the AGC should recognize the individual units that are synchronized and regulated in the plant and the producing MW, Min, Max and the prohibited zone (if any) per unit. The AGC should send a set-point for the entire plant. Note, the units of the hydro plant are committed and operated individually but there is one control set-point since there is a joint controller in the plant.

The cost-based RTD has to also recognize in real time how many units are actually in operation in a hydro plant (through SCADA) in order to adjust properly the “running” min and max limits. They usually declare as minimum zero and as maximum the sum of their available units. On the other hand (in real time) their actual minimum and maximum depends on the number of units that are in operation. The synchronization/de-synchronization of each hydro unit is done with specific instructions by the dispatchers.

This commitment/de-commitment of hydro units that comprise a hydro plant cannot be performed by the RDAS or DS as it is one market entity but the the cost-based RTD should recognize the situation when issuing dispatch instructions (so that the actual production limits are respected).

For hydro plants it is also possible that a unit in the plant is on-line but it operates as synchronous condenser while the others are in normal production mode. In this case the AGC and the cost-based RTD should recognize this configuration and regulate the units in production mode as one entity.

Special models for Combined Cycle generating should also be developed. The same principles could be applied also for Combined Cycle plants that are comprised by more than one unit (e.g. 2 GT and one ST).

In all cases it is important to recognize and properly treat all units that are aggregated under the plant. This is also important for accurately mapping resources between the AGC and other network applications such the State Estimators which require the unit configuration in an individual level. It is possible in many instances that one unit of a hydro plant or a Combined Cycle plant is connected to one bus-bar of the Island network while the remaining units of the power plant are connected to another bus-bar. All such cases need to be properly modelled for accurate treatment in AGC and proper mapping between the AGC and the network applications.

For cases that require aggregate modeling not covered by the description proposed above, the AGC should be able to send the set-points based on Generation

Distribution Factors (GDFs) with the ability to recognize a physical unit child of the aggregate resource if it is off-line and normalize the GDFs accordingly. When the aggregate resource is de-rated then the AGC should be able to handle any de-rate on the physical or logical (aggregate) level and not exceed the capacity of the units.

5.16 Instructions Recording and Associated Calculations

The Contractor should develop a software module for recording and logging information about the instructions sent through EMS to power plants and the respective telemetered signals and measurements from power plants (e.g., synchronization and regulating status, units' active power production, operating and regulating limits).

This information will be used by EMS to calculate for each dispatchable unit the primary and secondary reserves provided by regulating units for each hour (dispatch period). For this purpose the on/off line and the control status of the units, the regulating limits telemetered by the plant, the operating high limit, and the actual production of the units are recorded. The values collected by AGC and SCADA have been recorded in the HIS Database and then are sampled and averaged according to certain rules that will be discussed with the Contractor during the Detailed Design Phase of the Project.

The EMS will also use the recorded information about instructions and units measurement data in order to make calculations concerning the compliance of units to dispatch instructions during a month and compute average deviation quantities, after taking into account certain defined tolerances. For example, a deviation is the difference between the RTD instructions communicated through SCADA to a power plant and the active power production of the unit in a sample of measurements around five minutes in response to the instruction that has been received in the power plant. Units that have been on AGC regulation are deemed to be following automatically the AGC dispatch instructions and thus they have no deviation. The same principle can be applied to units that have been operated as not capable to follow RTD instructions e.g., during an hour in start-up conditions. The details of this method will be discussed with the Contractor during the Detailed Design Phase of the Project.

The AGC will also provide MVAR regulation. The specifics of this task will be finalized during the Detailed Design Phase of the Project.

5.17 AGC Wind Monitoring and Control Function

AGC should be capable with appropriate extension to curtail wind and PV generation to meet maximum wind penetration or maintain the system reliability during over-generation conditions or when a regional congestion (line overloading etc) appears due to high wind generation or high PV generation in the region. Current applications already in operations will be integrated in this function. New applications should be easily programmed by HEDNO personnel as required.

5.17.1 Balancing Requirement for Maximum Penetration

When the wind and PV total generation exceeds a percentage (user enterable), then the AGC should issue curtailment orders to these power plants in order to keep the percentage equal to the maximum permissible.

5.17.2 Balancing Requirement on Over-generation

The over-generation condition is most likely to occur when the following circumstances are present:

- Low level load conditions;
- Thermal units on-line and operating at their minimum levels because they are required for next periods;
- Wind and PV generation at high production levels etc.

Whenever there is an imbalance between generation and load, the AGC system sends control signals to units on regulation as well as to dispatchable units to decrease. In case of over-generation condition regulating units are moved to the bottom of their regulating range and dispatching instructions are issued to drive non regulating units to their minimum operating points.

In case of imbalance that could not be automatically removed and the total generation still exceeds the system load, Operators should either have to command units to shut down or to curtail renewable wind generation in order to keep system in balance.

Although the current legislation gives priority to RES generation sources it permits the curtailment, whenever applicable, when the security of the system is jeopardized, or upon contingencies to protect the assets and to avoid shutting down conventional (thermal) units needed for the next time period(s).

5.17.3 Congestions

In case network congestion appears in an area and certain limits (user enterable) are exceeded due to over-generation in this area, the AGC should issue curtailment orders to the power plants in the area (user selectable) in order to mitigate the constraint. Details will be worked out during the Detailed Design of the Project.

In such conditions wind and PV generators should be prepared to curtail some generation to mitigate serious over-generation conditions automatically through AGC.

The interface between SCADA and wind parks and PV generation should facilitate their monitoring and curtailment.

5.17.4 SCADA Interface to Wind Parks

In general, the information required to be exchanged between EMS and wind generators and PV are similar to the information required of other generators or network elements, e.g., measurements (active and re-active power, currents, voltages), status indications (on/off, local/remote, etc), single indications (e.g., equipment alarms), energy meter data, analog set-points and digital commands while wind parks can also be instructed to shut down in a predefined time period or even to switched off (disconnected from the grid) via the SCADA system.

5.17.5 AGC Extension for Wind and PV Curtailment

AGC should have the capability to issue dispatch orders for curtailment, periodically typically at LFC cycle, to all or to a group of wind parks and PV that are related to the constraint in case some criteria are met.

The total amount of generation decrease should be distributed to the respective wind parks as a maximum permitted limit of generation calculated according to a predefined formula. When there is not any requrement for curtailment (user defined limits are not excedded) dispatch orders to RES should be at the maximum generation of the wind park and PV.

The Wind Monitoring and Control functions for wind curtailment will be supported by a comprehensive set of relevant displays that will allow the user perform monitoring in real-time the wind production and PV and the management of the curtailment criteria. Appropriate fields will be maintained in the EMS database to support this application.

6 EMS Services and Applications

This Section presents the requirements for the following EMS Services and Applications:

- Power Advanced Applications (Section 6.1);
- EMS Modeling System (Section 6.2);
- EMS Real Time Data Export (Section 6.3);
- EMS Reporting (Section 6.4).

6.1 Power Advanced Applications

6.1.1 General Requirements

As part of the EMS, the Network Applications Subsystem consists of the functions that use the electric network model in the NII and the real-time measurements from SCADA to estimate the state of the power system as well as to perform security analysis and system studies.

In general the EMS Network Applications shall provide extensive functionality in order to efficiently solve the tasks of:

- Identifying and supervising the state of the Power System in real-time. As Power System is considered the NII system as well as interconnected neighboring systems (not applicable with the current configuration of the NII) within the NII SMO's observability area.
- Examining if security of supply is ensured under actual operational conditions as well as under conditions planned for future operational conditions
- Determination of preventive and/or corrective measures to minimize identified risks.

The EMS Network Applications shall include a number of real-time and study functions.

Activation of the EMS Network Application functions shall be:

- executed periodically (the period should be selectable);
- triggered by events e.g., changes of tele-metered status information, large deviations in net interchanges; rapid changes in selected analogs;
- manually executed (on operator's request at any time deemed necessary)

It shall be possible the Operator to temporarily suspend the periodical and event triggered execution of the EMS applications.

Incomplete or erroneous input data must not lead to total outage of the EMS functions. Islanding or collapse of the Power System must not lead to break-off of the EMS functions, but the functions shall be operational for subnets.

NII SMO expects all substations with Circuit Breakers will be equipped with RTUs in the long run. However, for the time being some parts of the network may not be monitored due to the absence of RTU installations. In the context of the following Sections, it will be referred to “observable” and “unobservable” parts of the network. Differences between those are mostly dynamic, depending on the actual availability of RTU data or on substitution strategies. Unobservable parts of networks are subnets with missing or incomplete data, which require strategies for equivalents and pseudo-measurements.

All EMS Network applications should be able to be customized and configured to meet the functional requirements of the NII network size and voltage level that are at the HV 150KV.

6.1.2 EMS Power System Network Model and Software Environments

The EMS network model may comprise but not be limited to:

- Buses;
- Nodes;
- Lines / power cables;
- Circuit breakers and isolators;
- Series and shunt capacitors/reactors;
- Static VAR compensators;
- Transformers with two or three windings;
- Loads of different types;
- Generators;
- DC lines/cables and converter substations;
- RES including CHP and storage;
- Network islands if present; and
- External network modeling.

The Load Model to be utilized shall be time dependent and hierarchical, supporting conforming and non-conforming loads.

According to the purpose of the different EMS Network Application functions, it shall be possible to perform them in the following different environments:

- **Real – time environment**: The real-time environment is used for normal real time operation of the Power System. Data will be provided by the Databases which are continually updated by information acquired by the SCADA Subsystem from the sources throughout the Power System.

- **<u>Off – line study environment</u>**: The off line study environment is isolated from the real-time environment and will be used for comprehensive in depth studies. The associated databases are completely separated from the Real-Time Databases and can be modified manually by the users. This environment shall provide facilities to work either on the latest solution from the real-time functions or on cases specially created or saved cases.

In what follows, a brief description is presented for the following Power Applications:

- State Estimator (SE) in Section 6.1.3;
- Power Flow (PF) in Section 6.1.4;
- Optimal Power Flow (OPF) in Section 6.1.5;
- Contingency analysis (CA) in Section 6.1.6;
- Short Circuit Analysis (SCA) in Section 6.1.7
- Outage Scheduler (OS) in Section 6.1.8;
- Automatic Voltage Control (AVC) in Section 6.1.9;
- Load Shedding in Section 6.1.10.

6.1.3 State Estimator (SE)

The State Estimator shall provide a consistent, reliable and updated real-time estimation of the Power System network.

6.1.3.1 State Estimator Functionality

The SE shall combine the real time measurements with the bus/branch oriented topological network model in order to determine the best estimate of the network state. No PMUs are envisioned to be installed at the present time.

The state estimation shall:

- Determine the topology of the network (Topology Processor);
- Estimate the values for the state variables (bus voltage magnitudes and angles, tap changers positions) in the entire network (observable and unobservable);
- Detect measurements errors and handle them properly;
- Compute the values of the derived variables (injections, flows);
- Provide SCADA with estimated values and information about measurements errors.

The default period of SE execution is 5 minutes but with operator selectable cycle time.

The SE shall also have the capability, during the topology processing, of identifying erroneous status indications for circuit breakers and/or isolators (that may be caused by non-reliable tele-measurement equipment or non-updated tagging information entered by operators). Identification of erroneous status indications shall be performed under consideration of analog measurements, status indications and manual entered tagging information.

The final result of SE shall be a comprehensive solution for the entire network, which can be used as a coherent real-time data base by other network functions.

The state estimation shall be able to process network islands and shall provide a solution for each energized island.

The number of valid measurements may not be sufficient to estimate the electrical state of the network. So, prior to running the state estimation an observability algorithm shall determine whether the sub-networks are observable or not, and re-establish full observability by using pseudo-measurements.

The SE shall have the capability of solving simultaneously observable and non-observable parts of the network in order to avoid boundary mismatch problems.

The choice of the mathematical method for the SE function (e.g. weighted least squares) is up to the Contractor. However, the Contractor shall provide a method that is suitable for the specific characteristics and needs of the NII SMO Power System, inform the chosen method and explain the basis of selecting the weights for the various types of measurements and pseudo-measurements. The Contractor shall also present the criteria for determining a good or bad state estimation.

The SE shall be capable of estimating transformer tap positions. Estimated tap positions shall be within the defined network model limits.

In the context of the real-time sequence, after state estimation, the loss sensitivities of generators and loads should be calculated. Loss sensitivities are considered as the partial derivatives of generation or load active power with respect to losses.

The SE shall also check the solution for violations of operating constraints. Constraints to be checked shall include:

- Voltage magnitude (kV or per unit or percent);
- Branch overload (MVA and A);
- Area interchange (total flows MW and/or MVAR on tie-lines, directional);
- Voltage angle separation (degrees) between designated pairs of buses.

It shall also be possible to check against user-specified limits the total MW and/or MVAR flow on user designated sets of branches.

6.1.3.2 Operator Interaction

Operator Inputs

Some tasks of SE have to be carried out by the control room Operator. Respective inputs shall be executed by means of a particular control window. Examples for Operator inputs are:

- Function execution, real-time mode, study mode;
- Activation/de-activation of measurements and manual entries;
- Response to Alarms;
- Initiation of selectable printouts;
- Initiation of selectable save case creation.

Alarms

The SE generates various results. Some have to be acknowledged by the Operator. The procedure for alarm handling by the Operator shall be the same as for other alarms in the EMS e.g.:

- Flashing of an alarm button in the basic window "Network Application";
- Pressing this icon shall lead to a window with alarm buttons of all network application functions;
- Pressing the flashing button of "State Estimator" shall lead to a detailed description of the event or failure;
- The detailed description shall inform the operator by understandable and clear information (not in software vocabulary) about the problem, its cause and how to act. All findings (i.e. violations) shall be displayed in the calculation log.

The main alarms generated by the SE shall include:

- Limit violation based on estimated measurements;
- Large bias between estimated value and corresponding measured analog value;
- Bad data in corresponding analog value;
- Plausibility check error;
- Unsuccessful state estimator execution.

