ODISHA POWER TRANSMISSION CORPORATION LTD

TECHNICAL SPECIFICATION

FOR

SUB-STATION AUTOMATION AND

PROTECTION SYSTEM

FOR GRID SUBSTATION

TECHNICAL SPECIFICATION FOR SUB-STATION AUTOMATION FOR GSS:
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The Substation Automation System (SAS) is proposed for Grid sub-station with installation of Bay control Unit in relay panels,work station (Main & stand by),Engineering Station, HMI, Large video screen of 70/80 inches, printers and remote transmission unit for Remote Network Control center & SLDC.

The Substation Automation System (SAS) shall be installed to control and monitor all the sub-station equipment from remote control centre (RCC) as well as from local control centre.

The SAS shall contain the following main functional parts:

i)   Bay control Intelligence Electronic Devices (IED s) for control and monitoring.
ii)   Station Human Machine Interface (HMI)
iii)   Redundant managed switched Ethernet Local Area Network communication infrastructure.
iv)   Peripheral equipment like printers, display units, key boards, Mouse etc.

It shall include communication gateways, intelligent electronic devices (IED) for bay control and inter IED communication infrastructure.

The communication gateways shall facilitate the information flow to remote control centres & Load despatch Centre. The bay level intelligent electronic devices (IED) for protection and control shall provide the direct connection to the switchgear without the need of interposing components and perform control, protection, and monitoring functions.

The substation switchyard configuration is provided in attached Single Line diagrams. The BCU & BCPU (for 33 kv side only) is to be installed in the relay panels. The substations are equipped with IEC61850 compliant numerical protection relays. The protection arrangements for the different voltage system for SAS of GSSs should be as envisaged below.

1. 400 kV Side: (One & half CB arrangement):

i)   Line bay: The line bay shall have one Bay controller Unit (BCU), Two distance protection, one backup directional over Current & earth fault relay. The CR panels are having IEC 61850 complied numerical distance, over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the technical specification.

The vendor needs to provide IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & carrier supervision function will be performed by Bay Controller Unit.

ii) Transformer bay: The transformer bay shall have Bay controller Unit (BCU), Two differential protection, dedicated REF protection and one backup directional over Current & earth fault relay. The CR panels should have IEC 61850 complied numerical differential, REF, over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the technical specification. The vendor needs to provide IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & Automatic voltage regulation function will be performed by Bay Controller Unit.

iii) Tie bay: Each bay shall have Bay controller Unit (BCU), backup over Current & earth fault relay. The CR panels should have IEC 61850 complied numerical over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the technical specification. The vendor needs to provide IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & station DC regulation function will be performed by Bay Controller Unit.

Note: Dedicated Bus-Bar protection for 400 KV system, which shall also to be connected to SAS.

2. 220 kV Side: (Two Main bus arrangement or two main and a transfer bus arrangement or one & half CB arrangement):

i) Line bay: The line bay shall have one Bay controller Unit (BCU), Two distance protection, one backup directional over Current & earth fault relay. The CR panels are having IEC 61850 complied numerical distance, over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the technical specification. The vendor needs to provide IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & carrier supervision function will be performed by Bay Controller Unit.

ii) Transformer bay: The transformer bay shall have Bay controller Unit (BCU), Two (for 220/132KV) or One (for 220/33KV) differential protection, dedicated REF protection and one backup directional over Current & earth fault relay. The CR panels should have IEC 61850 complied numerical differential, REF, over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the

technical specification. The vendor needs to provide IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & Automatic voltage regulation function will be performed by Bay Controller Unit.

iii) Bus Coupler bay: Each bay shall have Bay controller Unit (BCU), backup over Current & earth fault relay. The CR panels should have IEC 61850 complied numerical over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the technical specification. The vendor needs to provide IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & station DC regulation function will be performed by Bay Controller Unit.

iv) Transfer Bus Coupler bay: Each bay shall have Bay controller Unit (BCU), backup over Current & earth fault relay. The CR panels should have IEC 61850 complied numerical over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the technical specification. The vendor needs to provide IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & station DC regulation function will be performed by Bay Controller Unit.

Note: Dedicated Bus-Bar protection for 220 KV system, which shall also to be connected to SAS.

3. 132kV Side:

i)   Line bay: The line bay shall have one Bay controller Unit (BCU), one distance protection, one backup directional over Current & earth fault relay. The CR panels are having IEC 61850 complied numerical distance, over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the technical specification. The vendor has to provide IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & carrier supervision function will be performed by Bay Controller Unit.

ii) Transformer bay: The transformer bay shall have Bay controller Unit (BCU), one differential protection, dedicated REF protection and one backup directional over Current & earth fault relay. The CR panels should have IEC 61850 complied numerical differential, REF, over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the technical specification. The vendor has to provide

IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & Automatic voltage regulation function will be performed by Bay Controller Unit.

iii) Bus Coupler bay: Each bay shall have Bay controller Unit (BCU), backup over Current & earth fault relay. The CR panels should have IEC 61850 complied numerical over current & earth fault protection relays and electro mechanical trip & auxiliary relays as per the technical specification. The vendor ~~has~~ to provide IEC61850 compliant Bay Control unit & necessary auxiliary relays. The trip circuit supervision, electrical reset of the tripping relays & station DC regulation function will be performed by Bay Controller Unit.

4. 33kV Side:

Each bay shall be provided with on Bay controller & protection Unit (BCPU). The unit should be capable of protection, measurement, control & record and shall have IEC 61850 protocols for full system integration. The BCPU should be capable of following feeder protection functions.

1.   Current protection (50/50N,51/51N,67/67N & 64) ,

2.   Voltage protection (59,27).

3.   Frequency protection (81 U, 81O,81R)

4.   Power protection.

Additional Multifunction meter may be provided for monitoring the measurement, if monitoring of measurement is not available in BCPU.

QUALIFYING REQUIREMENT FOR SUPPLY INSTALLATION & COMMISSIONING OF THE SUBSTATION AUTOMATION SYSTEM:

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The SAS shall be sourced from Original Equipment Manufacturer (OEM). The offered equipment have to be designed, manufactured and tested as per relevant IS/IEC with latest amendments. The bidder/ Manufacturer should have installed/retrofitted & commissioned the system with trouble free operation for minimum three years in any of the power system utilities in India. Further, the bidder/ Manufacturer should fulfill the following criteria & supporting documents to the effect should be accompanied with the tender document.

1)   The minimum requirement of manufacturing capacity of offered type, size and rating of equipment shall be FIVE times tender/ bid quantity per annum. The bidder/ Manufacturer should indicate manufacturing capacity by submitting latest updated certificate of a Chartered Engineer (CE).

2)   The Substation Automation system shall be offered from a manufacturer who must have designed, manufactured, tested, installed and commissioned substation automation system which must be in satisfactory operation on 400/220/132/33KV system in India for at least 3 (Three) years as on the date of bid opening.

3)   The bidder should furnish performance report of SAS system supplied installed and commissioned by them/ Manufacturer indicating the quantity and Single Value Contract executed during last FIVE (5) years, for the offered equipment. The details are to be submitted in following format,

Sl.No	Name of the Utility.	Order No. & Date.	Items supplied With quantity & work done.	Date of Completion.	If completed Within Stipulated Period.	Performance of the system as on date.	Remark.

4)   Equipment offered shall have Type Test Certificates from accredited laboratory (accredited based on ISO/IEC Guide 25 / 17025 or EN 45001 by the National accreditation body of the country where laboratory is located), as per IEC / IS / technical specification. The type test reports shall not be older than FIVE years and shall be valid up to expiry of validity of offer.

SPECIFICATION:

I.   SCOPE :

The Substation Automation System (S.A.S) for EHV substations is to be used for the control, protection and supervision of new Air insulated (AIS) EHV substations of different voltage levels of OPTCL.

This specification covers technical, functional, configuration and testing requirements for a substation automation system for extra high voltage (EHV) substation.

The substation automation system shall be digital and shall include control, protection, monitoring, measurement functions and tele-transmission of data and commands.

II. STANDARDS:

The substation automation solutions should be future proof & compliant to international standards IEC 61850, and simplify maintenance and enable interoperability.

The standards applicable for this automated digital control, protection system & communication protocol for the EHV sub- station are as follows.

1.   IEC 61850

i.   IEC 61850-8-1, information is exchanged as GOOSE messages.

ii.   IEC 61850-9-2 exchange of analogue information.

2.   IEC 60870 set of standards which define systems used for tele-control (supervisory control and data acquisition) in electrical engineering and power system automation.

i.   IEC 60870-5-1 Transmission Frame Formats

ii.   IEC 60870-5-3 General Structure of Application Data

iii.   IEC 60870-5-4 Definition and Coding of Information Elements

iv.   IEC 60870-5-5 Basic Application Functions

v.   IEC 60870-5-6 Guidelines for conformance testing for the IEC 60870-5.

Also following companion standards may be referred during the design, which shall be applicable for basic tele-control tasks, transmission of integrated totals, data exchange from protection equipment & network access of IEC101 respectively.

•   IEC 60870-5-101 Transmission Protocols, companion standards especially for basic tele-control tasks

- IEC 60870-5-102 Companion standard for the transmission of integrated totals in electric power systems (this standard is not widely used)

- IEC 60870-5-103 Transmission Protocols, Companion standard for the informative interface of protection equipment

- IEC 60870-5-104 Transmission Protocols, Network access for IEC 60870-5-101 using standard transport profiles

III. CLIMATIC CONDITIONS

This automated digital control and protection system for EHV substations, shall be capable of withstanding the following climatic conditions:

a.   Ambient temperature during operation : -5 °C to +55°C

b.   Ambient temperature during storage : -5 °C to +55°C

c.   Relative humidity : 5% - 90%

d.   Altitude level:

IV. SUPPORT DOCUMENTS

This substation automation system for EHV substation shall be designed for AIS substation of OPTCL with the instructions contained in this technical specification and with the information provided in the following documents approved by OPTCL for the turnkey contract.

a. EHV substation single line diagram

b. EHV substation layout drawing in which the following are depicted:

- Location of EHV substation primary equipment

- EHV substation's control building

c. Switchgear interlocking arrangements.

d. List of commands to the substation equipment.

e. List of digital event and alarm signals for this hereby substation automation system.

f. List of analogue measurements for this thereby substation automation system

g. List of commands received from transmission's system Remote control center (RCC) and if applicable from the distributions peripheral control center (DCC).

h. List of events and alarms to be transmitted to the transmission's system control center and to the distribution's peripheral control center (if applicable)

i. List of measurements received from TCC and from DCC (if required).

j. Specifications for distance relays, overcurrent / Earth fault relays, autotransformer/Power transformer differential relays, bus-bar differential relays, transformer REF relays, voltage relays, Over flux & frequency relays shall be as per the technical specification under this bid document.

V. REQUIRED FUNCTIONS OF THE SUBSTATION AUTOMATION SYSTEM.

The substation automation system shall be capable of the following functions:

1. Control and supervision of the EHV substation

2. Switchgear interlocking.

3. Synchro-check with phasing.

4. Autotransformer tap-changer control

5. Power Transformer tap-changer control

7. Measurements

8. Event recording and alarm handling

9. Protection

10. Automatic switching

11. Full remote access control (Web browser access secured through fire wall and support up to 5 web client)

12. It must support the data (to be calculated during detailed Engineering and also considering the future scope) points and integration of 200 IEDs for 400/220 KV SS & 220/132/33 KV SS and 100 IED's for 220/33 KV & 132/33 KV SS in single ring.

13. It should support up to 4 high resolution screen

A. Control of the EHV substation

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i.   The control must handle selection of control Position

a.   Locally, via control switches located on the primary equipment

b.   From the bay control unit, - bay level (located in relay kiosks)

c.   From the HMI, - station level (Control building of the EHV Substation)

d.   From the transmission's system remote control center (RCC)

e.   The commands will be issued each time only from one control place excludingat the same time the other three. The priority (switching authority) of commands shall be in the order indicated above   and shall be carried out either via software or hardware. Each control level shall have proper indication indicating the selected position.

ii.   Selection of equipment and type of command for control operation (opening or closing).

iii.   Execution or cancellation of command.

iv.   Execution of the command when the conditions of interlocks, synchro-check or other conditions are met.

v.   Capability of overriding of interlocks and execution of the automatic switching sequences.

vi.   The apparatuses to be controlled are the following:

a.   400 KV,220kV ,132kV & 33kV Circuit Breakers   associated with transmission line bays, autotransformers, transformers ,reactor & capacitor banks.

b.   Dis-connectors of transmission line bays, autotransformers, Transformers, Reactors & capacitor banks.

d.   Earthing Switches of the 400KV Dis-connectors (If it is required.)

e. Mechanism of increase, decrease and emergency stop of the step of the tap changer (OLTC) of the autotransformers, power transformers (if it is required).

f.   At table 1 of the attached appendix, the necessary commands from the Substation Automation System (S.A.S) to the EHV substation equipment are presented, as well as the commands that required to be received from RCC (Remote Control Centre) remote control centers.

B. The supervision of the substation shall include the following:

1.   The position of each circuit breakers on a continuous basis.

2.   The position of each dis-connectors (isolators) on a continuous basis.

3.   The position of each earthing switch on a continuous basis.

4.   Every detected change shall cause a change in the single-line diagram displayed on the operator's terminal (HMI unit) located in the ehv substation control building, notation in the event list and a print-out.

5.   Alarms shall be issued, in the form of lists and print-out, in case the position changes are not caused by a command.

6.   At the operator's terminal and specifically at the colour visual display, the single-line diagram of the EHV substation (including the future bays of the switching station with dotted-lines), details of the status of breakers and dis-connectors (isolators) and measurements shall be depicted.

7.   The naming of the equipment shall be as indicated in the single-line diagram of the EHV substation which is provided.

8.   The substation automation system for EHV substation shall also allow supervision of all EHV substation circuit breaker and motor driven (electrically operated) disconnectors and earthing switches from the transmission system's Remote control center (RCC).

9.   The substation automation system shall allow supervision of the transformer bay circuit beakers and Dis-connectors & transformer Tap position.

VI. COMMUNICATION PROTOCOLS AND OTHER COMMUNICATIONS.

The following protocols are acceptable for the communications within the EHV substation and also for the communication of the substation automation system (S.A.S) with the system's control centers.

1. Between bay level control units and HMI center, the acceptable communication protocol is IEC-61850.

2. Between transmission's system (network) control center and this substation automation system the only acceptable protocol is the following:

- <mark>IEC 60870-5-104</mark>

- It must (SCADA) support to integrate at least 250 IEDs in single ring.

3. Between protection relays and HMI center, the communication protocol is IEC-61850.

4. Between bay level control units and protection relays the acceptable protocol is IEC-61850.

5. Security of the system, because the IEC-61850 protocol is based on a Ethernet platform, sufficient security measures, must be provided, that is beyond passwords, in order to prevent unauthorized access.

VII.   PLCC <mark>(If required & specifically asked for in the tender)</mark>

PLCC panels /end equipment of OPGW fortele-protection features   are to be installed in Carrier Room near Control Room. Yards' IED should communicate with PLCC /end equipment of OPGW panels through GOOSE commands. In this project supply is not in the scope of the contract, the same will be provided by OPTCL. The integration of PLCC /end equipment in the SAS is to be carried out by the contract awardee.

VIII. SOFTWARE

Any software needed for the configuration setting, parameterizing, documentation displaying and operation of the system or of the devices which is composed of (bay control units, protection relays, bus bar differential protection relays and GPS) should be Window based with latest version of Window operating software. The same should be provided on the basis of a royalty free, non-exclusive with irrevocable license to use by OPTCL. Software for the analysis of fault data shall also be provided with the same terms as above.

IX. DETAIL SCOPE OF WORK:

The Substation Automation System is envisaged for following substation of OPTCL.

1.   132/33kV Substation. in 132kV & 33kV System.

2.   220/132/33kV Substation.

3.   400/220/132 Substation.

4.   400/220/132/33kV Substation.

Bus arrangements are in general as follows.

i.   400kV : 1½ Breaker system.

ii.   220kV : Two Bus system.

iii.   220kV : Two Bus system with transfer Bus.

iv.   220kV : 1½ Breaker system

v.   132kV : Main and Reserve bus arrangement.

vi.   33kV : Main and Reserve bus arrangement.

The Remote operation and monitoring of control & protection system of above type of substation is to be executed by providing equipments/relays as specified in the schedule.

