TECHNICAL SPECIFICATION FOR SUB-STATION AUTOMATION FOR SIXTEEN NUMBERS OF 220/&, 132/33kV GSS OF ODISHA POWER TRANSMISSION CORPORATION LIMITED.

(SECTION-IV)

The Substation Automation System (SAS) is proposed for sixteen numbers of 220/33kV and 132/33kV of OPTCL with yard AC Kiosk arrangement. The substation automation system proposed is BCU based distributed architecture type. The typical architecture for SAS envisaged is as depicted in enclosed Architect drawing.

The substation automation will be provided with following protection and automation panel arrangement.

A. Control & Protection panel placed in the switchyard air condition Kiosk. The network and gateway panel will be installed in SAS control room.

Sl.	Name of Substation
1	132/33kV GSS,BHUBANESWAR
2	132/33kV GSS,SUNABEDHA
3	220/33kV GSS,NAYAGARH
4	132/33kV GSS,KHURDA
5	132/33kV GSS,CHAINPAL

B. Replacement of old Control & Protection panel with new panels with BCU will be placed in control room.. The network and gateway panel will be installed in SAS control room.

Sl.	Name of Substation
1	132/33kV GSS,RAIRANGPUR
2	132/33kV GSS,DHENKANAL
3	132/33kV GSS,PURI

C. Retrofitting of BCU in the existing Control & Protection panels. This will be adopted in new substations where IEC 61850 compliant IEDs are avaialable. The network and gateway panel will be installed in SAS control room.

Sl.	Name of Substation
1	132/33kV GSS,PHULNAKHARA
2	132/33kV GSS,CHANDPUR
3	132/33kV GSS,KHARGPRASAD
4.	132/33kV GSS,RANSINGPUR
5	132/33kV GSS,BANKI
6	132/33kV GSS,JHARSUGUDA

7	132/33kV GSS,KHAJURIAKATA
8	220/33kV GSS,LAXMIPUR

Automation System (SAS) shall be installed to control and monitor all the sub-station equipment & functions from Substation Control Room & Network control centre (NCC). The general description of SAS proposed for sixteen numbers of substation is as follows.

1. GENERAL:

The IED and Automation system for the project should be complied with latest edition of IEC 61850 and cyber security p such as NERC CIP, IEEE1686 & IEC62351-8.

1.1 The SAS functional parts:

- Bay Control Unit (BCU), Intelligent Electronic Devices (IEDs) for protection, control and monitoring.
- Industrial grade Redundant Station Human Machine Interface (HMI) with industrial grade servers.
- Redundant managed switched Ethernet Local Area Network communication infrastructure with hot standby.
- Redundant Gateway for remote monitoring and control via industrial grade hardware (to RCC) through Secure IEC 60870-5-104 protocol. There will be at least 3 RCCs.
- Redundant Gateway for remote monitoring and control via industrial grade hardware (to RSCC), the gateway should be able to communicate with RSCC on IEC 60870-5-104 protocol. It shall be the bidder's responsibility to integrate his offered system with existing SLDC system for exchange of desired data. The bidder shall also have the responsibility to integrate the system to RCC when it comes up in OPTCL system. The gateway system should have capability of transferring meter data for energy management.
- DR / Engineering PCs, as specified.
- Peripheral equipment like printers, display units, key boards, Mouse etc.
- Redundant power supply for Automation system.

1.2. Capabilities.

The Automation System should cover all the needs of a sub-station

- The control functions ;
  - Control of primary and secondary devices,
  - Internal automation,
  - Monitoring of control check parameters,
  - Locking of switching devices,
  - Generic control for specific actions,
  - Control of transformer tap changers,

        - Monitoring of interlock logics,
- The protective functions;
    - Protection of Lines,
    - Protection of Transformer,
    - Protection of Reactors,
    - Protection of Capacitor Banks,
- The fault and disturbance recording:
    - Settings configuration and modification,
    - Downloading of automatic disturbance record,
    - Automation parameters modification,
    - Event recording.
- The monitoring functions;
    - Manage condition monitoring data acquisition
    - Control and alarm management of condition
    - monitoring functions
    - Historian database management
    - Single-line diagram, topological view, substation
    - and bay levels, auxiliary systems and sub-systems
    - Full graphical representation of switching devices, analogue values, process information.
    - Display of automatisms state
    - Manage real-time and historical alarms with different list formats
    - Manage real-time and historical events with different list formats,
    - Secondary device supervision using SNMP

1.3. Communication.

The communication gateway shall facilitate the information flow with remote control centres..