The operator shall be able to suspend any alarm generated by the SE. The SE shall not create cycle alarms.

Results on Operator Request

Flows, injections voltages, and taps calculated by the state estimator shall be displayed in one-line diagrams together with respective real-time measurements. Estimated values may have additional flags, which are indicated in one-line diagrams by special colors or by special characters.

Furthermore, SE results shall be presented in lists, some of which are:

- List SE of limit violations;
- List of bad data and discrepancies;
- Displays of SE execution control;
- Displays of solution logs;
- Displays for each device type (e.g., units, lines, transformers);
- Displays with summary results for the whole and parts of the Power System;
- Display with indication of topological islands.

6.1.3.3 Input requirements

SE shall obtain the dynamic bus-oriented network model along with the actual real-time measurements from SCADA. In addition, these data shall include the following indicators for any measurement:

- Acquired quality status;
- Manual value status.

The state estimation shall have the ability to utilize the following measurements:

- Branch flows (MW, MVAr, Amps);
- Bus injections (MW, MVAr, Amps);
- Multiple measurements of voltage magnitude at a single bus;
- Voltage phase angle;
- Transformer and phase shifter tap positions (fixed and variable taps).

6.1.3.4 Output Requirements

The results of the State Estimation shall include:

- Identification of observable parts of the network, the unobservable parts being marked on the displays;
- List of erroneous measurements;
- Estimated values for all the measurements to be displayed in any of the graphic displays;
- Bus-voltage magnitude and angle;
- Active and reactive power flows on branches;
- Active and reactive power injections at buses;
- Quality criteria of the state estimation;
- Statistical analysis for calculation of measurement residuals, biases and variances;
- Solution analysis information for Analysts.

All the SE results shall be available for displays (tables and/or one-line diagrams) and for updating the real-time data base that is used by other network functions.

- SE outputs shall be accessible as follows at a minimum:
- Measured and estimated values shall appear on the network single line diagram and substation diagrams displays
- Any measurement determined to be erroneous by the state estimation shall appear with a different color (or any other sort of particular aspect) on the relevant display and with its replacement values; it shall be possible to show easily (one operation) estimated values together with measured values on these displays;
- Summary displays of rejected data items and an indication of the cause for rejection;
- A special display shall be available for observability indication;
- A diagram showing the current status of SE and showing the progress of the run, the number of iterations, indication of quality of the result;
- A list showing the status of SE for the previous 24 hours (at least);
- Violation lists by category of constraints shall be available for display;
- Violations shall be highlighted on the single line diagrams as well.

It shall be possible to print all or a user selection of input/output data.

6.1.3.5 Import / Export of SE Base Cases

It shall be possible to store SE solved cases periodically (selectable cycle) or on Operator's request. Saved SE solved cases shall be stored in binary form and could be retrieved later in the network study environment for in-depth analysis. The solved cases will be exported in selectable standard formats (text or xml) periodically or upon request.The file formats used to export the SE results are specified in a separate section.

In addition to the above, it shall be possible to execute the SE function in study mode based on an import of saved SCADA information, which has been stored at a specific timestamp.

6.1.4 Power Flow (PF)

6.1.4.1 General Approach

The Power Flow (PF) function will give the ability to the Operator to study the power flow under a wide variety of different network situations. It shall be possible to modify the network topology, the load and the generation. The PF function shall calculate power flows, currents and voltages in the network and check them for limit violations.

A Full Newton Raphson solution shall be implemented as the default choice because of its robustness.

6.1.4.2 Basic Data

The input data for the Power Flow program shall include:

- Network topology;
- Static parameters of the power system elements;
- P-Q capability curves of the generating units;
- Security and emergency limits for MVA/Amp flows in lines and transformers and for bus voltage magnitudes;
- External equivalents information.

Prior to the execution of PF function the Power Flow application shall carry out checks on consistency and plausibility of the input data provided by study cases or imported save cases.

6.1.4.3 Operator Interaction

The Operator shall be able to initialize the PF with a valid real-time network solution provided by the SE. For operation planning, the Operator shall be able to select a stored power flow case to study particular conditions of load, generation topology and regulation.

The Operator shall have the ability to request an execution of the PF to be saved as a reference case in binary form. It shall be possible to store multiple save cases produced by the PF on manual request. In addition, it shall be possible to export PF solved cases to various selectable standard formats (text and xml). The file formats used to export the PF results are specified in a separate section.

Extensive user interaction capabilities shall be provided, including the ability to modify the status of Island's Network lines, transformers, breakers and other network elements directly on the single-line diagrams.

Operator Inputs

To run the power load flow function the Operator shall be able to prepare a data set for the function. Preparing a data set must be simple for the Operator. A case study shall normally be based on the results of a state estimation, e.g. the last solution, or an archived case. Changing the base case set shall be possible from single line diagrams and lists. Variables are:

- Breaker and isolator status;
- Active and reactive loads;
- System/area load or interchange;
- Generator injections;

- Transformer taps.

Results on Operator request

The results of the PF calculations shall be displayable both on network diagrams and on substation one-line diagrams. It shall also be possible to present the results of the PF in tabular format. The output shall emphasize the indications of limit violations and the location of abnormal voltages.

More detailed outputs shall include:

- MW/MVar flows on branches;
- Bus voltage magnitudes and angles;
- Losses in lines, transformers and in the entire system;
- Tap position values;
- Reactive compensation in shunt devices and synchronous condensers;
- Indication of topological islands.

Additionally the following information shall be provided:

- Display of execution control;
- List of limit violations;
- List of adjusted equipment;
- Solution Analysis displays for Analysts.

In general, displays and presentations of the EMS Network Applications illustrating the same kind of information shall have similar design and appearance. The respective displays will be subject of detail design and approval during work statement phase.

6.1.4.4 Power Flow Functionality

The Load Flow calculation shall provide the following modeling capabilities:

- Secondary regulation AGC;
- Generator limit control for conventional, RES, and storage units;
- Interchange Control between areas;
- Automatic Voltage Regulation (AVR) on units +Volt/VAr control modes for RES stations/units;
- Automatic Voltage Regulation (AVR) on shunts;
- Automatic on load tap changer control;
- Power Regulation on Phase Shifters;
- DC link control.

6.1.5 Optimal Power Flow (OPF)

6.1.5.1 General Approach

The Optimal Power Flow (OPF) function shall offer the Operator a comprehensive set of tools for the optimization of actual and planned power system situations.

The OPF shall present recommendations to the Operator for solving active and reactive power system security violations while optimizing a user selected objective.

The Contractor shall provide:

- A study OPF application with all available objectives and controls (real and reactive) that can be used for off-line and planning studies.
- An OPF based application to be executed periodically in real-time mode to assist the Operators in taking quick and sustainable remedial actions on system constraints arising during operation in order to enhance system security.

6.1.5.2 OPF Modeling, User Inputs and Operation Modes

The OPF function shall be designed in a way that offers flexibility and simplicity regarding:

- Problem formulation;
- Selection of optimization objectives;
- Observation of constraints;
- Usage of controls.

The main inputs of the OPF application are:

- Network topology;
- Static parameters of system elements;
- The most recent solution of the SE (for real-time execution);
- PF solved cases (for study mode execution);
- Cost parameters (absolute and relative cost curves);
- Definition of optimization modes and constraints;
- Range of variation of the control variables;
- Priority of the control variables.

The OPF application should be able to import latest fuel unit cost data as declared in the MMS platform.

Control Variables

The user shall define the control variables applicable for optimization of the active and reactive power such as

- Unit MW generation;
- Transformers phase shift taps;
- MW transaction/interchange between regions;
- Load shedding;
- Generator Voltages / MVAr;
- Transformer voltage taps (OLTC);
- Regulating shunt capacitors/reactors;
- Static VAr compensators (SVC).

The user shall be able to define the control variables designated for activation or deactivation on a global or individual basis with multiple different priority levels for various combinations of controls to be used in the solution process. The solution process shall start at the highest priority level. In case no feasible solution is found at that priority level the solution process shall move to the next priority until a feasible solution is reached.

Operation Modes

The OPF function in study mode shall include at a minimum the following optimization modes, to be selectable by the user:

- MW Dispatch for minimization of generation cost using active power control variables, while observing power flow and control constraints;
- MVAr Dispatch for minimization of active power losses using reactive power control variables, while observing power flow and control constraints;
- MW and MVAr Dispatch for minimization of both generation cost and active power losses using active and reactive power control variables, while observing power flow and control constraints;
- User defined objective functions.

In addition, the OPF shall be part of a real-time mode operation for the calculation of remedial actions to be applicable by the Operators in case of abnormal conditions, such as overloads or abnormal voltage levels, resulted in real-time base case and/or contingency cases. The primary objective in this mode shall be to correct the system state with minimum selectable controls and control moves, thus driving the system back into a feasible state in a quick and secure way. The OPF in real-time mode shall include:

- Remedial actions of active power generation (MW dispatch)

  This mode shall solve thermal overloads based on the actual real-time scenario, while considering and satisfying the criteria on the contingency cases. In order to reach quick results, a simplified OPF approach could be applied, based on linearized models.

- Remedial actions of reactive power control (Voltage/Var Dispatch)

  This mode shall satisfy voltage levels by influencing reactive power generation, tap positions and capacitor/reactor switching based on the actual real-time scenario while considering and satisfying the criteria on the contingency cases.

The real-time mode shall support the remedial actions, as defined in the ENTSO-E Operations Handbook – Policy 3. Remedial action refers to any measure applied in due time by an Operator in order to fulfill the n-1 security principle of the Island's Network power system regarding power flows and voltage constraints. They are defined as preventive or curative (corrective).

- Preventive remedial action: Preventive remedial actions are those launched to anticipate a need that may occur, due to the lack of certainty to cope efficiently and in due time with the resulting constraints once they have occurred.
- Corrective remedial action: Corrective remedial actions are those needed to cope with and to relieve rapidly constraints with an implementation delay of time for full effectiveness compatible with the Temporary Admissible Island's Network Loading. They are implemented after the occurrence of the contingencies.

6.1.5.3 OPF Constraints

The OPF function shall compute solutions for the designated optimization modes while observing the respective constraints.

During the optimization the following types of constraints shall be possible to be imposed at a minimum:

- Branch flow limits;
- Sum of MW or MVAr flows in definable groups of branches (corridor constraints);
- Bus voltage limits;
- Active/reactive power reserves limits;
- Active/reactive power limits for interchanges between network areas;
- Generator limits in MW and MVAr;
- Contractual limits (import/export).

6.1.5.4 OPF Results and Displays

The results of the OPF application shall be displayable on single line diagrams and tables. Among others, a set of specific displays shall be created including:

- Display for the necessary on-line parameterizations;
- Overview display for tracking the OPF solution process;

- Overview display for recommended control actions;
- Logs with solution warnings/errors and recommended actions.

6.1.5.5 Non Convergence / Infeasibility

The OPF function shall include strategies in case of non-convergence and infeasibility of solving the power system situation without violation of constraints.

Non-solution or non-convergence may occur as a consequence of specific combinations of power system state, selected control variables and existing constraints. The user shall interactively be instructed how to follow up in order to achieve the optimum solution. In any case the system shall provide clear operator guidance how to cope with infeasible situations.

6.1.5.6 Closed-loop Capability for Voltage / Var Dispatch

The real-time mode shall be designed for application in closed-loop control as an option. Specifically, it shall provide the capability for the transfer of OPF optimization controls via the SCADA System for Voltage/VAr dispatch, e.g., voltage/Var setpoints to generators including wind and other RES generators.

The operator will be able to easily apply activation/deactivation of closed-loop control. Special damping mechanisms shall be included in the OPF function to avoid "pumping" of transformers caused by cyclical up and down commands initiated from one OPF cycle to another.

6.1.5.7 OPF Execution Modes

The OPF function shall be executed:

- Periodically, as part of the Real-time Network Analysis Sequence. The periodic cycle shall be user definable;
- Spontaneously, after specific changes of the energized network;
- Manually on user request based on the real-time data;
- Manually on user request as part of the Study Environment.

6.1.6 Contingency Analysis (CA)

6.1.6.1 General Approach

The Contingency Analysis (CA) application shall assist to improve the network security by providing a view of latent weaknesses of the power system in order to enable actions for the minimization of potential disruptions. It shall evaluate the steady-state security of the power system for various contingencies. Unforeseen events (outages of network elements) in a given contingency list resulting in overloading and/or abnormal voltage conditions or violations of the (n-1) criterion at any location in the network shall be detected. Contingencies may be single or multiple outages of network components.

The CA function depends on a consistent and complete model of the network to be provided as the result of the SE function or PF solution.

The CA function shall normally be performed in real-time mode but shall also be able to run in study mode, analyzing a network situation different than the current one. It shall have the capability of making use of cases created with the power flow function.

Particularly for CA, contractor may choose to use as a first solution attempt a simplified power flow algorithm i.e., decoupled or fast decoupled but in case of convergence failure the Operator will be able to switch to the more stable Full Newton Raphson algorithm.

6.1.6.2 Basic Data

The input to the Contingency Analysis program shall consist of:

- Network topology;
- Static parameters of the power system elements;
- P-Q capability curves of the generating units;
- The most recent execution results of the SE (in real-time mode);
- PF solution (in study mode);
- The list of pre-selected contingencies;
- Normal and emergency limits for Ampere/MVA flows in branches and for bus voltage magnitudes in buses;
- Limits of over-current trip relays for branches;
- External equivalents information.

6.1.6.3 Operator Interaction

Operator Inputs

The operator shall be able to:

- Verify the contingency list;
- Request detailed displays of results.

The Analyst / Support Engineer shall be able to define parameters for the ranking, screening and presentation of results. The analyst engineer shall be able to enter in particular control window parameters such as convergence criterion, maximum number of iterations and other parameters affecting the convergence of the algorithm.