The objective of the above work is as follows.

a.   The operation & monitoring of control & protection system is as per approved SLD and conforming to technical standard envisaged in CEA regulation-2010 for Technical Standard construction of Electrical Plant & Transmission line..

b.   On line capturing & monitoring of Transformer local readings & protection.

c.   All the local control & protection at the sub-station for its remote operation from MCC shall be substituted by bay controller and SCADA.

d.   While Main Sub Station will be master S/S option/ provision must be available to independently run slave S/S, i.e. the proposed sub-station locally.

e.   There must be provision for down loading event logger and D/R data at MCC at any time during the day.

f.   Remote connectivity between master & slave S/S for above shall be established by bidder by providing necessary terminal equipment for OPGW.

g.   Master Control Centre shall also be fully automated as per the 400KV/220KV/132/33 KV proposed substation by providing equipment/ relays for localized control (if specified).

h.   Scope also includes one week training to the executives of each substation. The list of topics and on-site training shall be finalized during the course of execution.

i.   Factory Acceptance test has to be performed before dispatching equipment in the presence of representative of OPTCL and the test report should be approved by OPTCL.

p.   It is the bidders' responsibility for complete engineering/supply of necessary equipment at both the end, installation, testing & successfully commissioning of entire system as stated above including putting it to commercial operation.

X.   GENERAL SYSTEM DESIGN.

•   The systems shall be of the state-of-the art suitable for operation under electrical environment present in Extra High Voltage substations.

•   The system shall incorporate the control, monitoring, metering, communication and protection functions specified, event recording and evaluation of disturbance records.

•   The Bay level unit comprising Bay Control Unit (BCU) are to be fitted in relay and protection panels installed in the control room.

•   PLCC panels are to be located in PLCC room near Control Room.

•   The station HMI & DR Work station should be located in Control Room building connecting bay level unit through optical cables /Ethernet cable for overall optimization in respect of cabling and control room building.

•   Remote control and monitoring of the substation shall be from Main Sub Station i. e. Master Control Centre through OPGW communication link unless specified otherwise. Required equipment for controlling the sub-station remotely from MCC as well as transmitting all necessary RTU data to SLDC should also be considered.

•   Maintenance, modification or extension of components may not cause a shutdown of the whole substation automation system. Self-monitoring of components, modules and communication shall be incorporated to increase the availability and the reliability of the equipment and minimize maintenance.

•   Adopt the latest engineering technology, and ensure long-term compatibility requirements.

• The system shall be designed such that personnel without any background knowledge in Microprocessor-based technology are able to operate the system. The operator interface shall be intuitive such that operating personnel shall be able to operate the system easily after having received some basic training.

• The Substation Automation System (SAS) shall be suitable for operation and monitoring of the complete substation including future extensions. Interoperability with third party IEC 61850 compatible IEDs to be incorporated in future with offered SAS shall be ensured and necessary data/information shall be provided in this regard.

• The offered SAS shall support remote control and monitoring from Master Control Center via gateway.

XI. System architecture

The Substation Automation System (SAS) shall be based on a decentralized architecture and on a concept of bay- oriented, distributed intelligence. The Bay Control Unit (BCU), Bay Control Protection Unit (BCPU), protective relays etc. shall be connected to Ethernet Fiber Switch EFS through fiber optic /Ethernet cable with PRP (**Parallel Redundancy Protocol**) configuration (to be selected based on system design requirement).

The main process information of the station shall be stored in distributed databases. The typical SAS architecture shall be structured in two levels, i.e. in a station and a bay level. At bay level, IEC 61850 compatible BCU shall be provided for 400kV, 220kV & 132kV system for all bay level functions regarding control, monitoring and I/O processing and IEC 61850 compatible Protective Relays shall be provided for different system as per specifications enumerated in the relevant section. The BCU / protection IEDs shall be connected to the switchgear through TB without any need for additional transducers. The IEC 61850 Bay Control & Protection Unit (BCPU) shall be provided for control, monitoring, I/O processing and protection.

Each bay controller & IED shall be independent from each other and its functioning shall not be affected by any fault occurring in any of the other bay control units of the station.

Separate BCU / RTU for station auxiliaries shall be provided.

Substation LAN data exchange is to be realized using IEC 61850 standard having minimum speed of 100 mbps with a redundant managed switched Ethernet communication infrastructure having priority tagging. Each component/module of SAS

including entire communication link shall be provided with built-in supervision and self-diagnostic features and any failures shall be alarmed to the operator.

Data exchange is to be realized using IEC 61850 protocol with a redundant managed switched Ethernet communication infrastructure.

The communication shall be made in 1+1 mode, including the links between individual bay IEDs to switch in PRP mode, such that failure of one set of fiber/Ethernet link shall not affect the normal operation of the SAS. However it shall be alarmed in SAS.

At station level, the entire station shall be controlled and supervised from the station HMI. It shall also be possible to control and monitor the bay from the bay level equipment at all times.

The control priorities as described in the section (V: Sub section- A. Control of the EHV substation) shall prevent operation of a single switch at the same time from more than one of the various control levels, i.e. MCC, station HMI, bay level or apparatus level. The priority shall always be on the lowest enabled control level.

The GPS time synchronizing signal for the synchronization of the entire system shall be provided. GPS system should be compatible with SCADA protocol IEC 61850. A time accuracy of 1ms shall be achieved for all the devices within SAS.

The PLCC panels' status, Inter-tripping signals exchange between BCU and PLCC panel BCU should work on IEC 61850 protocols through GOOSE concept.

XII. Functional Requirements:

The Substation elements shall be operated from different locations such as:

•   **Remote control centers.**

•   **Station HMI.**

•   **Local Bay Controller.**

But the operation shall be possible by only one operator at a time. Further, the operation shall depend on the conditions of other functions, such as interlocking, synchrocheck, etc. see description in 'Bay level control functions').

1.   Select-before-execute:

For security reasons the command is always to be given in two stages:

Selection of the object and command for operation under all mode of operation except emergency operation. Final execution shall take place only when selection and command are actuated.

2. Command supervision:

Bay/station interlocking and blocking:

Software Interlocking is to be provided to ensure that inadvertent incorrect operation of switchgear causing damage and accidents in case of false operation does not take place.

In addition to software interlocking hardwired interlocking are to be provided for:

i.   Bus Earth switch Interlocking.

ii.   Transfer Bus Interlocking.

It shall be a simple layout, easy to test and simple to handle when upgrading the station with future bays. For software interlocking the bidder shall describe the scenario while an IED of another bay is switched off or fails.

A software interlock override function shall be provided which can be enabled to bypass the interlocking function.

3.   Run Time Command cancellation:

Command execution timer (configurable) must be available for each control level connection. If the control action is not completed within a specified time, the command should get cancelled.

4.   Self-supervision:

Continuous self-supervision function with self-diagnostic feature shall be included.

5.   User configuration:

The monitoring, controlling and configuration of all input and output logical signals and binary inputs and relay outputs for all built-in functions and signals shall be possible both locally and remotely.

6.   Functions:

The Functional requirement shall be divided into following levels:

Bay Level Functions & System Level Functions

A.   Bay level functions:

In a decentralized architecture the functionality shall be as close to the process as possible. In this respect, the following functions can be allocated at bay level:

•   Bay control functions including data collection functionality.

•   Bay protection function.

1.   Bay control functions:

a.   Control mode selection

b.   Select-before-execute principle

c.   Command supervision:

i.   Interlocking and blocking

ii.   Double command

d.   Synchrocheck, voltage selection

e.   Run Time Command cancellation

f.   Transformer tap changer control (for power transformer bays)

g.   Operation counters for circuit breakers and pumps

h.   Hydraulic pump/ Air compressor control and runtime supervision

i.   Operating pressure supervision

j.   Display of interlocking and blocking

k.   Breaker position indication per phase

l.   Alarm annunciation

m.   Measurement display

n.   Local HMI (local guided, emergency mode)

o.   Interface to the station HMI.

p.   Data storage for at least 200 events

q.   Extension possibilities with additional I/O's inside the unit or via fiber-optic

Communication and process bus.

2.   Transformer tap-changer control:

Raise and lower operation of OLTC taps of transformer shall be facilitated through Bay controller IED.

3.   Bay protection functions:

The protection functions are independent of bay control function. The protection shall be   provided by separate protection IEDs (numerical relays) and other protection devices as per section Relay & Protection. However, for 33kV system the bay control & protection function may be provided in one unit (BCPU).

IEDs, shall be connected to the communication infrastructure for data sharing and meet the real-time communication requirements for automatic functions. The data presentation and the configuration of the various IEDs shall be compatible with the overall system communication and data exchange requirements.

Event and disturbance recording function.

Each IED should contain an event recorder capable of storing at least 200 time-tagged events. The disturbance recorder function shall be as per protective relays. All disturbances can be viewed at Master Control Centre.

B.   System level functions:

i.   Status supervision

The position of each switchgear, e.g. circuit breaker, isolator, earthing switch, transformer tap changer etc., shall be supervised continuously. Every detected change of position shall be immediately displayed in the single-line diagram on the station HMI screen, recorded in the event list and a hard copy printout shall be produced. Alarms shall be initiated in the case of spontaneous position changes.

The switchgear positions shall be indicated by two auxiliary switches, normally closed (NC) and normally open (NO), which shall give ambivalent signals. An alarm shall be initiated if these position indications are inconsistent or if the time required for operating mechanism to change position exceeds a predefined limit.

The SAS shall also monitor the status of sub-station auxiliaries. The status and control of auxiliaries shall be done through separate one or more IED and all alarm and analogue values shall be monitored and recorded through this IED.

ii.   Measurements

Analogue inputs for voltage and current measurements shall be connected directly to the voltage transformers (VT) and the current transformers (CT) without intermediate transducers. The values of active power (W), reactive power (VAR), frequency (Hz), and the rms values for voltage (U) and current (I) shall be calculated.

The measured values shall be displayed locally on the station HMI and in the control centre. The abnormal values must be discarded. The analogue values shall be updated every 2 seconds. Threshold limit values shall be selectable for alarm indications.

iii.   Event and alarm handling

Events and alarms are generated either by the switchgear, by the control IEDs, or by the station level unit. They shall be recorded in an event list in the station HMI. Alarms shall be recorded in a separate alarm list and appear on the screen. All, or a freely selectable group of events and alarms shall also be printed out on an event printer. The alarms and events shall be time-tagged with a time resolution of 1 ms.

iv.   Substation HMI:

1.   Operation:

On the HMI the object has to be selected first. In case of a blocking or interlocking conditions are not met, the selection shall not be possible and an appropriate alarm annunciation shall occur. If a selection is valid the position indication will show the possible direction, and the appropriate control execution button shall be pressed in order to close or open the corresponding object.

Control operation from other places (e.g. REMOTE) shall not be possible in this operating mode. The operator station HMI shall be a redundant with hot standby and shall provide basic functions for supervision and control of the substation. The operator shall give commands to the switchgear on the screen via mouse clicks or keyboard commands. The HMI shall give the operator access to alarms and events displayed on the screen. Aside from these lists on the screen, there shall be a printout of alarms or events in an event log.

An acoustic alarm shall indicate abnormalities, and all unacknowledged alarms shall be accessible from any screen selected by the operator.

The following standard pictures shall be available from the HMI:

a.   Single-line diagram showing the switchgear status and measured values.

b.   Control dialogues with interlocking and blocking details. This control dialogue shall tell the operator whether the device operation is permitted or blocked.

c.   Measurement dialogues

d.   Alarm list, station / bay-oriented

e.   Event list, station / bay-oriented

f.   System status

2.   HMI design principles

Consistent design principles shall be adopted with the HMI concerning labels, colours, dialogues and fonts. Non-valid selections shall be dimmed out.

The object status shall be indicated using different status colours for:

a.   Selected object under command

b.   Selected on the screen

c.   Not updated, obsolete values, not in use or not sampled

d.   Alarm or faulty state

e.   Warning or blocked

f.   Update blocked or manually updated

g.   Control blocked

h.   Normal state

Process status displays and command procedures

The process status of the substation in terms of actual values of currents, voltages, frequency, active and reactive powers as well as the positions of circuit breakers,

isolators and transformer tap-changers shall be displayed in the station single-line diagram.

In order to ensure a high degree of security against undesired operation, a "select-before-execute" command procedure shall be provided. After the "selection" of a switch, the operator shall be able to recognize the selected device on the screen, and all other switchgear shall be blocked. As communication between control centre and device to be controlled is established, the operator shall be prompted to confirm the control action and only then final execute command shall be accepted. After the "execution" of the command the operated switching symbol shall flash until the switch has reached its new position.

The operator shall be in a position to execute a command only, if the switch is not blocked and if no interlocking condition is going to be violated. The interlocking statements shall be checked by the interlocking scheme implemented at bay and station level.

After command execution the operator shall receive a confirmation that the new switching position has been reached or an indication that the switching procedure was unsuccessful with the indication of the reason for non-functioning.

3.   System supervision & display

The SAS system shall be comprehensively self-monitored such that faults are immediately indicated to the operator, possibly before they develop into serious situations. Such faults are recorded as a faulty status in a system supervision display. This display shall cover the status of the entire substation including all switchgear, IEDs, communication infrastructure and remote communication links, and printers at the station level, etc.

4.   Event list

The event list shall contain events that are important for the control and monitoring of the substation. The event and associated time (with 1 ms resolution) of its occurrence has to be displayed for each event.

The operator shall be able to call up the chronological event list on the monitor at any time for the whole substation or sections of it.

A printout of each display shall be possible on the hard copy printer.

The events shall be registered in a chronological event list in which the type of event and its time of occurrence are specified. It shall be possible to store all events in the computer for at least one month. The information shall be obtainable also from a printed event log.

The chronological event list shall contain:

a.   Position changes of circuit breakers, isolators and earthing devices

b.   Indication of protective relay operations

c.   Fault signals from the switchgear

d.   Indication when analogue measured values exceed upper and lower limits. Suitable provision shall be made in the system to define two level of alarm on either side of the value or which shall be user defined for each measurand.

e   Loss of communication.

Filters for selection of a certain type or group of events shall be available. The filters shall be designed to enable viewing of events grouped per:

f.   Date & time.

g.   Bay

h.   Device

i.   Function e.g. trips, protection operations etc.

j.   Alarm class

5.   Alarm list

Faults and errors occurring in the substation shall be listed in an alarm list and shall be immediately transmitted to the control centre. The alarm list shall substitute conventional alarm tableau, and shall constitute an evaluation of all station alarms. It shall contain unacknowledged alarms and persisting faults. The date and time of occurrence shall be indicated.

The alarm list shall consist of a summary display of the present alarm situation. Each alarm shall be reported on one line that contains:

a.   The date and time of the alarm.

b. The name of the alarming object.

c. A descriptive text.

d. The acknowledgement state.

Whenever an alarm condition occurs, the alarm condition must be shown on the alarm list and must be displayed in a flashing state along with an audible alarm. After acknowledgement of the alarm, it should appear in a steady (i.e. not flashing) state and the audible alarm shall stop. The alarm should disappear only if the alarm condition has physically cleared and the operator has reset the alarm with a reset command. The state of the alarms shall be shown in the alarm list (Unacknowledged and persistent, unacknowledged and cleared, Acknowledged and persistent).

Filters for selection of a certain type or group of alarms shall be available as for events.

6. Object picture

When selecting an object such as a circuit breaker or isolator in the single-line diagram, the associated bay picture shall be presented first. In the selected object picture, all attributes like:

a. Type of blocking.

b. Authority.

c. Local / remote control.

d. RCC / SAS control.

e. Errors etc. shall be displayed.

7. Control dialogues.

The operator shall give commands to the system by means of mouse click located on the single-line diagram. It shall also be possible to use the keyboard for command activation. Data entry is performed with the keyboard. Dedicated control dialogues for controlling at least the following devices shall be available:

a. Breaker and disconnector

b. Transformer tap-changer

8. User-authority levels

It shall be possible to restrict activation of the process pictures of each object (bays, apparatus...) within a certain user authorization group. Each user shall then be given access rights to each group of objects, e.g.:

Display only.

Normal operation (e.g. open/close of switchgear)

Restricted operation (e.g. by-passed interlocking)

System administrator

For maintenance and engineering purposes of the station HMI, the following authorization levels shall be available:

No engineering allowed

Engineering/configuration allowed

Entire system management allowed

The access rights shall be defined by passwords assigned during the login procedure. Only the system administrator shall be able to add/remove users and change access rights.