1.4. Security.

The Sub-station Automation system being offered shall generally conform to cyber security standards such as NERC CIP, IEEE1686 & IEC62351-8

2. SYSTEM DESIGN:

The present substation switchyard configurations is provided in attached Single Line diagrams.

The protection arrangements for 220kV,132 & 33kV system for up coming SAS should be as envisaged below.

2.1. 220kV System.

i) **Line bay**: The line bay will have one Bay controller Unit (BCU), two distance protection with current, voltage and frequency protections IEC 61850 protocols should be available for full system integration. The carrier supervision function will be performed by Bay Controller Unit. Auxiliary relays are to be provided for DC supervision & trip circuit supervision.

ii) **Each Power transformer bays** : The transformer bay will have Bay controller Unit(BCU),one differential protection, and one backup over Current & earth fault relay. IEC 61850 protocols should be available for full system integration. The Over current earth fault relay should have adequate input & out put contacts for transformer trouble functions. Two REF relays (for HV & LV) of type CAG 14 or equivalent should be provided. The OLTC raise lower function & cooler control function will be performed by Bay Controller Unit. Auxiliary relays are to be provided for DC supervision, transformer trouble & trip circuit supervision. The differential relay should also in built REF protection .

iii) **Bus Coupler bays** : Each bay will have Bay controller Unit(BCU), backup over Current & earth fault relay. IEC 61850, protocols should be available for full system integration.

All numerical relays & Bay Control Unit should have PRP protocol and PTP time synchronisation compliant.

2.2. 132kV Side:

i) Line bay: The line bay will have one Bay controller Unit (BCU), one distance protection, one backup over Current & earth fault relay. IEC 61850 protocols should be available for full system integration. The carrier supervision function will be performed by Bay Controller Unit. Auxiliary relays are to be provided for DC supervision & trip circuit supervision.

ii) Each transformer bays : The line bay will have Bay controller Unit(BCU),one differential protection, and one backup over Current & earth fault relay. IEC 61850 protocols should be available for full system integration. The Over current earth fault relay should have adequate input & out put contacts for transformer trouble functions. Two REF relays of type CAG 14 or equivalent (for HV & LV)should be provided. The OLTC raise lower function & cooler control function will be performed by Bay Controller Unit. Auxiliary relays are to be provided for DC supervision & trip circuit supervision. .

iii) Bus Coupler bays : Each bay will have Bay controller Unit(BCU), backup over Current & earth fault relay. IEC 61850, protocols should be available for full system integration.

All numerical relays & Bay Control Unit should have PRP protocol and PTP time synchronisation compliant.

2.3 33kV Side:

Each bay should be provided with on Bay controller & protection Unit (BCPU). The unit should be capable of protection, measurement , control & record .IEC 61850 protocols should be available for full system integration. The all numerical relays & Bay Control Protection Unit should have PRP protocol.

The BCPU should be capable of following feeder protection functions.

- Current protection (50/50N,51/51N,67/67N)
- Voltage function (59,27)
- Frequency Protection (81 U,81 O, 81R)
- Direction Power Protection (32)
- Monitoring & measurement function should be available.

2.4. **Substation Auxiliary** : Station auxiliary such as Dc supply system , Ac supply system, Substation lighting , Substation Air condition & fire fighting will be monitored by one Bay control Unit (BCU) provided for Auxiliary system monitoring & Control.

2.5. **Substation Automation System**: It shall enable local station control as well as remote control from NCC (Network Control Centre) by means of human machine interface (HMI) and control software package, which shall contain extensive range of Supervisory Control and Data Acquisition (SCADA) functions. HMI must be capable of handling all the future equipment over and above present scope of equipment supply. It shall include communication gateway, intelligent electronic devices (IED) for bay control and inter IED communication infrastructure. An **architecture drawing for SAS** is annexed. The panels equipped with IEDs, BCUs & supervision relays along with its LIU & Ethernet Fibre switches for 132kV bays (unless specified otherwise) can be housed in one Kiosk and another one for 33KV bays.