Alarms

The CA shall generate a list of results for each case defined in the contingency list. Only the most severe results shall lead to an alarm which has to be acknowledged by the Operator. The handling of alarms shall be the same as for other alarms within the control room, in particular:

- Flashing an alarm button in the basic window “Network Application”;
- Pressing this button leads to a window with alarm buttons of all network application functions;
- Pressing the flashing button of “Contingency Analysis” leads to a display with most harmful results of the analysis. The display shall be arranged in order of the most critical cases. The display shall use graphical symbols to highlight the type of failure;
- If the reason of the alarm is a non successful calculation, the detailed description shall inform the Operator in understandable and clear information (not in software vocabulary) about the problem;
- The Operator shall be able to suspend any alarm generated by the CA. The CA shall not create cycle alarms.

The main alarms that shall be generated by the CA are:

- De-energized: One or more cases result in the de-energization of a network or sub-network;
- Islanding: One or more cases will lead to a state of islanding;
- Limit violations: At least one branch/bus will have a current/voltage, which is larger than the defined threshold;
- Non-successful CA execution. This may happen if the scenario cannot be calculated due to non-convergence. A detailed explanation should be provided in the case of non-successful execution.

Results on Operator Request

The results of the CA shall be presented in clear displays. They shall show at least the following information:

- The results of every scenario shall be summarized and displayed in a window, in which the results are sorted according to a severity index. This window shall make use of graphical symbols to ease detection of the type and severe gravity of the failure;
- Identification of violations including Ampere flows, percentage of limit violations;
- Bus voltages and percentages of limit violations;
- Phase angle violations;
- Historical information about each violation, indicating time of occurrence and the worst value.

6.1.6.4 CA Functionality

Process

A contingency screening process shall be included in order to classify and rank the contingencies and simulate in detail only the critical ones. The screening shall utilize simplified algorithms to identify the potentially harmful contingencies which would lead the solution too close to the limits.

According to the ranking results of the Contingency screening, CA shall simulate in detail only the critical contingencies. The contingency screening shall meet the following criteria:

- The contingencies classification shall take into account both the thermal and the voltage violations;
- The contingencies ranking algorithm shall be considerably faster than the full simulation of all the contingencies from the contingency list;
- The ability shall be provided to process several contingency lists.

The following types of contingencies shall be handled by the Contingency Analysis program:

- Line and transformer outages;
- Generation outages;
- Bus outages;
- Outages in reactors or capacitors.

It shall be possible to perform the following:

- Model single contingencies as well as multiple contingencies;
- Assign each contingency to a category of related contingencies;
- Model the effects of protection equipment that would operate in the timeframe of the outage simulation under steady state assumptions.

The NII SMO is responsible for the n-1 secure operation of its own grid and all the interconnections (if applicable). As external network is defined a network operated by another Operator. According to ENTSO-E Operation Handbook – Policy 3, external network elements with an influence factor higher than a pre-defined threshold are considered as having a significant impact on the responsibility area and are included in an external contingency list. These external elements together with the necessary additional elements constitute the Observability Area. The CA should be able to process contingency lists of both the responsibility and the external observability area.

The solution technique, to be presented in detail by the Contractor, shall meet the following requirements:

- Each critical contingency shall be evaluated through a complete power flow;

- Both, real and reactive powers shall be considered;
- The simulation of generator contingencies shall provide for the automatic re-distribution of the lost generation among the other units;
- Normal and emergency limit violations shall be alarmed.

Execution

The activation of the program shall include:

- Periodical execution, as part of the Real-time Network Analysis Sequence. The execution frequency shall be user definable;
- Manual execution after specific changes in the energized network;
- Manual execution on user request based on the real-time data;
- Manual execution on user request as part of the Study Mode Network Analysis Sequence.

6.1.7 Short Circuit Analysis (SCA)

6.1.7.1 General Approach

The system shall include an application to analyze the effect of potential short-circuits in the network. It shall compute short circuit levels and currents in the Power System.

The SCA function can be operated in study mode, providing results suitable for:

- Assessment whether each circuit breaker will be able to operate safely;
- Selection of suitable circuit breaker ratings and design protective relays when planning for new network configurations.

The SCA function shall also be operated in real-time mode, analyzing the state of the system at any time according to the latest SE solution.

6.1.7.2 Basic Data

The input to the SCA function shall consist of:

- Network topology;
- Positive and zero sequence impedances of braches including zero sequence capacitance of cables;
- Positive and zero sequence impedances of generating units;
- Transformer coupling mode and ground connection;
- Ratings of power system equipment (circuit breakers, busbars etc.).

The program shall consider the following types of faults:

- Ssymmetrical three-phase to ground faults;

- Single-phase-to-ground faults;
- Phase to phase faults;
- Phase to phase to ground faults.

The user shall be able to choose among different fault classes such as at a minimum:

- Standard faults with selectable fault resistance;
- Intermediate faults (along lines with user selectable fault distance);
- Open-phase faults and open phase and grounded conductor.

Within each of the above mentioned fault classes the user shall be capable to specify the desired set of fault options and fault types to be processed and simulated by the SCA function. The user shall be able to apply at minimum two simultaneous faults of the above.

6.1.7.3 Operator Interaction

The Short Circuit Calculation shall calculate the short circuit levels of each bus initiated by short circuit in each energized bus. The results shall be displayed and alarmed in network diagrams as well as reported in user definable lists and reports.

6.1.7.4 Alarms

A violation of the user defined short circuit level shall lead to an alarm that has to be acknowledged by the Operator. The handling of alarms shall be the same as for other alarms within the control room:

- Flashing of an alarm button in the basic signaling window “Network Application”;
- Pressing this button shall lead to a window with alarm buttons of all network application functions;
- Pressing the flashing button of “Short circuit” shall lead to a display with most harmful results of the analysis.

If the reason of the alarm is an unsuccessful calculation, the detailed description shall inform the Operator in understandable and clear information (not in software vocabulary) about the problem.

6.1.7.5 Short Circuit Calculation Functionality

Control Input Parameters

It shall be possible to define in control list the limits of each bus bar.

Process

The basic implementation shall consider each bus as a fault location and calculate the total fault current at the bus and the fault currents for each branch connected to it.

For each simulated short circuit the calculation and output shall include:

- Short circuit currents and power;
- Voltages at neighboring buses of the faulted bus;
- Current on branches ending at the faulted bus;
- Voltages and currents at any selected buses/branches of the network;
- Sequences values (positive, negative and zero sequences) of currents/ voltages.

This function shall calculate the necessary short circuit ratings of each circuit breaker and report any devices where violations have been detected. Calculations will be consistent with the IEC standards (desirable for ANSI/IEEE standards).

The program shall be able to analyze bus faults with or without branch outages. It shall be possible to indicate a branch outage produced by a fault in one of its sides and to compute the corresponding fault currents.

Execution

The Short Circuit Calculations are are initiated:

- Periodically, as part of the Real-time Network Analysis Sequence. The execution frequency shall be user definable;
- Spontaneously after specific changes in the energized network;
- Manually on user request based on the real-time data;
- Manually on user request as part of the Study Environment.

6.1.8 Outage Scheduler (OS)

An Outage Scheduler (OS) function shall be provided to assist the authorized user in scheduling future outages of Power System equipment.

As a general requirement, OS provided under this Project shall be designed in a way to allow for operation compliant with the stipulations of the ENTSO-E Operation Handbook, i.e. Policy 4, according to the latest release.

The user shall be able to enter scheduled outages including:

- The device identification;
- Start date/time of the outage
- End date/time of the outage;
- Reason code for the outage;
- The status of the device during the outage.

An outage shall contain any combination of network elements.

It shall be possible to enter schedules for up to two years in the future. Historical schedules shall be retained on-line for a settable period of time.

The OS application shall validate all entries to verify that the time span and outage reason code are valid, the device status is valid and complete, and that the new schedule does not conflict with any pre-existing active schedules. The OS application shall also check the device identification against the devices known to the EMS System and shall inform the user if the device identification is not found.

The user shall be able to request a display of the schedule for all devices for a specified date and time. The user shall be able to view all of the schedules in the OS and to add, delete, and modify schedules.

The OS application shall provide interface to other Network applications (e.g., PF) in order to simulate the effects of switching actions along with the planned outages.

The OS application should also export, per operator request, tables with the planned outages. The time period and device shall be selectable.

6.1.9 Automatic Voltage Control (AVC)

The EMS system shall include an Automatic Voltage Control (AVC) application in order to facilitate engineers and operators in busbar voltage control both for a zone level and for global system control.

The AVC application should meet the following requirements:

- The voltage control at a zone level is related to a secondary control and should be implemented based upon real-time measurement at pilot nodes selected by the operators.
- The voltage control at a global system level is related to a tertiary control and should be implemented based on a solution provided from an EMS based OPF optimization control function.
- AVC application should be able to be customized to meet the control requirements of autonomous systems.
- The control commands for voltage control (output of AVC application) should be reactive power setpoints or voltage setpoints transmitted to controllers of the units.
- Unit reactive power limits should be considered either as declared by the respective unit operator or alternatively as calculated by the AVC application taking into account the measured active power and the P-Q capability curves of the units.
- AVC should use telemetry data such as busbar voltage measurements, unit limit settings, breaker status, and unit local/remote status. Measurement

values should be filtered in order to be used by the AVC application for control purposes.

- AVC should be able to exchange information with all EMS real time applications
- Time between two setpoint transmissions should be parameterized for each unit. A command supervision should also apply when sending setpoint commands to primary controllers in order to block command in case unit status changes from remote to local.
- The AVC application should provide at minimum displays such as system overall overview, zone overview display, signal flow display, unit overview display, unit control display and parameter display. Based on the above the contractor should provide solutions adaptable to HEDNO requirements during the phase of the Detailed design of the Project.

6.1.10 Load Shedding

The new SCADA/EMS System shall include a Load Shedding function in order to provide the operator with efficient and easy-to-use methods for reducing the power system load during emergencies. The Load Shedding function should provide both manual shed/restore functions as well as several types of shed/restore rotation sequences.

The Load Shed and Restore process will handle the operator-defined rotational shedding of the system load as measured in MWs. The operator will also define the type of rotation and the rotation duration in minutes. The operator will define the points to be shed in groups called blocks. Blocks or individual points will be manipulated for shed via operator selections.

The operator's Instructions for Load Shedding shall be issued to the Distribution Network Operator either following the activation of an alert or without it.

The following capabilities are usually supported at the minimum by the Load Shedding function:

- Manual Shed and Restore;
- Full Block Rotation;
- Partial Block Rotation;
- Feeder Rotation;
- Voltage Reduction;
- History of load shed and restore actions; and
- Issue a periodic report or on demand.

Load Shedding and Restore General Description

The Load Shedding function will accept operator requests to shed or restore one feeder breaker or one block.

Based on operator setup and trigger, Load Shedding and Restore performs a full block rotation to validate and shed all points for each block in turn for an operator-designated duration. After the period elapses, the currently shed block is restored and the next available block is shed.

Based on operator setup and trigger, the load shedding function performs a partial block rotation by validating and shedding points from a given block until an operator-designated load level has been shed. After the desired duration elapses, the shed feeders are restored and rotation proceeds to the next available block. Subsequent visits to the block will shed feeders that were not shed before. This methodology rotates the feeders within the block.

Load Shedding and Restore performs feeder rotation by validating and shedding feeder breakers until the desired load level has been shed. All feeders in all blocks are treated as one contiguous block. Load may be subsequently automatically restored by cancelling the rotation program and closing all feeder breakers that have been opened by the restore function.

Voltage reduction validates and executes dispatcher requests for raising and lowering a selected group of transformer taps.

Load Shed and Restore maintains a history file of all shed and restore actions, whether manual or automatic. A report is normally issued periodically at the end of a shift or on demand.

6.1.11 Import / Export of EMS Network Application Data Sets

All data of the EMS network applications– static data as well as dynamic data – have to be converted in PSS/E raw format for export for the PSS/E software package in order to use such data for steady state or dynamic studies within the PSS/E software environment. Selected data sets are to be exported periodically (for snapshots) or on request. State Estimator or Power Flow results are to be exported.

Unit fuel cost data declared by Generators in the Market Management System will be imported to the Network Applications of EMS in order to be used by the OPF function for the calculation of cost curves.

6.2 EMS Modeling System

6.2.1 General

Modeling of Source Databases and Displays should include an appropriate server and two operator workstations with appropriate software for the following:

- The modeling source database residing in a robust and capable for recovering from data loss RDBMS (like Oracle), to handle the storage of this information.

- Database administration and organization of data exchanges.
- The Source Data modeling software for data modification/ validation, visualization, exchange using CIM/XML, ASCII and other ways. In addition the routines for data deployment to EMS databases.
- A storage and testing environment for EMS full graphics displays.
- Full graphics displays editor tools for construction and changes of full graphics displays.

6.2.2 Modeling of Source Databases and Displays System

6.2.2.1 Main requirements

A system should be provided by the Contractor to facilitate the construction and maintenance of all EMS database data on a common metadata and business model, located and managed by an RDBMS (preferably Oracle) with at least the following capabilities:

- Manage the input of Electrical Power system data efficiently, using various ways and formats (ASCII, CIM/XML files, SQL scripts and others).
- Capability to manage the common model in smaller pieces that constitute an integral part of the network, like a control area, a region, bordering countries and others.
- Support of a multi-user working environment, based on User authentication and roles.
- Mechanisms to ensure data validation.
- Export data to CIM/XML models based on IEC standards and ASCII files.
- Provision of a rich user interface for working with the common model, providing data presentation and modification in various ways such as hierarchical, graphical network presentation, tabular and others.
- Full Graphic editor tools to build and maintain the EMS full graphics displays (both tabular and one-line) running in a Web or Rich client environment.