9. Reports

The reports shall provide time-related follow-ups of measured and calculated values. The data displayed shall comprise:

a. Trend reports:

- Day (mean, peak)

- Month (mean, peak)

- Semi-annual (mean, peak)

- Year (mean, peak)

b. Historical reports of selected analogue Values:

- Day (at 15 minutes interval)

- Week

- Month

- Year

. It shall be possible to select displayed values from the database in the process display on-line. Scrolling between e.g. days shall be possible. Unsure values shall be indicated. It shall be possible to select the time period for which the specific data are kept in the memory

Following printouts shall be available from the printer and shall be printed on demand:

o   Daily voltage and frequency curves depicting time on X-axis and the appropriate parameters on the Y-axis. The time duration of the curve is 24 hours.

o   Weekly trend curves for real and derived analogue values.

o   Printouts of the maximum and minimum values and frequency of occurrence and duration of maximum and minimum values for each analogue parameter for each circuit in 24 hr period.

o   Provision shall be made for logging information about breaker status like number of operation with date and time indications.

o   Equipment operation details shift wise and during 24 hours.

o   Printout on adjustable time period as well as on demand for MW, MVAR, Current, Voltage on each feeder and transformer as well as Tap Positions, temperature and status of pumps and fans for transformers.

o   Printout on adjustable time period as well as on demand system frequency and average frequency.

o   Reports in specified formats which shall be handed over to successful bidder.

c.   Trend display (historical data)

It shall be possible to illustrate all types of process data as trends –input and output data, binary and analogue data. The trends shall be displayed in graphical form as column or curve diagrams with a maximum of 10 trends per screen. Adjustable time span and scaling ranges must be provided.

It shall be possible to change the type of value logging (direct, mean, sum, or difference) on-line in the window. It shall also be possible to change the update intervals on-line in the picture as well as the selection of threshold values for alarming purposes.

d.   Automatic disturbance file transfer

All recorded data from the IEDs with integrated disturbance recorder as well as dedicated disturbance recording systems shall be automatically uploaded (event triggered or once per day) to a dedicated computer and be stored on the hard disc.

e.   Disturbance analysis

The PC-based work station shall have necessary software to evaluate all the required information for proper fault analysis.

f.   IED parameter setting

It shall be possible to access all protection and control IEDs for reading the parameters (settings) from the station HMI or from a dedicated monitoring computer. The setting of parameters or the activation of parameter sets shall only be allowed after entering a password.

g.   Automatic sequences

The available automatic sequences in the system should be listed and described, (e.g. sequences related to the bus transfer). It must be possible to initiate pre-defined automatic sequences by the operator and also define new automatic sequences.

XIII. Gateway

The Gateway shall use industrial grade components. The State of the Art Gateway requires usage of fast, powerful microcontroller based systems designed to function in the process environment in a functionally decentralized manner. The tasks of such systems are manifold and shall guarantee safe and secure operation of the entire system with high availability.

Gateway shall be utilized in substation Automation application to interface between the IEDs and the Master (control & monitoring) devices viz. SCADA. It shall be used for a real time monitoring & control operation of the switchgears and devices pertaining to a particular voltage level of the station.

The Gateway shall be multifunctional, designed in accordance with applicable International Electro-technical Commission (IEC), Institute of Electrical and Electronics Engineer (IEEE), American National Standards Institute (ANSI), and National Equipment Manufacturers association (NEMA) standards, unless otherwise specified in this Technical specification. Gateway shall comply to the Security as per BDEW White-Paper-conformity and integrated Krypto-Chip or other relevant international cyber security standards. In all cases the provisions of the latest edition or revision of the applicable standards in effect shall apply. The following scheme / features shall be available:

a) The system shall comprise the following in-built features namely failsafe control (i.e. in built check-before-execute feature), Control system, SOE buffer, Interfacing with third party IEDs if required (e.g. Multifunction Meters etc.), interfacing with third party computer system, direct GPS clock connectivity, through SNTP server or through the Master station (RCC/MCC) (main and standby mode) for time synchronization. Gateway shall support redundant time synchronization inputs.

b) Gateway shall be of the family of RTUs with high availability & reliability. Purchaser prefers to have gateway, which is easily expandable by addition of Processors & communication modules in existing rack to integrate with IEDs in future on open protocols.

c) Gateway shall not have any moving parts for data storage, heat dissipation etc.

d) Gateway shall have multi-processors capability within one rack. CPU, Power Supply and Communication redundancy shall be provided in the same gateway rack/chassis.

e) Gateway shall support hot swappable Processors, I/O modules & Power Supplies, so that components can be replaced without need to switching off the gateway.

f) The proposed Gateway shall have the capability to support simultaneous communications with two or more independent remote master (redundant) stations.

g) Gateway shall use removable flash memory for storing program/database.

h) Automatic start-up and initialization following power restoration.

i) Gateway shall be able to receive time synchronize packets from the master station over IEC-60870-5-104 protocol or from the slave clock provided in the respective substation on SNTP Protocol.

j) Communication ports shall supported PRP onboard for IED communication.

k) Accuracy of gateway's real time clock shall be better than +-5 ppm.

l) In case of power supply failure, auto start-up and restoration of the Gateway shall be possible without manual intervention.

m) Gateway shall comply to various internet security standards like – BDEW Whitepapers and integrated Krypto-Chip or other relevant IEC/IEEE standard.

n) Remote database downloading and uploading of Gateway from master station shall be possible.

o) It shall be possible to increase the number of communication ports in the Gateway by addition of plug-in modules, if required in future. The Gateway shall support the use of a different communication data exchange rate and scanning cycle on each port and different database for each master station.

p) The proposed Gateway shall be KEMA Certified or by equivalent certification body.

q) It shall be possible to generate events in HMI in case of failure of communication/power supply/processor module of Gateway.

The Gateways provided for the above system shall be rack mounted. LED indications should be provided on the front of the cards to know the status of communication by looking at the front of the communication card. The Gateway shall also support PLC programming for future controls at the sub-station. Technical parameters to be complied are stipulated hereunder.

A. Technical Parameters of Gateway

1. Power supply: 230 V + / - 10 V , 50 Hz AC

2. Processor Type   : Intel Pentium D 820 Processor, 2.8 GHz or

Higher Standard L2 2MB, 800 MHz front side bus   Intel R1208GZ4GC, 1U

3. Chipset   : Intel Core DUO ,INDUSTRIAL PUPOSE @ 3.1 GHz, or higher

4. Memory Type : 8 GB DDR3, 32 GB max.

5. Standard memory   : 4 GB

6. Memory slots : 2 DIMM

7. Hardware monitoring   : System Monitor (fan ,temp., Voltage)

8. Memory upgrade   : Expandable

9. Internal hard disk drive   : 500 GB, 3.5-in. SATA HDD

10. *Hard disk drive speed* : *7200 rpm*

11. *Protocols capabilities* : *IEC 61850, IEC 69870-5-101/104, Modbus*

12. *Optical drives* : *16X DVD-ROM (Combo)*

13. *Mounting* : *Rack mountable 4 U height*

14. *Chassis type : 19" 4 U Industrial Rack mount BP chassis*

15. *Fans, Air filter, cables* : *One 12cm & one 8 cm cooling fans with*

removable filter and lockable front door. ON/OFF, HDD, FDD, RESET with all power & Inter connecting cables.

16. *Video adapter, bus : PCI Express ™X16*

17. *Expansion slots* : *Two full –height PCI 2.3 slots, one full height*

PCI Express x1slot and one full–height PCI x16 slot.

18. *Audio : Integrated Audio with External speakers & Microphone.*

19. *Modem* : *Integrated 56K PCI Modem*

20. *Network Interface* : *Integrated 10/100/1000 Gigabit Fast*

Ethernet-WOL, Dual RJ-45 with Two LED indicators.

21. *External I/O ports* : *1xParallel port, 2xSerial port, Selectable*

RS-232/422/485x 1,6xUSB 2.0 ports , 4xRJ- 45

22. *Operating system installed : Gateway software*

23. *Warranty* : *3 year of on-site comprehensive*

24. *UPS* : *1000 VA or higher With 30 Minutes Backup*

25. *Operating Temp* : *0 - 55 ℃*

26. *Relative Humidity* : *5 to 95 %(Non-condensing at 40 ℃).*

27. *Antivirus s/w* : *Registered standard latest Anti-virus software*

B. Communication Interface

The Substation Automation System shall have the capability to support independent remote master station. The Substation Automation System shall have communication ports as follows:

(a)   ==Redundant link for data transmission to MCC/RCC/SLDC on IEC 104==.

The communication interface to the SAS shall allow scanning and control of defined points within the substation automation system independently for control centre. The substation automation system shall simultaneously respond to independent scans and commands from employer's control centers. The substation automation system shall support the use of a different communication data exchange rate (bits per second), scanning cycle, and/or communication protocol to each remote control centre. Also, each control center's data scan and control commands may be different for different data points within the substation automation system's database.

The SAS shall also allow all necessary RTU data transfer to SLDC main RTU system. There may require typical protocol converter depending upon SLDC RTU system. Communication media may be leased line, PLCC, Radio or any other means.

C. Master Control Centre Communication (NET WORK CONTROL CENTER) Interface

Communication channels between the Substation Automation System and the master control centre (Net Work Control Centre) will consist either of OPGW, power line carrier, microwave, optical fiber, VSAT or leased line, as the case may be, as specified.

D. Interface equipment:

The Contractor shall provide interface equipment for communicating between Substation Automation system and Remote control centre (RCC).

In case of PLCC communication any modem supplied shall not require manual equalization and shall include self-test features such as manual mark/space keying, analogue loop-back, and digital loop-back. The modems shall provide for convenient adjustment of output level and receive sensitivity. The modem should be stand alone complete in all respects including power supply to interface the SAS with communication channel. The configuration of tones and speed shall be programmable and maintained in non-volatile memory in the modem. All necessary hardware and software shall also be in the scope of bidder except the communication link along with communication equipment between substation control room and Remote Control Centre.

E. Communication Protocol

The communication protocol for gateway to control centre must be open protocol and shall support IEC 60870-5-104 and IEC 61850 for all levels of communication for sub-station automation such as Gateway to remote station and Bay to station HMI, etc. respectively.

XIV. System hardware:

A. SCADA Equipment:

The contractor shall provide redundant station HMI in hot standby mode.

It shall be capable to perform all functions for entire substation including future requirements as indicated in the SLD. It shall use industrial grade components.

Processor and RAM shall be selected in such a manner that during normal operation not more than 30% capacity of processing and memory are used. Supplier shall demonstrate these features.

The capacity of hard disk shall be selected such that the following requirement should occupy less than 50% of disk space:

1.   Storage of all analogue data (at 15 Minutes interval) and digital data including alarm, event and trend data for thirty (30) days.

2.   Storage of all necessary software,

3.   100 GB space for OWNER'S use.

Supplier shall demonstrate that the capacity of hard disk is sufficient to meet the above requirement.

B. HMI (Human Machine Interface)

The VDU shall show overview diagrams (Single Line Diagrams) and complete details of the switchgear with a colour display. All event and alarm annunciation shall be selectable in the form of lists. Operation shall be by a user friendly function keyboard and a cursor positioning device. The user interface shall be based on WINDOWS concepts with graphics & facility for panning, scrolling, zooming, decluttering etc.

C. Mass Storage Unit

The mass storage unit shall be built-in to the Station HMI. All operational measured values and indications shall be stored in a mass-storage unit of CD-ROM / DVD-ROM with 700 MB or more capacity. The unit should support at least Read (48X), Write (24X), and Re-Write (10X) operations, with Multi-Session capability. It should support ISO9660, Rockridge and Joliet File systems. It should support formatting and use under the operating system provided for Station HMI. The monthly back up of data shall be taken on disc. The facility of back up of data shall be inherent in the software.

D. Visual Display Units/TFT's (Thin Film Technology)

The contractor shall provide three display units, one for station HMI, one for redundant HMI and one for DR work station. These shall have high resolution and reflection protected picture screen. High stability of the picture geometry shall be ensured. The screen shall be at least 21" diagonally in size and capable of colour graphic displays.

The display shall accommodate resolution of 2560 X 1440 pixels. The HMI shall be able to switch the key board and cursor positioning device, as unit among all the monitors at a console with push button or other controls.

Large Video Wall-Full HD:
The large screen Video wall in the control room shall be used for the display of important graphics from the pc, workstation, Images from IP video cameras. The size of the large video display unit of 70 inches (for 132/33,220/33 & 220/132/33 KV S/S) & 80 inches (for 400/220 KV S/S) (Make: Toshiba/ SONY/ SAMSUNG) and its peripherals suitably connected to SAS shall be provided in each station as per the technical specification. The Visual Display Unit shall be Full HD LED. The light source should be LEDs of 3 different primary colours; Red, Green & Blue and not a single lamp using the LED as a light source. Light source 6x redundancy for each of 3 LEDs of three primary colors.

E. Printers

It shall be laser jet color printer & the printing operation shall be quiet with a noise level of less than 55 dB suitable for location in the control room. Printer shall accept and print all ASCII characters via master control computer unit interface.

The printer shall have in built testing facility. Failure of the printer shall be indicated in the Station HMI. The printer shall have an off line mode selector switch to enable safe maintenance. The maintenance should be simple with provisions for ease of change of print head, ribbon changing, paper insertion etc.

F. Switched Ethernet Communication Infrastructure:

The bidder shall provide the redundant switched optical Ethernet communication infrastructure for SAS. The bidder shall keep provision of 100% spare capacity for employer use. One switch shall be provided to connect all IEDs housed in respective kiosk.

One set of switches shall be provided to connect all IEDs of one bay of 400KV/220KV, all of IED 2 bays 132kV and for 33kV multiple bays(4 bays) need to be connected to one switch.

G. Bay level unit (BCU)

a)   Location:

The bay control units will be located inside the relay kiosks, which are located throughout the ehv substation's.

b)   Interfacing:

All bay control units shall contain an optical-fiber/ RJ45 (Selection of port by owner as per the suitability & project specific) serial interface for connection to the HMI center and a RS 232/USB (Selection of port by owner as per the suitability & project specific) serial interface for connection to a PC.

All optical-fiber cables/Ethernet (as per the selection by the owner) will be part of the supply as well.

c)   Interfacing with the equipment of the switchyard:

The bay control units shall be capable of interfacing with the equipment of the switchyard. All digital and analog input signals from the equipment of the switchyard and out-going carrying command and control signals to the various equipment will interface with the bay control units through terminal blocks located inside the relay kiosks. These incoming and out-going signals will be wired by PPC with conventional control cables of cross section of 2.5 mm2 (that is from the terminal blocks to and from the switchyard equipment) except for the VTs and CTs circuits, which utilize cables of 4mm2 in cross section

d)   Isolation from the switchyard equipment:

The bay control units shall provide isolation from the switchyard equipment via heavy duty relay contacts or by other means.

e)   Parameterization and control:

Control for the bay control units shall be performed via an integrated graphic display and keypad and Parameterization shall be done via PC/Laptop.

f)   Analog inputs signals:

Analog input signals can be input to the bay control units either via analog transducers or by direct connection to CTs and VTs. If transducers are required, the supplier will supply these transducers.

g)   Mounting:

The bay control units shall be suitable for panel flash mounting or ½ flash panel mounting.

The bay unit shall use industrial grade components. The bay level unit, based on microprocessor technology, shall use numerical techniques for the calculation and evaluation of externally input analogue signals. They shall incorporate select-before-operate control principles as safety measures for operation via the HMI. They shall perform all bay related functions, such as control commands, bay interlocking, data acquisition, data storage, event recording and shall provide inputs for status indication and outputs for commands. They shall be directly connected to the switchgear via TBs. Connections from BCU to switchgear should not be terminated directly on I/O boards but should be routed through Terminal Boards (TB). The bay unit shall acquire and process all data for the bay (Equipment status, fault indications, measured values, alarms etc.) and transmit these to the other devices in sub-station automation system. In addition, this shall receive the operation commands from station HMI and control centre. The bay unit shall have the capability to store all the data for at least 24 hours. One No. Bay level unit shall be provided for supervision and control of each 400, 220 and 132 KV bay (a bay comprises of one circuit breaker and associated disconnectors, earth switches, instrument transformers etc). The Bay level unit shall be equipped with analogue and binary inputs/outputs for handling the control, status monitoring and analogue measurement functions. All bay level interlocks are to be incorporated in the Bay level unit so as to permit control from the Bay level unit/ local bay mimic panel, with all bay interlocks in place, during maintenance and commissioning or in case of contingencies when the Station HMI is out of service. The Bay level unit shall meet the requirements for withstanding electromagnetic interference according to relevant parts of IEC 61850. Failure of any single component within the equipment shall neither cause unwanted operation nor lead to a complete system breakdown.