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2.6. **Communication: Gateway** to be provided for remote control & monitoring from NCC (Network Control Centre) and data transfer to SLDC through IEC60870-5-104 protocol. The protection coupler in OPGW network will be installed in Kiosk/Control room. The communication between Distance protection IED & Protection coupler should be through goose messaging. In this project the protection carrier equipment is not in the scope.

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

The bidder shall be Original Equipment Manufacturer (OEM). IEC 61850 & PRP compliant KEMA certified Bay Control Units, Numerical Protection relays, Gateways & managed Ethernet fibre switches . The offered equipment have to be designed, manufactured and tested as per relevant IS/IEC with latest amendments. The bidder 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 bidders should fulfil 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 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 in 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 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.
1	2	3	4	5	6	7	8

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 :

This specification covers technical, functional, configuration and testing requirements for a substation automation system for extra high voltage (EHV) substations with 400kV,220kV,132kV and 33kV buses respectively.
The substation automation system shall be digital and shall include control, protection, monitoring, measurement functions and tele-transmission of data and commands.

The Substation Automation System (S.A.S) for EHV substations, is to be used for the control, protection and supervision of new/existing Air insulated (AIS) 400/220/132/33KV EHV substations of OPTCL.

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.

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 are applicable based on system design 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 telecontrol 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 0 C to +55°C

b. Ambient temperature during storage : -5 0C to +55°C

c. Relative humidity : 5% - 95%

d. Altitude level:

IV. SUPPORT DOCUMENTS

This substation automation system for EHV substation shall be designed for selected AIS substation of OPTCL with the instructions contained in this technical specification and with the information provided in the following documents, which will be made available on inquiry.

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
- Bay Relay & BCU kiosks will be planned as per requirement.

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 control center (TCC) 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 (if required), voltage relays, Over flux & frequency relays.

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 up to 100000 data points and integration of at least 250 IEDs in single ring.

13. It should support up to 4 high resolution screen

A. <u>Control of the EHV substation</u>

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 network control center (NCC)
e. The commands will be issued each time only from one control place excluding at 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.
c. Earthing Switches of the 400KV Dis-connectors (If it is required.)

d. Mechanism of increase, decrease and emergency stop of the step of the tap changer (OLTC) of the autotransformers, power transformers (if it is required).
e. 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 TCC (Transmission Control Centre) remote control centers.

B. <u>The supervision of the substation shall include the following:</u>

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 control center (TCC).
9. The substation automation system shall allow supervision of the transformer bay circuit beakers and disconnectors & 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 centres.

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:

- IEC 60870-5-104
- 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

PLCC panels /end equipment of OPGW for tele-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 type of existing 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 : 1½ Breaker system.
iv. 220kV : Two Bus system with transfer Bus.
v. 132kV : Main and Reserve bus arrangement.
vi. 33kV : Main and Reserve bus arrangement /Single Bus

The Remote operation and monitoring of control & protection system of above type of substation as mentioned in the Schedule A is to be executed by replacement / modification of existing equipment/relays as specified in the schedule. The existing relays of substations conforming to IEC61850 standard, if found suitable will be retained.

The objective of the above work is as follows.

a. The operation & monitoring of control & protection system is as per SLD and conforming to technical standard envisaged in CEA regulation-2010 for Technical Standard construction of Electrical Plant & Transmission line.
b. DC & AC system LT Panel Boards for above SAS but excluding battery chargers
c. On line capturing & monitoring of Transformer local readings & protection.
d. All the local control & protection at the sub station for its remote operation from MCC shall be substituted by bay controller and SCADA.
e. 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.

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

g. If asked, optional price shall be submitted for 7 years AMC for remote control and protection of equipment and no down time is permitted except for tripping on faults.

h. List of optional spares for above stated scope shall be furnished separately along with prices however it will not be part of evaluation.