The Source Databases model engineering and Management will proceed through at least the following steps:

- Definition of modeling data and EMS displays.
- Deployment and population of the EMS real-time Databases and displays to the target systems, from the above modeling information.
  - The Contractor should provide the deployment and population software and procedures for the EMS real-time Databases and displays, in a clear and analytical way to ensure Database and Displays online consistency and robustness.

- The procedures and software should include all grouped modifications verification, before the components are placed online to check for referential integrity and finally ensure consistency and correctness of the databases and the corresponding displays.
- The deployment routines before taking the newly modified EMS databases online, should preserve and include in the population, all the manual operator entries and other necessary dynamic data.

6.2.2.2 Importing data

In general it should be possible to import data from other data sources in different formats.

6.2.2.3 Multi-user Support and Editing capabilities

The System should have the capability to accept entries of data from several operator consoles simultaneously, preserving the data consistency by a locking mechanism that should be presented by the Operator. Every user can work on his/her owned model change set, for creating/deleting/modifying the relative group of components, opened in his/her working area and then either accepting the changes and saving them to the model Database or Undoing them in case they were recognized as erroneous.

Copy/Paste operations should be supported as well as copy of a hierarchy of records to facilitate Network model changes. In addition, the above operations will be enhanced by flexible Insert functionalities (helping the user to select appropriate records to add) and intelligent delete operations for the selected record and relative child records.

6.2.2.4 Validation of Input Data

When editing source data, the entered data should be checked to guarantee correctness, by checking input data formats and data range values. Other data validation rules could be applied upon user request and finally others could be applied in all the components belonging to the model change set that the user modifies.

6.2.2.5 CIM/XML data exchange capability

The model of Power system should have the capability to exchange data via CIM/XML files following applicable IEC standards. The CIM/XML files representing the network model of another system can be imported to a model change set that is being modified by the user. Furthermore, the supported standards will support the exchange of network modeling information from EMS systems of different vendors.

6.2.2.6 User Interface

The Source Database Modeling system should provide a rich user interface to facilitate the data presentation, editing and processing using intuitive tools with at least the following characteristics or equivalent:

- Rich client or Web forms designed for a common look and feel and selected via menus and pop-ups will facilitate the data input and changes in a user friendly way, for regular data maintenance. Help displays will facilitate the user work. In addition tabular views and / or tree representation of the hierarchical model objects will be provided for enhanced visualization of power system model.
- A Graphics modeler software representing schematically the layout of the substations power components using information from the source database modeling. This substation layout should be capable to be enhanced by addition of items, connecting nodes, adding Island's Network lines connecting substations and others.

The Contractor should present what state of the art modeling features will provide to improve the development and maintenance of the complex power system models, required for operational success.

6.2.2.7 Full Graphics Displays Editor Tools

These full graphics editor tools should be provided to build and maintain the full graphics displays in the system in order to change, edit and add new displays without software modifications. Functionality of the well-known full graphic environment (i.e., lines, circles, rectangles, polygons, etc.) and their handling methodology (i.e., selection, drag and drop, cut & paste, etc.) or equivalent ways, should be supported by the tools as well as the full graphic variable elements linking mechanism to the EMS databases. The dynamic elements would have dynamic attributes (i.e., color, flashing state of the foreground and background color, etc.) controlled by EMS database field values.

6.3 EMS Real Time Data Export

The Contractor should provide the appropriate tools and infrastructure as part of the EMS platform to provide capabilities for real time data (data, single line diagrams, displays and reports) export from the EMS to be published on the NII SMO Intranet / internet.

This data export should be done in such a way (directly or through an EMS replication infrastructure) that will not endanger the data integrity and real time operation of the EMS or introducing security issues for unauthorized access to EMS.

6.4 EMS Reporting

The Contractor should provide the appropriate tools and infrastructure as part of the EMS platform to provide the capabilities to develop EMS reports, Web-based reports, diagrams and charts based on EMS data.

It should be able to produce Yearly, Monthly, Daily, hourly, 5minute or real time reports with real time or aggregated EMS data.

Appropriate report designer should be provided in order the NII SMO staff to be able to produce on-demand reports easily.

Reports should be able to be exported and presented in different forms, such as Excel spreadsheet, XML and PDF or web pages.

7 Historical Information System (HIS)

7.1 HIS and Data Exchange Requirements with the DW

The archive function runs at each Control Center independently of the operation at other Control Center. Similar to the results of calculations, archived data is not exchanged between Control Centers. Instead, the archive function processes the data and send it to the Data Warehouse system.

The HIS synchronizes user entries, that is, manual updates from Main Control Center to Backup Control Center. However, if required, HIS can provide re-synchronization (gap filling) between Main and Backup Control Center.

The HIS shall provide the capability of sampling, recording and archiving EMS real time data. Data to be stored by the HIS comprise subsets of data available within the EMS System DBs (SCADA, AGC, NETWORK, etc.). The HIS real time and stored data should be available to NII Operation department for internal use and analysis through the appropriate MMI interface. The HIS data should be aggregated and communicated to the DW to be used for NII SMO internal use and analysis.

The EMS should have appropriate mechanisms in order not to lose any data in case of disruption of data synchronization between EMS and HIS. The HIS should have appropriate areas to archive and reconstruct data to a later time if necessary.

The HIS should consist of RAC DB EE 11g (Oracle product) with partitioning that satisfies functional and performance requirements of this project.

The HIS shall realize a continuous recording of real-time data to an RDBMS (OLTP) and keep them online for a period of two (2) months and for the aggregated values for six (6) months. The recorded data shall be immediately available to users and applications in an efficient and reliable manner.

The HIS shall be fully integrated in the EMS System and the related utilities for Data Engineering, Visualization and Reporting. Moreover, the HIS application shall be integrated in the EMS platform via the Power Applications DBs.

HIS stored data shall be held in a relational data base management system and shall be provided in such a way to facilitate the interfaces adaptation with the interconnected to EMS systems while fully supporting the internal redundancy concept.

The DW is a separate system that is updated on a regular basis by bulk transfer of data from the HIS system. The DW data are kept in an RDBMS (Oracle RAC DW cluster) and they are kept online for a long period (at least five (5) years). The recorded data shall be available within the next day to the users and applications, in an efficient and reliable manner. The data shall be efficiently stored in this data warehouse to facilitate easy correlation and presentation of them to the users and applications.

7.2 HIS Functional Requirements

7.2.1 General Function Requirements

The HIS shall be designed to meet the following basic requirements in a real-time environment:

- Easy operability;
- High data reliability;
- Easy reconstruction of historical data (beyond the online ones)
- Consistency of stored data (no loss of data in case of desynchronization with EMS at least for 3 days); and
- Open interfaces to other systems.

The HIS System shall sample the EMS real-time data bases (SCADA, AGC, NETWORK, etc.) and store the specified data with their timestamp in the relational HIS database together with results of calculations applied to the sampled information.

In case the data timestamp goes out of the specified retention period, archiving in files shall be possible for numerical values, raw data, alarms and events and any other datasets sampled from the EMS System to an offline area.

7.2.2 HIS Recording Functionality

As a general requirement, the entire static or dynamic data, derived or necessary for all processes and functions of the EMS must be possible to be recorded and archived. Information on the output of processes/functions or the functions themselves must be possible to be archived in order to draw conclusions from these data. As an example the least transfer capabilities are described:

- Analog values (i.e., MW, MVAR, AMP, MWH, Setpoints, Volts) with their quality flags;
- Calculated values that are stored in the EMS real-time DBs and sampled in seconds by HIS;
- Status of Digital Points and quality flags;
- Alarms and Events;
- EMS schedules.

The types or Recording modes required are:

- Historical or cyclical mode, where all the values are stored in HIS according to the user defined sampling rate (the bulk transfer needed mode);

- Recorded by event or when changed more than a user defined deadband; and
- Update mode where only the newest updated data are recorded (overwriting the older values), according to the user defined sampling rate from the EMS real-time DBs.

Data Engineering, Administration and Parameterization of the different archive types shall be performed utilizing User Interface (HIS UI) administration tools and utilities under consideration of user specific access rights. Thus the respective tools shall be integrated in the HIS data engineering tools.

The HIS shall include the following features:

- Optimal performance (e.g., optimized access times for read/write operations) without disturbing the EMS performance strict requirements;
- Minimum resources in terms of memory space needed, while utilizing common standards of database administrations;
- Minimum administration necessary, i.e., archiving shall be designed in a way facilitating administration through the HIS UI including automatic back-up and recovery utilities of the DB (RMAN online backup) and backup and retrieve of old data (archive files) using the Tape Library. The needed SW and licenses should also be provided by the Contractor.

Since requirements for operation and archiving may be subject of change, the HIS must be flexible to provide:

- Ability for inclusion or deletion of data in existing archives
- Avoidance of multiple storage of data
- Delete functions to be applicable for archives or parts of archives
- Reorganization of archives to be performed automatically without loss of performance

Time information stored within the archives has to consider daylight saving in order to avoid data losses.

7.2.2.1 Cyclic Value Archives

Cyclic value archives serve for storage of numerical values in chronological variation.

Numerical values shall be distinguished and marked in the archives as follows:

- Measurements;
- Accumulator values;
- Set point values; and
- Calculated values.

The HIS shall include the capability for condensation of archives of different time series towards condensed archives, such as average values within dedicated timeframes.

In addition, HIS shall support calculation of Maximum/ Minimum values within dedicated timeframes, as well as statistical functions such as standard deviation. Those calculated values shall be possible to be archived as well.

Each of the values shall be kept in the online database including the respective:

- Technological address;
- Time information;
- Qualifiers.

Qualifiers indicate the “quality of information” which is assigned to the respective value stored in the archive, such as:

- Actual;
- Invalid
- Blocked;
- Edited;
- Substituted;
- Limit violation (warning);
- Limit violation (alarm);
- Provided by State Estimation, etc.

Qualifiers for values derived from calculations or from archive condensations shall be created by logical gating of the respective values.

HIS should record almost all EMS data in order to be able to analyze any normal or abnormal situation. The data should be archived and their associated time series that represent the minimum information that is required. The retention period implies a rolling windows of tablespaces that should automatically created and deleted (old) in order this to be kept in the HIS DB schema.

Indicative data along with respective time stamps are as follows:

- **Frequency and time error:** The system frequency and time error from the SCADA DB;
- **MW, MVAR and AMPS**: MW, MVAR and AMPS on all island network brances from the SCADA DB;
- **Bus voltages KV**: The voltages on all busses (KV) are transferred from the SCADA DB;
- **AVG hourly MW MVAR flows**: AVG hourly MW MVAR flows on all branches;

- **MW, MVAR, KV of generators:** The MW, MVAR, KV of generators of all the generators from the SCADA DB;
- **AVG hourly MW, MVAR of generators:** the AVG hourly MW, MVAR of all generators from the SCADA DB;
- **Units / plants Setpoints and Market Basepoints**: Setpoints and Market Basepoints for all units / plants from the SCADA DB;
- **Units / plants AVG hourly Setpoints and Market Basepoints**: AVG hourly Setpoints and Market Basepoints for all units / plants from the SCADA DB;
- **Transformer tap positions**: All Transformer tap positions from the SCADA DB;
- **Weather data** : Weather data from the SCADA DB;
- **Contingency Summary data:** Contingency Summary data are transferred from the NETWORK;
- **AGC Operation Mode:** AGC Operation Mode data from the AGC DB;
- **Island Generation:** Island Generation Data are transferred from the AGC DB. Indicative Data are: NET LOAD,Total INTERCHANGE, FREQUENCY, ACE, SYSTEM LOAD, REGULATION RESERVE DOWN, GENERATION, SYSTEM REGULATION REQUIREMENT, REGULATION RESERVE UP or their respective hourly average, etc.
- **PLC DATA:** All units /plants PLC data transferred from the AGC DB. Indicative data per PLC are: LFCMAX, LFCMIN, PLC MODE (AUTO, STATUS, SUSPEND, PAUSED, MMS_MODE), MMS BASEPOINT GROSS, MMS_BASEPOINT NET, MMS LFCMAX, MMS LFCMIN, OFFLINE PLC, ADJUSTMENT, PRODUCTION or their respective hourly average etc.
- **PLC limits and rates:** all units /plants PLC limits and rates from the AGC db. Indicative Data are: CAPACITY MAX, CURRENT CAPACITY, ECOMAX, ECOMIN, RATE NOMINAL UP / DOWN or their respective hourly average etc.
- **PLC reserves:** PLC reserves Data are transferred from the AGC DB. Indicative Data per PLC are: SPINNING RESERVE or their respective hourly average etc.
- **Island RTNET Summary:** Island RTNET Summary from the network applications.

8 Dispatcher Training Simulator (DTS)

8.1 General

A Dispatchers Training Simulator (DTS) shall be supplied under this Contract.

The main DTS objective is to train dispatchers by giving them a view of the system behavior which is the same as in the EMS. The DTS shall provide an EMS-like environment that allows new Operators to learn power system operation, training to the MMI (Man Machine Interface) of EMS, get familiar with the EMS system applications, training to switching procedures for maintenance activities in the grid, training to security calculation (n-1) procedures, etc.

The DTS will also be used for engineering analysis. For example, experienced users will use the simulator to study the preventive, corrective and restorative actions necessary for various power system conditions under normal and abnormal situations (look-ahead simulations and planning studies).

Finally, DTS will be used for the testing of software development, database alterations and system integration.

The DTS should cover all requirements imposed by the ENTSO-E Operation Handbook Policy 8, valid for CE synchronous area (former UCTE).