Surface-mount technology (SMT) should be used for printed circuit boards (PCB) of BCU. Further a conformal coating should be applied to the PCB for ensuring optimum performance under the toughest environment conditions.

i. Input/Output (I/O) modules

The I/O modules shall form a part of the bay level unit and shall provide coupling to the substation equipment. The I/O modules shall acquire all switchgear information (i.e. data coming directly from the switchgear or from switchgear interlocking devices) and transmit commands for operation of the switchgear. The measured values of voltage and current shall be from the secondary of instrument transformers. The digital inputs shall be acquired by exception with 1 ms resolution. Contact bouncing in digital inputs shall not be assumed as change of state. Connections from BCU to switchgear should not be terminated directly on I/O boards but should be routed through Terminal Boards (TB).

ii. Technical Parameters of BCU

1. Power supply: 220 VDC, + 20%, Power consumption: < 50W Ripple (peak to peak): < 12%.

2.   Protocol Capabilities: The BCU should have ethernet module to connect   to the communication buses (like the station   bus) that use the IEC 61850-8-1 protocol.

The module should have two optical ports with LC connectors or two Ethernet electrical RJ 45 connectors in PRP mode based on SAS design requirement.

IEC 61850-8-1 communication protocol-100BASE-FX/TX,

Transmission rate-1000Mbit, Ethernet Electrical –RJ45,Test Volt-500V AC against ground. Distance Max. 20meter.

 Ethernet Optical- LC/ST connecter , Wavelength- 1300nm,Distance-Max.1.5kM.

3.   IED Communication:

1. IEC 60870-5-103 (T103)

2. Modbus

3. DNP3

4. IEC 60870-5-101 (T101)

All these networks use a serial link to communicate with IEDs.

5. Time synchronisation : External Time Synchronization from IRIG B BNC plug, Amplitude modulated/ Ethernet SNTP Time Server (<1ms accuracy)

4 Binary Input processing : Hardwired Digital Input should be acquired via digital boards or IED connected by a serial link. Software Digital Input coming from configurable relays & other devices with 1 ms time tagging support GOOSE mode digital boards or IED connected by a serial link. Software Digital Input coming from configurable relays & other devices with 1 ms time tagging. Support GOOSE mode.

No of Binary Input: 32 Nos. for 33KV, 36 Nos. for 132kV, 43 Nos. for 220kV and 48 Nos. for 400kV System.

Operating Volt: 220V DC. (Max.300V)

5. Analogue Input processing :

a. Four Voltage Inputs :

Nominal AC voltage (Vn) range :110V,110V/√3

Frequency operating range: 50 Hz ± 10%

VT load rating: 10 seconds with no destruction 880 V r m s

b. Four Current Input:

Nominal AC current (In) :1 A r m s Minimum measurable current with same accuracy :0.2 A r m s Maximum measurable current 4 A r m s (4*In) Frequency 50 Hz ± 10%.

c. Analogue Transducers input :

8 insulated transducer input (-20mA to +20mA) values on 8 independent galvanic-isolated channels. This means that there is no common point of contact between two analogue inputs. Each analogue input can be configured in the current range or voltage range.

Overload Capacity : 100mA

Sampling period 100 ms

Accuracy 0,1% full scale for each range at 25°C

AD conversion 16 bits (15 bits+sign bit).

6.   Measured value acquisition   :

Monitoring of calculated four CT & four PT/CVTdirect primary measures.

7   Derived values: From the direct primary measures:

RMS currents & voltages, network frequency, active power, reactive power, apparent power, Power factor, Phase angles.

8   Digital Outputs: DO used for switching device in field or inside

C/R via digital boards, should also configurable & contain security, interlocks etc.

<mark>17 Nos. for 33KV, 23 Nos. 132KV System, 25 Nos. for 220kV System and 32 Nos. for 400kV System.</mark>

<mark>Note: GIS Monitoring signal shall be required to wired direct from communicable type annunciator in LCC over Modbus protocol.</mark>

Nominal operating voltage :220VDC (Max.300V)

Make: 5A

Carry: 5A continuously

30A for 500 mseconds.

Break DC: 50 W resistive, 15 W inductive (L/R = 40 ms).

9. Sub-station/bay: Should use logical equation and pre defined Inter-locking rules & sub-station topology for operation.

: Should use logical equation and pre defined Inter-locking rules & sub-station topology for operation.

10   Trip Circuit Supervision :Supervise trip circuits for both the conditions of Breaker.

11   Event Logging : Storage of events up to ~~2000~~ <mark>200</mark> in ROM.

:Storage of events up to ~~2000~~ <mark>200</mark> in ROM.

12   Disturbance files & wave forms   : Minimum Five records of waveforms and disturbance record of wave forms files stored and accessible by HMI/DR work Station.

13   Gateway support   :Should interface with Gateway for Remote Control facility

14   Local control, Operation   :Local control & Operation should be possible and Display   using backlit LCD Display and keypad of BCU.

15   Self- monitoring: Power ON and continuous cyclic self-monitoring

tests. Abnormality result should be displayed.

16   I/O processing: As per our required I/O and ==I/O count provided above== list with 20% extra for Capacities each bay.

17   Internal Ethernet : 2 X 10/100 Base T (RJ-45) ports ==or== 2X10/100 Base Fx (optical) ports for redundant Ethernet network ==in PRP.==

18   Additional ports : 1 X RS232==/USB== in front for parameterization

Modbus, should be s/w configurable.

19   Environmental conditions :   :Operating temperature: -5°C to + 70 °C

Storage temperature: -5°C to + 70 °C

        : 0°C to + 70 °C Humidity: 5 to 95 % (Non-condensing).

20   Mounting & design : ==Flush or Rack Mounted Type== with modular design.

21   Warranty   .:3 year of on-site comprehensive.

XV. Inverters of UPS

Redundant ,SCADA Compatible, Output: 230 V Stabilized AC with 30 X 12V, 26 AH battery set ,Capable of handling all SCADA equipment containing HMI PCs, DR Work station, Gateways, modems, all Printers, etc. installed in C/R. One battery set will be common for both the inverters. An arrangement should be made such that it should be always connected with the inverter which provides load to SCADA equipment.

INPUT SPECIFICATIONS

        Voltages   230 VAC

        Voltage Range   -20% to +15%

        Frequency   50 Hz

Protection   Input circuit breaker provided protection to the unit, load and personnel. Input Circuit Breaker will be higher interruption rated.

Input Current   Sinusoidal, .95 PF under all line/load conditions

Number of Wires   2 Wires Plus Ground

OUTPUT SPECIFICATION

Available Output Ratings (KVA or KW to be specified) 3 KVA / 2.1 KW

Output Voltages   230 VAC

Voltage Regulations ±3% No Load to Full Load, High Line to Low Line

Frequency   50 Hz +/-0. 5 HZ (when on inverter)

Output Wave Form Sine Wave

Harmonic Distortion   <5 % THD; <3% Single Harmonic

Crest Factor 3 to 1

Overload   125% for Ten (10) Minutes; 150% Surge for 10 seconds

Protection   Internal electronic overload protection. Circuit breaker provides inherent overload protection.

Efficiency   90% typical

Isolation   Complete from line. Output neutral bonded to ground

Noise Isolation   120 dB Common-Mode: -60 dB Transverse- Mode

Power Connections Hard Wired (Terminal Block) Optional Output Receptacle Panels w/

NEMA Type Receptacles and Overcurrent Protection

Number of Wires   2 Wires Plus Ground

BATTERY SPECIFICATIONS   Run Time   5 minutes – up to 6 hrs available

Optional Run Time Select 15 min, 30 min, 45 min, 60 min, 90 min,120 min, 180 min or 240 min.

Battery Type Sealed, Maintenance-Free (AGM) battery, (Optional Long Life Battery)

       Expected Life 10 Years

       Charger Ampacity   < 10 times discharge

       Float Voltage 2.25 Volts per Cell

       Protection   Fuses, DC Disconnect or Circuit Breaker

XVI. Extendibility in future

Offered substation automation system shall be suitable for extension in future for additional bays. During such requirement, all the drawings and configurations, alarm/event list etc. displayed shall be designed in such a manner that its extension shall be easily performed by the employer. During such event, normal operation of the existing substation shall be unaffected and system shall not require a shutdown. The contractor shall provide all necessary software tools along with source codes/ device configuration files to perform addition of bays in future and complete integration with SAS by the user. These software tools shall be able to configure IED, add additional analogue variable, alarm list, event list, modify interlocking logics etc. for additional bays/equipment which shall be added in future. HMI h/w & s/w should also support extreme extendibility as per future layout.

XVII. Software structure.

The software package shall be structured according to the SAS architecture and strictly divided in various levels. Necessary firewall shall be provided at suitable points in software to protect the system. An extension of the station shall be possible with lowest possible efforts. Maintenance, modification or an extension of components of any feeder may not force a shut-down of the parts of the system which are not affected by the system adaptation.

1. Station level software:

a. Human-machine interface (HMI)

The base HMI software package for the operator station shall include the main SAS functions and it shall be independent of project specific hardware version and operating system. It shall further include tools for picture editing, engineering and

system configuration. The system shall be easy to use, to maintain, and to adapt according to specific user requirements.

Systems shall contain a library with standard functions and applications.

b. System software

The system software shall be structured in various levels. This software shall be placed in a non-volatile memory. The lowest level shall assure system performance and contain basic functions, which shall not be accessible by the application and maintenance engineer for modifications. The system shall support the generation of typical control macros and a process database for user specific data storage. In case of restoration of links after failure, the software along with hardware shall be capable of automatically synchronizing with the remaining system without any manual interface. This shall be demonstrated by contractor during integrated system test.

c. Gateways Software

i. Gateway (RCC)

Software of Gateway should be suitable for controlling s/s remotely.

ii. Gateway (RTU)

Software of Gateway should be suitable for controlling s/s remotely and sending station monitoring data and station Auxiliary data.

d. Application software

In order to ensure robust quality and reliable software functions, the main part of the application software shall consist of standard software modules built as functional block elements. The functional blocks shall be documented and thoroughly tested. They form part of a library. The application software within the control/protection devices shall be programmed in a functional block language.

e. Network Management System for D.R. Work Station:

The contractor/ Manufacturer shall provide network management system software for following management functions:

 i. Configuration Management

ii. Fault Management

iii. Performance Monitoring.

This system shall be used for management of communication devices and other IEDs in the system. This NMS can be loaded in DR work-station and shall be easy to use, user friendly and menu based. The NMS shall monitor all the devices in the SAS and report if there is any fault in the monitored devices. The NMS shall ;

i. Maintain performance, resource usage, and error statistics for all managed links and devices and present this information via displays, periodic reports and on demand reports.

ii. Maintain a graphical display of SAS connectivity and device status.

iii. Issue alarms when error conditions occur.

iv. Provide facility to add and delete addresses and links.

f. The contractor shall provide each software in two copies in CD to load into the system in case of any problem related with Hardware/Communication etc.

XVIII. TESTS

The bidder shall submit the complete type test reports as stated hereunder for the offered item along with the offer otherwise the offer shall be liable to be rejected. These tests must have been conducted in the NABL approved laboratory as per IEC 60255, IEC 60068, IEC 61000, IEC 60529, IEC 61010-1 & IEC 61850 within last 5 years prior to date of validation of the offer. Complete type test reports containing test procedure, drawings, oscillograms etc. shall be submitted.

The substation automation system offered by the bidder shall be subjected to following tests to establish compliance with IEC 61850 for EHV substation equipment installed in sheltered area in the outdoor switchyard and specified ambient conditions:

A. Type Tests:

1. Control IEDs and Communication Equipment:

a. Performance tests

   i. Accuracy requirements

   ii. Limits of operating range of auxiliary energizing inputs and auxiliary Voltage dependence.

    iii.   Limits of frequency range and frequency dependence

    iv.   Rated burden

    v.   Mechanical Endurance test

    vi.   Characteristic and Functional test

b.   Thermal requirements

    i.   Maximum allowable temperature

    ii.   Limits of short time thermal withstand value of input energizing quantities

    iii.   Limiting dynamic value

c.   Insulation Tests:

    i.   Dielectric Tests

    ii.   Impulse Voltage withstand Test

    iii.   Insulation resistance measurement

d.   Influencing Quantities:

    i.   Permissible ripples

    ii.   Interruption of input voltage

e.   Electromagnetic Compatibility Test:

    i.   1 MHZ burst disturbance test

    ii.   Electrostatic Discharge Test

    iii.   Radiated Electromagnetic Field Disturbance Test

    iv.   Electrical Fast transient Disturbance Test

    v.   Conducted Disturbances Tests induced by Radio Frequency Field

    vi.   Magnetic Field Test

    vii.   Emission (Conducted rand Radiated) Test.

    viii.   Surge Immunity Test

f.   Contact performance Test

    i. Contact making/Breaking capacity test

    ii. Continuous capacity

g.   Environmental tests:

    i. Cold Temperature

    ii. Dry Heat

    iii. Storage temperature test

    iv. Humidity (Damp heat Cycle)

h.   Mechanical Tests:

    i. Vibration response & Vibration endurance test

    ii. Bump test

    iii. Shock response test

    iv. Seismic test

i.   Enclosure Test:

    i. Degree of Protection test – IP51

j.   Safety Test:

    i. Single fault condition assessment

    ii. Earth bonding impedance test

    iii. Mechanical resistance to shock and impact

    iv. Protection against electrical shock

    v. Protection against the spread of fire

k.   IEC 61850 Compatibility tests

B. Factory Acceptance Tests:

The supplier shall submit a test specification for factory acceptance test (FAT) and commissioning tests of the station automation system for approval. For the individual bay level IED's applicable type test certificates shall be submitted. The manufacturing phase of the SAS shall be concluded by the factory acceptance test (FAT). The purpose is to ensure that the Contractor has interpreted the specified requirements correctly and that the FAT includes checking to the degree required by the user. The general philosophy shall be to deliver a system to site only after it has been thoroughly tested and its specified performance has been verified, as far as site conditions can be simulated in a test lab. If the FAT comprises only a certain portion of the system for practical reason, it has to be assured that this test configuration contains at least one unit of each and every type of equipment incorporated in the delivered system. If the complete system consists of parts from various suppliers or some parts are already installed on site, the FAT shall be limited to sub-system tests. In such a case, the complete system test shall be performed on site together with the site acceptance test (SAT).

C. Integrated Testing:

The integrated system tests shall be performed as detailed in subsequent clauses as per following configuration:

Redundant Station HMI, DR work station, two switches (i.e. for two diameters) along with all IEDs for the Dia. and printers.

All other switches for complete sub-station as detailed in section project shall be simulated as needed.

D. Hardware Integration Tests:

The hardware integration test shall be performed on the specified systems to be used for Factory tests when the hardware has been installed in the factory. The operation of each item shall be verified as an integral part of system. Applicable hardware diagnostics shall be used to verify that each hardware component is completely operational and assembled into a configuration capable of supporting software integration and factory testing of the system. The equipment expansion capability shall also be verified during the hardware integration tests.

E. Integrated System Tests:

Integrated system tests shall verify the stability of the hardware and the software. During the tests all functions shall run concurrently and all equipment shall operate a

continuous 100 Hours period. The integrated system test shall ensure the SAS is free of improper interactions between software and hardware while the system is operating as a whole.

F. Field Tests:

The field tests shall completely verify all the features of SAS hardware and software.

G. System Performance:

It shall be the responsibility of the bidder to predict and indicate in the bid, the worst case loading condition and design the system accordingly to meet the same. The worst case loading condition shall include following

• All analogue inputs scanning and processing in progress and all data is being transmitted over the system bus every one second.

• A burst of 100 alarms is generated over a period of 10 seconds.

• An operator control is generated every 10 seconds.

• Data collection for logs/reports is in progress.

• Data collection for historical storage and trend function in progress.

• Data collection of fault record is in progress.

• All health monitoring functions/diagnostics in progress.

• All output devices are in operation with rated performance/speed.

• All data are transferred to the control centre.

The updating time on the operator station under normal and calm/worst conditions in the station shall be:

Function   Response Time

From Selection of object to picture colour change form object   < 1 Sec.

Command Execute < 1 Sec.

Display of binary change   < 0.5 Sec.

Display of Analog Value Change <1 Sec.

System Display with 100 variables   Max.3 Sec.

Times taken to report the last of 50 simultaneous alarms   Max. 5 Sec.

Updating Database < 1 Sec.

H. Duty cycle time

a.   Under worst loading condition processor shall have

1.   40 % free time when measured over any two second period

2.   60% free time when measured over any one minute period

b.   Substation network spare time

50 % spare time when measured over any two second period during worst case loading conditions.

Bidder shall furnish necessary data to fully satisfy employer that processor spare duty cycle figures quoted by the bidder are realistic and based on configuration and computational capability of the offered system and these shall be actually implemented system as commissioned at project site.