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

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

k. 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.

l. 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.

m. Relay settings and coordination is part of scope. The setting will be as per the approved philosophy adopted by OPTCL

n. Local existing DC and AC system at Main Sub Station can be used, but it is bidder's responsibility to verify before bidding.

o. Any other local input requirement at Main Sub Station must be clearly specified by bidder.

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) relay and protection panels should be housed in air-conditioned Kiosks suitably located in switchyard.
- PLCC panels are to be located in PLCC room near Control Room/Bay Kiosk as per suitability. The proposal to be submitted by bidders after examining the site.
- The station HMI & DR Work station should be located in Control Room building connecting bay level unit through optical cables 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 beconsidered.

- 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 ofthe 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 thisregard.
- 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. inside the kiosk shall be connected to Ethernet Fiber Switch EFS through fiber optic / Ethernet cable to be selected based on system design requirement with PRP (Parallel Redundancy Protocol) configuration.

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 for 33kV system.

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.

The data exchange between the electronic devices on bay and station level shall take place via the communication infrastructure. This shall be realized using fiber-optic cables, thereby guaranteeing disturbance free communication. The fiber optic cables shall be run in separate HDPE ducts of suitable size. Ducts are to be tied on cable trench at a regular distance of 2 meters.

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 shall not affect the normal operation of the SAS. However it shall be alarmed in SAS. Each fiber optic cable shall have spare fibers in ring topology.

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 yard BCU and PLCC panel BCU should work on IEC 61850 protocols through GOOSE concept.

The Bay Units (BU) for Bus-bar protection should be separately provided in each bay panel. The Central Unit (CU) should be placed in panel kiosk defined for Bus Bar protection. CUs shall have connectivity to IEC 61850 ring topology. In case of the substation where numerical IEC61850 compatible Bus bar protection are in operation the same should be integrated to the SAS system through IEC61850 ring topology.

Separate BCU is to be used for each bay of 400 kV, 220 kV & 132kV level and BCPU shall be provided for 33kV system. The no of control & protection panel for different voltage level shall be provided as per the description below.

System:	Dimension & number of Simplex Cubicle type for process bus equipment , Swing frame front access (VSG),
400kV Line.	2300mm (H) X 900mm (D) X 900mm (W), 2 Nos. per line
400kV ICT	2300mm (H) X 900mm (D) X 900mm (W), 1No. per ICT
400kV TIE	2300mm (H) X 900mm (D) X 900mm (W), 1 No. per Tie.
220kV Line	2300mm (H) X 900mm (D) X 900mm (W), 1 No. per line
220kV AT/Transf.	2300mm (H) X 900mm (D) X 900mm (W), 1 No. per Trfr.
220kV BC/TBC	2300mm (H) X 900mm (D) X 900mm (W), 1 Nos. per BC/TBC
132kV Line	2300mm (H) X 900mm (D) X 1000mm (W), 1 No. per 2 line
132kV AT/Transf.	2300mm (H) X 900mm (D) X 1000mm (W), 1 No. per 2 Trfr.
132kV BC/TBC	2300mm (H) X 900mm (D) X 1000mm (W), 1 Nos. per 2 bays.
33kVLine/Trfr/BC	2300mm (H) X 900mm (D) X 900mm (W), 1 No. per 3 feeders.

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. This shall give alarm if 70% memory is full. 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:

- 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.
- Weekly trend curves for real and derived analogue values.
- 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.
- Provision shall be made for logging information about breaker status like number of operation with date and time indications.
- Equipment operation details shift wise and during 24 hours.
- 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.
- Printout on adjustable time period as well as on demand system frequency and average frequency.
- 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 gateways perform the communication interface between the electrical substation and the area dispatch centres (SCADA), allowing SCADA operators to control and monitor remotely the substation in coherence with the operation of the whole area of the electrical grid. The main functions of the Gateway are to transmit: substation indications, measurements, disturbance records, metering data, and substation events to the remote centres & remote centres commands to the substation control system.

This role is performed within the structure of the Energy Management System (EMS) of the overall grid.