8.2 Training Simulator Key Features

The DTS shall be integrated into the EMS and shall be used mainly for training system operators for normal, emergency, and restorative control of the Island's Network grid. Thus, the DTS shall provide an effective training mechanism by satisfying the following minimum requirements:

- The DTS shall simulate the power System in a realistic manner. This means that the behavior of the model will be similar to that of the real system. The simulator shall provide static and dynamic simulation of the power System and responses to simulated events, instructor's actions, and trainees' actions that are identical to those observed by the system operator in the EMS environment, as well as monitoring and control options for the trainee and trainer to influence the process, through the MMI.
- The DTS shall include an exact representation of the EMS applications and functionality.
- The DTS shall be installed and run on its own hardware physical or virtual. This includes 2 dedicated workstations (1 for trainee and 1 for trainer) and one printer. The trainees shall use them to operate the simulated power system. The instructor shall use the above workstation in order to prepare

training scenarios and to set up, control, participate in, and review the results of a training session.

- In order not to interfere with the real-time operation, the DTS shall be isolated from the EMS environment, but shall have the capability to obtain data from the EMS during initialization.
- The DTS shall simulate all various types of units. It shall provide appropriate modeling of the main components of thermal units (boiler, turbine, diesel engines, generator, governor, exciter, voltage stabilizer etc.).
- The DTS shall simulate RES generation as well as energy storage units like pumps, batteries, and hybrid units.
- The DTS will not be redundant.

8.3 Power System Model

The Power System Model (PSM) shall consist of a model of the electrical network that will include:

- Island's Network equipment;
- Generation units;
- Storage facilities;
- Demand Response;
- RES units;
- Aggregate models for Distributed Energy Resources (DERs);
- System loads with voltage and frequency dependence;
- Automatic Generation Control (AGC);
- Standard protective relays;
- A representation of mechanisms which allow personnel other than the system operator to affect the power system;
- A simulation of all interfaces and functions that have an impact on operator work.

The basic simulation will be a periodic power flow solution (solution of algebraic equations) combined with a slow dynamic simulation in between (solution of differential equations). The models of all the Power System components must fall within these two categories (algebraic/differential). The DTS network model solution (algebraic equations of power flow) shall be updated at an average rate of once every few seconds but no more than eight seconds. Dynamic equations (e.g. differential equations of units and frequency models) shall be solved using a time step suitable for the power system dynamics under consideration.

In general, PSM shall be valid under any conditions in which the power system being modeled is stable. It shall be valid for normal, emergency, and restorative conditions including a frequency range of 47 to 52 Hz and voltages of 0.80 to 1.15 per unit. If voltage variations exceed this range, the PSM should remain valid.

The PSM will be suitable for simulating unbalanced operating conditions in the network, including the dynamic response of generating units and their protections to such conditions.

DTS shall simulate conditions in which electrical islands exist, each with its own frequency. The frequency in each electrical island of the power system shall be modeled as a function of the island power mismatch, inertias and sensitivity of the island load to frequency. The island power mismatch is the difference between the island generation and the island load including losses. The collapse of any electrical island shall not cause the entire system simulation to abort. When islanding or island blackout occurs, the EMS functions shall continue to perform for the trainee in the same function as they would if the same situation occurred at the real system.

The DTS shall include default values for all model parameters if NII SMO chooses to use generic models.

8.3.1 Load Modeling

The PSM shall model both real and reactive power loads in the power system. The real and reactive power loads values shall be calculated based on stored load curves. Each Load curve shall represent a profile of the Load over 24 hours for different types of days, using straight-line interpolation within each five-minute period or more. It shall be possible for the NII SMO to have a separate Load curve for any combination of the following partitions of the power system:

- A substation;
- An area (e.g. a group of substations);
- A Region (a group of areas);
- Entire control area.

The Load shall be distributed to the bus loads using a set of instructor modifiable distribution factors. It shall be possible to have different sets of distribution factors depending on the day and time of day. The reactive part of the conforming bus Load shall depend on a defined power factor.

The non-conforming part of the bus load shall be a time-varying set of real and reactive power values with five-minute maximum resolution. The random component of the Load shall consist of a random variation, which follows a uniform probability distribution applied to each individual Load.

The bus loads calculated above are the loads at nominal voltage and frequency. The sensitivity of the loads to voltage and frequency is modeled so that the actual loads depend on the deviations of voltage and frequency from nominal values (based on variation coefficients entered by the instructor).

The Load model shall also include the following features:

- Load shedding and restoration by under frequency relaying and supervisory control;
- Constant power, constant impedance, and constant current Loads and mixed P and Q combinations of the above.

8.3.2 Energy Source Models

Commonly available types of energy sources shall be modeled in the DTS, for example, hydro, diesel, fossil steam, gas turbine generating units combined cycle plants and various types of RES such as wind power and solar generation etc. Each energy source model shall include a governor model and a turbine model. The excitation system, including power system stabilizers, shall be modeled.

8.3.3 Electrical Network Simulation

The DTS shall include a model of the electrical network which is identical to that modeled in EMS. Electrical network simulation shall also include the following features:

- Steady state models with appropriate dynamic time delays for automatic tap changing shall be used to model tap changing and phase shifting transformers.
- Modeling of the automatic control of VAr resources shall be provided including capacitor/reactor devices.
- Modeling of different types of FACTS devices e.g. Static VAr Compensators (SVCs).
- Modeling of HVDC links.

Models for the following types of protective relays shall be included:

- Distance protection;
- Differential protection and protections relevant to power generation units;
- Inverse time;
- Underfrequency;
- Overfrequency;
- Under/Overvoltage;
- Synchrocheck;
- Automatic Reclosure;
- Time Switched;

- Inverse time overcurrent (phase and ground);
- Directional overcurrent.

The PSM shall model measurement and device conditions collected by the RTUs and Local I/O and those transmitted to the EMS via data exchange. This shall include but not be limited to measurements from measurement devices, status devices, and accumulators. The PSM shall also accurately model the output of a time deviation monitor based on the integrated difference between the model frequency and 50 Hz.

The simulator shall accept control signals generated by the Control Centre Model function, respond in a manner analogous to the actual device, produce the output signals necessary for the network model, and produce the output signals normally monitored by RTUs, Local I/O, and data exchange.

8.3.4 Control Centre Model (CCM)

The CCM shall represent the EMS system. It shall consist of the same software used in the EMS with modifications necessary to interface with the PSM.

The CCM model shall duplicate the EMS from the perspective of the trainee interacting with the DTS from the training console. It shall include all functions included in the EMS. The functions shall be exact copies of the corresponding in the EMS with the exception of those such as Data Acquisition, Data Exchange, Supervisory Control, and AGC, which interact with the real power system. Differences between these and the corresponding ones in the EMS shall be limited to those changes required for interaction with the PSM; functional differences apparent to the trainee are not acceptable.

8.3.5 Data Acquisition and Data Dissemination

The DTS Data Acquisition and Data Dissemination functions shall be modified versions of the corresponding EMS functions and shall scan the Output of the PSM to update the SCADA database. The DTS shall simulate the process in which the power system data are sampled by the RTUs and exchanged over the data links. The following situations can be simulated:

- Failure/restoration of an RTU by instructor;
- Substitution of analog measurements or status values by an event or instructor action;
- Measurement values exceeding its reasonability limit by an event or instructor action.

8.3.6 Supervisory Control

The DTS Supervisory Control function shall be a modified version of the EMS function and shall control the status of simulated devices in the PSM including but not limited to breakers, switches, multi-state devices, transformer taps, phase shifter taps and all other devices controllable by supervisory control from the EMS. It shall be possible for the instructor or an event to cause the device to fail to respond to the supervisory control signals.

8.3.7 Generation Control

The DTS function shall be a modified version of the EMS – Generation Control System function and shall control the energy source model in the PSM. It shall be possible for a scheduled event or the instructor to cause the selected model to fail to respond to AGC control signals. The DTS AGC function shall include all the AGC capabilities specified for the EMS.

8.3.8 Configuration Control

The DTS Configuration Control function shall be a modified version of the EMS function. It shall provide control of all devices, such as consoles and printers, attached to the DTS. Any console or printer properly assigned shall be attached to the DTS and interact only with the simulator software. Those devices attached to the DTS shall be capable of being restricted to trainee function, or instructor functions, or both. The assignment of functions to devices shall be accomplished interactively via displays. Devices attached to the DTS shall be shown as such in EMS configuration control displays.

8.3.9 Instructor Control

The DTS shall include features to allow an instructor to perform pre-session, session, and post-session activities.

Pre-session activities consist of scenario building and development of events, which occur during the training scenario. A power flow function shall be provided in the DTS to support this feature.

Session activities performed by the instructor include initiation, control, and participation in the training scenario. Facilities shall be provided in the DTS for the instructor to perform these tasks.

Post-session activities consist of session review and evaluation of a trainee's performance. The DTS shall maintain records of the training session so that events, trainee actions, and operational performance may be reviewed and evaluated.

The tasks performed by an instructor shall be supported by a separate dedicated console, which shall include all the capabilities of the trainee's console and additional instructional capabilities.

Provision shall be made for the instructor to play the role of personnel at locations remote from the Control Centres. For example, it shall be possible for the instructor to play the role of a power station or substation operator and place generating units on and off line and on and off generation control, change a unit's limits, and perform other manual actions usually performed by power station and substation personnel.

Provision shall be made for modeling branch faults. The instructor shall be able to specify a fault by indicating the time of its occurrence, its location, and its duration. At the proper time the DTS shall automatically open all switching devices that are supervised by protective relays and that are necessary to clear the fault. Should the trainee or instructor attempt to reclose any of these devices while the fault still exists, i.e., before the specified fault duration has expired, the device shall automatically trip again. If the trainee or instructor should isolate the fault using sectionalizing switches, reclose the devices that cleared the fault, and then attempt to reclose the sectionalizing devices while the fault still exists, the DTS shall clear the fault in the same manner as it first cleared the fault.

8.3.10 Pre-Session Activities

The DTS shall provide the instructor with the ability to create a base case. This includes such features as the selection of the network configuration and system loads. Capability shall be provided for the instructor to execute a power flow if desired and initialize the simulation from the base case. The instructor shall also have the capability to build groups of events scheduled to occur during the training session. A training scenario shall be built by combining one or more event groups with a base case.

Scenario Construction

The following features, at a minimum, shall be provided for the purpose of building a training scenario:

- Base Case Construction: Allows the instructor to set conditions, parameters, and limitation for equipment in the network database. It shall be possible to initialize a base case from the following sources:
    - A stored base case;
    - A power flow solution;
    - A saved copy of the real-time network solution (snapshots).
- Base Case Store: Allows the instructor to save network conditions for future use. It shall be possible to store and retrieve base cases to and from auxiliary storage devices.
- Base Case Select: Allows the instructor to select a specific base case for modification or further processing. Base case selection may be indexed by title or subject.
- Base Case Review: Allows the instructor to display conditions, parameters, and limitations for equipment in the network database.
- Base Case Edition: Allows the instructor to modify an existing base case and to store the updated version.
- Event Group Construction: Allows the instructor to construct event groups containing one or multiple events. It shall be possible to define the events

within the event group to occur simultaneously or according to other parameters of time or system conditions. Checks shall be performed to assure that each event entered is one of the predefined sets of valid events and that the equipment and parameters associated with the event are valid and complete for the event specified.

- Event Group Store: Allows the instructor to save the event group constructed for future use. The instructor shall have the ability to archive event groups by transferring event groups to auxiliary storage.
- Event Group Select: Allows the instructor to select one or more event groups for incorporation into a training scenario.
- Event Group Review: Allows the instructor to display events and conditions within an event group.
- Event Group Edition: Allows the instructor to modify an existing event group and to store the updated version.

Event Types

The instructor shall be provided with a set of permissible event types, which can be scheduled as part of a scenario. Displays shall be provided which allow the instructor to create, review and edit an event group; an event group may consist of several events. These events can be:

- Time Dependent Events: These events shall be scheduled by the instructor to occur at a simulated clock time or at time intervals relative to the start time of the scenario.
- Conditional Events: During the training scenario, the trainee may perform certain control actions that alter system conditions. Conditional events shall be based on system conditions brought about by the trainee actions.

8.3.11 Session Activities

The instructor shall have the capability to monitor the training scenario and guide it toward a specific objective by inserting new events or omitting scheduled events and monitoring the status of various power system components within the PSM. A facility shall be provided for the instructor to play the role of outside personnel in contact with the trainee. The following commands shall be provided to control a trainee scenario:

- Pause/Resume: Allows the instructor to suspend or resume the training scenario without affecting the scenario.
- Event Instruction: Allows the instructor to add new events, when a training scenario is in progress, without the need to interrupt the training scenario.
- Event Omission: Allows the instructor to omit a scheduled event from the training scenario in progress without interrupting the training scenario.

- Periodic Snapshot: Allows the instructor to create a historical file that is periodically updated with critical session data, as it occurs during the simulation. The DTS shall not pause while the snapshots are being collected and saved.
- Demand Snapshot: Allows the instructor to create a historical file that is updated with critical and specified session data when it is demanded during the simulation.

8.3.12 Post-Session Activities

The DTS shall provide the following capabilities to assist the instructor in reviewing a training session with the trainee:

- Snapshot Review: After a snapshot has been loaded, the trainee and instructor shall be able to call displays to examine any data normally available during a session.
- Snapshot Resume: Resumes the simulation from a snapshot.
- A report should be provided after a training session with the view of evaluation.

8.4 DTS Sizing and Performance Requirements

The performance requirements for the CCM model functions shall be identical to those of the corresponding EMS real-time functions.

The DTS model shall be sized the same in all respects as the EMS system.

In addition, it shall be sized to include the following items:

- 10 DTS Base cases;
- 10 scenarios;
- 50 event groups;
- 10 events per groups;
- 15 session snapshots (periodic plus demand).

The DTS database shall be generated from the same source data as the EMS database. The source data shall contain all data necessary to generate the EMS database and the DTS database. When a new database is built the existing one shall not be replaced or invalidated unless directed by the programmer/engineer. The network model used in the PSM shall be based on the network model used in the EMS Network Application functions.

There shall be only one description of display formats and one set of display linkages for displays that are common to the EMS and the DTS. All EMS displays shall be directly useable in the DTS. DTS displays shall be distinguishable from real-time displays.