XIX. System Operation

1. Substation Operation

a. Normal Operation

Operation of the system by the operator from the MCC or at the substation shall take place via industry standard HMI (Human Machine interface) subsystem consisting of graphic colour VDU, a standard keyboard and a cursor positioning device (mouse).

The coloured screen shall be divided into 3 fields:

i)   Message field with display of present time and date

ii)   Display field for single line diagrams

iii)   Navigation bar with alarm/condition indication

For display of alarm annunciation, lists of events etc a separate HMI View node shall be provided.

All operations shall be performed with mouse and/or a minimum number of function keys and cursor keys. The function keys shall have different meanings depending on the operation. The operator shall see the relevant meanings as function tests displayed in the command field (i.e. operator prompting). For control actions, the switchgear (i.e. circuit breaker etc.) requested shall be selectable on the display by means of the cursor keys.

The switching element selected shall then appear on the background that shall be flashing in a different color. The operator prompting shall distinguish between:

Prompting of indications e.g. fault indications in the switchgear, and prompting of operational sequences e.g. execution of switching operations.

The summary information displayed in the message field shall give a rapid display of alarm/message of the system in which a fault has occurred and alarm annunciation lists in which the fault is described more fully.

Each operational sequence shall be divided into single operation steps which are initiated by means of the function keys/WINDOW command by mouse. Operator prompting shall be designed in such a manner that only the permissible keys are available in the command field related to the specific operation step. Only those switching elements shall be accessed for which control actions are possible. If the operation step is rejected by the system, the operator prompting shall be supported by additional comments in the message field. The operation status shall be reset to the corresponding preceding step in the operation sequence by pressing one of the function keys. All operations shall be verified. Incorrect operations shall be indicated by comments in the message field and must not be executed.

The offer shall include a comprehensive description of the system. The above operation shall also be possible via WINDOWS based system by mouse.

XX. Power Supply

Power for the substation automation system shall be derived UPS. Inverter of suitable capacity shall be provided for station HMIs, DR work station, Gateways and its peripheral devices e.g. printers etc. There must be redundant Inverter to feed power in case of one inverter fails. In case of failure of one Inverter supply should automatically switched over to second one. In the event of total Power failure, necessary safeguard software shall be built for proper shutdown and restart.

XXII. Documentation

The following documents shall be submitted for employer's approval during detailed engineering:

(a)   System Architecture Drawing

(b)   Hardware Specification

(c)   Sizing Calculations of various components

(d)   Response Time Calculation

(e)   Functional Design Document

The following documentation to be provided for the system in the course of the project shall be consistent, CAD supported.

☐   List of Drawings.

☐   Substation automation system architecture.

☐   Block Diagram.

☐   Guaranteed technical parameters, Functional Design Specification and guaranteedavailability and reliability.

☐   Calculation for power supply dimensioning.

☐   I/O Signal lists.

☐   Schematic diagrams.

☐   List of Apparatus.

☐   List of Labels.

☐   Logic Diagram (hardware & software).

☐   Control Room Lay-out.

☐   Test Specification for Factory Acceptance Test (FAT).

☐   Product Manuals.

☐   Assembly Drawing.

☐   Operator's Manual.

    ☐   Complete documentation of implemented protocols between various elements.

    ☐   Listing of software and loadable in CD ROM.

Other documents as may be required during detailed engineering.

Two sets of hard copy and four sets of CD ROM containing all the as built documents/drawings shall be provided.

XXII. GUARNTEE.

The availability for the complete SAS shall be guaranteed by the Manufacturer. Bidder shall include in their offer the detailed calculation for the availability. The contractor shall demonstrate their availability guaranteed by conducting the availability test on the total sub-station automation system as a whole after commissioning of total Sub-station Automation system. The test shall verify the reliability and integrity of all sub-systems. Under these conditions the test shall establish an overall availability of 99.98%. After the lapse of 1000 Hours of cumulative test time, test records shall be examined to determine the conformance with availability criterion. In case of any outage during the availability test, the contractor/ Manufacturer shall rectify the problem and after rectification, the 1000 Hours period start after such rectification. If test object has not been met the test shall continue until the specified availability is achieved.

The contractor/Manufacturerhas to establish the availability in a maximum period of three months from the date of commencement of the availability test.

After the satisfactory conclusion of test both contractor and employer shall mutually agree to the test results and if these results satisfy the availability criterion, the test is considered to be completed successfully. After that the system shall be taken over by the employer and then the guarantee period shall start.

The SAS supplied under this specification shall be designed and constructed to meet all specification requirements for 15 years. Further the bidder/Manufacturer should support for hardware and software for 15 (fifteen) years to guard against obsolescence. SAS equipment or components that cannot meet this life expectancy or specified design and operational requirement or likely to become obsolete during entire service life shall be identified and their expected failure rate/obsolescence period with corrective action shall be indicated by the bidder in his proposal. Otherwise SAS shall be deemed to be suitable for above requirements. All requirements/devices not listed

under recommended spares shall have a normal expectancy exceeding the specified expected life of SAS

XXIII. TRAINING, SUPPORT SERVICES, MAINTENANCE AND SPARES

A. TRAINING

The contractor/ Manufacturer shall impart training for two batches of engineers of OPTCL on the topics of SAS as listed below .

1. SAS Computer System Hardware Course

A SAS computer system hardware course shall be offered, but at the system level only. The training course shall be designed to give Employer hardware personnel sufficient knowledge of the overall design and operation of the system so that they can correct obvious problems, configure the hardware, perform preventive maintenance, run diagnostic programs, and communicate with contract maintenance personnel. The following subjects shall be covered:

a.   System Hardware Overview: Configuration of the system hardware.

b. Equipment Maintenance: Basic theory of operation, maintenance techniques and diagnostic procedures for each element of the computer system, e.g., processors, auxiliary memories, LANs, routers and printers. Configuration of all the hardware equipments.

c.   System Expansion: Techniques and procedures to expand and add equipment such as loggers, monitors, and communication channels.

d.   System Maintenance: Theory of operation and maintenance of the redundant hardware configuration, failover hardware, configuration control panels, and failover switches. Maintenance of protective devices and power supplies.

e.   Subsystem Maintenance: Theory of design and operation, maintenance techniques and practices, diagnostic procedures, and (where applicable) expansion techniques and procedures. Classes shall include hands-on training for the specific subsystems that are part of Employer's equipment or part of similarly designed and configured subsystems. All interfaces to the computing equipment shall be taught in detail.

f.   Operational Training: Practical training on preventive and corrective maintenance of all equipment, including use of special tools and instruments. This training shall be provided on Employer equipment, or on similarly configured systems.

2. SAS Computer System Software Course

The Contractor/ Manufacturer shall provide a computer system software course that covers the following subjects:

a.   System Programming: Including all applicable programming languages and all stand-alone service and utility packages provided with the system. An introduction to software architecture, Effect of tuning parameters (OS software, Network software, database software etc.) on the performance of the system.

b.   Operating System: Including the user aspects of the operating system, such as program loading and integrating procedures; scheduling, management, service, and utility functions; and system expansion techniques and procedures.

c.   System Initialization and Failover: Including design, theory of operation, and practice

d.   Diagnostics: Including the execution of diagnostic procedures and the interpretation of diagnostic outputs,

e. Software Documentation: Orientation in the organization and use of system software documentation.

f. Hands-on Training: One week, with allocated computer time for trainee performance of unstructured exercises and with the course instructor available for assistance as necessary.

3. SAS Application Software Course:

The Contractor shall provide a comprehensive application software courses covering all applications including the database and display building course. The training shall include:

a. Overview: Block diagrams of the application software and data flows. Programming standards and program interface conventions.

b. Application Functions: Functional capabilities, design, and major algorithms. Associated maintenance and expansion techniques.

c. Software Development: Techniques and conventions to be used for the preparation and integration of new software functions.

d. Software Generation: Generation of application software from source code and associated software configuration control procedures.

e. Software Documentation: Orientation in the organization and use of functional and detailed design documentation and of programmer and user manuals.

f. Hands-on Training: One week, with allocated computer time for trainee performance of unstructured exercises and with the course instructor available for assistance as necessary.

B. MAINTENANCE

Maintenance Responsibility during the Guaranteed Availability Period. During guaranteed Availability Period, the Contractor shall take continual actions to ensure the guaranteed availability and shall make available all the necessary resources such as specialist personnel, spare parts, tools, test devices etc. for replacement or repair of all defective parts and shall have prime responsibility for keeping the system operational.

C. Reliability and availability.

The SAS shall be designed so that the failure of any single component, processor, or device shall not render the system unavailable. Each component and equipment offered by the bidder shall be of established reliability. The minimum target reliability of each piece or equipment like each electronic module/card Power supply, Peripherals etc. shall be established by bidder considering its failure rates/mean time between failures (MTBF), meantime to repair (MTTR), such that the availability of complete system is assured. The guaranteed annual system availability shall not be less that 99.9%. This shall be supported by detailed calculation according to availability calculations specified in IEEE standard –1046 or equivalent. This shall be submitted by bidder along with offer. The SAS shall be designed to satisfy the very high demands for reliability and availability concerning:

i.   Mechanical and electrical design

ii.   Security against electrical interference (EMI)

iii.   High quality components and boards

iv.   Modular, well-tested hardware

v.   Thoroughly developed and tested modular software

vi.   Easy-to-understand programming language for application programming

vii.   Detailed graphical documentation and application software

viii.   Built-in supervision and diagnostic functions

ix.   Security

x.   Experience of security requirements

xi.   Process know-how

xii.   Select before execute at operation

xiii.   Process status representation as double indications

xiv.   Distributed solution

xv.   Independent units connected to the local area network

xvi.   Back-up functions

xvii.   Panel design appropriate to the harsh electrical environment and ambient

xviii. conditions

xix.   Panel grounding immune against transient ground potential rise

Outage terms

i. Outage: The state in which substation automation system or a unit of SAS is unavailable for Normal Operation due to an event directly related to the SAS or unit of SAS. In the event, the owner has taken any equipment/ systems other than Sub-station Automation System for schedule/forced maintenance, the consequent outage to SAS shall not be considered as outage for the purpose of availability.

ii. Actual outage duration (AOD)

The time elapsed in hours between the start and the end of an outage. The time shall be counted to the nearest 1/4th of an hour. Time less than 1/4th of an hour shall be counted as having duration of 1/4th of an hour.

iii. Period Hours (PH)

The number of hours in the reporting period. In a full year the period hour are 8760h (8784h for a leap year).

iv. Actual Outage hours (AOH)

The sum of actual outage duration within the reporting period AOH = S AOD

v. Availability:

Each SAS shall have a total availability of 99.98 % i.e. the ratio of total time duration minus the actual outage duration to total time duration.

D. SPARES:

The contractor shall make a list of spares which may be required for ensuring the guaranteed availability of the system. The contractor should keep the same at site for free replacement during the guaranteed period. Further, the contractor shall make a list of spares for running the system with guaranteed availability beyond the guaranteed period. The said spares list shall form the part of scope of supply and accordingly the price thereof shall be quoted by the bidder and shall be considered.

All consumables such as paper, cartridges shall be supplied by the contractor till the SAS is taken over by the owner.

XXIV. ADDITIONAL REQUIRED DESIGN CHARACTERISTICS OF THE SUBSTATION AUTOMATION SYSTEM FOR THE EHV SUBSTATION

1. All wording appearing on the VDU with regard the single line diagrams of the ehv substation shall be in English language.

2. Care shall be taken so that the system can be expanded in the future, if needed.

3. The database, after it has been created, will be delivered on CD-ROMs.

4. Due to IEC-61850 communication protocol implementation, the following should be applied:

4.1 For all "functions" within the substation, an object oriented data model will be provided grouping the data into the smallest possible independent functions named Logical Nodes (LN). Entire functionality of S.A.S split into LNs.

The LNs and all data attributes contained therein will be named according to standardised "semantic". The Substation Configuration Language used to configure the S.A.S and individual IEDs is the SCL language.

4.2   Complete S.A.S will be formally documented within SCL especially through SCD (Substation Configuration Description) files.

The SCD files will ensure that all system engineering work has been recorded for re-use in future adaptations, extensions and refurbishment of the S.A.S. The SCD files is part of the documentation that PPC will receive with the delivery of the System.

ANNEXURE-I

DATA ON EXPERIENCE

[a]   Name of the manufacturer.

[b]   Standing of the firm as manufacturer of equipment quoted.

[c]   Description of equipment similar to that quoted [supplied and installed during the last two years with the name of the organizations to whom supply was made].

[d]   Details as to where installed etc.

[e]   Testing facilities at manufacturer's works.

[f]   If the manufacturer is having collaboration with another firm, details regarding the same and present status.

[g]   A list of purchase orders, executed during last three years.

[h]   A list of similar equipments of specified MVA rating, voltage class, Impulse level, short circuit rating, Designed, manufactured, tested and commissioned which are in successful operation for at least two years from the date of commissioning with legible user's certificate. User's full complete postal address/fax/phone must be indicated.

Place:

Date:

Signature of tenderer

Name, Designation, Seal

ANNEXURE-II

SCHEDULE OF INSTALLATIONS.

Rated MVA	Rated Voltage	Place of installation and complete postal address	Year of commissioning

Place: -

Date   Signature of Tenderer:

                                                              Name, Designation, Seal

PROTECTION PANELS

1.0 Panels

General

Simplex panels shall be provided to suite the substations site. Panels shall be free standing mounted on floors fitted with embedded channels, insert plates or foundation bolts. The panels shall be made vibration and shock proof by providing anti vibration strips. The base frame of all panels shall have a smooth bearing surface such that when fixed on the embedded foundation channels/insert plates it shall be free standing and provide a level surface. The panels shall be completely metal enclosed, dust, moisture and vermin proof. The enclosure shall provide a degree of protection not less than IP-31 in accordance with IS 13947.The design, materials selection and workmanship shall be such that it provides a neat appearance both inside and outside without signs of welds, rivets or bolt heads from outside. The exterior surfaces shall be smooth and sleek. The panels of modern modular construction in 19 inch hinged racks would also be acceptable. Cable entry to the panels shall be from the bottom. The provision of all cable glands and shrouds of the panel shall be part of the scope of supply. Cable gland plate fitted on the bottom of the panel shall be connected to earthing of the panel/station through a flexible braided copper conductor.

Bidder shall be fully responsible for his bids to match the dimensions, colour and fittings with those in the existing control rooms where the extensions are required. In no case any proposal for increase in price at a later date shall be entertained by the Employer. However, panels not matching those already installed may be acceptable & only after Specific approvals will be required on a case by case basis

1.1 Simplex Panel

Simplex panels shall be provided with equipment mounted on front panel vertically. The wiring access shall be from rear for control panels and either from front or rear for relay panels. Where panel width is more than 800 mm, double leafed doors shall be provided. Doors shall be fitted with either built-in locking facility or with padlock.

1.2 Constructional Features

It is the responsibility of the Contractor to ensure that the equipment specified and such unspecified complementary equipment required for completeness of the protective/control schemes can be properly accommodated in the panels without congestion. Panels shall be free standing, floor mounting type and shall comprise of structural frames completely enclosed with smooth finished, cold rolled sheet steel of thickness not less than 3 mm for all weight bearing members such as base frame, front panel, door frames. All other parts may be provided with 3.0 mm thick steel sheet. There shall be sufficient reinforcement to provide level surfaces, resistance to vibration and rigidity during transportation and installation. All doors, removable covers and panels shall be gasketted all around with neoprene or superior material. Ventilating louvres, where provided shall have screens and filters. The screens shall be made of either brass or GI wire mesh.

1.3 Mounting

All equipment on and in panels shall be mounted and completely wired to the terminal blocks ready for external connections. The equipment on front of panel shall be mounted flush. Equipment shall be mounted such that removal and replacement can be accomplished individually without interruption of service to adjacent devices. Equipment shall be readily accessible without use of special tools. Terminal marking on the equipment shall be clearly visible. The Contractor shall carry out cut-out, mounting and wiring of all equipment and items

which are to be mounted in his panel. Cut-outs if any, provided for future mounting of equipment shall be properly blanked off with blanking plates. The center lines of switches, push buttons and indicating lamps shall be not less than 750 mm from the bottom of the panel. The center lines of relays, meters and recorders shall be not less than 450 mm from the bottom of the panel. The center lines of switches, push buttons and indicating lamps shall be matched to give a neat and uniform appearance. The top lines of all meters, relays and recorders etc. shall be matched. No equipment shall be mounted on the doors. All the equipment connections and cabling shall be designed and arranged to minimise the risk of fire and damage which may be caused by fire.