The Gateway shall be offered from the OEM manufacturer. The OEM manufacture must have three years of experience in designing, manufacturing, testing and commissioning of Gateways for 132kV system or higher as on the date of bid opening.

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 Crypto-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 Gateway should be capable of controlling & monitoring though its' processor & I/O modules substation auxiliaries such as Station DC , Station AC, Air Conditioning, Substation lighting , fire fighting system etc.

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

h) The gateway shall be capable of sending and receiving metering data.

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

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

k) 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.

l) Communication ports shall supported PRP on board for IED communication.

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

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

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

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

q) 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.

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

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

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. Remote /Master Control Centre Communication (NET WORK CONTROL CENTERS) Interface

Communication channels between the Substation Automation System and the master control center (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 center (NCC).
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.

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 20% spare capacity for employer use such as metering information.

Kiosk arrangement: One switch shall be provided to connect all IEDs housed in respective kiosk
Control room arrangement: One switch shall be provided to connect all IEDs of Two bays of 220 & 132kV. For 33kV multiple bays may 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/ control room..

b) **Interfacing:**

All bay control units shall contain an optical-fiber / RJ 45 interface for connection to the HMI over IEC 61850 Protocol and a RS 232 serial interface for connection to a PC.
All optical-fiber / Ethernet cables 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 1.5 mm^2 (that is from the terminal blocks to and from the switchyard equipment) except for the VTs and CTs circuits, which utilize cables of $4mm^2$ 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 ST/LC connectors & Ethernet electrical RJ 45 connector inPRP 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:	IEC 61850-8-1.
4.	Time synchronisation :	External Time Synchronization from IRIG B BNC plug, Amplitude modulated/ Ethernet SNTP Time Server (<1ms accuracy)
5.	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 : 28 Nos. for 132kV & 220kV System and 48 Nos. for 400kV System. Operating Volt: 220V DC. (Max.300V)
6	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(for Transformer Application) : 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/CVT direct 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. No. of out put relays : 24 Nos. for 132kV System. 24 Nos. for 220kV and 32Nos. for 400kV system. 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.
10	Trip Circuit Supervision	:Supervise trip circuits for both the conditions of Breaker.
11	Event Logging	:Storage of events up to 2000 in ROM.
12	Disturbance files & wave forms	: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 list with 20% extra for Capacities each bay.
17	Internal Ethernet	:4 X 10/100 Base T (RJ-45) ports+2X10/100 Base Switches Fx (optical) ports for redundant Ethernet network in PRP.
18	Additional ports	:1 X RS232 and 3 X RS485 can support IEC 103 Modbus, should be s/w configurable.
19	Environmental conditions :	:Operating temperature: -5°C to + 70°C Storage temperature: -5°C to + 70°C Humidity: 5 to 95 % (Non-condensing
20	Mounting & design	:Flush or Rack fitting 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
	Number of Wires	2 Wires Plus Ground

	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 SPECIFICATIONS	Battery Type	Sealed, Maintenance-Free (AGM) battery, (Optional Long Life Battery)
	Expected Life	10 Years
	Charger Ampacity	$\leq$ 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 :

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 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 and Radiated) Test.
   viii. Surge Immunity Test

f. Contact performance Test
   i. Contact making/Breaking capacity test
   ii. Continuous capacity
   iii.

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 guaranteed availability and reliability.
- Calculation for power supply dimensioning.

- I/O Signal lists.
- Schematic diagrams.
- List of Apparatus.
- List of Labels.
- Logic Diagram (hardware & software).
- Kiosk layout drawing.
- GA of kiosk and GTP.
- 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 Contractor. 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 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 has 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 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

The guarantee for all auxiliary items supplied should be guaranteed for trouble free service for the period as mentioned in the Guarantee clause.

XXIII. TRAINING, SUPPORT SERVICES, MAINTENANCE AND SPARES

A. TRAINING

The contractor shall impart training for one batch of engineers of OPTCL at each location 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 equipment.

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 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

<u>Outage terms</u>

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.

XXV. COMMISSIONING

The commissioning of the system shall be carried out by the supplier of the system, therefore the cost of the commissioning of the system must be included in the economic offer.

XXVI. Specification of SAS project items are attached herewith.