9 Development System

The Development System should be consisted of a stand-alone fully configured EMS program development environment with the DTS software also installed to facilitate testing. It should provide a complete and autonomous environment for future program development, application building and testing as well as system integration. This system should at least include all EMS real-time databases and applications, all the full graphics displays and the DTS environment for testing.

Additional Capability of Development System to communicate and receive real time data from the EMS shall be helpful for testing of new functions.

The Deployment and population functionalities of the Source Database Modeling system would also be applied to online EMS databases on the Development system.

The system requirements at a minimum should include an appropriate server and two operator workstations with the appropriate software for hosting and managing the following:

- EMS databases;
- EMS applications;
- Full graphics displays; and
- DTS applications environment for testing.

The Development System shall not be redundant.

10 Migration

The Contractor is responsible for the Migration of all information from the existing SCADA to the new EMS. Indicatively but not restrictively, the following data should be extracted and migrated to the new EMS:

- All modeling data from the EMS Databases (SCADA and NETWORK etc.);
- All existing Full Graphics displays (One-line diagrams of all substations and Island Overview as well as Special NII SMO displays). The same colors should be used so that the transitional time of the operators is minimal.

Information extraction from the existing EMS shall be implemented by the Contractor with the assistance of the NII SMO staff. The NII SMO shall provide the Contractor the appropriate information for the databases and full graphics in order to facilitate the data migration.

In case the Contractor is not able to access the NII SMO's databases due to well proven technical or legal reasons, then the NII SMO shall undertake this task by extracting all information required, from the existing EMS and the information will be delivered to the Contractor in order to be migrated to the new EMS. All information will be provided by NII SMO to the Contractor in a simple common file format that will be agreed in the Detailed Design.

All information from the existing EMS shall be migrated to the new EMS either automatically or manually with the responsibility of the Contractor. The Contractor has the full responsibility to correctly migrate all information to the new EMS.

The data migration should be done before the FAT so that during the FAT it will be possible to validate the correctness of data in use and the integrity of new EMS databases to the maximum extent possible. The final verification for successful data migration will be concluded during the SAT and before the new EMS is launched during the trial operation phase.

11 RTUs Specifications

11.1 Introduction

The electrical SCADA system is used to monitor and control the High Voltage (HV) electrical supply network, including the station units (conventional and RES), and signals for the Rhodes ECC. The master stations interface to the electrical network via a system of RTUs over the Island's communication network. RTUs are generally located in substations and high voltage distribution substations (33kV and above), including power stations. These locations contain equipment such as HV AC circuit breakers, transformers and other miscellaneous equipment.

In what follows, substation in general covers substations, power stations and other electrical locations that might contain RTUs. The supplier is meant to be the supplier of the RTU. Also, an Intelligent Electronic Device (IED), such as a PLC, protection relay or an RTU specifically refers to devices that communicate by a serial protocol to the main RTU at a substation. IEDs do not communicate directly to the SCADA master station.

11.1.1 Application

This specification is applicable to all new electrical SCADA system RTUs and to those that are replacing existing RTUs due to plant expansion or RTU obsolescence.

11.1.2 Purpose

This specification defines the requirements for an electrical SCADA System Remote Terminal Unit. It establishes functional and performance requirements for selection and system design of RTUs to be incorporated into the Rhodes ECC electrical SCADA network.

11.1.3 Major Components of the Electrical SCADA System

The three major components of the electrical SCADA system are:

- **Master Station:** The SCADA master station provides electrical operators with facilities to remotely monitor and control electrical plants and the network. Each location is capable of operating the entire SCADA network.

  The master station should combine extensive IED integration capabilities, a programming interface (preferably IEC 1131 compliant), configuration and diagnostic tools, and various advanced features like WAN support, data encryption and HTML server capabilities, to make it a perfect Substation Data Concentrator. It is HEDNO preference for the master station to support features normally found in RTUs and PLCs: 1ms Time Stamping, SOE handling, momentary, change Detect, Select-Before-Execute controls, and a

IEC1131 compliant PLC programming interface. This is important to ensure that no SCADA and automation functionality is sacrificed

- **Communication Network:** The communications network connects the SCADA master stations with all of the RTUs located in the substations. The communication network is a private network that will be implemented by the contractor with telecommunication lines provided by HEDNO.

- **Remote Terminal Units (RTUs):** The RTUs interface to the electrical plant within a substation and monitor the status of the plant via digital and analogue inputs. This data is transferred to the master station when requested by the master station. The RTUs deliver set-points to generation units and provide for control outputs to switch plant such as circuit breakers and tap changers. In newer RTUs, serial links are provided to interface into IEDs such as electrical protection relays.

11.2 RTU System Design

HEDNO requires that each substation will have an RTU that is designed in accordance with this specification. The RTU shall be of proven design and suited for electric power transmission and distribution SCADA applications. Also the RTUs installed in the generation units will be able to communicate the AGC commands to the units.

In general the RTU design should aim to minimize power consumption and heat generation. It should be designed to work in a HV electrical installation by being of robust physical construction with immunity to electrical noise.

The RTU shall be assembled from modular units, for example, power supply module, CPU and communications module, communication interface modules and modules for input/output purposes. I/O and serial cards shall be able to be arranged in the RTU rack in any order.

Modules shall be interconnected via a suitably robust plug and socket method. It shall not be necessary to unscrew individual wires/cables, both internal RTU wiring and I/O wiring, to replace faulty modules. The failure of one module will not affect the performance of any other module.

The RTU should preferably be a Communications Gateway, a Programmable Logic Controller and an HTML server. It should combine extensive IED integration capabilities and configuration and diagnostic tools. It should also meet the NERC CIP cyber security requirements. it should consists of a CPU and will include a sufficient number of I/O modules taking into account the spare parts too. The RTU should support a full range of standard and specialized I/O modules including digital input, analog input, digital output and analog output. Specialized I/O modules should provide for direct measurement of Pt-100 and Ni-100 resistive temperature devices.

The RTU should allow the user to be able to review the substation's real-time data, review RTU error logs, compare communication port statistics, and upload / download firmware and configuration files via encrypted data communications. The RTU should also accomplish automation tasks and will provide users with the option of different graphical and text-based programming languages that comply with IEC 1131-3. Simpler automation tasks may involve consolidation of alarms, data conversion and human machine interface (HMI) lockout.

The RTU should come with an internally mounted GPS clock. This OEM-style GPS clock is a very cost-efficient substitute for stand-alone GPS clocks.

A marshalling terminal area shall be incorporated with each RTU to provide terminations for field cables. This area can be located in the RTU cubicle itself for an RTU replacement but for new locations there should be a separate marshalling cubicle. The RTU and marshalling cubicles shall normally be bolted together to form a 2-bay cubicle suite. A separation plate may be located between the cubicles.

The RTU and the cubicles shall be designed to accommodate the actual number of input/outputs and IEDs at the specific substation, plus spare capacity.

11.2.1 RTU Spare Capacity

The spare capacity, which includes equipped, wired and cubicle capacity, shall be supplied as described below. The supplier shall detail the steps required to activate the spare capacity.

Equipped Capacity

Equipped capacity will include all electronic cards and output terminals. To activate this capacity, an input/output connection shall be made to the designated field terminals in the marshalling cubicle. This additional capacity is generally provided to cover the initial substation design and commissioning. It includes rounding up the quantities specified to the modulus of the number of points per card. Unless this is otherwise specified, the initial equipped spare capacity shall be not less than 20% for each type of input and output used. Unless specified, any I/O lists or quantities given for a particular RTU will not include spare capacity. Therefore these quantities will need to be increased by 20% to meet spare capacity requirements.

Wired Capacity

Wired capacity means that a card slot is provided. To activate this capacity, in addition to connection of the field input, an additional input card or output card is required to be supplied and fitted, and wiring arranged from the I/O card to the terminals in the marshalling cubicle; the wiring is usually done by a preformed cable. This capacity is specifically provided to cater for some future known requirement, which may be 4-5 years away. Unless otherwise specified during the Detailed Design Phase of the Project, this additional capacity shall be zero.

Cubicle Capacity

Cubicle capacity is a requirement to provide adequate cubicle space capacity, such that additional card files and terminations could be retro-fitted at some stage in the future. This is to cater for expansions possibly 8-10 years or more away. Unless otherwise specified during the Detailed Design Phase of the Project, this additional capacity shall be zero.

11.3 RTU I/O Structure

The RTU I/O quantities shall be developed in accordance with HEDNO requirements specified at the time of order of an RTU.

Each RTU interfaces both directly and indirectly with substation, electrical equipment and protection systems within the supply power and the network.

The direct interface is via wiring directly from digital and analogue sensors located within the substation equipment to the RTU, and from relay outputs within the RTU to equipment panels in the substation. This wiring is routed via the marshalling cubicle.

The indirect interface is via a local communication network between the RTU and the IEDs in the substation.

Field cable terminations located within an RTU marshalling cubicle shall define the point of separation between the Electrical SCADA RTU and the substation electrical system.

Restricted space within a substation building may necessitate location of the marshalling terminals within the RTU cabinet.

11.4 RTU Power Supply

Various supply options are presented next. The exact determination will be made during the detailed Design Phase of the Project. The power supply to run the RTU will be provided by HEDNO and will come from one of a number of sources, as detailed in the following sections. The particular power source shall be specified at the time that the RTU is to be ordered. The supplier is required to inform HEDNO of, and supply all power converters required to permit acceptance of the power supply specified by HEDNO.

11.4.1 Power Source – 125VDC or 48VDC Substation Battery

In the case of this supply source, the RTU shall derive its power requirements from the substation battery provided by HEDNO, which supplies essential equipment in the substation. At most locations, the power source is 125V DC (which is sometimes referred to as 120V DC) although at some older sites the power source may be supplied at 48V DC (which is sometimes referred to as 50V DC).

In locations where a 125V DC or a 48V DC power supply is provided, it shall be considered to be a secure supply and no other battery backup system is required for the RTU.

As this power supply is not earthed, isolation of the station battery supply to the RTU system shall be via 2 pole isolating switches.

The RTU power supply shall be designed to operate at full-specified performance for DC supplies conforming to IEC 61508 and IEC 61511 for the following categories:

- Voltage ripple: Class VR3 (not more than 5% of nominal supply voltage, peak to peak).
- Voltage tolerance: Class DC3 (+15%/-20%).

The substation battery is sized to provide power to the RTU (and substation switch gear) for a period of 10 hours. In this period, supply shall remain within the range specified above, i.e. 100 – 143.7V DC for a 125V DC battery.

The RTU power supply shall be designed to operate at fully specified performance for DC supply earthing condition E+/E-/EC/EF (positive earth / negative earth/centre earth / floating) of IEC 60870-2-1. As the supply is floating, power should still be available for any single inadvertent earth connection.

11.4.2 Power Source – 230V AC General Purpose

In some locations, usually control rooms, equipment rooms, stations, field switches, compressor rooms or pumping stations for example, a general purpose 230VAC supply is used to power the RTU. At these sites, the RTU is required to function for a period of at least 10 hours in case of AC supply failure. A combination battery charger and battery shall be provided by the supplier for this purpose, in case UPS is not used. The RTU and its communication equipment are the only equipment to be powered from this source at these locations.

HEDNO prefers the batteries provided by the supplier to be 12VDC. Batteries shall be of the sealed absorbed glass mat or gel type lead acid, and shall be supplied in a separate wall mounted cubicle, with venting to atmosphere of approximately 10cm square. The preference is to use 24V DC (made of two 12V batteries). HEDNO may specify a need for a battery at these alternate voltage levels. The battery voltage required at a particular location shall be specified by HEDNO at time of order placement.

The supplier is required to provide design calculations to demonstrate the battery capacity to be supplied. The calculation of the required battery capacity shall include a margin to ensure system integrity. This margin shall include a design allowance of 20% minimum, a temperature correction and an ageing factor for at least 4 years obtained from the battery manufacturer. The battery shall be suitable to be recharged from its design end-of-discharge voltage to full charge in 5 hours.

11.4.3 General

In all cases, galvanic isolation shall be provided on each power supply of the RTU that connects to the power supply source.

In cases where the supply battery voltage undergoes a gradual decline to the lower specified limit due to lack of charger input, the RTU shall continue to perform in a reliable and predictable manner. No false inputs shall be recorded, or control outputs executed by the RTU at any time. The supplier shall provide descriptions of design mechanisms that handle this requirement.

11.5 RTU CPU

The RTU shall be microprocessor based. Once power is supplied to the unit, it shall be designed to operate without manual intervention; additionally, it shall auto restart and be able to communicate with the master station without reporting spurious state changes on power resumption after a power failure. Suitable, reliable indicators such as LEDs shall be provided for personnel to readily ascertain the status of the RTU.

The processor shall monitor the health of the RTU with built in diagnostics, which are capable of remote interrogation including diagnostics for memory and bus errors, buffer overflows, local software routine health, communication ports status, input/output card health. Diagnostics shall also be supplied that shall permit complete testing of the RTU with a portable computer. Diagnostic checking of the communication ports shall be provided to permit checking by a portable computer. Diagnostics and configurations can be performed from the ECC without built in laptops. A small number of laptops should be provided for the communications. The laptops should contain low power platform design, sunlight readable panel, WLAN integration, ability for anti-shock and vibration, full IP65 protection and anti-corrosion coating with aluminum alloy housing.

Power supply and battery low volts or failure conditions shall be monitored.

The RTU shall possess memory to permit storage of a minimum of 2000 events (input changes) locally for subsequent transmission to the SCADA master station and these events shall not be lost on buffer overflow; an indication shall be provided of this latter condition. Events will be retained in the buffer until they are correctly read by the master station. As a minimum, separate buffers shall be provided for digital and analogue events.

To enable fault finding to occur, there shall be a separate event list to record internal RTU events such as health, time synchronization and any internal errors. This shall permit storage of up to 2000 events.

When memory is provided for the purposes of local control or communications routines, spare capacity shall be provided equal to the amount utilized.