1.4 Terminal Blocks
Terminal blocks and boards shall conform to the requirements of the relevant sections of this Specification. De-link type terminal blocks shall be provided in all the circuits and Terminals.

1.5 Supporting steel
All necessary embedded levelling steel, sills, anchor bolts, channels and other parts for supporting and fastenings the panels and vibration damping shall be supplied by the Contractor.

1.6 Panel internal wiring

Panels shall be supplied complete with interconnecting wiring provided between all electrical devices mounted and wired in the panels and between the devices and terminal blocks for the devices to be connected to equipment outside the panels. When panels are arranged to be located adjacent to each other all inter panel wiring and connections between the panels shall be furnished and the wiring shall be carried out internally. All wiring shall be carried out with 1100V grade, single core, stranded copper conductor wires with PVC (with FRLS) insulation. The minimum size of the multi-stranded copper conductor used for internal wiring shall be as follows.

a) All CT/ CVT/VT circuits shall be using 2.5 sq. mm lead.

b) All other circuits shall be using 2.5 sq. mm lead

All internal wiring shall be securely supported, neatly arranged, readily accessible and connected to equipment terminals and terminal blocks. Wiring gutters & troughs shall be used for this purpose. Auxiliary bus wiring for AC and DC supplies, voltage transformer circuits, annunciation circuits and other common services shall be provided near the top of the panels running throughout the entire length of the panels. Wire germination shall be made with solder less crimping type and tinned copper lugs, which firmly grip the conductor. Insulated sleeves shall be provided at all the wire terminations. Engraved core identification plastic ferrules marked to correspond with panel wiring diagram shall be fitted at both ends of each wire. Ferrules shall fit tightly on the wire and shall not fall off when the wire is disconnected from terminal blocks. All wires directly connected to trip circuit breaker or device shall be distinguished by the addition of red coloured unlettered ferrule. Longitudinal troughs extending throughout the full length of the panel shall be preferred for inter panel wiring. Inter-connections to adjacent panel shall be brought out to a separate set of terminal blocks located near the slots of holes meant for taking the inter-connecting wires. Contractor shall be solely responsible for the completeness and correctness of the internal wiring and for the proper functioning of the connected equipments.
All wiring shall be switch board type single flexible conductor tinned annealed copper wire insulated with varnished cambric, faulted asbestos, single braided cotton cover painted overall with flame proof moisture resistant paint and suitable for 660 volt service or equivalent polyncychloride insulation which has proved its utility in tropical regions against hot and moist climate and vermin (Misc. white ants and cockroaches etc) Rubber insulated wiring will not be accepted. The sizes of wiring in different circuits shall not be less than those specified below

The following colour scheme shall be used for the wiring.

Circuit where use. Colour of wire and ferrule.

Red phase of instrument transformer circuit: Red.
Yellow phase of instrument transformer: Yellow.
Blue phase of instrument transformer circuits: Blue.
Neutral connections earthed or not earthed in the instrument transformer circuit: Green.
A.C. Control wiring circuits using D.C. supply: Grey

Wiring connected to the space heaters in the cubicles shall have porcelain braided insulation over a safe length from the heater terminals.

Each wire shall be continuous from end to end without having any joint within itself. Individual wires shall be connected only at the connection terminals or studs of the terminal blocks, meters, relays, instruments and other switchboard devices.

Terminal ends of all wires shall be provided with numbered ferrules suitable coloured for phase identification. At point of inter/connection where a change of number is necessary, duplicate ferrules shall be provided with the appropriate numbers on the changing end.

At the terminal connection, washers shall be interposed between terminals, wire terminals and the holding nuts. All holding nuts shall be secured by locking nuts. The connection stud shall project at least 6 mm. from the lock nut surface.

Wire ends shall be so connected at the terminal studs that no wire terminal number ferruled gets masked due to succeeding connections. All wires shall be suitable for bending to meet the terminal stud at rectangles with the stud axis, and they shall not be skewed.

All studs, nuts, bolts, scores, etc. shall be threaded according to the British Standard practice unless Employer's prior approval to any other practice of threading is obtained. Spare quantities of nuts, lock nuts and washers of all varieties used on the panel board shall be supplied to the extent of 10% of the used quantities.

1.7 TERMINAL BLOCKS

All the terminal blocks to be used in the panel shall be provided with 1100V grade stud type terminal block of Polyamide material of **Phoinex/Elmex / Connectwell**. At least 20% spare terminals shall be provided.

(i) All internal wiring to be connected to external equipment shall terminate on terminal blocks. Disconnecting type Terminal blocks shall be 1100 V grade and have 20 Amps. Continuous rating, molded piece, complete with insulated barriers, stud type terminals, washers, nuts and lock nuts, Markings on the terminal blocks shall correspond to wire number and terminal numbers on the wiring diagrams. All terminal blocks shall have shrouding with transparent unbreakable material. Terminal Block connectors built from cells of moulded dielectric and brass stud inserts shall be provided for terminating the outgoing ends of the cubicle wiring and the corresponding incoming tail ends of the control cables. All the terminal connectors shall have de-link (disconnecting) facilities.

(ii) Disconnecting type terminal blocks for current transformer and voltage transformer secondary leads shall be provided. Also current transformer secondary leads shall be provided with short-circuiting and earthling facilities.

(iii) At least 20% spare terminals shall be provided on each panel and these spare terminals shall be uniformly distributed on all terminal blocks.

(iv) Unless otherwise specified, terminal blocks shall be suitable for connecting the following conductors of external cable on each side.

(v) There shall be a minimum clearance of 250mm between the first row of terminal blocks and the associated cable gland plate or panel sidewall. Also the clearance between two rows of terminal blocks edges shall be minimum of 150mm

(vi) Arrangement of the terminal block assemblies and the wiring channel within the enclosure shall be such that a row of terminal blocks is run in parallels and close proximity along each side of the wiring duct to provide for convenient attachment of internal panel wiring. The side of the terminal block opposite the wiring duct shall be reserved for the owner's external cable connections. All adjacent terminal blocks shall also share this field-wiring corridor. All wiring shall be provided with adequate support inside the panels to hold them firmly and to enable free and flexible termination without causing strain on terminals.

(vii) The number and sizes of the Owner's multi core incoming external cables will be furnished to the contractor after placement of the order. All necessary cable-terminating accessories such as gland plates, supporting clamps & brackets, wiring troughs and gutters etc. (except glands & lugs) for external cables shall be provided.

1.8 SPACE FOR CONTROL CABLES AND CABLE GLANDS

Sufficient space for receiving the control cables inside the board at the bottom of the cubicles and mounting arrangement for the terminal cable glands shall be provided. The specification does not cover supply of control cables and cable glands for which the employer will make separate arrangement.

1.9 SPACE HEATERS

60 W. 240 V. 50 HZ tubular space heaters with thermostat auto suitable for connection to the single phase AC supply complete with on-off switches located at convenient positions shall be provided at the bottom of the switch board cubicle to prevent condensation of moisture. The watt loss per unit surface of heater shall be low enough to keep surface temperature well below sensible heat.

2.0 DISTRIBUTION AND CONTROL OF AUXILIARY POWER CIRCUIT

2.1 D.C. CIRCUIT

There shall be separate D.C. supply source from the main DCDB to be connected to each panel. The incoming DC supply sources (source I and source II) circuits in the panel shall be controlled by the two pole DC MCB's as incoming to the panels and the sub circuits shall be controlled by HRC fuses of different circuits having both "+" ve and "-" ve control. A continuous D.C. bus shall be provided in the panel for control, protection, supervision and indication circuit and other equipments shall be teed off in each panel from D.C. bus through a set of HRC Fuse (both on +ve and –ve side) D.C. supply to individual panel thus teed off shall be distributed within the panel as below.

2.2 SWITCHES & FUSES:

Each panel shall be provided with necessary arrangement for receiving, distributing and isolating of DC and AC supplies for various control, signaling, lighting and space heater circuits. The incoming and sub-circuits shall be separately provided with fuses. The selection of the main and sub circuit fuses rating shall be such as to ensure selective clearance of sub-circuit faults. Voltage transformer circuits for relaying and metering shall be protected by fuses. All fuses shall be HRC catridge type confirming to IS: 3703 mounted on plug in type fuse bases. The short time fuse rating of fuses shall be not less than 9 KA. Fuse carrier base shall have imprints of the fuse rating and voltage.

DC supply source1 & 2 supervision SCADA compatibility relays are to be mounted in the panel. Provision of DC illumination lamp with switch to be provided in each panel.

2.3 A.C. CIRCUIT

240 volts, single phase, A.C. auxiliary supply to the control and relay board will be fed from A.C. distribution board through a suitable fuse switch provided thereof. A continuous A.C. bus shall be provided the panel where from A.C. supply to each panel shall be teed off through a set of links. One 16 Amp rated M.C.B. shall be provided for the incoming A.C. supply. A set of fuse and link rated for 6 amps for 3 pin plug circuit, 6 amps for 2 pin ply circuit and 6 amps for heater and illuminating lamp circuits shall also be provided.
AC supply supervision SCADA compatibility relays are to be mounted in the panel.

2.4 TEST BLOCKS

Switchboard type, back connected, test blocks with contacts shall be provided with links or other devices for shorting terminals of C.T. leads before interrupting testing instruments in the circuit without causing open circuit of the C.T. The potential testing studs shall preferably be housed in narrow recesses of the, block molding insulation to prevent accidental short-circuit across the studs. All Test Blocks for meters, relays, etc. shall be placed as close to the respective equipment as possible.

2.5 SAFETY EARTHING FOR THE PANEL

All panels shall be equipped with an earth bus securely fixed. Location of earth bus shall ensure no radiation interference for earth system under various switching conditions of isolators and breakers. The materials and size of the bus shall be at least 25X6 sq.mm perforated copper threaded holes at gap of 50mm with a provision of bolts and nuts for connection with cable armours and mounted equipment etc for effective earthing. When several panels are mounted adjoining each other, the earth bus shall be made continuous and necessary connectors and clamps for this purpose shall be included in the scope of supply. Provision shall be made for extending the earth bus bars to future adjoining panels on either side.

Provision shall be made on each bus bar of the end panels for connecting substation earth grid. Necessary clamps and connectors shall be included in the scope of contract.

All metallic case of the relays, instruments and other panel mounted equipment including gland plate shall be connected to the earth bus by copper wires of size not less than 2.5 sq mm.The colour code of earthing shall be green.

Looping of earth connections, which would result in loss of earth connections to other devices when loop is broken shall not be permitted. However looping of earth connections between equipment to provide alternative path to earth bus shall be provided.

VT and CT secondary neutral or common lead shall be earthed at one place only at the terminal blocks where they enter the panel. Such earthing shall be made through links so that earthing may be removed from one group without disturbing the continuity of earthing syatem for other groups.

2.6 PANEL BOARD LIGHTING

The panel interior shall be illuminated by 20W, CFL tube light connected to 240 V. single phase A.C. The illumination of the interior shall be free from hand shadows and shall be planned to avoid any strain or fatigue to the fireman likely to be caused due to subnormal or non-uniform illumination. One emergency D.C. light (CFL type) shall also be provided for each relay panel with individual switch, with proper identification mark.

A door operated button switch shall be provided for control of the A.C. lighting for all the control and relay panel interiors.

One 5 amps. two pin socket and one 15 amps. 3 pin power socket outlets together with plugs shall be provided at convenient points in the panel board for A.C. supply.

3.0 Relays

General

The Numerical Relays in general shall comply with the following requirements:

1. All relays shall conform to the requirements of IS: 3231/IEC60255/IEC 61000 or other applicable standards. Relays shall be suitable for flush or semiflush mounting on the front with connections from the rear.

2. The offered relays shall be completely numerical.
- The communication protocol shall be as per IEC 61850 & IEC60870-5-103
- The test levels of EMI as indicated in IEC 61850 shall be applicable to these relays.
- Protection elements should be realised using software algorithm.
- Hardware based measurement shall not be acceptable.
3. The relay shall be provided with both 1A and 5A CT inputs and shall be selectable at site.
4. It shall be possible to energise the relay from either AC or DC auxiliary supply.

5. The offered relay shall have a comprehensive local MMI for interface. It shall have the following minimum elements so that the features of the relay can be accessed and setting changes can be done locally.

- At least 48 character alphanumeric backlit LCD display unit Fixed LEDs (for trip, Alarm, Relay available & Relay out of service) & programmable LEDs which can be assigned to Tactile keypad for browsing and setting the relay menu and protection function for local annunciation.

6. The minimum pickup voltage of relay for 220 V DC systems must be 176 V for binary input in order to prevent pick up during DC earth fault condition.

7. The relays supplied should be compatible to redundant communication architecture, shall be complied with the IEC 62439-3 standards of parallel redundancy protocol (PRP).

8. The relays provided should be complied with the international standards of NERC CIP for cyber security to provide protection against unauthorized disclosure, transfer, modification, or destruction of information and/or information systems, whether accidental or intentional.

9. All PCB used in relays should have harsh environmental coating as per standard IEC 60068 (HEC) to increase the particle repellency and thereby increasing the life of relay.

10. The offered relays shall be completely numerical and should comply to IEC 61850 protocol. The relay must support following requirements for communication ports and protocols,

- The relays shall generate GOOSE messages as per IEC 61850 standards for interlocking and also to ensure interoperability with third party relays.
- The relay must have front RS232/USB/RJ45 port for local communication with the device
- The communication protocol shall be as per IEC 61850
- The relay should be compatible to redundant communication architecture and shall be complied with IEC 62439-3 standards of parallel redundancy protocol (PRP)
- The relays shall generate GOOSE messages as per IEC 61850 standards for interlocking and also to ensure interoperability with third party relays.
- Necessary user friendly configuration tool shall be provided to configure the relays. It should be compatible with SCL/SCD files generated by a third party system.
- GOOSE signals shall be freely configurable for any kind of signals using graphic tool/user friendly software.
- The offered relay must support at least 4 no's or more of 61850 clients
- The relay must support time synchronization through SNTP/IRIG B demodulated.
- The relays provided should be complied with the international standards of NERC CIP for cyber security to provide protection against unauthorized disclosure, transfer, modification, or destruction of information and/or information systems, whether accidental or intentional.
- The relay settings shall be provided with adequate password protection. The password of the relay should be of 4 character upper case text to provide security to setting parameter.

11. The relays shall have the following tools for fault diagnostics

- Fault record – The relay shall have the facility to store at least 5 last fault records with information on cause of trip, date, time, trip values of electrical parameters.
- Event record – The relay shall have the facility to store at least 200 time stamped event records with 1ms resolution.
- Disturbance records – The relay shall have capacity to store the waveforms for a minimum duration of at least 5 secs with settable pre and post fault duration times at a minimum sampling rate of 800 Hz or Higher.
- Except for differential protection the disturbance recorder must have capability to capture at least 8 analogue channels (IA, IB, IC, IN, VA, VB, VC, and VN) and 15 digital channels (start of protection element, trip of protection element, binary input, trip output etc) selectable at site.
- For differential protection relay, the disturbance recorder must have capability to capture

at least 15 analogue channels and 30 digital channels.

- Necessary software shall be provided for retrieving and analyzing the records.

12. The relay settings shall be provided with adequate password protection. The password of the relay should be of 4 character upper case text to provide security to setting parameter

13. The relay shall have comprehensive self-diagnostic feature. This feature shall continuously monitor the healthiness of all the hardware and software elements of the relay. Any failure detected shall be annunciated through a output watchdog contact. The fault diagnosis information shall be displayed on the LCD and also through the communication port.

14. The Numerical Relays shall be provided with 1 Set of common support software compatible with both Windows 7 and higher which will allow easy settings of relays in addition to uploading of event, fault, disturbance records, and measurements.

- The relay settings shall also be changed from local or remote using the same software.
- Additional functions can be added to relay by software upgradation and downloading this upgraded software to the relays by simple communication through PC.

15. All protective relays shall be in draw out or plugin type/modular cases with proper testing facilities. Necessary test plugs/test handles shall be supplied loose and shall be included in contractor's scope of supply.

16. All AC operated relays shall be suitable for operation at 50 Hz. AC Voltage operated relays shall be suitable for 110 Volts VT secondary and current operated relays for 1 amp CT secondary. All DC operated relays and timers shall be designed for the DC voltage specified, and shall operate satisfactorily between 80% and 110% of rated voltage. Voltage operated relays shall have adequate thermal capacity for continuous operation.