The RTU shall have a real time clock, with a resolution of 1msec. Every RTU will deploy its GPS technology for synchronization purposes. It shall also have the capability of time stamping events.

The synchronization should be local. No remote synchronization with the ECC is recommended since the level of required resolution may not be achievable. Also local synchronization is required to ensure the availability of signals for analysis purposes after a communications failure.

The GPS should not be built in with the CPU for safety reasons. The GPS should have anti lighting protection.

Within the RTU, events shall be reported to an accuracy of +/-1msec.

The RTU shall be equipped with a “controls isolate” switch, which shall inhibit all control outputs from being executed. The status of this switch shall be monitored by the RTU.

The RTU shall be scanned by the master station using the following protocols:

- IEC 60870-5-101; and
- IEC 60870-5-104.

The supplier must be able to demonstrate a significant history of satisfactory operation of the RTU connected to the master station or similar.

The RTU shall be capable of programming in a high level language to implement local control and logic routines. It shall also be capable of being programmed using at least two IEC1131-3 programming languages.

11.6 Communication Ports

The minimum requirement for communications is as follows:

- The RTU shall be equipped and configured to communicate via dual 100Base-TX Ethernet ports, and be capable of using 100BaseFX, to the master stations.
- An RS-232 serial port shall provide connection to a local or dialup PC for diagnostic and configuration purposes.
- A specified number of RS-485 channels may be required to interface to local computing devices such as IEDs or other sub RTUs and, if required, will be specified at the time of the placement of an order. Capability to use IEC 60870-5-103, IEC 60870-5-101, IEC 61850 and IEC 60870-5-104 is required for this purpose.
- An RS-232/RS-485 port for communication to a local or dialup master station may be required and, if required, will be specified at the time of the placement of an order.

- Dual V.23 ports may be required for communications via the existing pilot wire communications network to the master station in lieu (temporarily) of the fiber ports. This method of communication requires a 1200 baud VF modem, and if the modem offered to be supplied is not acceptable to HEDNO then RS232 ports to an externally supplied approved modem will be required.
- A port for connection of a slave RTU. This port may be a V.23, RS-232/RS-485 or other port. A slave RTU is scanned by an RTU and has its database incorporated into the master RTU database. A slave RTU is not directly scanned by the master station. The Supplier shall indicate what protocol variants are available for a slave RTU and any incremental costs associated with each protocol type. HEDNO's preference is to use a publicly available protocols.

The specific communications ports required shall be detailed when the RTU is specified as it is recognized that both RTU and communications network components may change in the future.

Isolation of all communications circuits shall conform to IEC 60870.2.1. Galvanic isolation shall be provided for any port that is not based on a fiber interface. This is not required for the diagnostic port.

11.7 RTU Input/Output Modules

This section relates to direct wired input/output equipment.

11.7.1 Digital Inputs

Digital inputs shall comprise both active & passive types. Where passive inputs are nominated, the power shall originate at the input module. Active inputs shall be powered from external equipment. Both the active and passive inputs shall normally have identical voltage ratings & types, which shall be the substation battery supply voltage. Some inputs, detailed at time of issue of specification, shall require different voltage levels which will usually be accommodated by the use of interposing relays, mounted in the marshalling cubicle.

Digital input signals will conform to published standards and galvanic isolation shall be provided.

Each input shall be provided with individual 'anti-bounce' signal conditioning and noise filtering such that a value can be varied to adjust the sensitivity of the input from 0-30ms. This ensures compatibility with older equipment with contacts that do not make solid contact initially.

Each input shall be able to detect a minimum change, from High to Low or Low to High, of 4ms. The threshold voltage shall be set such that an input will not change from Low to High unless the input voltage is at least 35% of the nominal battery voltage and it will not change from High to Low unless the input voltage is less than 65% of the nominal battery voltage.

Each group of inputs shall be protected by fuses (or equivalent). Fuse monitoring in groups shall be provided to detect whether fuses have failed, and alert the master station operator of this occurrence.

For locations where there are two battery systems, digital inputs shall be clearly labeled to identify which battery system is used. There shall also be separation of inputs from the two battery systems. The inputs shall be separated by being on different card racks and marshalling terminal strips which shall be labeled for identification.

Scanning and processing of the inputs should be executed with resolution of 1 ms.

11.7.2 Digital Outputs

Digital outputs shall comprise voltage free contacts rated for switching. Relays shall conform to IEC 60255-3 (formerly IEC 255-4).

Loads shall be typically:

- 125V DC 1 Amp inductive;
- 230V AC 2 Amps;
- 24V DC 1 Amp.

Appropriate relays shall be selected for the specific type of load. The minimum contact whetting current shall be specified for the relays selected.

Digital output signals shall conform to IEC 60870.3 and galvanic isolation shall be provided.

The preference is to use voltage free contacts for the digital outputs. This applies to all controls which therefore require 2 wires in the field cabling for each control. This requirement does not apply to DCCBs, which use single-wire controls to maintain system-wide compatibility. For DCCBs, a +125V DC supply is derived from a control bus in the RTU marshalling panel which is wired to the DCCB via the RTU output relay contact. The negative connection for the control circuit is made at the DCCB (i.e., there is no return to the RTU). An additional complication occurs with the Tap changer controls which use three wires for each up/down control pair. Voltage free control contacts are used, but only a single positive wire is used from the field equipment, requiring a loop between the two RTU control relay contacts.

11.7.3 Analogue Inputs

Analogue input signals will conform to IEC60870.3 and galvanic isolation shall be provided. Analogue signals will be inputted in the RTUs via converters, which will transfer the information digitally or via lan.

Analogue inputs shall be bipolar, but normally configured to accept 0-20mA DC or ±20mA DC or ±10mA DC or ±2V DC using full resolution. Eleven (11) bit plus sign resolution shall be provided as a minimum for analogue-to-digital conversion range. The conversion should take place outside the actual RTU facility.

Scanning of analogue signals should be less than 200 msec.

Each input shall be provided with individual software filtering.

The resistors used to convert the current loop to a voltage shall be precision resistors. The overall minimum accuracy of analogue measurement shall be 0.25% over the full scale and full temperature range. This includes resistors, ADC and software accuracy.

With respect to the analong, signals, they should be derived by the RTUs via converters. The converters will be delivered by the Contractor. These converters will be installed at the substation sites by HEDNO, and their output will be digital, i.e., they will communicate the signals to the RTUS via a protocol as a digital output.

11.8 Diagnostic and Configuration Utilities

The RTU shall be supplied with a port that provides connection for a laptop PC. These are equipped as follows:

- Metal frame construction, supplied with robust carry cases for field use;
- 15” screen TFT or better because these are used outdoors in sunlight and screen visibility is a sometimes difficult;
- Separate serial port because some third party software used may be incompatible with USB to serial converters;
- CD writer;
- Dial up modem for VF connection;
- Newer OS as specified by HEDNO;
- Possible to connect remotely to an Ethernet connection to access the HEDNO LAN system.

The supplier is required to provide diagnostic and configuration software to run in these laptops and access the RTU. This software shall include facilities for:

- Monitoring of all inputs, control of all outputs and testing of calculation logic. Monitoring of all inputs and logic at card level and logic level;
- Display of communications statistics and eavesdropping of communications channels, including Ethernet, IP, and protocols IEC 60870-5-101 and IEC 60870-5-104;

- Download & upload of RTU software, database configuration and calculations, upload the complete configuration from RTU to modify and then download to RTU;
- On-line help;
- Display current firmware, software and configuration running in the RTU;
- Configuration and diagnostic software must run on both Windows 2000, XP, or newer.

The diagnostic and configuration utility software shall be provided on a CD/DVD that is compatible with the laptop PC. The current version number of such software shall be provided. Any costs in upgrading to subsequent version numbers shall be included in the pricing.

11.9 Local Logic Control Routines

This section outlines basic local logic control routines to be incorporated in the RTU.

Each RTU will include the following input/output from miscellaneous equipment, which will be detailed in the input/output list provided by HEDNO at the time of placement of order:

- Digital Inputs from limit switches on substation doors, up to a maximum of 6, supplied and connected by HEDNO;
- Digital Inputs from switches designated as “Staff Access Switches,” supplied and connected by HEDNO;
- Digital Inputs from push buttons supplied and connected by HEDNO;
- Digital Output to drive audible alarms supplied and connected by HEDNO;
- Digital Outputs for trip and close commands of a latched relay designated as the ‘Dummy Circuit Breaker’, supplied as part of the RTU;
- Digital Input to determine the open or closed status of the Dummy Circuit Breaker, part of the RTU internal wiring;
- Digital Input from the “Controls Isolate” switch, supplied as part of the RTU, to determine its status;

Local control logic routines shall be incorporated into the RTU by the supplier as follows.

The dummy circuit breaker shall be a mounted magnetically latched relay, driven by a trip/close relay pair. This is a diagnostic device used to prove that telemetry to that RTU is functioning correctly, without the need to operate actual substation equipment.

11.10 RTU and Marshalling Enclosure Cubicles

Marshalling terminals located within an RTU marshalling cubicle shall define the point of separation between the electrical SCADA RTU and the substation electrical system. Note that for some sites, restricted space within the substation building may necessitate location of the marshalling terminals within the RTU cabinet.

An RTU with marshalling terminals may be specified for purchase either with or without enclosing cubicles.

If an RTU is specified to be supplied with an enclosing cubicle, the normal arrangement is for an RTU cubicle and a separate RTU marshalling cubicle bolted side by side to form a cabinet suite. Details of dimensions, doors and cubicle access will be contained in the particular specification for that RTU.

Note that irrespective of how an RTU is supplied, the warranty provisions shall still apply. Any special wiring and/or assembly conditions required to ensure these warranties are not compromised shall be clearly stated in the tender response.

11.10.1 RTU Cubicle

Each RTU shall be supplied fully assembled, together with all ancillary equipment, including wiring terminals, mounting rails, wiring ducts & wiring, to form a complete system, subject only to connection of substation equipment to field terminals.

Ancillary equipment to be supplied with the RTU includes the following:

- 2 x 48v power supplies (125V DC to 48V DC converters, if there is a 125V substation battery present, 48 V – 48V DC converters shall be used for isolation). These are used to power auxiliary communications equipment, and optionally input/output circuits and supervisory telephone circuits.
- Cubicle switch/lighting and a 230V AC GPO. Note that this circuit is fed from a separate circuit breaker, but shall require earth leakage protection. The GPO shall be mounted near the bottom of the RTU cubicle.
- A dummy circuit breaker.
- 4 x 48V DC isolating relays for monitoring circuits rated for different voltage levels. These 4 x 48V DC relays are for the communications circuits. Others may be specified on specific sites.

11.10.2 RTU Marshalling Cubicle

The RTU marshalling cubicle shall incorporate cable-marshalling terminals for all incoming field cables. Terminals shall normally be rail mounted vertically. The marshalling cubicle with the terminal strips will be installed near the new RTU of each substation, where the signals will be wired. The cubicle shall have terminal strips for all specified signals, plus an additional 20% (for the needs of future expansion). The Marshalling cubicle will contain all the supporting facilities for the commands. All RTUs will incorporate marshalling cubicles except fine RTUs which already have marshalling cubicles.

The reasons for providing a marshalling facility are to:

- Provide a means of isolating plant from RTU in cases where either is in a power down mode, but fed from the other end. This will assist to prevent accidental electric shock.
- Provide a means to easily upgrade the RTU in the future, by separation of the RTU from field cables.
- Facilitate commissioning, with ease of disconnecting untested field wiring on a point by point basis.
- Provide a simplified means of connecting field cables and RTU cables such that spares can be utilized, additions and alterations can be readily made, and different voltage sources can be utilized.

Terminals shall be provided for each core of all field cables. The number of field cables, including the number and size of all cores, shall be provided by HEDNO at time of order. The individual cores of a field cable will be terminated in a row of adjacent terminals.

Adequate means of support for field cables shall be provided. This will typically be a section of cable ladder/tray/ducting to which the field cables can be tied for support. Normal field cable access shall be bottom entry into the marshalling cubicle. Provision shall be made for both top and bottom entry for field cables.

Space shall be allocated between sections of terminals allocated to different cables to provide adequate space for labeling – a minimum label width of 9 mm shall be provided.

Wiring looms shall be provided between each RTU I/O module in the RTU cubicle and the terminals in the RTU marshalling cubicle. One of two methods shall be used to connect to the field cables.

In the first method (method A), two separate rows of terminals, designated RTU terminals and field terminals shall be provided on vertical rails located adjacent to each other. The cables from the RTU will terminate on consecutive RTU terminals. These shall be arranged and labeled according to the module position in the RTU cubicle. The cables from the field will terminate on the field terminals, which shall be arranged in cable groups. The connections between the 2 vertical rows of terminals shall be made in the factory, to a separate "cross wiring" schedule. Note that only one of these rows of terminals, the field terminals, shall be of the disconnect type.

In the second method (method B), where space may be at a premium, only one vertical row of terminals shall be provided. In this case, the cables from the RTU shall be stripped to individual cores at the top of the cubicle, and wired to individual terminals as required by the termination schedules. Spare cores shall be wired to the bottom of the terminal strip such that future allocation to any point on the terminal strip is possible. In this case, the terminals shall be of the disconnect type. Terminals will be arranged in cable order, with individual cores from the same field cable arranged together.

A space of at least 50mm shall be provided between the cable ducts or cable ladder and the terminals (note that 140mm between the two sets of cable ducts, including the terminal, has been found to be adequate – this equates to 48mm using WDU terminals of 44mm width). This shall be provided to ensure the cores can be manipulated and that adequate space for ferrules is provided.

Where ducting is provided for locating cables, the duct size shall be large enough to hold all the cables permitting the duct lid to be fitted when cables are installed.

The design of the marshalling cubicle layout shall be to HEDNO's approval.