17. The protective relays shall be suitable for efficient and reliable operation of the protection scheme described in the specification .Necessary auxiliary relays and timers required for interlocking schemes for multiplying of contacts suiting contact duties of protective relays and monitoring of control supplies and circuits, lockout relay monitoring circuits etc. also required for the complete protection schemes described in the specification shall be provided. All protective relays shall be provided with at least two pairs of potential free isolated output contacts. Auxiliary relays and timers shall have pairs of contacts as required to complete the scheme; contacts shall be silver faced with spring action. Relay case shall have adequate number of terminals for making potential free external connections to the relay coils and contacts, including spare contacts.

18. Timers shall be of solid state type. Time delay in terms of milliseconds obtained by the external capacitor resistor combination is not preferred and shall be avoided.

a. No control relay, which shall trip the power circuit breaker when the relay is deenergised, shall be employed in the circuits.
b. Provision shall be made for easy isolation of trip circuits of each relay for the purpose of testing and maintenance.
c. Auxiliary seal in units provided on the protective relays shall preferably be of shunt reinforcement type.
d. The setting ranges of the relays offered, if different from the ones specified shall also be acceptable if they meet the functional requirements.

19. Any alternative/additional protections or relays considered necessary for providing complete effective and reliable protection shall also be offered separately. The acceptance of this alternative/ additional equipment shall lie with the OPTCL

20. The relay must be able to continuously measure following parameters with a typical

accuracy of ± 1%.

- Current (0.05 to 3 In) +/- 1.5% of reading,
- Voltage (0.05 to 2 Vn) +/- 1.0% of reading
- Frequency (40 to 70 Hz) +/- 0.03 Hz
- Phase 0° to 360° +/- 5.0%
- Power (W) +/- 5.0% of reading at unity power factor
- Reactive power (VARS) +/- 5.0% of reading at zero power factor
- Apparent power (VA) +/- 5.0% of reading

4.0 PROTECTION SYSTEM

4.1 PROTECTIVE SYSTEM

4.1.1 Protection discrimination

On the occurrence of a fault on the power system network the high speed discriminating protection systems (main protection) shall rapidly detect the fault and initiate the opening of only those circuit breakers which are necessary to disconnect the faulted electrical element from the network. Protection equipment associated with adjacent electrical elements may detect the fault, but must be able to discriminate between an external fault and a fault on the electrical element which it is designed to protect. Sequential time delayed tripping is not permitted except in the following specific circumstances:

- Protection for short connections between post current transformer housings and circuit breakers when the technical advantages of complete overlapping of the protection are outweighed by economic considerations, (i.e. short-zone protection)

- Operation of time graded back-up protection takes place as a result of either the complete failure of the communication links associated with the main protection systems, or the fault resistance is substantially greater than a value which can be detected by main protection systems.

- Operation of line back-up protection to disconnect primary system faults in the case of a circuit breaker failing to operate, (i.e. circuit breaker failure protection)

- All back-up protection systems shall be able to discriminate with main protection systems, circuit breaker fail protection and with other back-up protection systems installed elsewhere on the transmission system.

4.1.2 Protection settings

A list of the settings to be applied to all protection systems together with all associated calculations, shall be provided for review and approval not less than three months prior to the first programmed date for commissioning. The settings for line protection shall be such as to permit correct operation of the protection for earth faults with up to 100 ohms fault resistance. Any limitations imposed on the power system as a result of the settings proposed shall be explicitly stated. In the absence of system data required for calculation purposes, assumptions may be made providing these are clearly identified as such in the relevant calculations.

4.1.3 Fault clearing time

The protection equipment shall be capable of achieving the following discriminative fault clearing times, inclusive of circuit breaker and signaling times:

- One millisecond for all electrical elements whose boundary connections are defined by circuit breakers located within a given substation.

- For interconnecting tie lines in which the boundary connections of the electrical element being protected are defined by circuit breakers located in adjacent switching stations, an additional 20 ms fault clearance time is allowed at the substation remote from the fault point. This additional fault clearance time is permitted subject to the requirement that the positive sequence impedance of the primary circuit from the switching terminal to the point of fault shall not be less than ten ohms.

The Contractor shall supply the Project Manager with details of the operating times under defined conditions of all protection equipment proposed. Any limitation in operating time performance shall be declared by the Contractor, e.g. end of zone faults where distance protection is applied, high resistance faults, faults at high X/R with significant DC component and time constant, faults coincident with communication channel noise. The Contractor shall specify the increase in operating time which could occur under such conditions.

4.1.4 Signaling equipment operating times:

For design purposes the operating times of signaling equipment to provide a contact signal for use with associated distance protection shall be assumed to be as follows:

- Intercropping (transfer trip) not greater than: 20 milliseconds

- Permissive transfer trip: 15 to 20 milliseconds

- Blocking signal operate time: 10 milliseconds

- Blocking signal reset time: 10 milliseconds

4.2 PROTECTION SCHEMES

4.2.1 Line protection

General requirement for line protection relays:

The line protection relays shall protect the line and clear faults on line in the shortest possible time with reliability, selectivity and full sensitivity to all types of line fault. The general concept for

1. 400kV and 220kV levels is to have primary and back-up protection systems having equal performance requirement especially in respect of time as would be provided by two Main protections called **Main-I** and **Main-II.** It is desirable that Main-I and Main-II protection should work on two different principles of operation and one back up dir O/C & E/F protn is envisaged.

2. For 132 kV level the concept of one main distance protection and one backup directional O/C and E/F protection is envisaged.

3. For 33 kV level, the requirement is that of modular directional O/C and E/F protection.
    The protection requirements are summarised below, and illustrated in the single line diagrams in the schedules.

- #### 400kV and 220kV lines

  - Main I Numerical non switched distance protection meeting performance levels.

  - Main II Numerical non switched phase comparison, carrier aided or of numerical distance using a different principle of operation

  - Phase segregated tele protection facility

  - Power swing detection blocking and tripping

  - Synchronizing.

  - Line overvoltage (Only for 400kV and 220kV line □ 200kM long)

  - Autoreclosure

- • Numerical directional overcurrent and earth fault
- • Three phase to ground
- • Numerical local breaker back up
- • Pole discrepancy protection

4.2.2 Distance Protection Relay

a. The IEC 60255-121 standard "Functional requirements for distance protection" published in March 2014, specifies the minimum requirements for functional and performance evaluation of distance protection relays, describes the tests to be performed and how to publish the test results. The relay should conform to above standard.
b. The protection should be fully numerical and be based on a non-switched scheme.
c. Provide protection for the transmission line from all types of faults-phase to earth faults as well as multiphase faults. The protection algorithm shall have dual redundant distance protection algorithms to detect all types of power system faults so as to arrive at a secure trip decision with correct phase selection and proper direction discrimination in the shortest possible time.
d. The protection should have non-switched measurement, which implies processing of six possible fault loops (six –loop measurement)
e. It should have polygonal characteristics with independently adjustable reactive and resistive reaches for maximum selectivity and maximum fault resistance coverage. The zones shall have independent settable earth fault compensation factors to cater to adjacent lines with different zero sequence to positive sequence ratios
f. Selection shall be so that the first zone of the relay can be set to about 80% - 85% of the protected line   without any risk of non-selective tripping.
g. The second and third zone elements shall provide backup protection in the event of the carrier protection or the first zone element failing to clear the fault, zone-2 shall cover full protected section plus 50 % of the next section, zone-3 shall normally cover the two adjacent sections completely.
h. It must have load encroachment features and must support blocking of the selected zones during heavy load condition.
i. It should have adequate number of forward zones (minimum three) and a reverse zone. The zone reach setting ranges shall be sufficient to cover line lengths appropriate to each zone. Carrier aided scheme options such as permissive under reach, over reach, & blocking and non-carrier aided schemes of zone 1 extension and Loss of load accelerated tripping schemes shall be available as standard. Weak in feed logic and current reversal guard also shall be provided.
j. In case the carrier channel fails, one out of the non-carrier based schemes cited above should come into operation automatically to ensure high speed and simultaneous opening of breakers at both ends of the line.
k. In addition to the conventional impedance measuring algorithm the distance protection relay should have a separate measuring technique in the same hardware completely different to the conventional impedance measuring principal. Both the algorithms should run in parallel and should take trip decisions independently.
l. Have a maximum operating time up to trip impulse to circuit breaker (complete protection time   including applicable carrier and trip relay time) with CVT being used on the line :
- • For SIR 0.01-4 : as 40ms at the nearest end and 60ms at the other end of   line
- • For SIR 4-15   : as 45ms at the nearest end and 65ms at the other end of line
- • With carrier transmission time taken as 20ms.
m. Have a secure directional response under all conditions, achieved by memory voltage polarizing and/or healthy phase voltage polarizing as appropriate.
n. Shall have an independent Directional Earth Fault (DEF) protection element to detect highly resistive faults. This element shall have an inverse time/definite time characteristic with a possibility to configure the DEF as a channel-aided DEF or a channel-independent DEF

o. Have logic to detect loss of single/two phase voltage input as well as three phase voltage loss during energisation and normal load conditions. The voltage circuit monitoring logic should in addition to blocking the distance protection element, enable an emergency overcurrent element to provide a standby protection to the feeder till the re-appearance of voltage signal.

- The VT fuse failure function shall function properly irrespective of the loading on the line. In other words the function shall not be inhibited during operation of line under very low load conditions.

p. Have necessary logic to take care of switch-on-to-fault condition. Energisation of transformers at remote line ends and the accompanying inrush current shall not cause any instability to the operation of relay.

q. The line protection IED should have power swing blocking feature, with facilities for :

    i.   fast detection of power swing
    ii.   selective blocking of zones
    iii.   Settable unblocking criteria for earth faults, phase faults and three phase faults.

r. Also the Distance protection IED should have following features in built in it.

- Suitable for single pole or three pole tripping.
- Shall have inbuilt CT supervision facility. A time-delayed alarm shall be issued if a CT open circuit is detected.
- Shall have inbuilt Trip circuit supervision facility to monitor both pre- and post close supervision facilities. An alarm shall be generated.
  Shall have inbuilt Circuit Breaker Failure protection based on undercurrent detection and/or circuit breaker auxiliary contact status and/or distance protection reset status. Provision shall be given to initiate the breaker fail logic using a digital input from external protection devices.
- Shall have inbuilt in broken conductor detection by measuring the ratio of I 2 & I1. The sensitivity of the logic shall not be affected during operation under low load.
- Shall have a fault locator with an accuracy of ±3%. The display shall be in kilometers, miles or percentage impedance. The fault locator should have built in mutual compensation for parallel circuit.

s. Be capable of performing basic instrumentation functions and display various instantaneous parameters like Voltage, current, active power, reactive power etc. in primary values. Additionally all sequence current and voltage values shall be displayed on-line. Also the direction of power flow shall be displayed.

t. The relay shall have a built-in auto-reclose function with facilities for single pole / three pole / single and three pole tripping. It shall be possible to trigger the A/R function from an external protection. A voltage check function which can be programmed for dead line charging/dead bus charging / check synchronising shall be included.

u. Records containing discrete data on the last five faults shall be made available. In particular the fault resistance value shall be available for each record.

v. Facility for developing customized logic schemes inside the relay based on Boolean logic gates and timers should be available. Facility for renaming the menu texts as required by operating staff at site should be provided.

w. The protection relay should have the following additional elements

i. Under / over voltage protection. The relay shall have two stages of voltage protections where each stage can be set as under/over voltage. The drop off/Pickup ratio can be set up to 99.5%.

ii. The relay shall have built in Circuit Breaker Supervision Functions for Condition based Circuit Breaker Maintenance
iii. The relay shall be able to detect any discrepancy found between NO & NC contacts of breaker
iv. The relay shall monitor number of breaker trip operations
v. The relay shall record the sum of the broken current quantity
vi. The relay shall also monitor the breaker operating time
vii. In all the above cases the relay shall generate an alarm if the value crosses the threshold value.

4.2.2 Numerical transformer differential relay

a. **General requirements for transformer protection scheme : The differential protection IED**
- The offered relay must be suitable providing complete protection for 2 winding transformer, 3 winding transformer and auto transformer
- **Category-A:** For 3 winding differential Protection, it must have 12 CT input, 3 for phase CT HV side, 3 for phase CT LV side, 3 for Phase CT TV side,1 for neutral CT HV, 1 for neutral CT LV, 1 for neutral CT TV.
- **Category-B:** For 2 winding differential protection, it must have 8 CT input, 3 for phase CT HV side, 3 for phase CT LV side, 1 Neutral CT HV side, 1 Neutral CT LV side.
- The relay must be suitable for providing low impedance REF protection for auto transformer.
- For 2 Winding transformer, 1 VT input and for 3 winding transformer 4 VT input are required.
- The protection function requirement for Transformer protection relays are as mentioned below,
- Differential protection (Low Impedance type with 3 slope characteristic)
- 2 elements of REF Protection for 2 winding transformer and must be selectable between Low Impedance and High impedance REF as per the site requirement's
- 3 elements of REF protection for 3 winding transformer and must be selectable between Low and High impedance REF
- REF protection for autotransformers.
- Backup Over current and Earth fault for each winding
- Thermal overload protection
- Over excitation protection
- Over and Under frequency protection
- CB Fail protection for each Winding (CT) input
- Shall be stable during magnetizing inrush and over fluxing conditions. Stabilization under inrush conditions shall be based on the presence of second harmonic components in the differential currents. The second harmonic blocking threshold shall be programmable one.
- Shall have facility to deactivate harmonic restraint and over fluxing restraint functions.
- Shall have saturation discriminator as an additional safeguard for stability under through fault conditions.
- The relay should be capable of detecting the CT saturation. Relay should use appropriate algorithm to detect light saturation condition.
- It shall be possible in the relay to individually set MVA rating of transformer per winding.
- Relay should have vector group and magnitude correction. Relay should have facility for filtering zero seq. current for stability of X-mer differential protection (87T) during through fault.

- Thermal overload protection as per IEC 60255.
- The relay shall have through fault monitoring element to monitor the HV, the LV or the TV winding to give the fault current level, the duration of the faulty condition, the date & time for each through fault.
- The relay shall have REF protection, be selectable separately for each winding and programmable as either high or low impedance. The REF function should be able to share CT's with the biased differential function. The REF protection provided should be suitable for auto transformer also.
- Shall have all output relays suitable for both signals and trip duties.
- Shall be stable during magnetizing inrush and over fluxing conditions. Stabilization under inrush conditions shall be based on the presence of second harmonic components in the differential currents. The second harmonic blocking threshold shall be programmable one.
- Shall have facility to deactivate harmonic restraint and over fluxing restraint Functions.

- Shall have saturation discriminator as an additional safeguard for stability under through fault conditions.
- Shall have software for interposing current transformers for angle and ratio correction to take care of the angle & ratio correction.
- Shall have all output relays suitable for both signals and trip duties.
- Shall have transient bias to enhance the stability of differential element during external fault condition.
- The relay should have combined harmonic blocking and restraint features to provide maximum security during transformer magnetizing inrush conditions

b.   **Functional Description.**
   i. Differential Protection:

- The relay shall be biased differential protection with triple slope tripping characteristics with faulty phase identification / indication. The range for the differential pick-up shall be from 0.1 to 2.5 pu. Its operating time shall not exceed 30 ms at 5 times rated current.
- The relay shall have adjustable bias slopes m1 from 0 % to 150 % and slope m2 from 15% to 150 % so as to provide maximum sensitivity for internal faults with high stability for through faults.
- The relay shall have an unrestrained highest element to back up the biased differential function and the setting range for it shall have a minimum setting of 5pu and a maximum setting of 30pu.
- The relay shall have the stability under inrush conditions. The ratio of the second harmonic component to the fundamental wave for the differential currents of the measuring system shall serve as the criterion.
- The device shall have reliable detection technique, preferably no gap detection technique to ensure stability during inrush. Any type of time delay is not acceptable to differentiate inrush and fault condition.
- The relay shall provide restraint for over fluxing condition for the transformer by measuring the ratio of the fifth harmonic to the fundamental for the differential current if subjected to transient over fluxing. The fifth harmonic blocking feature should have variable percentage setting.

 ii. Restricted Earthfault Protection (64 R)

This function should be provided to maximise the sensitivity of the protection of earth faults. The REF function should be selected separately for each winding

and programmable as either high or low impedance. The REF function should be able to share CT's with the biased differential function. As in traditional REF protections, the function should respond only to the fundamental frequency component of the currents. The REF protection provided should be suitable for auto transformer also.

iii. Over fluxing Protection (99 GT)

The relay shall over fluxing protection Volts/Hertz protection to the transformers protected. By pairs of v/f and t, it shall be possible to plot the over fluxing characteristics in the relay so that accurate adaptation of the power transformer Over fluxing characteristics is ensured. In addition the relay should have a definite time element for alarm. The reset ratio for over fluxing Protection shall be 98%.

iv. Overload Protection.

Shall have thermal overload protection for alarm and trip condition with continuously adjustable setting range of 10-400% of rated current

v. Overcurrent Protection (50,51)

The relay shall have three stages of definite time overcurrent protection as backup operating with separate measuring systems for the evaluation of the three phase currents, the negative sequence current and the residual current. In addition the relay shall have three stages of Inverse time overcurrent protection operating on the basis of one measuring system each for the three phase currents, the negative sequence current and the residual current.

vi. Over / Under frequency

The relay shall have four stages of frequency protections where each stage can be set as under/over frequence, under/over frequence with df/dt

vii. Over / Under Voltage

The relay shall have two stages of voltage protections where each stage can be set as under/over voltage. The adjustable drop off/Pickup ratio better than 97% should be available.

viii. Local Breaker Back up protection:

The relay shall in built LBB protection to detect the failure in the local breaker using the undercurrent criteria and trip the upstream breaker.

4.2.3: FEEDER MANAGEMENT RELAY

Protection and Control function requirements for feeder Management Relay.
• 	The Relay provides the following current based protection functions:
• 	Phase/Neutral/Ground instantaneous overcurrent
o 	Phase/neutral/ground time overcurrent
o 	Negative sequence Timed overcurrent
o 	Phase/neutral directional overcurrent
o 	Restricted Ground Fault (87REF)
o 	Breaker Failure (50BF)

- o   Thermal Model (49)
- o   Cold Load Pickup (CLP)
- •   The Relay provides the following voltage based functions:
- o   Phase Over and Under Voltage
- o   Neutral Over Voltage
- o   Directional Power
- o   Forward Power
- •   The Relay provides the following control functions:
- o   4 Shot Auto Reclose (79)
- o   VT Fuse failure (VTFF)
- o   Over/Under Frequency (81O/81U)
- o   Rate of change of Frequency (81df/dt)
- o   Synchrocheck (25)
- o   Breaker Failure (50BF)
- •   At least 5 user configurable commands for local and remote (Remote through   SCADA on MMS)
- •   Configurable one line diagram for the substation bay
- •   The relay should have 2 switchable setting groups for dynamic reconfiguration of the protection elements due to changed conditions
- •   Programmable LOGIC
- •   Relay supports user defined logic to build control schemes supporting logic gates, timers, nonvolatile latches.
- •   The Relay configuration tool has an embedded graphical user interface to build programmable logic.

Front-Panel Visualization

- •   The front panel includes user-programmable LEDs and pushbuttons and navigation keys.
- •   For bay information that includes user programmable screens for:
- o   One line diagram displaying
- o   Switchgear operation
- o   Access to metering information
- o   Alarm panel display.
- o   I/O status display.
- o   Relay settings

4.2.4 BACKUP RELAYS (Current Protection).

The combined overcurrent and earth-fault relay is connected to the current transformers of the object to be protected. The overcurrent unit and the earth-fault unit continuously measure the phase currents and the neutral current of the object. On detection of a fault, the relay will start, trip the circuit breaker, provide alarms, record fault data, etc., in accordance with the application and the configured relay functions.

i. Functional description:

(a) Three-Phase Overcurrent (50/51) & Earth Overcurrent (50N/51N)

Three independent stages are available either for phase and earth fault protection. For the first and second stage the user may independently select definite time delay (DTOC) or inverse time delay (IDMT) with different type of curves (IEC, IEEE/ANSI, IS 3231:1987).

(b) Three-Phase & Earth-Fault Directional Overcurrent (67/67N)

Each of the three-phase overcurrent stages & earth fault stages can be independently configured as directional protection and with specific characteristic angle (RCA) and boundaries as per IEC, IEEE/ANSI,IS . The phase fault directional elements should be internally polarised by quadrature phase to phase voltages. A synchronous polarising function or any other suitable algorithm may be provided to ensure a correct operation of the overcurrent elements for close-up three phase faults where the collapse of the polarising line voltages occurs.

(c)Under / Over Voltage (27/59)

Independent under-voltage stage and two or more over-voltage stages may be provided. They should be definite time elements. Each stage can be configured to operate from either phase-neutral or phase-phase voltages. The drop off to pick up ratio should be 99.5%.

(d) Under / Over Frequency (81U/O)

Time delayed under and over frequency protection on the fundamental form of frequency protection is to be provided When the frequency measured is crossed 6 pre-defined thresholds, the relays should generate a start signal and after a user settable time delay, a trip signal.

(e) Circuit Breaker Failure Protection (50BF)

The circuit breaker failure verifies the effective opening of the CB by a dedicated undercurrent threshold. The circuit breaker failure function can be activated by trip of a generic protection or/and external command by the relevant digital input. The circuit breaker failure protection can be used for tripping upstream circuit breakers too.

4.2.5 BUS BAR PROTECTION:

Bus bar protection schemes shall be provided for each main and transfer bus of 400 KV and 200 KV provided in the switch yard. This shall constitute main and check features. The overall scheme shall be engineered such that operation of both main and check features connected to the faulty bus shall result in tripping of the same. The scheme shall be provided with necessary expansion capacity and interfaces for adding features when the switch yard is extended in future to its ultimate capacity. The bus bar relay shall be of latest numerical relay having IEC protocol 61850 compliance.

(a) Bus-bar protection (Latest version numerical having IEC-61850 protocol compliance)

Bus bar protection schemes shall be provided for each main bus of 400kV and 220kV switchyard. The overall scheme shall be engineered so as to ensure that operation of any one out of two schemes connected to main faulty bus shall result in tripping of the same. However in case of transfer bus, where provided, only one bus-bar protection scheme shall be required.

(b) Each bus-bar protection scheme shall:

1.   Be of modular construction and have features of self-monitoring facility to ensure maximum availability of scheme. The scheme shall be Numerical based.

2.   Have maximum operating time up to trip impulse to trip relay for all types of faults of 15 milli seconds at 5 times setting value.

3. Operate selectively for each busbar.

4. Give hundred percent security up to 40kA fault level.

5. Incorporate a check feature.

6. Incorporate continuous supervision for CT secondary against any possible open circuit and if it occurs, shall render the relevant zone of protection inoperative and initiate alarm.

7. Not give false operation during normal load flow in bus-bars.

8. Incorporate clear zone indication.

9. Be of phase segregated and triple pole type and provide independent zones of protection for each bus (including transfer bus if any). If a bus section is provided then each side of the bus section shall have separate bus-bar protection scheme.

10. Include individual high speed hand reset tripping relays for each feeder, including future ones.

11. Be of low/medium impedance biased differential type and have operate and restraint characteristics.

12. Be transient free in operation

13. Include continuous DC supplies supervision.

14. Shall include multitap auxiliary CT's for each bay including future bays as per SLD and also include necessary CT switching relays wherever CT switching is involved.

15. Include protection 'in/out' switch for each zone with at least six contacts for each switch.

16. Shall have CT selection incomplete alarm wherever CT switching is involved.

17. Have necessary auxiliary relays to make a comprehensive scheme.
    At existing substations bus-bar scheme with independent zones for each bus will be available. All necessary co-ordination for 'CT' and 'DC' interconnections between existing schemes (panels) and the bays proposed under the scope of this contract shall be fully covered by the bidder. Any auxiliary relays, trip relays, flag relays required to facilitate the operation of bays covered under this contract shall be fully covered in the scope of the bidder.

4.2.6 TIME SYNCHRONIZATION EQUIPMENT FOR SUBSTATION

The Bidder shall offer necessary time synchronisation equipment complete in all respects including antenna, all cables, processing equipment etc. required to receive co-ordinated universal time (UTC), transmitted through GEO Positioning Satellite System (GPS).

The time synchronising system should be compatible for synchronisation with event loggers, disturbance recorders, relays, computer systems and all other equipment provided in the protection, control and metering system of the substation wherever required.

Equipment should operate up to an ambient temperature of 50C and 100% humidity. The synchronisation equipment shall have two microsecond accuracy. Equipment should give real time corresponding to IST (taking into consideration all factors such as voltage and temperature variations, propagation and processing delays etc.

Equipment should meet the requirement of IEC 255 for storage and operation. The system should be able to track the satellites to ensure no interruption of synchronisation signal.

The output signal from each port shall be programmable at site for either one hour, half hour, minute or second pulse, as per requirement.

The equipment offered shall have six output ports. Various combinations of output ports shall be selected by the Project Manager, during detailed engineering, from the following:

1.   Voltage signal : 0-5V continuously settable, with 50 ms. minimum pulse duration.
2.   Potential free contact : minimum pulse duration of 50 ms
3.   IRIG-B & SNTP
4.   RS232C

The equipment should have a periodic time correction facility of one second periodicity.

Time synchronisation equipment shall be suitable for operation from 220V DC as available at substation with a voltage variation of +10% and -20%. Any other power supply that may be required for proper functioning of the equipment shall be derived by the Bidder from his own equipment which shall form an integral part of the system.

Equipment shall have real time digital display in hour, minute, second (24 hour mode) and have a separate time display unit to be mounted on the top of panels having display size of approximately 100 mm height.

4.2.7 No. of Devices in different protection panels:

(a) Line Feeder Protection Panel

The line protection panel or panels may be a single panel or more panels to accommodate all the equipment listed below.

		Quantities required			
SI. No	Equipment	400kV	220kV	132kV	33kv
1	Main-I protection scheme (composite numerical distance protection relay with auto reclosing and check syncronising facility)	1 set	1 set	1 set	Not required
2	Main-II protection scheme(composite numerical distance protection or phase comparision relay with auto reclosing and check syncronising facility)	1 set	1 set	Not required	Not required
3	Composite numerical directional & or non-directional over current and earth fault relay.(selectable Features Dir & Non Dir)	1 set	1 set	1 set	1 set
4	Over voltage/ Under voltage/Frequency protection scheme (if not available in the main-I& II and Back-up protection relay)	1 set	1 set	1 set	1 set
5	Selector switch for carrier in/out for main-I and main-II protection scheme	2 Nos.	2 Nos.	1No.	Not required
7	Disturbance recorder (if not available in the	1 set	1 set	1 set	1set

	main-I& II and Back-up protection relay)				
8	Distant-to-fault locator for phase and earth faults(if not available in the distance protection or main protection module)	1 set	1 set	1 set	Not required
9	CVT/VT selecting relays or switches (depending on switching scheme)	1 set	1set	1set	required for two bus scheme
10	Test terminal blocks for Main-I/ Main II/other protection relay	1 set for each module	1 set for each module	1 set for each module	1 set for each module
11	Auxiliary relays for carrier supervision of Main-I and Main II protection relays (depending on its application)	1 set	1 set	1 set	Not required
12	Carrier receive lockout relay (depending on its application)	1 set	1 set	1 set	Not required
13	Breaker failure protection scheme (if not available in the main-I& II and Back-up protection relay)	1 set	1 set	1 set	1 set
14	Trip circuit pre and post supervision relays for trip coil I and II	1 set	1 set	1 set	1 set
15	DC and AC supply supervision relay	1 set	1 set	1 set	1 set
16	Electrical reset relays for circuit breaker trouble shooting	1 set	1 set	1 set	1 set
17	Trip relays single/three phase for group-A	1 set	1 set	1 set	1 set
18	Trip relays single/three phase for group-B	1 set	1 set	1 set	1 set
19	Trip relays single/three phase for LBB	1 set	1 set	1 set	1 set
20	Under Frequency Relay(in built feature of O/C & E/F relay)	1 set	1 set	1 set	1 set
21	Numerical Bay Control Unit of adequate BI, BO, Transducers etc as per the site requirement & detailed Engg. done.	1 No	1 No	1 No	* 1 No * BCPU can be considered.

(b) Transformer Protection Panel:
The transformer protection panel or panels may be a single panel or more panels to accommodate all the equipments listed below.

Sl. No	Equipment	Quantities required		
		For each High Voltage panel of 400/220kV and 220/132kV transformers	For each High Voltage panel of 220/33kV and 132/33kV transformers	For each Low Voltage Panel of transformers
1	Main-I Transformer composite numerical protection comprising of the following: • Differential protection • Restricted earth fault protection • Over fluxing protection	1 set	1 set	Not required
2	Main-II Duplicated numerical protection as Main-I	1 set	Not required	Not required
3	Composite numerical directional over current and earth fault protection relay(selectable Features Dir & Non Dir)	1 set	1 set	1 set
	Numerical Restricted earth fault protection (high impedance with Stabilising resistor & metrosil)	2 set	1 set	1 set
4	Over load protection (if not included in sl.no. 1 ,2 & 3 above)	1 set	1 set	1 set
5	Over voltage / Under voltage/Frequency protection scheme (if not available in the main protection & back-up protection module)	1 set	1 set	1set
6	Auxiliary relays for thermal imaging, MOG, WTI, OTI, Bucholz, PRV, OSR and status indication etc.. (1.MOG-Al, 2.WTI,BUCH,OTI – Al & Trip,3. PRV,OSR – Trip)	1 set	1 set	Not required
7	CVT/PT selection relays (depending upon the switching scheme of the system)	1 set	1 set	1 set
8	Breaker failure protection scheme (if not available in the main protection & back-up protection module)	1 set	1 set	1 set

9	Trip circuit pre and post supervision relays for trip coil I and II.	1 set	1 set	1 set
10	DC / AC supply supervision relay	1 No for each panel	1 set	1 set
11	Aux relays for circuit breaker trouble shooting	1 set	1 set	1 set
12	Trip relays three phase for group-A	1 set	1 set	1 set
13	Trip relays three phase for group-B	1 set	1 set	1 set
14	Test terminal blocks for all protection relays	1 set for each module	1 set for each module	1 set for each module
15	Numerical Bay Control Unit of adequate BI, BO, Transducers etc as per the site requirement & detailed Engg. done.	1 No	1 No	* 1 No * BCPU can be considered.

(c) Transfer bus coupler / Bus coupler and Busbar protection panel

Bus bar protection panel shall be equipped to accommodate all present and future bays.

Sl. No	Equipment	Quantities required			
		400kV	220kV	132kV	33kv
1.	Composite numerical Directional Over current and earth fault protection (selectable Features Dir & Non Dir)	1 set	1 set	1 set	1 set
2.	Test terminal block for all protection relays	1 set for each module	1 set for each module	1 set for each module	1 set for each module
3.	Trip circuit pre and post supervision relays for trip coil I and II	1 set	1 set	1 set	1 set
4.	DC supply supervision relay	Not required	1 set	1 set	1 set
5.	Flag relays for circuit breaker trouble and status indication etc.	Not required	1 set	1 set	1 set
6.	Breaker failure protection scheme	Not required	1 set	1 set	1 set

7.	Trip relays single/three phase for group-A	Not required	1 set	1 set	1 set
8.	Trip relays single/three phase for group-B	Not required	1 set	1 set	1 set
9.	Numerical Bus bar differential relay for Bus-I & Numerical Bus bar differential relay for Bus-II and Numerical Bus bar differential relay for Transfer Bus (if required depending on the Bus configuration) having check zone features with SCADA compatibility.	1 set	1 set	Not required	Not required
10.	Numerical Bay Control Unit of adequate BI, BO, Transducers etc as per the site requirement & detailed Engg. done.	1 No	1 No	1 No	* 1 No * BCPU can be considered.

(d) Bus sectionalizer protection panel

Sl. No	Equipment	Quantities required
1.	Composite numerical directional Over current and earth fault protection relay(selectable Features Dir & Non Dir)	2 sets
2.	Test terminal block for all protection relays	1 set or as required
3.	Trip circuit pre and post-supervision relay for trip coil I and II	2 sets or as required
4.	DC supply supervision relay	1 set or as required
5.	Aux relays for circuit breaker trouble and status indication etc.	1 set or as required
6.	Breaker failure protection scheme (if not available in the back-up protection relay	1 set or as required
7.	Trip relays three phase for group-A	2 set
8.	Trip relays three phase for group-B	2 set
9.	Bus bar differential relay for Bus-I (numerical type- IEC -61850)	1 set
10.	Bus bar differential relay for Bus-II (numerical type- IEC -61850)	1 set

NOTE: Any other protection device/relays/equipment besides above required to complete the scheme are also required to be considered. The SAS shall be in the PRP based.

4.2.8 RELAY TEST KIT:

(a) One relay test kit of OMICRON make (latest model) suitable for conducting testing of protection devices with different techniques, report preparation, memory etc duly adopted to be provided. (Optional)

(b) Other tools as required for testing, attending to the troubles in the panel, suitable screwdriver set, nose plier/plier set, cutter, soldering kits, testing cords, etc: 3 Sets

(c)Test plugs: 2 set.