11.11 RTU Configuration

It is HEDNO's intention that all RTU configuration be done by HEDNO staff. Nevertheless, there are times when workload may not permit this activity to be done by HEDNO. The configuration work for the RTU so that it works with HEDNO's master stations will use as inputs:

- I/O lists produced by HEDNO;
- Calculations as specified by HEDNO;
- Serial interfaces as outlined by HEDNO to acquire data from PLCs and Protection Relays.

This detail will be listed in any specific requirements at time of order. The participation of the Contractor in the RTU configuration will be agreed upon the Detailed Design Phase of the Project.

11.12 RTU Performance Requirements

11.12.1 Environmental Conditions

The RTU shall be designed and supplied suitable for indoor equipment conditions. For RTUs installed indoors, the ambient temperature range is -5° to +55°C. RTUs installed in a cubicle on Overhead Wiring structures in the field (outdoors) are required to work successfully in an ambient temperature range of -10°C to +65°C. They should be also capable of operating under relative humidity less than 95%.

Heat dissipation calculations shall be provided to demonstrate the RTU's ability to comply with the temperature ratings of the equipment in the range specified. These calculations shall be done on the assumption that maximum spare capacity as defined earlier is implemented.

11.12.2 Maintainability

It is a requirement that all RTUs require no routine or planned maintenance. Therefore, no fans or moving parts shall be used in the RTU to avoid any need for maintenance. To ensure this requirement is met the RTU should be constructed to resist the entry of dust.

A single technician shall be able to remove and replace for repair purposes, without special tools and test equipment, all equipment involved in the operation of an RTU. Restoration of equipment to full operational use shall be possible within 15 minutes (nominally) of repairs being completed.

It should not be necessary to dismantle (remove multiple pieces of) the RTU in order to replace a module.

11.12.3 Reliability

The equipment will normally remain in continuous service to provide SCADA facilities. Failure can result in the interruption of the operation of the ECC and a high level of reliability is therefore required.

The supplier shall provide the predicted mean time to failure and the mean time to repair of the equipment. Where insufficient historical data is available, the supplier shall state the methods used to determine the reliability performance.

Predicted availability of equipment supplied should exceed 99.99% for the following functions:

- Control and onitoring of any one breaker,
- Monitoring of any one single alarm;
- Monitoring of any one analogue input.

11.12.4 Service Life

HEDNO prefers that the equipment shall be capable of complying with this standard, including performing its intended purpose, for a minimum of 20 years from the date of supply.

The supplier shall indicate the following:

- The date at which the product was released for sale;
- The anticipated date at which the product will be withdrawn from sale, but support will continue to be supplied;
- The anticipated date that product support will be withdrawn, i.e., spares will no longer be available and technical support is no longer provided.

11.12.5 Interchangeability

RTU parts shall be interchangeable individually, and as a whole RTU. Any such change or replacement shall not reduce the capability of the equipment to conform to the requirements of this specification.

11.12.6 Type and Routine Testing

The provided unit must be fully tested to ensure full compliance with the technical and functional specifications. Type test certificates should be provided by the Contractor during the Detailed Design Phase. Based on the certificates provided, type testing requirements will be drafted and agreed with HEDNO.

In addition to the above, each single unit provided will undergo routine testing. Routine testing should include, but not be limited to, functional tests as follows:

- Checks for technical details, construction and wiring as per drawings;
- Checks for RTU database and configuration settings;
- Checks of all inputs/outputs operation;
- Checks of all communication ports operation;
- Tests for diagnostic features;
- Tests for SOE fetures;
- Other tests as agreed during the Detailed Design Phase of the Project.

Type tests should also include, in addition to the above, EMI/EMC immunity tests, insulation tests and environmental tests as required per IEC applicable standards.

The Contractor shall provide a detailed Type and Routine Testing Plan with the Detailed Design document, including certificates that indicate compliance with above requirements. Type tests to be performed will be agreed upon the Detailed Design Phase of the Project.

12 Display Wall

12.1 General

The Control Center in Rhodes should have an appropriate display wall infrastructure based on latest LED technology to provide an overview of all island's Electricity Generation and Island’s Network in sufficient clarity and detail. This infrastructure will assist to effectively manage critical situations arising from extensive disruptions in the electrical network that affect a considerable area of the network. Its size should be 3 x 2 m to ensure clarity.

The proposed system display wall shall consist of the following main components:

- The Wall Display Projection that is made up of a suitable number of stackable rear projection screens, and
- The Wall Display Controller system that will concentrate all image and video inputs to be displayed and also provide the necessary control functionality for the wall display.

Display Wall should be capable to project any Full Graphics (FG) display selected from the NII IT Systems. Additional UPS for display wall should be provided.

The preparation of the overall layout design will ensure the proper positioning of the Wall Display System, and that all necessary and proper clearances between the Wall Display and the surroundings are preserved. Special attention shall be given to the clearances on the rear side of the Wall Display to allow for easy maintenance. The proposed design shall ensure that all viewing angles are such that there will be no limitations in the viewing of the whole of the display wall by the two Operators.

The detailed design will be finalized with the vendor during the Detailed Design Phase of the Project.

12.2 Display Wall Projection

Main Display Wall Projection characteristics should be:

12.2.1 Projection Technology

The proposed system shall make use of Digital Light Processing (DLP®) technology and employ rear projection to produce the images on the screens.

The proposed system shall use solid state Light Emitting Diode (LED) illumination source for the wall display screens. In each screen, illumination shall be achieved by LED sources to generate the red, green and blue colors without the use of a color wheel.

12.2.2 Wall Display Size

The maximum useful size available for the Wall Display should be 3 x 2 meters.

Each screen in the proposed configuration shall have a minimum image diagonal of 65 inches and an image aspect ratio of 16:10 or 16:9.

The Wall display final size will be defined in the deatailed design phase of the Project.

The minimum image resolution per screen shall be SXGA+ (1920X1080 pixels).

12.2.3 Seamless Image

The construction of the screens shall be specifically intended for operation in a multi-screen environment ensuring a seamless image over the total display area and preventing the loss of data (pixels) within adjacent screen gaps.

12.2.4 Control Room 24/7 Operation

The proposed system shall be intended for operation on a 24/7 basis in a Control Room environment.

The Contractor shall perform a heat dissipation study as part of the Detailed Design Phase, and shall specify the cooling requirements to ensure that the environmental conditions indicated below shall prevail during normal system operation of the Wall Display:

- Temperature : From 20^{o}C to 26^{o}C;
- Relative humidity : From 45% to 60%.

The heat dissipation study shall take into account all other computer equipment that shall be installed in the room which will be erected behind the Wall Display. The NII SMO shall provide to the Contractor all information regarding all other equipment to be installed in the above room.

12.2.5 Environmental Conditions during A/C Failures

During failure of mains power and/or air-conditioning the system shall be able to withstand the following conditions:

- Temperature: From -5^{o}C to 50^{o}C;
- Relative humidity: From 50% to 95%.

12.2.6 Cooling and Acoustics

Each screen shall contain a cooling mechanism ensuring that the temperature of the screen circuitry and structure does not exceed acceptable levels.

The acoustic noise produced by the operation of each screen shall not exceed the level of 40db when measured at a distance of 1m from the screen. Bidders must state the noise level of the proposed system.

12.2.7 LED Module Useful Life and Guarantee

The LED modules shall be guaranteed to attain a useful life in excess of 50.000 hours in normal mode of operation. LED Modules that fail before reaching the above guaranteed useful life will be replaced by the Contractor free of charge in case of such failure. The Contractor must be able to replace faulty LED modules immediately to avoid partial system unavailability for prolonged periods.

12.2.8 Image Quality

- The color temperature range capabilities shall minimally be in the range of 3200K to 9600K with a true white point temperature of 6500K and the gamut of the proposed screens shall be consistent with those proposed by European Broadcasting Union (EBU).
- The screen full field contrast ratio shall be at least 1400:1.
- Screen brightness when measured at a viewing angle of 0 degrees (perpendicular to the screen) shall be at least 160 cd/m2.
- The projection and screen technology employed shall prevent the occurrence of screen memory effect resulting from the projection of still or slow changing images.
- The minimum horizontal and vertical half gain viewing angles of the proposed screens shall be 35 and 27 respectively.
- In order to provide a seamless image over the total image area, the vertical and horizontal pixel-to-pixel gap (mullion) between adjacent screens shall not exceed 1mm (measured at 30°C).

12.2.9 Manual Image Control

The proposed solution shall also allow the control of at least the following parameters/processes.

- Color Temperature;
- Contrast;
- Brightness Uniformity;
- Colour Uniformity;
- Colour Space;
- Image Freezing;
- Projector Networking and Control;
- Input Signal Control;
- Motion Filtering;
- Geometry;

- Video Format.

12.2.10 Automatic Color and Brightness Adjustment

The wall display shall be capable of maintaining Color and Brightness uniformity in excess of 90% over the entire wall display by user interaction through specialised software and automatically by monitoring and adjusting in real-time the brightness of the entire wall display and each screen individually without the need of user intervention.

Automatic adjustment shall be initiated, without intervention as follows:

- During initial setup of the wall display screens;
- After the degradation of the color and/or brightness in one or more LED illumination modules;
- After the replacement of one or more LED illumination modules.

12.3 Display Wall Controller

The redundant Wall Display Controller(s) shall be of the rack-mount type (1U or 2U) and shall run on standard 64-bit Windows Server Operating System (Windows Server 2008 R2 64-bit is preferred) and shall have the hardware specifications required to fully support the appropriate software and hardware to meet the Display Wall Operation.

The Wall Display Controller shall be capable of driving the supplied number of screens of the wall display and also two (2) additional screens to account for future expansion.

The Wall Display Controller shall be able to fully control the resolution of the entire wall

The Wall Display Controller shall be capable to project any display selected from the NII IT Systems.

External source inputs physically connected to the controller. At least the following shall be supported:

- VGA 15-PIN D-SUB one (1) is required;
- DVI (Digital);
- Composite SCART/RCA;
- HDMI two (2) required;
- Standard definition (SD) video inputs (NTSC/PAL).

The processing of such external sources shall be carried out by a separate controller subsystem that will not affect the performance of the graphical controller and the applications.

12.4 Display Wall Control and Diagnostic Utilities

An appropriate software application that shall be used to monitor and control both the Wall Display Screens and the Wall Display Controller.

The displayed applications shall be capable to use the entire resolution (the resolution of the single cube multiplied per the number of cubes) without limitations.

The proposed software application shall:

- Allow the positioning of any controller output signal and any desktop-captured signal at any position and any size on the wall display.
- Enable the positioning of any controller output signal and any desktop-captured signal on more than one position on the Wall Display simultaneously.
- Allow users to Preview wall display modifications, such as image size and image position changes, before they are activated on the Wall Display.
- Allow the creation and storage of various situation scenarios (presets) that will be selected according to network status. Each situation scenario shall allow the definition of at least the following parameters:
  - Controller output and desktop-captured signals to be displayed;
  - Each image position on the Wall display;
  - Each image window size on the Wall Display.
- Allow users to control the brightness and the color properties of:
  - Each Wall Display Screen;
  - The entire Wall Display.
- Support source cycling with configurable cycle time within the same window frame on the Wall Display for selected controller output and desktop-captured signals.
- Provide diagnostic and fault reporting functionality for critical Wall Display Controller and Wall Display Screen components.
- Allow the control of at least the following parameters/processes.
  - Color Temperature;
  - Contrast;
  - Brightness Uniformity;
  - Color Uniformity;
  - Color Space;
  - Image Freezing;
  - Projector Networking and Control;

- Input Signal Control;
- Motion Filtering;
- Geometry;
- Video Format.

- Be protected against unauthorized accesses by applying an appropriate security policy based on user credentials (username/password). It shall provide at least two different levels of system accesses:
  - The administrator access level;
  - The user access level.

  At the administrator access level, the proposed application shall allow the definition of operations that users at the User access level shall be able to perform. These shall include at least the following:
  - Defining a portion of the Wall Display that a user shall be permitted to modify;
  - Restricting/Permitting relocation of windows on the entire and certain portion of the Wall Display;
  - Restricting/Permitting resizing of windows on the entire and certain portion of the Wall Display;
  - Restricting/Permitting the modification of brightness and color properties of the entire Wall Display.

13 Time Frequency Devices (TFDs)

A Time and Frequency Device facility is required at the ECC to determine the system wide coordinated time, power system time, time deviation, power system frequency, and power system frequency deviation.

The TFDs receive from satellite astronomical time - date data from the built in GPS technology they contain. They calculate the electrical time and its difference from the astronomical time by measuring the network frequency (time deviation). The TFDs also measure the frequency in every isolated system which is sent to the SCADA system and then to the EMS.

The TFDs should be available in Rhodes Local ECC to provide to EMS the following values to be used by the appropriate applications:

- Frequency (up to 0,001 Hz);
- Frequency deviation;
- Standard Time (HH:mm:ss);
- Time deviation (mm:ss-sign);
- Day of month, month of year, year (DD, MM, Y).

The GPS time subsystem is equipped with two high accuracy GPS synchronized time receiver (redundant) with front display and network synchronization board to synchronize the network equipment.

The GPS time subsystem consists of:

- GPS clock;
- Clock Switch;
- Licenses.

The main features of GPS clock oscillator are:

- Accuracy GPS synchronous: $\pm 1 \cdot 10^{-11}$;
- Short term stability: $1 \cdot 10^{-9}$;
- Accuracy free run one day: $\pm 2 \cdot 10^{-8}$;
- Accuracy free run one year: $\pm 4 \cdot 10^{-7}$.

The GPS time subsystem should be enclosed in a rack system. Each antenna should be protected against over-voltage.

An additional integrated board should manage the frequency reference acquisition (it will calculate the frequency, frequency deviation, reference time, power line time and the time deviation).

Rhodes Local ECC will require a complete TFD to be procured. Athens Central ECC, where only MMS is installed, will only require GPS time so that all systems are synchronized.

